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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

GAS TRANSMISSION AND STORAGE POLICY

[NO REBUTTAL TESTIMONY]
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
REBUTTAL TESTIMONY OF SUMEET SINGH
SUMMARY OF 2019 GT&S RATE CASE

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Sumeet Singh. This testimony responds to the direct testimony
of the Office of Ratepayer Advocates (ORA),\textsuperscript{1} The Utility Reform Network
(TURN),\textsuperscript{2} Indicated Shippers and Northern California Generation Coalition
(IS/NCGC),\textsuperscript{3} Indicated Shippers (IS),\textsuperscript{4} Calpine, and California State
University (CSU).\textsuperscript{5} Pacific Gas and Electric Company (PG&E) summarizes
parties' positions in Section B, below.

B. Summary of Policy Rebuttal Testimony

Q 2 Please provide a summary of parties' policy positions to which you will be
responding.

A 2 This testimony responds to parties' testimony concerning the following
issues: (1) the affordability of PG&E's revenue and rate requests in this
case; (2) proposals to create, modify and discontinue balancing and
memorandum accounts; (3) proposals for mitigating the rate impacts of
recovering decommissioning and depreciation costs for Los Medanos and
Pleasant Creek; (4) whether to combine the Gas Transmission and Storage
(GT&S) Rate Case and PG&E's General Rate Case (GRC); and (5) TURN's
recommendations to disallow over $500 million in prudent investments and
operating expenses.

C. Affordability

Q 3 Did any parties comment specifically on the affordability of PG&E's revenue
requirement and rate requests in this GT&S Rate Case?

\textsuperscript{1} ORA-01, ORA-05, ORA-07, ORA-14B/C and ORA-21.
\textsuperscript{2} TURN, Chapter 1, Chapter 5A, Chapter 7.
\textsuperscript{3} IS/NCGC-1.
\textsuperscript{4} IS-1.
\textsuperscript{5} CSU-1.
Yes. Both TURN and IS/NCGC addressed affordability in their respective testimony.

Please describe TURN’s testimony related to affordability.

To summarize briefly, TURN states that the California Public Utilities Commission (CPUC or Commission) needs to balance affordability and safety when evaluating PG&E’s request in this case, and that PG&E has failed to justify its requests for funding for various programs by showing optimal safety improvement in relation to the dollars spent.6

What is your response to TURN’s claims summarized above?

detailed descriptions regarding how PG&E prioritizes work to maximize risk reduction are provided in chapter 4 of PG&E’s prepared testimony and in PG&E’s first risk assessment mitigation phase (RAMP) filing submitted on November 30, 2017.7 In addition, PG&E’s GT&rs line details of the risk register, the details of the risk informed budget allocation scoring for each program, and certain individual program summary sheets; these workpapers provided PG&E’s documentation of the assessment of how each program impacts safety as well as other consequences.8 Finally, the pace of many of PG&E’s programs is aligned to meeting the Interstate Natural Gas Association of America’s (INGAA) industry objectives and best practices. For example, as detailed in chapter 5 of PG&E’s prepared testimony, the pace of PG&E’s valve automation program is designed to meet the INGAA industry objective to achieve an incident mitigation management producing a 1-hour response time for pipes greater than 12-inch diameter in high consequence areas (HCA) and class 3 and 4, non-HCA. A large contribution to PG&E achieving this goal is the valve automation program.9

What is your response to TURN’s claim that, “the utility has financial incentives and goals that may cause it to propose higher levels of spending

6 TURN, Chapter 1, p. 3, line 3 to p. 4, line 4.


8 PG&E WP 4-32 to WP 4-53; PG&E June 5, 2018 Errata WP 4-64 to WP 4-71; and WP 4-119 to WP 4-123.

9 PG&E prepared testimony, chapter 5, p. 5-78, lines 6-13.
than are warranted by priority safety needs. Utilities generate increased rates of return (i.e., profit) by increasing rate base, and gaining approval of higher than necessary expense forecasts makes it easier for the utility to meet its financial goals”?

TURN’s general comments about “utility” incentives do not apply to PG&E’s 2019 GT&S Rate Case. PG&E did not “propose higher levels of spending than are warranted by priority safety needs.” Rather, PG&E proposed funding for programs targeted to reducing the most risk on PG&E’s gas system, consistent with resource constraints.

Nor did PG&E submit “higher than necessary” expense forecasts. In fact, PG&E’s expense and capital forecasts reflect efficiencies PG&E has realized—or expects to realize—as part of its successful Gas Stewardship effort launched in 2017. Other than vague assertions, TURN has no basis for claiming that PG&E’s forecasts were inflated beyond what PG&E needs to operate a safe and reliable system.

Q 7 Has the Commission established a framework for evaluating the affordability of utilities’ rate proposals?

A 7 To date, no. However, the Commission initiated a Rulemaking (R.18-07-006) in July 2018 to:

1) Develop a framework and principles to identify and define affordability criteria for all utility services under California Public Utilities Commission jurisdiction; and

2) Develop the methodologies, data sources, and processes necessary to comprehensively assess the impacts on affordability of individual Commission proceedings and utility rate requests.

This rulemaking will provide a framework for evaluating the impact of individual utility rate requests.

Q 8 Please describe IS/NCGC’s testimony concerning affordability.

A 8 IS/NCGC’s witness Michael Brubaker testifies that the Commission should consider rate impacts to noncore customers, and claims that PG&E did not
demonstrate that its proposed rates—if adopted—would be affordable for noncore customers. Mr. Brubaker also testifies that PG&E substitutes an analysis of cost efficiency for an analysis of affordability.\textsuperscript{13}

Q 9 How does PG&E respond?

A 9 Mr. Brubaker is correct that PG&E considers customer affordability by incorporating cost efficiencies, in order to forecast a scope of work that maximizes risk reduction, while keeping rates affordable in the long term.

As PG&E explained in a data request response to IS:

\begin{quote}
PG&E determines affordability by its ability to find cost efficiencies in the way it operates, without compromising safety or compliance, allowing us to keep customers’ rates at a reasonable level over the long term.

PG&E incorporated this affordability aspect by presenting a forecast that achieves the greatest amount of risk reduction for the investment made, given the constraints to perform the work (e.g. availability of skilled resources, clearances, etc.).\textsuperscript{14}
\end{quote}

Q 10 Why does PG&E determine affordability in this manner, instead of by directly considering whether customers can afford PG&E’s proposed increases?

A 10 PG&E is not in a position to evaluate whether customers—particularly noncore customers—can afford PG&E’s rate proposals. All customers are uniquely situated. PG&E does not have visibility into the impact of PG&E’s rates on noncore customers’ business operations or profitability. It is also worth noting that IS—whose members include Chevron U.S.A. Inc. and Shell Oil Products US—did not submit any evidence concerning the impact of PG&E’s proposed rate increase on their business.

Q 11 How does PG&E recommend the Commission evaluate affordability in this case?

A 11 Rather than attempting to determine whether particular customers can afford PG&E’s proposed rate increases, the Commission should consider whether the proposed rates are just and reasonable to accomplish the work needed to maintain a safe and reliable gas system. PG&E agrees that its rates must be affordable for customers. PG&E has endeavored to strike the right balance between safety and affordability. If the Commission authorizes a lower revenue requirement than PG&E requests, it must recognize that less

\begin{footnotesize}
\begin{enumerate}
\item IS/NCGC-1, Chapter 2, p. 2-1, lines 11-29, p. 2-3, lines 17-24 and p. 2-6, lines 1-6.
\item IS-007, Question 6.
\end{enumerate}
\end{footnotesize}
work may be done to reduce risk, and that PG&E will need to reprioritize the
work that can be performed during the rate case period.

D. Balancing and Memorandum Accounts

Q 12 Which parties provide testimony on balancing and memorandum accounts
that you will address?
A 12 ORA, TURN, Calpine, and CSU.

Q 13 What are those parties’ recommendations?
A 13 ORA, TURN, Calpine, and CSU make several recommendations regarding
balancing and memorandum accounts that I will address, including the
following:
1) ORA recommends creation of several new one-way balancing accounts
   and memorandum accounts;
2) ORA and TURN oppose discontinuation of the one-way balancing
   accounts for Engineering Critical Assessment (ECA) Phases 1 and 2
   and the memorandum accounts for critical documents and station
   strength testing. ORA opposes discontinuation of the one-way
   balancing account for Work Required by Others (WRO), if ORA’s
   forecast for WRO is not adopted;
3) ORA, TURN, Calpine, and CSU oppose PG&E’s proposal to modify the
   Transmission Integrity Management Program (TIMP) balancing account
   from one-way to two-way; and
4) TURN supports PG&E’s proposal for a two-way balancing account for
   Storage programs.\(^\text{15}\)

Q 14 What is your response to these recommendations generally?
A 14 I will respond to each recommendation separately below. In general,
balancing accounts are sometimes advisable, but only under limited
circumstances. PG&E’s forecasts are subject to changing conditions and
emerging information, and PG&E requires flexibility to respond to changing
priorities and not be burdened or hampered by the constraints of
unnecessary balancing accounts.\(^\text{16}\) Such flexibility is especially important in

\(^{15}\) ORA-05, p. 11, lines 5-7, p. 18, lines 6-12; ORA-07, p. 2, lines 7-13, p. 3, lines 7-10 and
   lines 15-18; TURN, Chapter 5A, p. 3, lines 8-13, Chapter 6, p. 1, lines 14-17, Chapter 7,
   p. 15, lines 5-9 and p. 17, lines 10-12; and Calpine, p. 57, lines 1-2; CSU-1, p. 3.

\(^{16}\) PG&E Prepared Testimony, Chapter 2, p. 2-13, line 14 to p. 2-17, line 2.
the context of PG&E’s current transition to a more quantitative risk assessment methodology. As the CPUC has acknowledged in the pending RAMP and Safety Model Assessment Proceeding (S-MAP), PG&E’s risk management processes are expected to continue to evolve, and as they evolve, it follows that spending priorities may shift as a result. That said, in some cases balancing accounts are appropriate. Such cases include: (1) where external factors drive significant uncertainty in a forecast; and (2) where balancing accounts are required by law. In any case, balancing accounts should almost always be two-way, and rarely be one-way, because of disincentives to maximize risk reduction, and other unintended—and undesirable—consequences.

Q 15 What is your response to ORA’s proposal for additional one-way balancing and memorandum accounts?

A 15 Balancing accounts in general constrain operational flexibility; one-way balancing accounts are particularly problematic. Under a one-way balancing account, utility shareholders bear the burden of any overspending, even if the additional costs are necessary and warranted. This can result in a disincentive from doing an appropriate level of work, as the Commission’s Independent Review Panel specifically recognized. Chapter 17B rebuttal testimony describes how balancing accounts and memorandum accounts are not “cost-free” and require additional resources, special accounting, and reporting and monitoring by PG&E, parties, and the Commission. Balancing accounts are only appropriate under limited circumstances and should not be overused. None of the new accounts proposed by ORA fits those circumstances, as described in rebuttal testimony for Chapters 5, 7 and 10.

Q 16 What is your response to ORA’s and TURN’s recommendation that the existing one-way balancing accounts for ECA Phases 1 and 2 and the

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17 PG&E Prepared Testimony, Chapter 4 and PG&E Rebuttal Testimony, Chapter 4.
18 PG&E Prepared Testimony, Chapter 2, p. 2-12, line 21 to p. to 2-17, line 2.
19 PG&E Prepared Testimony, Chapter 2, p. 2-14, lines 12-23.
20 PG&E Rebuttal Testimony, Chapter 17B.
memorandum accounts for critical documents and station strength testing be retained?  

Q 16 See my response regarding ORA’s proposal to create new balancing and memorandum accounts; for the same reasons, these accounts should be discontinued. These particular balancing accounts are no longer necessary, for the reasons explained in Chapter 7 prepared and rebuttal testimony.  

Q 17 What is your response to ORA’s recommendation that the one-way balancing account for WRO be retained unless ORA’s recommended reduction to PG&E’s forecast for WRO is adopted?  

A 17 As more fully discussed in Chapter 5 rebuttal testimony, while there is some inherent variability for WRO driven by the fact that such work is externally driven, the basis for creating the balancing account in the 2015 GT&S proceeding was driven by a large number of high speed rail projects included in the forecast. The WRO forecast for the 2019 GT&S proceeding does not include specific forecasts for high speed rail projects, but rather is based on recorded costs, so there is no longer a reason for this balancing account. If anything, PG&E is entering a period where WRO costs are likely to be more, not less, if they vary from the forecast. Thus, if the Commission is inclined to apply a balancing account, it should be two-way, not one-way.  

Q 18 What is your response to the recommendations by ORA, TURN, Calpine, and CSU that PG&E’s proposal to modify the TIMP balancing account from one-way to two-way be rejected?  

A 18 ORA, TURN, Calpine, and CSU provide little justification for maintaining the TIMP balancing account as a one-way rather than a two-way account, largely just asserting that the Commission should “keep the account the way it is.” To the extent more specific points are raised by these parties, Chapter 5 rebuttal addresses them.

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21 ORA-07, p. 22, line 18 to p. 23, line 2 and TURN, Chapter 7, p. 14, lines 16-17, p. 16, lines 5-9 and p. 17, lines 10-12.  
22 ORA-05, p. 18, line 6 to p. 19, line 6.  
23 ORA-05, p. 11, lines 5-11; ORA-21, p. 2, lines 19-22 and p. 10, lines 29-30; TURN, Chapter 5A, p. 3, lines 8-13 and p. 16, line 5 to p. 17, line 11; Calpine, p. 56, line 8, to p. 57, line 2; and CSU-1, p. 3.
Q 19 Can you provide more insight into the inherent uncertainty associated with TIMP work that justifies a two-way balancing account?
A 19 Yes. In PG&E’s Traditional In-Line Inspection (ILI) Program, PG&E is forecasting to conduct first-time assessments on 43 sections of pipeline (11 in 2019, 16 in 2020, and 16 in 2021). PG&E cannot accurately forecast the number of anomalies that will be identified in a first-time run. In PG&E’s ILI Direct Examination and Repair forecast, PG&E applied its historical dig-per-mile ratio to all ILI inspections, including first-time inspections; however, PG&E has experienced instances where the anomaly find rate on first-time inspections is far in excess of the historical find rate. In PG&E’s ILI Direct Examination and Repair forecast, a dig-per-mile ratio of 0.252 digs-per-mile was calculated using data from 2012-2016. In 2018, PG&E has conducted first-time inspections of various pipelines and the year to date digs-per-mile rate is 2.24, far in excess of the historical rate of 0.252 digs-per-mile.

Q 20 Can PG&E estimate the incremental costs over its forecasts to account for this uncertainty?
A 20 No. PG&E cannot accurately estimate the incremental costs over its forecasts to account for this uncertainty. However, PG&E forecasts a unit cost of approximately $235,000 per dig for the ILI Program. If PG&E experiences a higher dig-per-mile ratio than forecast, PG&E is required by 49 Code of Federal Regulations (CFR) 192.933(a) to address these findings, and PG&E should be permitted to recover the costs of such mandated work.

Q 21 TURN supports PG&E’s proposal for a new two-way balancing account for Storage programs. How would this new balancing account meet the “limited circumstances” for balancing accounts you describe above?
A 21 As I stated in my opening testimony, this balancing account “addresses a situation where external factors, such as the requirements of new

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24 PG&E WP 5-38 to 5-39, Workpaper Table 5-4.
25 PG&E WP 5-44, Workpaper Table 5-9, line 21.
26 PG&E WP 5-44, Workpaper Table 5-9, line 22.
27 49 CFR § 192.933(a).
anticipated regulations that are yet to be finalized and our ability to access skilled resources, drive significant uncertainty in the forecast.”

While Division of Oil, Gas and Geothermal Resources regulations have been finalized since the time this application was filed, other significant uncertainties identified in Chapter 6 prepared testimony still remain, including: (1) unit costs to implement compliance with these regulations could be higher than PG&E’s forecasts because all storage operators will be vying for the same third-party resources to complete the work; and (2) if PG&E’s Natural Gas Storage Strategy proposal is not adopted by the CPUC and PG&E must perform new compliance and ongoing work at Los Medanos and Pleasant Creek storage facilities, costs will increase over those forecast, among other things.

E. Rate Impacts of Recovering Decommissioning and Depreciation Costs of Los Medanos and Pleasant Creek

Q 22 Do parties make alternative proposals for recovery of the decommissioning costs and remaining depreciation for Pleasant Creek and/or Los Medanos?

A 22 Yes. ORA recommends that the Pleasant Creek facility depreciation rates be maintained at their currently authorized rates for three years (2019-2021), and that the remaining net book value be converted into a regulatory asset upon the commencement of decommissioning activities (at the end of 2021). ORA recommends that this regulatory asset then be amortized over five years, with no return, for a total 8-year recovery period (2019-2026). ORA also recommends that the Pleasant Creek facility decommissioning expense be spread over eight years (2019-2026), consistent with its depreciation proposal (as compared to PG&E’s 3-year proposal), and that the annual decommissioning expense be reduced from $8.0 million to $3.0 million. ORA recommends similar treatment for the Los Medanos facility, except that ORA’s primary recommendation is that the Commission delay deciding on whether to retire the facility until the next rate

29 PG&E Prepared Testimony, Chapter 6, p. 6-7, line 22 to p. 6-8, line 24.
30 ORA-14B/C, p.4, lines 16-24 and p.28, lines 16-22.
case.\textsuperscript{31} Other parties (such as IS and Calpine) propose to defer the recovery of decommissioning costs until after this rate case period, and to extend the period over which decommissioning and depreciation are recovered, with no return.\textsuperscript{32}

Q 23 What is PG&E’s response to these proposals?

A 23 Parties’ proposals are addressed in detail in Chapters 11, 14B and 14C of PG&E’s rebuttal. To summarize briefly here, with respect to depreciation, ORA’s recommendation is contrary to standard industry and Commission practice, in that it does not result in PG&E recovering its investment over the remaining useful life of the assets. With respect to decommissioning, it is standard utility practice to fully recover decommissioning costs over the remaining useful lives of the assets, rather than after an asset has been retired.

Q 24 Should the Commission depart from precedent in this case and defer or extend the period for recovering depreciation or decommissioning costs for Los Medanos and Pleasant Creek beyond the remaining useful lives of these assets?

A 24 As a matter of ratemaking, no. However, the Commission could decide as a matter of policy to depart from utility standard practice and precedent in order to mitigate the rate impacts of closing Los Medanos and Pleasant Creek. Although PG&E does not advocate this approach, the Commission should be careful if it departs from standard utility practice not to render a decision that does not allow PG&E to recover a return on these investments. It is important to remember that the reason PG&E recommends retiring the Los Medanos and Pleasant Creek storage facilities is because doing so will save customers hundreds of millions of dollars and is in customers’ best interest. Particularly in light of this fact, if the Commission were to decide to deviate from standard utility practice and extend cost recovery beyond the useful lives of the assets, it should reject ORA’s and IS’s recommendation to

\textsuperscript{31} ORA-14B/C, p. 5, lines 3-14 and p. 28, lines 16-27 and ORA-01, p. 17.

\textsuperscript{32} Calpine, p. 22, lines 3-7 and IS-1, Chapter 11, p. 11-5, lines 5-8.
deny PG&E any return on its investment for the post-retirement period as improper and not supported by the Commission decisions ORA cites.33

F. Combination of GT&S Rate Case With PG&E’s GRC

Q 25 Did PG&E include a proposal to combine its GT&S Rate Case with its GRC when it filed this GT&S Rate Case on November 17, 2017?

A 25 Not explicitly. At the time PG&E filed this case, the Commission’s Rate Case Plan called for a 3-year rate case cycle for GRCs,34 and for PG&E’s GRC and GT&S rate case to be filed separately.35 In light of these expectations, PG&E did not formally propose the combination of the two rate cases. However, PG&E included—for the evidentiary record—a third attrition year forecast in this case, in the event that the Commission decided to combine the GRC and GT&S Rate Case beginning in 2023.

Q 26 Have there been developments in the Commission’s Order Instituting Rulemaking (R.)13-11-006 with respect to combining the two rate cases?

A 26 Yes. Earlier this year, the Commission’s Energy Division issued a workshop report in the Rulemaking recommending combining PG&E’s GT&S and GRC proceedings.36

Q 27 Did PG&E comment on the Energy Division’s recommendation to combine the two PG&E rate cases?

A 27 Yes. On April 5, 2018, PG&E filed comments supporting Energy Division’s recommendation with respect to combining the cases. As PG&E explained in its comments, PG&E agrees with the Energy Division that a combination of the cases will provide parties with a better understanding of the integration of the RAMP report into PG&E’s entire gas operations. It will

33 ORA-14B/C, p. 29, lines 8-12; IS-1, Chapter 11, p. 11-6, lines 5-15.

34 D.14-12-025, mimeo, p. 40 (“On the three-or four-year GRC cycle, we will retain the three-year cycle. Should the S-MAP, RAMP, and GRC processes pose scheduling conflicts, we may need to revisit the need for a four-year rate cycle.”).

35 D.14-12-025, mimeo, pp. 40-41 (“[W]e decline to combine PG&E’s GRC application involving its electric operations and gas distribution operations, with its separate application for its gas transmission and gas storage facilities. Combining the two proceedings will result in a massive amount of information in one proceeding, and is likely to slow down the issuance of a decision.”).

also decrease the workload of the parties, including PG&E, ORA, TURN and others who participate in both proceedings.37

Q 28  Do other parties to CPUC Rulemaking13-11-006 support combining the two cases?

A 28  Yes. In its comments on the Energy Division Report in R.13-11-006, TURN supported the Energy Division recommendation to combine the GT&S and GRC proceedings, and asked that the Commission direct PG&E to file a combined GRC and GT&S case in 2023.38

Q 29  Did any parties support the potential combination of the two PG&E rate cases in testimony in this GT&S Rate Case?

A 29  Not explicitly. ORA recommended adoption of a fourth year (2022) in this rate case, for reasons other than that the adoption of a third attrition year would facilitate combination of the GT&S Rate Case with the GRC in 2023.39

Q 30  Does any party in this GT&S Rate Case oppose combining the two cases?

A 30  Yes. Calpine opposes such consolidation and instead supports the continuation of periodic stand-alone GT&S and GRC filings.40

Q 31  What are Calpine’s stated reasons for opposing consolidation?

A 31  Calpine offers two reasons: (1) the established structure for determining backbone, local transmission, and storage rates on the PG&E system for natural gas would become a subset of the wider issues considered in a GRC; and (2) the interests of parties to the GT&S rate cases are specific to natural gas transportation and storage rate issues; consolidating the GT&S rate case with the GRC would result in diminishment of focus on natural gas issues.41

Q 32  Can the Commission combine the two PG&E rate cases in a way that addresses Calpine’s concerns?

37 PG&E’s Response to Administrative Law Judge’s Ruling Issuing Energy Division Workshop Report for Comment (Apr. 5, 2018) p. 3.
39 ORA-01, p. 8, line 18 to p. 9, line 3.
40 Calpine, p. 10, lines 10-12.
41 Calpine, p. 10, lines 16-24.
Yes. As PG&E recommended in its April 5, 2018 comments on the Energy Division report, the Commission should clarify that gas rate and revenue allocation issues that are currently in PG&E’s GT&S proceeding be litigated in PG&E’s Gas Cost Allocation Proceeding, where cost allocation and rate design are considered. With that bifurcation, the GRC can focus—as it does currently—on the revenue requirement for gas distribution and transmission. This will reduce the number of new parties to the GRC.42

Q 33 Please summarize PG&E’s current position with respect to this issue.

A 33 PG&E supports the Energy Division’s recommendation to combine PG&E’s GRC and GT&S Rate Case beginning with the 2023 GRC, and asks that the Commission adopt a third attrition year (2022) in this GT&S Rate Case in order to facilitate such a combination.43

G. TURN’s Recommendations for Disallowance of Cost Recovery

Q 34 TURN recommends substantial disallowances in cases where: (1) PG&E did not perform all work forecast in the 2015 GT&S Rate Case; and (2) PG&E’s 2015-2018 recorded costs for capital projects were higher than the forecast the Commission adopted in the 2015 GT&S Rate Case. How does PG&E respond?

A 34 PG&E addresses this issue in Chapter 23, sponsored by witness Bruce Smith, as well as the operational chapters that forecast the specific work at issue—Chapters 5, 7 and 10. In sum, TURN recommends a permanent disallowance of more than $500 million over 2015-2021. TURN has not argued that PG&E acted imprudently; nor has TURN put forth any evidence that PG&E invested unreasonably. Rather, the basis for TURN’s recommendation is that the work PG&E performed and the money PG&E spent did not align perfectly with the forecast the Commission adopted in the 2015 GT&S Rate Case. This amounts to a $500 million penalty, including removing from rate base hundreds of millions of dollars prudently invested in used and useful assets, merely because PG&E’s investments did not match its forecast. PG&E urges the Commission to reject TURN’s

42 PG&E’s Response to Administrative Law Judge’s Ruling Issuing Energy Division Workshop Report for Comment (Apr. 5, 2018) p. 3.

43 PG&E’s Response to Administrative Law Judge’s Ruling Issuing Energy Division Workshop Report for Comment (Apr. 5, 2018) p. 3.
recommendations that are contrary to forecast ratemaking and the regulatory compact.

Q 35 Does this conclude your rebuttal testimony?
A 35 Yes, it does.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

SUMMARY OF REQUEST

[NO REBUTTAL TESTIMONY]
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
REBUTTAL TESTIMONY OF
CHRISTINE COWSERT AND ANDY ABRANCHES
SAFETY, RISK AND PLANNING

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.
A 1 My name is Christine Cowsert, and I sponsor sections C through G of this rebuttal testimony. My name is Andrew Abranches, and I sponsor sections G through J of this rebuttal testimony. This testimony responds to the direct testimony of the Office of Ratepayer Advocates (ORA),\(^1\) the Office of Safety Advocate (OSA),\(^2\) The Utility Reform Network (TURN),\(^3\) and Indicated Shippers (IS).\(^4\) Pacific Gas and Electric Company (PG&E) summarizes parties’ positions in Section B.

B. Summary of Safety, Risk and Planning Rebuttal Testimony

Q 2 Please provide a summary of the issues you will be addressing.
A 2 This rebuttal addresses the following issues: (1) OSA’s claims regarding risks associated with Natural Gas Storage Strategy (NGSS); (2) ORA’s recommendations regarding PG&E’s Risk-Informed Budget Allocation (RIBA) and Risk Evaluation Tool (RET); (3) PG&E’s advancement to progressively more quantitative risk processes; (4) IS’ comments regarding PG&E’s use of the Multi-Attribute Risk Score (MARS); (5) TURN’s and IS’ testimony regarding PG&E’s spending relative to safety; (6) IS’ testimony regarding managing risk and rate impacts;\(^5\) (7) ORA’s and TURN’s recommendations regarding PG&E’s reprioritization of work; and (8) TURN’s recommendations regarding 2018 capital expenditures.

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\(^1\) ORA-04.
\(^2\) OSA-1.
\(^3\) TURN, Chapters 1, 5B, 7, 10 and 14A.
\(^4\) IS-1.
\(^5\) IS-1, p. 4-5, lines 12-14.
C. OSA’s Claims Regarding Risks Associated with Natural Gas Storage Strategy (Cowsert)

Q 3 OSA states that PG&E’s proposed NGSS increases operational risk. How does PG&E’s NGSS affect PG&E’s risk profile from a Risk Assessment and Mitigation Phase (RAMP) perspective?

A 3 As described in PG&E’s RAMP filing included in workpapers supporting Prepared Testimony, NGSS mitigates a RAMP risk, “Natural Gas Storage Well Failure – Loss of Containment with Ignition at Storage Facility.” These mitigations include the well inspections and decommissioning of wells. As stated in the RAMP filing, “PG&E’s proposed Natural Gas Storage Strategy (NGSS) (footnote omitted) has an impact on PG&E’s risk exposure. In summary, this strategy involves reducing PG&E’s risk through ceasing operations at the Los Medanos and Pleasant Creek storage facilities, leaving McDonald Island in operation.” This will be accomplished by retiring 27 wells at the Los Medanos and Pleasant Creek facilities and replacing them with 11 new wells at McDonald Island. See Chapter 11 rebuttal for more detail regarding operational risks; see Chapter 19 rebuttal for more detail regarding market power and pricing risk; see Chapter 6 rebuttal regarding OSA safety recommendations.

Q 4 Did OSA object to PG&E’s characterization of NGSS as a risk mitigation in the RAMP proceeding?

A 4 No. OSA’s opening comments on PG&E’s RAMP Report raise no such issue (though OSA notes that “due to staffing constraints [OSA did not] provide a more in-depth review”).

D. ORA’s Recommendations Regarding Risk-Informed Budget Allocation and Risk Evaluation Tool (Cowsert)

Q 5 Please describe ORA’s testimony regarding RET and RIBA scoring.

6 OSA-1, p. 3-4, lines 3-25.
7 PG&E WP 4-269 to WP 4-290.
8 PG&E Prepared Testimony, Chapter 4, p. 4-37, lines 12-14.
9 PG&E WP 4-274.
10 OSA’s Opening Comments on PG&E RAMP Report and Associated SED Report, I.17-11-003 (May 10, 2018), Section 1, p. 1.
ORA states that the method for RET and RIBA scoring is non-intuitive and lacks transparency due to its use of a log-10 scale in the scoring, lack of basis in units, and reliance on the subjective decisions and assumptions of Subject Matter Experts (SME). ORA supports PG&E’s transition to a more quantitative risk assessment methodology, as represented by their 2017 RAMP filing.

How does PG&E respond?

First, based on the Gas Storage and Transmission (GT&S) Scoping Memo, “The GT&S rate case should not evaluate PG&E’s risk methodology or be a forum to propose changes or alternatives to the risk methodology including models.” Second, PG&E is currently transitioning its RET and RIBA to a quantitative risk assessment methodology. The first step in this transition was provided as part of PG&E’s 2017 RAMP filing. PG&E will continue to work with interested parties through the Safety Modeling Assessment Phase (S-MAP) proceeding to determine the future state of the quantitative models and then determine how the current PG&E processes would change to incorporate this information. While in the transition phase, PG&E proposes to continue the use of RET and RIBA tools until the methodology developed in the S-MAP proceeding is finalized and utilized in PG&E’s RAMP filing. Such transitions are an expected part of PG&E’s continuous improvement in risk management.

E. PG&E’s Advancement to Progressively More Quantitative Risk Processes (Cowser)

Do parties acknowledge that PG&E’s risk management processes are expected to continue to evolve?

Yes. “ORA supports PG&E’s transition to a more quantitative risk assessment methodology, as represented by their 2017 RAMP filing,” and “looks forward to PG&E’s increased incorporation of such quantitative probabilistic risk modeling in its risk management and investment planning.

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12 ORA-04, p. 1, lines 16-18.
In the RAMP proceeding, TURN characterized PG&E as having made “[e]normous strides … in prioritizing safety and improving quantitative risk analysis.” TURN also said “[t]here is room for continued significant improvement, but the work to date has already paid significant dividends.”

IS acknowledged the “state of transition in the area of risk management” in the S-MAP and “elected not to challenge the details of PG&E’s methodology.”

Q 8 How did the California Public Utilities Commission (CPUC or Commission) characterize this progress in the S-MAP proceeding?

A 8 The CPUC noted in the S-MAP proceeding that “the idea is for each successive S-MAP to become more sophisticated, be able to respond to changing circumstances, and be able to build on its predecessor S-MAP to tackle increasingly difficult issues.”

Q 9 What are the implications of PG&E’s continued progress in its risk management processes?

A 9 PG&E’s management will need flexibility to adapt spending as PG&E’s evolving risk management processes drive changes in spending as a result of changing priorities.

F. Indicated Shippers’ Testimony Regarding PG&E’s Use of Multi-Attribute Risk Score (MARS) (Cowsert)

Q 10 Was MARS used in developing PG&E’s GT&S forecast?

A 10 No. MARS was part of the RAMP submittal. As discussed in Chapter 4 Prepared Testimony, the RAMP submittal was developed in parallel with the GT&S forecast. The GT&S forecast was prepared through PG&E’s Investment Planning Processes (IPP), using RET and RIBA processes, and was not based on RAMP or MARS.

14 ORA-4, p. 1, lines 16-18, and p. 5, lines 5-7.
16 Id.
17 IS-1, p. 4-2, lines 13-15.
19 PG&E Prepared Testimony, Chapter 4, p. 4-30, lines 21-26.
Q 11 Is it your understanding that evaluation of PG&E’s risk models such as RAMP is part of the GT&S case?

A 11 Based on the GT&S Scoping Memo, “The GT&S rate case should not evaluate PG&E’s risk methodology or be a forum to propose changes or alternatives to the risk methodology including models.”

Q 12 Describe IS’ testimony relating to the MARS.

A 12 IS isolated the safety component of the MARS to provide a percent risk reduction by implementing the risk mitigations in this rate case. Based on isolating the safety score, IS indicates that “the level of safety mitigation relative to the cost increase as proposed by PG&E in this proceeding is very expensive.”

Q 13 How does PG&E respond?

A 13 It is not appropriate to isolate the safety component of the MARS score to quantify risk reduction benefit. The safety component of the MARS is related to injuries and fatalities; however, the other components of the MARS (environmental, reliability, compliance, and finance) could also have some safety related impact. The combination of all the consequences provides the best characterization of the risk event for each of the six risks in the RAMP proceeding. The models developed in PG&E’s RAMP proceeding have known limitations and improvements in the quality and availability of data, and a deeper understanding of risk tolerance are needed before risks and the effectiveness of mitigations truly can be compared and used for decision making, so reaching a conclusion that the safety mitigation is expensive based on the RAMP model is premature. PG&E provided testimony regarding the first-generation models and known limitations.

G. TURN’s and Indicated Shippers’ Testimony Regarding PG&E’s Spending Relative to Safety (Cowsert/Abranches)

Q 14 TURN claims that PG&E’s general assertions and discussions do not address whether the proposed pace and scope of programs produce the...

20 GT&S Scoping Memo, p. 7.
21 IS-1, p. 4-5, lines 12-13.
22 PG&E Prepared Testimony, Chapter 4, p. 4-32, line 1 to p. 4-33, line 29.
optimal safety improvement in relation to the ratepayer dollars spent.\textsuperscript{23}

Similarly, IS claims that “the level of safety mitigation relative to the cost increase proposed by PG&E in this proceeding is very expensive.”\textsuperscript{24}

How does PG&E respond?

PG&E interprets TURN’s and IS’ claims as stating that PG&E did not use risk spend efficiency (RSE) in developing the GT&S forecast. PG&E discussed why RSEs were not used to develop the GT&S forecast in Chapter 4 Prepared Testimony.\textsuperscript{25} Because the RAMP proceeding and the 2019 GT&S Rate Case were prepared concurrently, and PG&E was unable to feed the output of the RAMP models into the forecast. PG&E also provided an explanation on the limitations of using the first-generation RAMP models in its Prepared Testimony.\textsuperscript{26} Therefore, PG&E used its Integrated Planning Process and provided Prepared Testimony on its risk management and IPP.\textsuperscript{27} In addition to testimony, PG&E provided workpapers with the details of the risk register, the details of the RIBA scoring for each program, and the individual program summary sheets; these workpapers provided PG&E’s documentation of the assessment of how each program impacts safety, as well as other consequences. PG&E continues to work with the CPUC and stakeholders to refine the RAMP models through the Safety Modeling Assessment Proceeding for decision-making.\textsuperscript{28}

Is it reasonable to judge PG&E’s forecast on whether it is quantitatively proven to be “optimal”?

No. As TURN and all parties to the RAMP proceeding know, there is currently no proven methodology to do this.
Q 16 How do you respond to TURN’s related claim that PG&E’s alternative analysis discussion was not sufficient to explain why the chosen forecasted pace or scope is the optimal use of ratepayer funds?  

A 16 PG&E does not agree with the assertions made by TURN to the extent that TURN is suggesting that PG&E did not provide explanations regarding alternative analyses or the justification for the rate case forecast. PG&E provided information regarding the alternative analysis performed for the RAMP proceeding. The various operational chapters provide additional information to explain the forecast request.

H. Indicated Shippers’ Testimony that Rate Impacts Do Not Play a Role in Managing Risk (Abranches)

Q 17 What is’ position on risk scoring and the rate impact for retail customers?  

A 17 IS states that “the level of safety mitigation relative to the cost increase as proposed by PG&E in this proceeding is very expensive, and rate impacts do not play a role in managing risk.” They also state that RIBA risk investments and financial performance should be pursued and prioritized to manage rate impacts on retail customers.

Q 18 Does PG&E agree with IS that, in addition to cost, PG&E’s risk scoring should consider rate impacts for particular classes of customers?  

A 18 No, it does not. Rate impact is not part of risk scoring and risk mitigation activities. As noted above in Section D, RIBA will be phased out in the near future. RIBA does not take into account rate impacts, revamping the models would require considerable investment in technology for PG&E to consider rate impact for every single project or program. For further discussion on affordability for noncore customers, see Chapter 2 rebuttal.

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29 TURN, Chapter 1, p. 3, line 20 to p. 4, line 4.  
30 PG&E Prepared Testimony, Chapter 4, p. 4-37, line 16 to p. 4-39, line 12.  
31 IS-1, p. 4-5, lines 11-14.  
32 IS-1, p. 4-5, line 14 to p. 4-6, line 4.
I. ORA’s and TURN’s Recommendations Regarding PG&E’s Reprioritization of Work and Other Recommended Disallowances (Abranches)

Q  19 Which parties commented on PG&E’s reprioritization of work between the time it prepared its forecast in 2013 for the 2015 rate case to the time it executed work in 2015, 2016, 2017, and 2018?

A  19 ORA and TURN.

1. Response to ORA’s Recommendations Concerning Reprioritization

Q  20 What was ORA’s criticism?

A  20 ORA states:

   PG&E testimony in this chapter [PG&E opening testimony Chapter 4] does not provide sufficient insight into PG&E’s decision making process for reprioritizing work. It provides no explanation or example of what type of new information or change in system needs would lead PG&E to reprioritize work, and there is no discussion of the specific factors that led to the differences between the planned and adopted amounts shown in Tables 4-3 and 4-4. PG&E instead seems to leave much of the discussion of why work was deferred to [] specific chapters, like Chapters 5, 7 and 10, that include deferred [work] projects or programs.33

Q  21 How does PG&E respond to this criticism?

A  21 PG&E has provided detailed descriptions of how it prioritizes, and reprioritizes, its work in many fora. Chapter 4, Section D of PG&E’s prepared testimony describes PG&E’s risk management and IPP; Section E describes how the company reprioritized work and complied with the provisions of the 2017 GRC Settlement Agreement and the investment decisions PG&E made for the 2015-2018 period (Section E.3); and summarizes changes in planned capital and expense expenditures for 2015-2018 (Section E.4).34

   In addition, PG&E provided hard copies of the RIBA Master File in workpapers.35 In discovery responses, PG&E provided TURN soft copies of the RIBA Master File and RIBA scoring sheets36 and the master

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33 ORA-4, p. 3, lines 11-18.
34 PG&E Prepared Testimony, Chapter 4, Section E.
35 PG&E WP 4-64 to WP 4-118. Note, errata was filed on June 5 for WP 4-46 to WP 4-70.
36 TURN-009, Questions 1 and 2.
prioritization files.\textsuperscript{37} The outcomes of PG&E’s IPP are documented in Session 1 and 2 executive decks, which were provided to ORA,\textsuperscript{38} and the Finance IT and Governance Committee meeting documents, which were provided to TURN.\textsuperscript{39} Moreover, ORA’s own criticism acknowledges that PG&E provided additional detail in Chapters 5, 7 and 10. PG&E did this because the witnesses for Chapters 5, 7 and 10 are SMEs and better qualified to explain why certain decisions were made than the witnesses for Chapter 4. For this same reason, Chapters 5, 7 and 10 of PG&E’s rebuttal testimony also contain additional information regarding the reprioritization of the work described in those chapters, in response to TURN’s criticisms, and as discussed below. It is unreasonable for ORA to suggest that one chapter must sponsor all of the evidence concerning how PG&E prioritized its portfolio of work.

2. Response to TURN’s Recommended Disallowances

Q 22 Can you please summarize TURN’s recommendations?
A 22 Yes. TURN Witness Yap addresses PG&E’s testimony regarding PG&E’s reprioritization of work in TURN Chapters 5B, 7 and 10.\textsuperscript{40} This testimony recommends reductions or disallowances for various programs and/or projects where PG&E did not complete all of the forecast work. TURN also recommends substantial disallowances to recorded costs that TURN asserts are not reasonable because they exceeded the forecast adopted in the 2015 case. These recommendations are in Chapters 5B and 7. The following summarizes TURN’s recommendations:

Chapter 5 – Asset Family – Transmission Pipe

- Direct Assessments – TURN says PG&E failed to perform “required” mileage of Direct Assessment and recommends disallowing

\textsuperscript{37} TURN-009, Question 5.
\textsuperscript{38} ORA-049, Question 1.
\textsuperscript{39} TURN-009, Question 8.
\textsuperscript{40} TURN-5B, Sections III and IV, and TURN-10, Section III.
$22.3 million per year of PG&E’s 2019-2021 forecast as a remedy
(meaning PG&E does the work and shareholders pay);\textsuperscript{41}

- Vintage Pipe Replacement – TURN criticizes PG&E for not completing
  all forecast pipeline replacement, but does not recommend an
  associated disallowance. Separately TURN recommends a
disallowance for spending more per mile than the adopted forecast;\textsuperscript{42}

- Geo-Hazard Mitigation – TURN opines that PG&E mischaracterized the
  number of projects assumed in the 2015 adopted forecast, but makes
  no specific recommendations as a result.\textsuperscript{43} Separately TURN
  recommends a disallowance to recorded costs because PG&E’s
  recorded costs exceeded the adopted forecast.\textsuperscript{44}

Chapter 7 – Asset Family – Storage

- Simple and Complex Station Rebuild – TURN agrees that it was
  “reasonable for PG&E to reprioritize funds from simple station rebuild
  work to complex station rebuild work,” but recommends disallowances
  for spending more per project than the adopted forecast.\textsuperscript{45}

- Burney K-2 Replacement Project – TURN recommends a disallowance
  for spending more than the adopted forecast.\textsuperscript{46}

- Gerber Station Controls Replacement – TURN recommends a
  disallowance for spending more than the adopted forecast.\textsuperscript{47}

Chapter 10 – Gas System Operations

- Capacity for Load Growth – TURN recommends $144.4 million “credit”
  against 2019-2021 forecast for spending less than the adopted forecast
  from 2015-2018;\textsuperscript{48}

\textsuperscript{41} TURN-5B, p. 7, line 1 to p. 8, line 7.
\textsuperscript{42} TURN-5B, p. 8, line 8 to p. 12, line 9.
\textsuperscript{43} TURN-5B, p. 12, line 10 to p. 13, line 9.
\textsuperscript{44} TURN-5B, p. 13, line 10 to p. 13, line 9.
\textsuperscript{45} TURN-7, p. 19, line 5 to p. 24, line 4.
\textsuperscript{46} TURN-7, p. 25, line 7 to p. 26, line 23.
\textsuperscript{47} TURN-7, p. 27, line 12 to p. 28, line 16.
\textsuperscript{48} TURN-10, p. 6, line 13 to p. 7, line 10, including Table 10-2.
• Capacity to Support Normal Operating Pressure Reductions – TURN recommends $25.6 million “credit” against 2019-2021 forecast for spending less than the adopted forecast from 2015-2018.49

Q 23 Which PG&E rebuttal chapters respond to TURN’s recommendations?

A 23 Chapters 5, 7 and 10 each respond to the recommendations concerning the work covered by their respective opening chapters. In addition, Chapter 23 responds to all of TURN’s disallowance recommendations, explaining that they are inconsistent with forecast test year ratemaking. Finally, this Chapter 4 provides additional information in response to TURN’s recommendations concerning PG&E’s reprioritization of work during the 2015-2018 period.

Table 4-1 summarizes the reductions or disallowances TURN recommends, whether they relate to reprioritization or purported unreasonableness, and identifies the PG&E rebuttal chapters that respond to TURN’s recommendations.

49 Id.
# Table 4-1

**TURN’S PROPOSED DISALLOWANCES AND REDUCTIONS**

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<td>3</td>
<td></td>
<td>Total Expense Reduction</td>
<td></td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>22,349</td>
<td></td>
<td></td>
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<tr>
<td>4</td>
<td></td>
<td></td>
<td></td>
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<td>–</td>
<td>–</td>
<td>–</td>
<td>22,349</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>5B</td>
<td>Vintage Pipe Replacement</td>
<td>75E</td>
<td>–</td>
<td>67,416</td>
<td>47,868</td>
<td>201,790</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>317,074</td>
<td>Reasonableness</td>
<td>5, 23</td>
</tr>
<tr>
<td>6</td>
<td></td>
<td>Geo-Hazard Mitigation</td>
<td>75J</td>
<td>–</td>
<td>5,616</td>
<td>2,308</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>7,924</td>
<td>Reasonableness</td>
<td>5, 23</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td></td>
<td>Simple Station Rebuild</td>
<td>763 44A</td>
<td>4,727</td>
<td>3,281</td>
<td>–</td>
<td>4,474</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>12,482</td>
<td>Reasonableness</td>
<td>7, 23</td>
</tr>
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<td>8</td>
<td></td>
<td>Complex Station Rebuild</td>
<td>764 44A</td>
<td>18,512</td>
<td>8,509</td>
<td>267</td>
<td>90,048</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>117,336</td>
<td>Reasonableness</td>
<td>7, 23</td>
</tr>
<tr>
<td>9</td>
<td></td>
<td>Compressor Replacement (Burney K-2)</td>
<td>76X</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>16,145</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>16,145</td>
<td>Reasonableness</td>
<td>7, 23</td>
</tr>
<tr>
<td>10</td>
<td></td>
<td>Gerber Station Controls Replacement</td>
<td>76T</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>2,388</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>2,388</td>
<td>Reasonableness</td>
<td>7, 23</td>
</tr>
<tr>
<td>11</td>
<td></td>
<td>Capacity for Load Growth</td>
<td>73A</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>46,684</td>
<td>47,358</td>
<td>50,371</td>
<td>144,413</td>
<td>Reprioritization</td>
<td>4, 10, 23</td>
</tr>
<tr>
<td>12</td>
<td>10</td>
<td>Capacity to Support Normal Operating Pressure Reductions</td>
<td>73C</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>10,840</td>
<td>7,880</td>
<td>6,868</td>
<td>25,588</td>
<td>Reprioritization</td>
<td>4, 10, 23</td>
</tr>
<tr>
<td>13</td>
<td></td>
<td>Total Capital Expenditure Reductions</td>
<td></td>
<td>23,239</td>
<td>84,822</td>
<td>50,443</td>
<td>298,700</td>
<td>73,669</td>
<td>55,238</td>
<td>57,239</td>
<td>643,350</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Note: The TURN values for Capacity are recommended reductions; all others are recommended disallowances.*
Q 24 Are there programs for which PG&E did not complete all of the forecast work and that PG&E identified as being subject to the provisions of the 2017 General Rate Case (GRC) Settlement Agreement that TURN does not address?
A 24 Yes. The TURN-Yap testimony does not address the valve automation, shallow pipe, and Supervisory Control and Data Acquisition Visibility programs.

Q 25 How does PG&E respond to TURN's recommended reductions and disallowances?
A 25 Chapter 5 of PG&E's rebuttal testimony explains the reasons why PG&E performed fewer units of DA and Vintage Pipe Replacement, and Chapter 10 explains why PG&E performed less units of Normal Operating Pressure (NOP) and capacity work (as did Chapters 5 and 10 of PG&E's opening prepared testimony). Chapter 23 of PG&E's rebuttal explains how TURN's recommendations are inconsistent with test year forecast ratemaking and generally unsupported. This Chapter 4 provides additional information concerning PG&E's overall 2015-2018 investment plan, as well as other sources of information available to TURN that TURN's testimony ignores.

Q 26 Did PG&E explain the basis for its reprioritization in its opening prepared testimony?
A 26 Yes. PG&E's opening testimony explained the several reasons that the work PG&E ultimately performed did not match the adopted forecast:

- PG&E's Chapter 4 testimony generally explained the reasons why work performed in 2015 through 2018 differs from what PG&E forecasted in the 2015 GT&S rate case; 50
- In Tables 4-3 and 4-4, PG&E provided a high-level summary of reprioritized work, and Chapter 4 explained that specific factors that led to the differences between planned and adopted work were provided in the chapters that cover the specific program listed in Tables 4-3 and 4-4;

50 PG&E Prepared Testimony, Chapter 4, p. 4-23, line 3 to p. 4-24, line 11.
Chapter 5 addressed details for vintage pipe, Geo-Hazard and ECDA/ICDA programs;\textsuperscript{51} Chapter 7 addressed details for stations;\textsuperscript{52} and Chapter 10 explained how PG&E planned NOP reduction and capacity work.\textsuperscript{53}

Q 27 In PG&E’s prepared opening testimony, PG&E provided tables showing that, over the 2015-2018 period, PG&E expected to spend more on expense and capital than the adopted forecasts.\textsuperscript{54} Does PG&E still believe this will be the case?

A 27 In total, yes. PG&E has prepared errata to Figures 4-7 and 4-8 in the prepared opening testimony. The errata reflect PG&E’s forecast, at the time of the application, to spend $139 million more in expense and $187 million more in capital than the adopted forecasts. TURN witness Florio points out that PG&E’s GT&S capital budget as of June of this year, was $965 million (corrected to $978 million by PG&E in errata). If PG&E executes this level of work, its capital spend over the 2015-2018 period will be about $22 million lower than the adopted forecasts, and its expense spend over the same period will be about $87 million more than the adopted forecast. As witness Smith explains in rebuttal Chapter 23, taken as a whole, PG&E will have spent more than the adopted revenue requirement over the 2015-2018 period.

Q 28 You mentioned above other sources of information available to TURN that TURN’s testimony ignores. Please elaborate.

A 28 As PG&E states in its testimony, “Every six months, PG&E files its GT&S Safety Report, and describes any differences between the planned and actual amounts of safety and reliability work; in addition, PG&E reports Vintage Pipe, Strength Test, and In-Line Inspection (ILI) programs in quarterly Transmission Pipeline Compliance Reports.”\textsuperscript{55}

\textsuperscript{51} PG&E Prepared Testimony, Chapter 5, p. 5-37, line 13 to p. 5-38, line 22 discusses ECDA/ICDA; p. 5-59, line 13 to p. 5-61, line 2 discusses vintage pipe; p. 5-70, line 14 to p. 5-71, line 28 discusses Geo-Hazard.

\textsuperscript{52} PG&E Prepared Testimony, Chapter 7, p. 7-66, line 12 to p. 7-75, line 25.

\textsuperscript{53} PG&E Prepared Testimony, Chapter 10, p. 10-22, line 14 to p. 10-26, line 26.

\textsuperscript{54} PG&E Prepared Testimony, Chapter 4, p. 4-26, Figure 4-7, and p. 4-28, Figure 4-8.

\textsuperscript{55} PG&E Prepared Testimony, Chapter 4, p. 4-23, lines 30-35. Copies of excerpts from PG&E’s GT&S Safety Reports are included herewith as Attachment A.
Q 29 Why does PG&E prepare and send these reports?
A 29 The Commission ordered PG&E to prepare and serve these reports to address the concerns ORA and TURN raised about ensuring that utility reprioritization is reasonable. Specifically, the Commission stated:

This Safety Report will provide Commission staff with the necessary details to: (1) monitor what storage and pipeline-related safety, reliability and integrity capital projects and maintenance activities are being undertaken by PG&E and the amounts spent on such activities; (2) determine whether projects which have been identified by PG&E with high risk assessments are being carried out or whether other higher risk projects have been undertaken instead; (3) determine PG&E’s rationale for reprioritization of projects; and (4) to monitor the status of PG&E’s compliance with Subpart O.

CPSD staff [now SED] shall review these reports to monitor PG&E’s storage and pipeline-related activities, to assess whether the projects which have been identified by PG&E to be high risk are being carried out, and to track whether PG&E is spending its allocated funds on these storage and pipeline-related safety, reliability, and integrity activities.

Should [SED] detect any problems with PG&E’s prioritization or administration of the storage or pipeline capital projects or O&M activities, [SED] shall bring these problems to the Commission’s attention immediately. 56

Q 30 Who does PG&E send these reports to?
A 30 PG&E serves these reports on the Directors of the Commission’s Energy Division, Safety and Enforcement Division (SED) and all parties in PG&E’s 2015 GT&S Rate Case, including ORA and TURN.

Q 31 Does PG&E explain its reprioritization in these reports?
A 31 Yes. Reprioritizing work is explained in PG&E’s seven semi-annual GT&S Safety Reports, as well as eight quarterly Transmission Pipeline Compliance Reports. 57 For example, in PG&E’s September 1, 2015 GT&S Safety Report, PG&E explained that it was reprioritizing its entire portfolio because the Commission had yet to issue a decision in the 2015 GT&S Rate Case.

Q 32 To your knowledge, did SED detect any problems with PG&E’s prioritization or administration of storage or pipeline capital projects or Operations and Maintenance (O&M) activities?

57 In D.16-06-056, the Commission ordered PG&E to continue preparing and serving the GT&S Safety Report that initiated with D.11-04-031 (Gas Accord V Decision, pp. 168-169), and to begin preparing and serving the Transmission Pipeline Compliance Report. (Id., p. 477, OP 11.)
A  32 No. If SED detected any such problems, no one ever brought this to
PG&E’s attention.

Q  33 Did ORA or TURN raise any concerns with PG&E regarding these reports?
A  33 No. ORA and TURN do not.

Q  34 Did PG&E’s reprioritization compromise the safety or reliability of PG&E’s
gas transmission system?
A  34 No, it did not. As discussed in prepared opening testimony, though PG&E
slowed the pace of some of its long-term infrastructure sustainability
programs, PG&E accelerated other, higher priority, long-term infrastructure
sustainability programs. PG&E did not postpone any work that needed to be
done in the 2015-2018 period to maintain the safety or reliability of its gas
transmission system.\textsuperscript{58}

J. **TURN’s Recommendations Regarding 2018 Capital Expenditures**
   (Abranches)

Q  35 Please describe TURN’s recommendation.
A  35 TURN recommends two approaches for the Commission to consider
regarding PG&E’s 2018 capital expenditure forecast:\textsuperscript{59}

\begin{enumerate}
\item[a)] Limit PG&E’s forecast to the amount approved in the 2015 GT&S
decision, which TURN indicates is $771 million; or
\item[b)] Limit PG&E’s forecast to 2017 recorded capital expenditures, which
   TURN indicates is $759 million, “plus a modest amount of escalation.”
\end{enumerate}

Q  36 How does PG&E respond?
A  36 PG&E objects to TURN’s proposal, for two reasons. First, both of TURN’s
proposals reflect a capital forecast for 2018 that is lower than, not only
PG&E’s 2018 capital forecast, but also PG&E’s budget for 2018, which is
$978 million, with no justification for any reductions to specific Major Work
Category or Maintenance Activity Type Code forecasts. If TURN’s
proposals are adopted, PG&E will not receive cost-recovery for
approximately $200 million of 2018 capital expenditures. Second, TURN’s
proposals do not comport with Commission utility ratemaking principles.

\textsuperscript{58} PG&E Prepared Testimony, Chapter 4, p. 4-22, lines 28-31.
\textsuperscript{59} TURN, Chapter 14A, p. 1, lines 14-17.
This issue is addressed in Chapter 23 rebuttal testimony, sponsored by Mr. Smith.

Q 37 Does PG&E have an update of it's expense and capital forecasts for 2018?

A 37 No, but because TURN has referenced the recent budget information provided by PG&E, PG&E has updated the figures to reflect its 2018 budget below. The figures also summarize PG&E's 2015-2017 recorded spending, and compare those values, and the 2018 budget values, to the adopted imputed amounts by year.

FIGURE 4-1
2015-2018 RECORDED AND FORECAST EXPENSE VERSUS ADOPTED/IMPUTED VALUES

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Recorded/Forecast Amount</td>
<td>$466</td>
<td>$583</td>
<td>$547</td>
<td>$567</td>
<td>$2,164</td>
</tr>
<tr>
<td>2</td>
<td>Adopted/Imputed Amount</td>
<td>479</td>
<td>495</td>
<td>545</td>
<td>558</td>
<td>2,077</td>
</tr>
<tr>
<td>3</td>
<td>Change</td>
<td>$(14)</td>
<td>$88</td>
<td>$3</td>
<td>$9</td>
<td>$87</td>
</tr>
</tbody>
</table>

Note: The updated Figure reflects PG&E's June 5, 2018 errata. It also reflects new errata to remove $20.81 million in the 2015 recorded amount that is shareholder-funded activity primarily related to corrosion work. Similarly, the 2016 recorded amount removes $10.29 million and the 2017 recorded amount removes $0.76 million for shareholder-funded corrosion work.

60 These are updates for Figures 4-7 and 4-8 from PG&E's Chapter 4 prepared testimony and are consistent with the information provided in PG&E's revised response to TURN-035, Question 3.
**Figure 4-2**

2015-2018 Recorded and Forecast Capital versus Adopted/Imputed Values

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Recorded Cost/Forecast</td>
<td>$613</td>
<td>$735</td>
<td>$745</td>
<td>$978</td>
<td>$3,070</td>
</tr>
<tr>
<td>2</td>
<td>Adopted/Imputed Amount</td>
<td>695</td>
<td>789</td>
<td>838</td>
<td>771</td>
<td>3,092</td>
</tr>
<tr>
<td>3</td>
<td>Change</td>
<td>$(82)</td>
<td>$(54)</td>
<td>$(93)</td>
<td>$207</td>
<td>$(22)</td>
</tr>
</tbody>
</table>

Note:

1) Both recorded/forecast costs and adopted/imputed amounts include the $850 million safety-program costs in D.16.02.010.

2) The recorded/forecast excludes PSEP costs.

3) The changes to figures and tables reflect errata.

---

Q 38 What do Figures 4-1 and 4-2 show?

A 38 Figures 4-1 and 4-2 show that PG&E’s spending—as compared to adopted/imputed amounts from the 2015 GT&S Rate Case Decision—is $87 million more for expense and $22 million less for capital expenditures. PG&E’s addresses the relevance of this fact in Chapter 23 rebuttal testimony, sponsored by Mr. Smith.

Q 39 Does this conclude your testimony?

A 39 Yes.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

EXCERPTS FROM PG&E’S GAS TRANSMISSION AND STORAGE SAFETY REPORTS:

NO. 2015-01, NO. 2015-02, NO. 2016-01, NO. 2016-02,
NO. 2017-01, AND NO. 2017-02
PACIFIC GAS AND ELECTRIC COMPANY

GAS TRANSMISSION AND STORAGE SAFETY REPORT

NO. 2015-01

REPORTING PERIOD
JANUARY 1 – JUNE 30, 2015

IN COMPLIANCE WITH CPUC DECISION 11-04-031

SUBMITTED SEPTEMBER 1, 2015
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NO. 2015-01
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APPENDICES


B. Pipeline Safety Enhancement Plan Costs – from inception to date

C. Pipeline and Hazardous Materials Safety Administration Form 7100.2-1, Annual Report for Calendar Year 2014 Natural or Other Gas Transmission and Gathering Systems – Pacific Gas and Electric Company (March 13, 2015)

Introduction and Background

This Gas Transmission and Storage (GT&S) Safety Report is submitted in compliance with the California Public Utilities Commission (CPUC or Commission) Decision 11-04-031 in Pacific Gas and Electric Company’s (PG&E or the Company) 2011 GT&S Rate Case, which approved the Gas Accord V Settlement Agreement. Ordering Paragraph (OP) 5 of that decision directs PG&E to prepare, on a semi-annual basis, a “Gas Transmission and Storage Safety Report” (GT&S Safety Report) containing information provided in Appendix C of the decision. This safety report (GT&S Safety Report No. 2015-01) reflects the reporting period of January 1 through June 30, 2015, and is being served on the directors of the Commission’s Safety and Enforcement Division (SED), the Energy Division, the service list in the 2011 GT&S Rate Case proceeding (A.09-09-013), and the service list in the 2015 GT&S Rate Case proceeding (A.13-12-012).

In OP 6 of Decision 11-04-031, the Commission directed the SED to review the GT&S Safety Report, establish procedures to monitor PG&E’s storage and pipeline related activities set forth in the reports, assess whether the projects PG&E identified in the proceeding are at risk of not being implemented, and to track whether PG&E is spending its allocated funds on storage and pipeline related safety, reliability, and integrity activities. The Energy Division will provide assistance to the SED to review and monitor the reports. The SED was ordered to immediately bring to the Commission’s attention any detected problems with PG&E’s prioritization or administration of its Gas Transmission (GT) capital and operations and maintenance (O&M) activities.

GT&S Safety Report No. 2015-01 is separated into the eight specific requirements listed in Appendix C of Decision 11-04-031. The introduction of each section of this report quotes the requirement from Appendix C.
PG&E’s 2015 GT&S Application (A.13-12-012) is currently pending before the Commission. Consequently, revenue requirements for the period 2015-2017 or recommendations to improve the existing semi-annual report format have not yet been adopted by the Commission. Until a final decision is adopted by the Commission, PG&E will continue to use the current report format.

Pipeline Safety Enhancement Plan

Decision 12-12-030, issued December 28, 2012, approved Phase 1 of PG&E’s Pipeline Safety Enhancement Plan (PSEP). OP 10 of Decision 12-12-030 required PG&E to submit quarterly compliance reports on PSEP activities through the end of Phase 1 (2014). Consistent with prior GT&S semi-annual reports, PG&E continues to include PSEP activities through June 30, 2015 in this report. PG&E has included in Appendix A an updated list of PSEP projects that were completed in the reporting period, under construction or yet to begin construction. Included in Appendix B is a table that provides PSEP costs from inception to date broken down by month and by activity.

Summary

In total, PG&E budgeted over $1.1 billion in capital expenditures and expenses for GT&S as of January 1, 2015.

Capital

As of June 30, 2015, PG&E expects to spend $582.1 million in total for 2015 for GT Capital Major Work Categories (MWC) (not including the Adder and StanPac Projects of $15.4 million). The total actual capital spend through June 30, 2015 was $251.1 million: $248.7 million for safety and reliability related capital and $2.4 million for Adder and StanPac projects. The Adder projects are only included in rates after becoming operational. See Table 1 below for a summary of the capital costs described above. See Table 2-1 on page 8 for further details.

Expense

As of June 30, 2015, PG&E expects to spend $566.9 million for GT Expense MWCs in 2015, not including the $2.7 million for StanPac projects. The total actual spend through June 30, 2015 for GT expense was $200.2 million: $198.8 million for safety and reliability related expense and $1.4 million for StanPac. See Table 1 below for a summary of the expense costs described above. See Table 2-2 on page 9 for further details.
TABLE 1
2015 GAS STORAGE, PIPELINE SAFETY, INTEGRITY AND RELIABILITY PROJECTS
REPORTING PERIOD JANUARY 1 – JUNE 30, 2015
(IN MILLIONS OF 2015 DOLLARS)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Costs(a)</th>
<th>Annual Budget 1/1/15</th>
<th>Annual Budget 6/30/15</th>
<th>Actual 1/1-6/30</th>
<th>2015 CPUC Authorized</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>Capital</td>
<td>541.4</td>
<td>582.1</td>
<td>248.7</td>
<td>N/A</td>
</tr>
<tr>
<td>2</td>
<td>Expense</td>
<td>597.9</td>
<td>566.9</td>
<td>198.8</td>
<td>N/A</td>
</tr>
</tbody>
</table>

(a) Excluding StanPac and Adder Projects.

For the period January 1 to June 30, 2015, PG&E has completed O&M activities including 66,412 cumulative miles of pipeline inspections, and 13,729 facility inspections. The pipeline inspection activities include 5,974.1 miles of pipeline leak surveys, 60,341 miles of pipeline patrols, 44.2 miles of pipeline hydrostatic testing work (which includes 18.9 miles of validated records for prior hydrostatic testing in the first half of 2015), and 53 miles of integrity management assessments. The facility inspection activities include 6,955 Cathodic Protection (CP) reads, and maintenance and inspection performed on 1,243 district regulator stations and 5,531 valves. In addition, PG&E standby personnel were sent out to 1,094 sites to ensure pipeline safety where third parties were performing excavation work. See Table 7-1, Gas Transmission Pipeline Inspection Plan, for more details on the work described above for the current reporting period.

This report also includes detailed information on over 936 capital projects and work activities and over 851 expense projects and work activities, as shown in Table 3-1.
1. **Explanation for Ranking Gas Transmission Pipeline, Storage, Safety, Integrity, Inspection, Reliability and Operations and Maintenance Projects**

A thorough description and explanation of the strategic planning and decision-making approach PG&E uses to determine and rank the gas storage projects, pipeline transmission safety, integrity, and reliability of its pipeline projects, O&M activities, and inspections of its gas transmission pipelines. If there has been no change in PG&E’s approach for determining and ranking which projects and activities are prioritized since the last Safety Report, the Safety Report may reference the earlier Safety Report.

**Response**

**Strategic Planning**


**Reprioritization Due to Delay in 2015 GT&S Rate Case Decision**

In November 2014, Gas Transmission re-prioritized the investment portfolio due to the delay in the 2015 GT&S rate case proceeding. The result was a portfolio that facilitated flexibility of execution by including more design and engineering work in 2015 versus planned construction, while including execution of all mandatory work to ensure compliance requirements are met. This enables PG&E flexibility to execute on the portfolio of work in accordance with the Commission's decision on PG&E’s 2015 GT&S rate case. Although a reduction in 2015 construction has occurred, efforts to increase engineering work activities will allow PG&E to scale work execution based on the rate case decision.

In re-planning the portfolio, the GT organization utilized the same framework outlined in previous GT&S Safety Reports¹ to reallocate funding for projects based on risk. The outcome of the re-planning effort was reviewed with and approved by senior Gas Operations leadership during the Finance and IT Governance meeting, and changes to the original plan were recorded in SAP.

---

Budgeting and Spending

2. Explanation of Funds Budgeted and Spent for Each Major Work Category

   The Safety Report must describe the amount of funds budgeted at the beginning of each calendar year and over the rate case period, as well as the amount spent during the reporting period and for that calendar year, for each MWC related to gas storage, pipeline safety, integrity and reliability for capital expenditures and for O&M activities. To the extent these funds are specified in the settlement or other document, such as work papers or testimony, references to where these amounts are mentioned must be provided.

Response

   The 2015 amounts budgeted and spent under the capital and expense MWCs related to GT system safety, integrity, and reliability are displayed under Tables 2-1 and 2-2. PG&E has added MWCs since GT&S Safety Report No. 2014-02 was published. Refer to Figure 2-1 which summarizes the additions.
Budgets are approved by management on an annual basis in the fourth quarter of the previous year and updated as needed throughout the year. PG&E’s initial 2015 budget for GT Capital MWCs (excluding the Adder and StanPac Projects of $15.4 million) was $541.4 million. PG&E’s adjusted budget on June 30, 2015 (excluding the Adder and StanPac Projects of $15.4 million) was $582.1 million. The adjustments to the budget were due to modifications to the 2015 Plan based on new information, identification of emergent work, changes in cost estimates, and/or changes in execution schedules. The GT organization utilized the framework outlined in Section 1 of the previous GT&S
Safety Report No. 2014-02 and completed a risk-based reallocation of funding earlier in the year.

PG&E’s initial 2015 budget for GT Expense MWCs, excluding $2.7 million for StanPac projects, was $597.9 million. PG&E’s adjusted budget on June 30, 2015, excluding $2.7 million for StanPac projects, was $566.9 million. The adjustments to the budget were based on changes to the 2015 Plan. Similar to capital work, the GT organization modified its expense budget to incorporate new information, identified emergent work, updated cost estimates and/or execution schedules.

Although less than 50 percent of the amounts budgeted for 2015 have been spent during the first six months of the year, the full amounts budgeted are expected to be spent by year end.

The following MWCs are excluded from this report, consistent with prior GT&S Safety Reports:

- Capital: 5 (Tools & Equipment), 12 (Implement Environment Projects),
- 26 (GT Customer Connects), 78 (Manage Buildings), 83 (GT Work Required by Others (WRO)), 2F (Build IT Applications and Infrastructure).
- Expense: AK (Manage Environmental Operations), AY (Habitat & Species Protection), CR (Manage Waste Disposal & Transportation), CX (Gas Transmission Marketing, Sales & Strategy), GZ (Research and Development Non-Balancing Account), GM (Manage Energy Efficiency-Non-BA), JV (Maintain IT Applications and Infrastructure), AB (Miscellaneous Expense), DN (Develop and Provide Training).
### TABLE 2-1

**2015 GAS STORAGE, PIPELINE SAFETY, INTEGRITY AND RELIABILITY PROJECTS CAPITAL BUDGET BY MWC**

**REPORTING PERIOD JANUARY 1 TO JUNE 30, 2015**

**(IN THOUSANDS OF 2015 DOLLARS)**

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Budget As of 1/1</th>
<th>Annual Budget As of 6/30</th>
<th>Actual Spend 1/1 - 6/30</th>
<th>CPUC Adopted Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>73</td>
<td>GT Pipeline Capacity</td>
<td>31,425</td>
<td>33,415</td>
<td>6,150</td>
<td>N/A</td>
</tr>
<tr>
<td>75</td>
<td>GT Pipeline Reliability</td>
<td>203,039</td>
<td>236,131</td>
<td>79,788</td>
<td>N/A</td>
</tr>
<tr>
<td>76</td>
<td>GT Station Reliability</td>
<td>76,884</td>
<td>79,366</td>
<td>33,403</td>
<td>N/A</td>
</tr>
<tr>
<td>84</td>
<td>GT Gas Gathering System Manage</td>
<td>258</td>
<td>643</td>
<td>392</td>
<td>N/A</td>
</tr>
<tr>
<td>98</td>
<td>GT Integrity Management</td>
<td>86,398</td>
<td>88,826</td>
<td>32,948</td>
<td>N/A</td>
</tr>
<tr>
<td>2H</td>
<td>GT PL Safety Enhance Plan- Cap</td>
<td>96,500</td>
<td>96,500</td>
<td>74,144</td>
<td>N/A</td>
</tr>
<tr>
<td>3K</td>
<td>Gas Trans RemEDIATE Corrosion</td>
<td>44,382</td>
<td>44,382</td>
<td>19,451</td>
<td>N/A</td>
</tr>
<tr>
<td>3L</td>
<td>Gas Trans Storage Wells</td>
<td>2,525</td>
<td>2,820</td>
<td>2,315</td>
<td>N/A</td>
</tr>
<tr>
<td>2J</td>
<td>GT&amp;D Impl Regulatory Change</td>
<td>0</td>
<td>0</td>
<td>78</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Gas Transmission Capital** | 541,411 | 582,083 | 248,669 | - |

**Gas Transmission Adder Projects**

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Budget As of 1/1</th>
<th>Annual Budget As of 6/30</th>
<th>Actual Spend 1/1 - 6/30</th>
<th>CPUC Adopted Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>73</td>
<td>GT Pipeline Capacity</td>
<td>10,052</td>
<td>10,052</td>
<td>1,991</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**StanPac**

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Budget As of 1/1</th>
<th>Annual Budget As of 6/30</th>
<th>Actual Spend 1/1 - 6/30</th>
<th>CPUC Adopted Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>44</td>
<td>Gas Capital:GasTrans-Subsidiary</td>
<td>5,328</td>
<td>5,328</td>
<td>450</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Gas Transmission Capital- Including Adder Projects and StanPac** | 556,791 | 597,463 | 251,109 | - |

**Footnotes:**

1 There were several projects that were designated as “Adder” projects for the Gas Accord V period, in Section 7.4 of the Gas Accord V Settlement.

2 MWC 3K is new in 2015. Corrosion related work within MWC 75 has been separated into a second MWC to promote greater visibility.

3 MWC 3L is new in 2015. Corrosion related work within MWC 76 has been separated into a second MWC to promote greater visibility.
TABLE 2-2
2015 GAS STORAGE, PIPELINE SAFETY, INTEGRITY AND RELIABILITY O&M ACTIVITIES
BUDGET BY MWC
REPORTING PERIOD JANUARY 1 TO JUNE 30, 2015
(IN THOUSANDS OF 2015 DOLLARS)

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Budget As of 1/1</th>
<th>Annual Budget As of 6/30</th>
<th>Actual Spend 1/1 - 6/30</th>
<th>CPUC Adopted Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>JO</td>
<td>GT Pipeline Maintenance</td>
<td>37,621</td>
<td>37,621</td>
<td>15,531</td>
<td>N/A</td>
</tr>
<tr>
<td>JP</td>
<td>GT Station Maintenance</td>
<td>24,691</td>
<td>24,691</td>
<td>12,891</td>
<td>N/A</td>
</tr>
<tr>
<td>JT</td>
<td>GT Reliability &amp; General Maint</td>
<td>247,393</td>
<td>247,393</td>
<td>73,450</td>
<td>N/A</td>
</tr>
<tr>
<td>CM</td>
<td>GT Operate System</td>
<td>21,132</td>
<td>19,632</td>
<td>8,640</td>
<td>N/A</td>
</tr>
<tr>
<td>KE</td>
<td>GT PL Safety Enhance Plan-Exp</td>
<td>21,598</td>
<td>10,000</td>
<td>9,178</td>
<td>N/A</td>
</tr>
<tr>
<td>KF</td>
<td>GT&amp;D Impl Regulatory Change</td>
<td>-</td>
<td>-</td>
<td>9</td>
<td>N/A</td>
</tr>
<tr>
<td>DF</td>
<td>G&amp;E T&amp;D Locate &amp; Mark</td>
<td>7,833</td>
<td>7,833</td>
<td>3,682</td>
<td>N/A</td>
</tr>
<tr>
<td>GJ</td>
<td>Gas Transmission Mitigate Corr</td>
<td>53,815</td>
<td>35,903</td>
<td>6,158</td>
<td>N/A</td>
</tr>
<tr>
<td>II / HP</td>
<td>GT Integrity Management</td>
<td>183,840</td>
<td>183,840</td>
<td>69,215</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Gas Transmission Expense**

<table>
<thead>
<tr>
<th></th>
<th>Annual Budget As of 1/1</th>
<th>Annual Budget As of 6/30</th>
<th>Actual Spend 1/1 - 6/30</th>
<th>CPUC Adopted Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>JO</td>
<td>37,621</td>
<td>37,621</td>
<td>15,531</td>
<td>N/A</td>
</tr>
<tr>
<td>JP</td>
<td>24,691</td>
<td>24,691</td>
<td>12,891</td>
<td>N/A</td>
</tr>
<tr>
<td>JT</td>
<td>247,393</td>
<td>247,393</td>
<td>73,450</td>
<td>N/A</td>
</tr>
<tr>
<td>CM</td>
<td>21,132</td>
<td>19,632</td>
<td>8,640</td>
<td>N/A</td>
</tr>
<tr>
<td>KE</td>
<td>21,598</td>
<td>10,000</td>
<td>9,178</td>
<td>N/A</td>
</tr>
<tr>
<td>KF</td>
<td>-</td>
<td>-</td>
<td>9</td>
<td>N/A</td>
</tr>
<tr>
<td>DF</td>
<td>7,833</td>
<td>7,833</td>
<td>3,682</td>
<td>N/A</td>
</tr>
<tr>
<td>GJ</td>
<td>53,815</td>
<td>35,903</td>
<td>6,158</td>
<td>N/A</td>
</tr>
<tr>
<td>II / HP</td>
<td>183,840</td>
<td>183,840</td>
<td>69,215</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Gas Transmission Expense- Including StanPac</strong></td>
<td>600,594</td>
<td>569,584</td>
<td>200,170</td>
<td>-</td>
</tr>
</tbody>
</table>

**Footnotes:**

1 MWC GJ is new in 2015. Budget and Actual values reflect Transmission only. Corrosion mitigation work within MWC HP has been separated into a second MWC to promote greater visibility.

2 Gas Transmission Integrity Management expenses are recorded in MWC II and HP. The creation of MWC HP was necessitated for accounting purposes by the authorization of a one-way balancing account for Gas Transmission Integrity Management expenses in Gas Accord V. PG&E will continue to spend under both MWCs until a final decision is reached with the 2015 GT&S rate case and cost treatment of Integrity Management program for 2015-2017 is finalized.
PACIFIC GAS AND ELECTRIC COMPANY
GAS TRANSMISSION AND STORAGE SAFETY REPORT
NO. 2015-02

REPORTING PERIOD
JULY 1 – DECEMBER 31, 2015

IN COMPLIANCE WITH CPUC DECISION 11-04-031

SUBMITTED MARCH 1, 2016
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I. Stress Corrosion Cracking Direct Assessment – TD-4810P-13 (Formerly RMP-13)
J. Continual Evaluation – TD-4810P-17 (Formerly RMP-17)
K. Direct Examination Procedure – TD-4810P-18 (Formerly RMP-18)
L. Integrity Management Quality Control Plan – TD-4810P-20 (Formerly RMP-20)
M. Management of Change – TD-4810P-21 (Formerly RMP-21)
N. 2014 Transmission Integrity Management – Assessment Plan (Revision 10, August 11, 2015)
P. CPUC Resolution ALJ-274 Self-Identified Non-Compliance Notification – March 3, 2015
Introduction and Background

This Gas Transmission and Storage (GT&S) Safety Report is submitted in compliance with the California Public Utilities Commission (CPUC or Commission) Decision (D.) 11-04-031 in Pacific Gas and Electric Company’s (PG&E) 2011 GT&S Rate Case, which approved the Gas Accord V Settlement Agreement. Ordering Paragraph (OP) 5 of that decision directs PG&E to prepare, on a semi-annual basis, a “Gas Transmission and Storage Safety Report” (GT&S Safety Report) containing information provided in Appendix C of the decision. This safety report (GT&S Safety Report No. 2015-02) reflects the reporting period of July 1 through December 31, 2015, and is being served on the directors of the Commission’s Safety and Enforcement Division (SED), the Energy Division, the service list in the 2011 GT&S Rate Case proceeding (Application (A.) 09-09-013), and the service list in the 2015 GT&S Rate Case proceeding (A.13-12-012).

In OP 6 of D.11-04-031, the Commission directed the SED to review the GT&S Safety Report, establish procedures to monitor PG&E’s storage and pipeline related activities set forth in the reports, assess whether the projects PG&E identified in the proceeding are at risk of not being implemented, and to track whether PG&E is spending its allocated funds on storage and pipeline related safety, reliability and integrity activities. The Energy Division will provide assistance to the SED to review and monitor the reports. The SED was ordered to immediately bring to the Commission’s attention any detected problems with PG&E’s prioritization or administration of its Gas Transmission (GT) capital and operations and maintenance (O&M) activities.

GT&S Safety Report No. 2015-02 addresses each of the eight specific requirements listed in Appendix C of D.11-04-031. The introduction of each section of this report quotes the requirement from Appendix C.
PG&E’s 2015 GT&S Application (A.13-12-012) is currently pending before the Commission. Consequently, revenue requirements for the period 2015-2017 or recommendations to improve the existing semi-annual report format have not yet been adopted by the Commission. Until a final decision is adopted by the Commission, PG&E will continue to use the current report format.1

Pipeline Safety Enhancement Plan

D.12-12-030, issued December 28, 2012, approved Phase 1 of PG&E’s Pipeline Safety Enhancement Plan (PSEP). OP 10 of D.12-12-030 required PG&E to submit quarterly compliance reports on PSEP activities through the end of Phase 1 (2014). Consistent with prior GT&S semi-annual reports, PG&E continues to include PSEP activities through December 31, 2015 in this report. PG&E has included in Appendix A an updated list of PSEP projects that were completed in the reporting period, under construction or yet to begin construction. Included in Appendix B is a table that provides PSEP costs from inception to date broken down by month and by activity.

Summary

For 2015, PG&E’s total actual spend was over $1.1 billion in capital expenditures and expenses for GT&S related activities. PG&E’s annual budget as of December 31, 2015 was adjusted due to modifications based on new information, identification of emergent work, changes in cost estimates, and/or changes in execution schedules.2

Capital

For 2015, PG&E expected to spend $581.8 million for GT Capital Major Work Categories (MWC) (not including the Adder and StanPac Projects of $15.4 million). The total actual capital spend through December 31, 2015 was $629.8 million: $618.5 million for safety and reliability related capital and $11.3 million for Adder and StanPac projects. See Table 1 below for a summary of the capital costs described above. See Table 2-1 on page 8 for further details.

1 In the absence of a Commission decision on the 2015 GT&S rate case, PG&E continued to prioritize its work based on risk. The projects included in PG&E’s 2015 Gas Transmission and Storage Safety Reports may differ from the programs and projects categorized as “safety related” in a Phase II Decision in A.13-12-012, since the San Bruno Penalty Decision 15-04-024 adopted specific criteria for categorizing programs and projects as “safety-related.”

2 The beginning-of-year budgeted amounts vary from the budgeted amounts as reported in GT&S Safety Report No. 2015-01 due to planning order re-alignment between MWCs.
Expense

For 2015, PG&E expected to spend $577.4 million for GT Expense MWCs, not including the $2.7 million for StanPac projects. The total actual spend through December 31, 2015 for GT expense was $554.7 million: $552.6 million for safety and reliability related expense and $2.1 million for StanPac. See Table 1 below for a summary of the expense costs described above. See Table 2-2 on page 9 for further details.

### TABLE 1
2015 GAS STORAGE, PIPELINE SAFETY, INTEGRITY, AND RELIABILITY PROJECTS REPORTING PERIOD JULY 1 – DECEMBER 31, 2015 (MILLIONS OF 2015 DOLLARS)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Annual 1/1/15 Budget</th>
<th>Annual 12/31/15 Budget</th>
<th>Actual 7/1-12/31 Spend</th>
<th>YTD Actuals 12/31</th>
<th>2015 CPUC Authorized</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Capital</td>
<td>541.1</td>
<td>581.8</td>
<td>369.7</td>
<td>618.5</td>
</tr>
<tr>
<td>2</td>
<td>Expense</td>
<td>597.9</td>
<td>577.4</td>
<td>353.6</td>
<td>552.6</td>
</tr>
</tbody>
</table>

(a) Excluding StanPac and Adder Projects.

For the period of July 1 to December 31, 2015, PG&E has completed O&M activities including 67,512 cumulative miles of pipeline inspections and 12,061 facility inspections. The pipeline inspection activities include 4,370.1 miles of pipeline leak surveys, 63,007 miles of pipeline patrols, 56.11 miles of pipeline hydrostatic testing work (which includes 20.93 miles of validated records for prior hydrostatic testing in the second half of 2015), and 78.9 miles of integrity management assessments. The facility inspection activities include 6,127 Cathodic Protection reads, and maintenance and inspection performed on 3,124 district regulator stations and 2,810 valves. In addition, PG&E standby personnel were sent out to 2,176 sites to ensure pipeline safety where third parties were performing excavation work. See Table 7-1, Gas Transmission Pipeline Inspection Plan, for more details on the work described above for the current reporting period.

This report also includes detailed information on 1,135 capital projects and work activities and 1,007 expense projects and work activities, as shown in Table 3-1.
1. Explanation for Ranking Gas Transmission Pipeline, Storage, Safety, Integrity, Inspection, Reliability, and Operations and Maintenance Projects

A thorough description and explanation of the strategic planning and decision-making approach PG&E uses to determine and rank the gas storage projects, pipeline transmission safety, integrity, and reliability of its pipeline projects, O&M activities, and inspections of its gas transmission pipelines. If there has been no change in PG&E’s approach for determining and ranking which projects and activities are prioritized since the last Safety Report, the Safety Report may reference the earlier Safety Report.

Response

Strategic Planning


Other Risk Groups on the Risk Register

In addition to the asset family structure described in GT&S Safety Report No. 2014-02, some risks are outside the scope of the risk registers for the asset families and are managed by separate “risk groups.” These types of risks often span multiple asset families. Examples include risks identified within the Gas System Operations organization (e.g., Failure to Maintain Capacity for System Demands). Risks from risk groups are included in the risk register, Session D, and have mitigation programs that are ranked alongside asset family mitigation programs during S1 and S2.

Similar to asset families, risk groups have a defined risk owner and subject matter experts that are responsible for identifying, mitigating, and reporting on risk. Risk groups follow the same general process as asset families for the risk register as described in the GT&S Safety Report No. 2014-02.

Reprioritization Due to Delay in 2015 GT&S Rate Case Decision

In November 2014, Gas Transmission re-prioritized the investment portfolio due to the delay in the 2015 GT&S rate case proceeding. The result was a portfolio that facilitated flexibility of execution by including more design and engineering work in 2015 versus planned construction, while including execution
of all mandatory work to ensure compliance requirements are met, providing PG&E flexibility to execute on the portfolio of work. Although a reduction in 2015 construction has occurred, efforts to increase engineering work activities will allow PG&E to scale work execution based on the rate case decision.

In re-planning the portfolio, the Gas Transmission organization utilized the same framework outlined in previous GT&S Safety Reports\(^3\) to reallocate funding for projects informed by risk. The outcome of the re-planning effort was reviewed with and approved by senior Gas Operations leadership during the Finance and Information Technology (IT) Governance meeting, and changes to the original plan were recorded in SAP.

\(^3\) [http://pgera.azurewebsites.net/Regulation/search?CaseID=882](http://pgera.azurewebsites.net/Regulation/search?CaseID=882)
### Budgeting and Spending

2. **Explanation of Funds Budgeted and Spent for Each Major Work Category**

   *The Safety Report must describe the amount of funds budgeted at the beginning of each calendar year and over the rate case period, as well as the amount spent during the reporting period and for that calendar year, for each MWC related to gas storage, pipeline safety, integrity and reliability for capital expenditures and for O&M activities. To the extent these funds are specified in the settlement or other document, such as work papers or testimony, references to where these amounts are mentioned must be provided.*

**Response**

The 2015 amounts budgeted and spent under the capital and expense MWCs related to GT system safety, integrity, and reliability are displayed under Tables 2-1 and 2-2. 4 PG&E added MWCs in 2015. Refer to Figure 2-1, page 6, in GT&S Safety Report No. 2015-01 for a summary of the addition.

Budgets are approved by management on an annual basis in the fourth quarter of the previous year and updated as needed throughout the year. PG&E’s initial 2015 budget for GT Capital MWCs (excluding the Adder and StanPac Projects of $15.4 million) 5 was $541.1 million. PG&E’s adjusted budget as of December 31, 2015 (excluding the Adder and StanPac Projects of $15.4 million) was $581.8 million. The adjustments to the budget were due to modifications to the 2015 planned budget based on new information, identification of emergent work, changes in cost estimates, and/or changes in execution schedules. The GT organization utilized the framework outlined in Section 1, as described in Report No. 2014-02, and completed a risk-based reallocation of funding.

---

4 The projects included in PG&E’s 2015 Gas Transmission and Storage Safety Reports may differ from the programs and projects categorized as “safety related” in a Phase II Decision in A.13-12-012, since the San Bruno Penalty Decision 15-04-024 adopted specific criteria for categorizing programs and projects as “safety related.”

5 In Section 7.2 of Appendix A of D.11-04-031, the Commission set forth the adopted amounts for capital expenditures for each year in the period 2011-2014. PG&E continues to list separately the adder projects identified in Section 7.4.1 of the Gas Accord V Settlement Agreement and includes the yearly capital spend, even though the Adder projects are no longer subject to the cost caps identified in the Gas Accord V Settlement.
PG&E’s initial 2015 budget for GT Expense MWCs, excluding $2.7 million for StanPac projects, was $597.9 million. PG&E’s adjusted budget as of December 31, 2015, excluding $2.7 million for StanPac projects, was $577.4 million. The adjustments to the budget were based on changes to the 2015 Plan. Similar to capital work, the GT organization modified its expense budget to incorporate new information, identified emergent work, updated cost estimates and/or changes in execution schedules.

To the extent that there are material differences in the annual budget by MWC and the actual spend at Year-End, those variance explanations can be found in the response to Section 5.

The following MWCs are excluded from this report, consistent with prior GT&S Safety Reports:

- Capital:  5 (Tools & Equipment), 12 (Implement Environment Projects);  
- 26 (GT Customer Connects), 78 (Manage Buildings), 83 (GT Work Required by Others), 2F (Build IT Applications and Infrastructure); and  
- Expense:  AK (Manage Environmental Operations), AY (Habitat & Species Protection), CR (Manage Waste Disposal & Transportation), CX (Gas Transmission Marketing, Sales & Strategy), GZ (Research and Development Non-Balancing Account), GM (Manage Energy Efficiency-Non-BA), JV (Maintain IT Applications and Infrastructure), AB (Miscellaneous Expense), DN (Develop and Provide Training).
# Table 2-1

## 2015 Gas Storage, Pipeline Safety, Integrity, and Reliability Projects Capital Budget by Major Work Category

**Reporting Period: July 1 to December 31, 2015**

(Thousands of 2015 Dollars)

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Budget As of 1/1</th>
<th>Annual Budget As of 12/31</th>
<th>Actual Spend 7/1 - 12/31</th>
<th>YTD Actuals 12/31</th>
<th>Variance (YTD Actuals - 1/1 Budget)</th>
<th>CPUC Adopted Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>73</td>
<td>GT Pipeline Capacity</td>
<td>31,425</td>
<td>34,055</td>
<td>10,601</td>
<td>16,970</td>
<td>(14,454)</td>
<td>N/A</td>
</tr>
<tr>
<td>75</td>
<td>GT Pipeline Reliability</td>
<td>195,425</td>
<td>223,507</td>
<td>160,789</td>
<td>234,836</td>
<td>39,411</td>
<td>N/A</td>
</tr>
<tr>
<td>76</td>
<td>GT Station Reliability</td>
<td>77,398</td>
<td>84,469</td>
<td>56,661</td>
<td>84,123</td>
<td>16,725</td>
<td>N/A</td>
</tr>
<tr>
<td>84</td>
<td>GT Gas Gathering System Manage</td>
<td>295</td>
<td>643</td>
<td>962</td>
<td>1,354</td>
<td>1,097</td>
<td>N/A</td>
</tr>
<tr>
<td>98</td>
<td>GT Integrity Management</td>
<td>86,398</td>
<td>88,826</td>
<td>95,589</td>
<td>128,553</td>
<td>42,155</td>
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<tr>
<td>2H</td>
<td>GT PL Safety Enhance Plan - Cap</td>
<td>96,500</td>
<td>96,500</td>
<td>7,283</td>
<td>81,401</td>
<td>(15,099)</td>
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</tr>
<tr>
<td>3K</td>
<td>Gas Trans Remediate Corrosion</td>
<td>44,382</td>
<td>44,382</td>
<td>27,470</td>
<td>46,915</td>
<td>2,533</td>
<td>N/A</td>
</tr>
<tr>
<td>3L</td>
<td>Gas Trans Storage Wells</td>
<td>9,325</td>
<td>9,400</td>
<td>10,480</td>
<td>14,310</td>
<td>4,985</td>
<td>N/A</td>
</tr>
<tr>
<td>2J</td>
<td>GT&amp;D Impt Regulatory Change</td>
<td>0</td>
<td>0</td>
<td>(31)</td>
<td>(4)</td>
<td>(4)</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Gas Transmission Capital**

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Budget As of 1/1</th>
<th>Annual Budget As of 12/31</th>
<th>Actual Spend 7/1 - 12/31</th>
<th>YTD Actuals 12/31</th>
<th>Variance (YTD Actuals - 1/1 Budget)</th>
<th>CPUC Adopted Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>73</td>
<td>Gas Transmission Adder Projects</td>
<td>10,052</td>
<td>10,052</td>
<td>8,178</td>
<td>9,917</td>
<td>(135)</td>
<td>N/A</td>
</tr>
<tr>
<td>44</td>
<td>StanPac</td>
<td>5,328</td>
<td>5,328</td>
<td>931</td>
<td>1,381</td>
<td>(3,947)</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Gas Transmission Capital - Including Adder Projects and StanPac**

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Budget As of 1/1</th>
<th>Annual Budget As of 12/31</th>
<th>Actual Spend 7/1 - 12/31</th>
<th>YTD Actuals 12/31</th>
<th>Variance (YTD Actuals - 1/1 Budget)</th>
<th>CPUC Adopted Amount</th>
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<tr>
<td>556,491</td>
<td>Gas Transmission Capital</td>
<td>597,163</td>
<td>378,843</td>
<td>629,757</td>
<td>73,266</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

**Footnotes:**

1. Budgets are generally approved by management on an annual basis, in the 4th quarter, for the following calendar year and updated as needed throughout the year.
2. A proposed decision in PG&E’s 2015 GT&S application is currently pending. A Phase II decision will determine which programs proposed in A.13-12-012 meet the safety related definitions established in D.15-04-024.
3. Variance between Budget 1/1 for MWC 75 as filed in Safety report 2015-01 (Jan-June) due to planning order re-alignment between MWCs.
4. Variance between Budget 1/1 for MWC 76 as filed in Safety report 2015-01 (Jan-June) due to planning order re-alignment between MWCs.
5. MWC 3K is new in 2015. Corrosion related work within MWC 75 has been separated into a second MWC to promote greater visibility.
6. MWC 3L is new in 2015. Corrosion related work within MWC 76 has been separated into a second MWC to promote greater visibility. Variance between Budget 1/1 for MWC 3L as filed in Safety report 2015-01 (Jan-June) due to planning order re-alignment between MWCs.
7. There were several projects that were designated as “Adder” projects for the Gas Accord V period, in Section 7.4 of the Gas Accord V Settlement.
## 2015 Gas Storage, Pipeline Safety, Integrity, and Reliability O&M Activities
### Budget by Major Work Category
#### Reporting Period July 1 to December 31, 2015
(Thousands of 2015 Dollars)

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Budget As of 1/1</th>
<th>Annual Budget As of 12/31</th>
<th>Actual Spend 7/1 - 12/31</th>
<th>YTD Actuals 12/31</th>
<th>Variance (YTD Actuals-1/1 Budget)</th>
<th>CPUC Adopted Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>JO</td>
<td>GT Pipeline Maintenance</td>
<td>37,621</td>
<td>37,621</td>
<td>17,726</td>
<td>33,263</td>
<td>(4,358)</td>
<td>N/A</td>
</tr>
<tr>
<td>JP</td>
<td>GT Station Maintenance</td>
<td>24,691</td>
<td>24,691</td>
<td>12,328</td>
<td>25,194</td>
<td>503</td>
<td>N/A</td>
</tr>
<tr>
<td>JT</td>
<td>GT Reliability &amp; General Maint</td>
<td>247,393</td>
<td>247,393</td>
<td>128,336</td>
<td>201,705</td>
<td>(45,667)</td>
<td>N/A</td>
</tr>
<tr>
<td>CM</td>
<td>GT Operate System</td>
<td>21,132</td>
<td>19,632</td>
<td>8,837</td>
<td>17,477</td>
<td>(3,654)</td>
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<tr>
<td>KE</td>
<td>GT PL Safety Enhance Plan-Exp</td>
<td>21,598</td>
<td>10,000</td>
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<td>15,858</td>
<td>(5,740)</td>
<td>N/A</td>
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<tr>
<td>KF</td>
<td>GT&amp;D Impi Regulatory Change</td>
<td>0</td>
<td>0</td>
<td>28</td>
<td>37</td>
<td>37</td>
<td>N/A</td>
</tr>
<tr>
<td>DF</td>
<td>GT T&amp;D Locate &amp; Mark</td>
<td>7,833</td>
<td>7,833</td>
<td>5,007</td>
<td>8,689</td>
<td>856</td>
<td>N/A</td>
</tr>
<tr>
<td>GJ</td>
<td>Gas Transmission Mitigate Corr</td>
<td>53,815</td>
<td>35,903</td>
<td>22,820</td>
<td>29,061</td>
<td>(24,754)</td>
<td>N/A</td>
</tr>
<tr>
<td>II / HP</td>
<td>GT Integrity Management</td>
<td>183,840</td>
<td>194,340</td>
<td>152,083</td>
<td>221,316</td>
<td>37,476</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>Gas Transmission Expense</td>
<td>597,922</td>
<td>577,412</td>
<td>353,576</td>
<td>552,599</td>
<td>(45,323)</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>StanPac</td>
<td>2,672</td>
<td>2,672</td>
<td>646</td>
<td>2,063</td>
<td>(609)</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>Gas Transmission Expense- Including StanPac</td>
<td>600,594</td>
<td>580,084</td>
<td>354,222</td>
<td>554,662</td>
<td>(45,932)</td>
<td>-</td>
</tr>
</tbody>
</table>

**Footnotes:**
1. Budgets are generally approved by management on an annual basis, in the 4th quarter, for the following calendar year and updated as needed throughout the year.
2. A proposed decision in PG&E's 2015 GT&S application is currently pending. A Phase II decision will determine which programs proposed in A.13-12-012 meet the safety related definitions established in D.15-04-024.
3. MWC GJ is new in 2015. Budget and Actual values reflect Transmission only. Corrosion mitigation work within MWC HP has been separated into a second MWC to promote greater visibility.
4. Gas Transmission Integrity Management expenses are recorded in MWC II and HP. The creation of MWC HP was necessitated for accounting purposes by the authorization of a one-way balancing account for Gas Transmission Integrity Management expenses in Gas Accord V. PG&E will continue to spend under both MWCs until a final decision is reached with the 2015 GT&S rate case and cost treatment of Integrity Management program for 2015-2017 is finalized.
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APPENDICES


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D. Time-Dependent Threat Algorithm – TD-4810P-02 (Former RMP-02)

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F. Weather-Related and Outside Forces Threat Algorithm – TD-4810P-04 (Former RMP-04)

G. Manufacturing and Construction Threat Algorithm – TD-4810P-05 (Former RMP-05)

H. Incorrect Operations and Equipment Failure Threat Algorithm – TD-4810P-19 (Former RMP-19)

I. Strength Test as an Integrity Assessment – TD-4810P-23 (Former RMP-23)

J. Pipeline and Hazardous Materials Safety Administration Form 7100.2-1, Annual Report for Calendar Year 2015 Natural or Other Gas Transmission and Gathering Systems – Pacific Gas and Electric Company (March 15, 2016)

K. Pipeline and Hazardous Materials Safety Administration Form 7100.2-1, Annual Report for Calendar Year 2015 Natural or Other Gas Transmission and Gathering Systems – Standard Pacific Gas Line, Inc. (March 15, 2016)
Introduction and Background

This Gas Transmission and Storage (GT&S) Safety Report is submitted in compliance with the California Public Utilities Commission (CPUC or Commission) Decision (D.) 11-04-031 in Pacific Gas and Electric Company’s (PG&E or the Company) 2011 GT&S Rate Case, which approved the Gas Accord V Settlement Agreement. Ordering Paragraph (OP) 5 of that decision directs PG&E to prepare, on a semi-annual basis, a “Gas Transmission and Storage Safety Report” (GT&S Safety Report) containing information provided in Appendix C of the decision.¹ This safety report (GT&S Safety Report No. 2016-01) reflects the reporting period of January 1 through June 30, 2016, and is being served on the directors of the Commission’s Safety and Enforcement Division (SED), the Energy Division, the service list in the 2011 GT&S Rate Case proceeding (Application (A.) 09-09-013), and the service list in the 2015 GT&S Rate Case proceeding (A.13-12-012).

In OP 6 of D.11-04-031, the Commission directed the SED to review the GT&S Safety Report, establish procedures to monitor PG&E’s storage and pipeline related activities set forth in the reports, assess whether the projects PG&E identified in the proceeding are at risk of not being implemented, and to track whether PG&E is spending its allocated funds on storage and pipeline related safety, reliability, and integrity activities. The Energy Division will provide assistance to the SED to review and monitor the reports. The SED was ordered to immediately bring to the Commission’s attention any detected problems with PG&E’s prioritization or administration of its Gas Transmission (GT) capital and operations and maintenance (O&M) activities.

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¹ See also Decision 16-06-056, Conclusion of Law (COL) 112.

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GT&S Safety Report No. 2016-01 addresses each of the eight specific requirements listed in Appendix C of D.11-04-031. The introduction of each section of this report quotes the requirement from Appendix C.

On July 1, 2016, the Commission issued D.16-06-056 in PG&E’s 2015 GT&S Application (A.13-12-012). Pursuant to COL 112, PG&E will continue preparing and serving this report on a semi-annual basis, consistent with the requirements in the Gas Accord V decision.

**Pipeline Safety Enhancement Plan**

D.12-12-030, issued December 28, 2012, approved Phase 1 of PG&E’s Pipeline Safety Enhancement Plan (PSEP). OP 10 of D.12-12-030 required PG&E to submit quarterly compliance reports on PSEP activities through the end of Phase 1 (2014). Consistent with prior GT&S semi-annual reports, PG&E continues to include PSEP activities through June 30, 2016 in this report. PG&E has included in Appendix A an updated list of PSEP projects that were completed in the reporting period, under construction or yet to begin construction. Included in Appendix B is a table that provides PSEP costs from inception to date broken down by month and by activity.

**Summary**

In total, PG&E budgeted approximately $1.2 billion for 2016 in capital expenditures and expenses for GT&S related activities. PG&E’s initial budget as of January 1, 2016 was adjusted due to modifications based on new information, identification of emergent work, changes in cost estimates, and/or changes in execution schedules.

**Capital**

As of June 30, 2016, PG&E expects to spend $682.9 million for GT Capital Major Work Categories (MWC), not including StanPac Projects of $8.8 million in 2016. The total recorded capital spend through June 30, 2016 was $314.6 million. Of this total amount, $313.7 million is for safety and reliability related capital and $.98 million is for StanPac projects. See Table 1 below for a summary of the capital costs described above. See Table 2-1 on page 7 for further details.

**Expense**

As of June 30, 2016, PG&E expects to spend $551.4 million for GT Expense MWCs in 2016, not including the $3.5 million for StanPac Projects. The total recorded spend through June 30, 2016 for GT expense was $244.7 million. Of this total amount, $244.3 million is for safety and reliability related expense and $.48 million is for StanPac
Projects. See Table 1 below for a summary of the expense costs described above. See Table 2-2 on page 8 for further details.

**TABLE 1**

**2016 GAS STORAGE, PIPELINE SAFETY, INTEGRITY AND RELIABILITY PROJECTS**

**REPORTING PERIOD JANUARY 1 – JUNE 30, 2016**

**(MILLIONS OF 2016 DOLLARS)**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Costs(a)</th>
<th>Annual 1/1/16 Budget</th>
<th>Annual 6/30/16 Budget(b)</th>
<th>Actual Spend 1/1-6/30</th>
<th>2016 CPUC Authorized(c)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Capital</td>
<td>685.7</td>
<td>682.9</td>
<td>313.7</td>
<td>676.1</td>
</tr>
<tr>
<td>2</td>
<td>Expense</td>
<td>551.4</td>
<td>551.4</td>
<td>244.3</td>
<td>404.1</td>
</tr>
</tbody>
</table>

(a) Excluding StanPac. All numbers in table are in new cost model.
(b) While the annual expense budget as of June 30 has not changed, the expectation is that by the end of the year budgets will be modified to reflect the CPUC adopted amounts.
(c) Based on amounts authorized in D.16-06-056; adjusted for adopted Post Test Year escalation.

For the period of January 1 to June 30, 2016, PG&E has completed O&M activities including 66,994 cumulative miles of pipeline inspections, and 10,987 facility inspections. The pipeline inspection activities include 7,574 miles of pipeline leak surveys, 59,353 miles of pipeline patrols, 39.55 miles of pipeline hydrostatic testing work, and 27.7 miles of integrity management assessments. PG&E also validated records for 21.1 miles of pipe that would otherwise have been hydrostatically tested in 2016. The facility inspection activities include 5,483 Cathodic Protection reads, and maintenance and inspection performed on 3,117 district regulator stations and 2,387 valves. In addition, PG&E standby personnel were sent out to 4,182 sites to ensure pipeline safety where third parties were performing excavation work. See Table 7-1, Gas Transmission Pipeline Inspection Plan, for more details on the work described above for the current reporting period.

This report also includes detailed information on over 1,324 capital projects and work activities and over 1,080 expense projects and work activities, as shown in Table 3-1.
1. **Explanation for Ranking Gas Transmission Pipeline, Storage, Safety, Integrity, Inspection, Reliability and Operations and Maintenance Projects**

   A thorough description and explanation of the strategic planning and decision-making approach PG&E uses to determine and rank the gas storage projects, pipeline transmission safety, integrity, and reliability of its pipeline projects, O&M activities, and inspections of its gas transmission pipelines. If there has been no change in PG&E’s approach for determining and ranking which projects and activities are prioritized since the last Safety Report, the Safety Report may reference the earlier Safety Report.

   **Response**

   **Strategic Planning**

   Similar to the planning process described in GT&S Safety Report No. 2015-02, PG&E established plans and budgets for its 2016 GT capital expenditures and expenses as part of its Integrated Planning Process. Please refer to the GT&S Safety Report No. 2015-02 for details on the planning process.

   **Reprioritization Due to Delay in 2015 GT&S Rate Case Decision**

   In the spring of 2016, GT re-prioritized the investment portfolio due to the delay in the 2015 GT&S rate case proceeding. The result was a portfolio that facilitated flexibility of execution by prioritizing design and engineering work in 2016 versus planned construction, while including execution of all mandatory work to ensure compliance requirements are met. This will provide PG&E with the flexibility to execute on the portfolio of work in accordance with the Commission’s decision on PG&E’s 2015 GT&S rate case. Although a reduction in 2016 construction has occurred, efforts to maintain consistent level of engineering work activities will allow PG&E to scale work execution based on the rate case decision.

   In re-planning the portfolio, the GT organization utilized the same framework outlined in previous GT&S Safety Reports² to reallocate funding for projects based on risk and the ability to execute within the given year.

---
Budgeting and Spending

2. Explanation of Funds Budgeted and Spent for Each Major Work Category

The Safety Report must describe the amount of funds budgeted at the beginning of each calendar year and over the rate case period, as well as the amount spent during the reporting period and for that calendar year, for each MWC related to gas storage, pipeline safety, integrity and reliability for capital expenditures and for O&M activities. To the extent these funds are specified in the settlement or other document, such as work papers or testimony, references to where these amounts are mentioned must be provided.

Response

The 2016 amounts budgeted and spent for the capital and expense MWCs related to GT system safety, integrity, and reliability are displayed in Tables 2-1 and 2-2. PG&E added MWCs in 2015. Refer to Figure 2-1, page 6, in GT&S Safety Report No. 2015-01 for a summary of the addition.

2016 Budget

Effective January 1, 2016, the Company’s budget and recorded costs reflect a new cost model. PG&E’s cost model is the structure by which costs are assigned to certain processes or activities in the Company. PG&E’s cost model is used for forecasting, budgeting and tracking costs for internal management purposes as well as for external reporting purposes. The core of the cost model change is related to labor rates. Labor rates are used by employees to charge labor hours to expense and capital jobs. The old cost model used a fully inclusive labor rate which factored in all support and overhead costs, e.g., benefits, payroll taxes, supervision, technical support and office space. The old cost model approach made it easy to evaluate the full costs of field and other work, but it was more difficult to monitor the individual cost components of the work. The new cost model uses a “labor only” labor rate which no longer includes support and overhead costs. In the new cost model, support and overhead costs are budgeted by the organizations best able to control the costs. As a result, expense jobs do not include support and overhead costs. For capital jobs, the new cost model allocates support and overhead costs to the work proportionate to labor costs as required by the Federal Energy Regulatory Commission Uniform System of Accounts. Accounting for existing balancing account activities is treated similar to capital work. In other words, support and overhead costs are
included, to ensure balancing accounts reflect fully allocated costs, and to provide a means to compare recorded amounts to authorized amounts in D.16-06-056.

The 2016 budget information included in this report is shown in PG&E’s new cost model. For comparison purposes, PG&E has translated PG&E’s 2016 budget to the old cost model. Future GT&S Safety Reports will be prepared using the new cost model.

While the new cost model shifts costs among MWCs and organizations to improve accountability and visibility by assigning costs to the service providers where costs can be better monitored (e.g., Shared Services and Information Technology), this shift does not change the overall costs at a Companywide level. Neither will the shift change the Company’s headcount or organization structure.

PG&E’s budgets are approved by management on an annual basis in the fourth quarter of the previous year and updated as needed throughout the year. PG&E’s initial 2016 budget for GT Capital MWCs (excluding $8.8 million for StanPac Projects) was $685.7 million. PG&E’s adjusted budget as of June 30, 2016 (excluding $8.8 million for StanPac Projects) was $682.9 million. The adjustments to the budget were due to changes in the 2016 plan. The GT organization utilized the framework outlined in Section 1 of this report and completed a risk-based reallocation of funding.

PG&E’s initial 2016 budget for GT Expense MWCs (excluding $3.5 million for StanPac Projects) was $551.4 million. PG&E’s adjusted budget as of June 30, 2016 (excluding $3.5 million for StanPac Projects) was $551.4 million.

Although less than 50% of the amounts budgeted for 2016 have been spent during the first six months of the year, the expectation is that all programs and projects will track to the year-end budget.

The following MWCs are excluded from this report, consistent with prior GT&S Safety Reports:

- Capital: 5 (Tools & Equipment), 12 (Implement Environment Projects), 26 (GT Customer Connects), 78 (Manage Buildings), 83 (GT Work Required by Others), 2F (Build IT Applications and Infrastructure); and
- Expense: AK (Manage Environmental Operations), AY (Habitat & Species Protection), CR (Manage Waste Disposal & Transportation), CX (Gas Transmission Marketing, Sales & Strategy), GZ (Research and Development Non-Balancing Account), GM (Manage Energy Efficiency-Non-BA),

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-6-
JV (Maintain IT Applications and Infrastructure), AB (Miscellaneous Expense), DN (Develop and Provide Training).

TABLE 2-1
2016 GAS STORAGE, PIPELINE SAFETY, INTEGRITY AND RELIABILITY PROJECTS CAPITAL BUDGET BY MAJOR WORK CATEGORY
REPORTING PERIOD JANUARY 1 TO JUNE 30, 2016
(THOUSANDS OF 2016 DOLLARS)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>73</td>
<td>GT Pipeline Capacity</td>
<td>121,212</td>
<td>117,162</td>
<td>93,171</td>
<td>92,797</td>
<td>90,390</td>
<td>89,983</td>
<td>14,321</td>
</tr>
<tr>
<td>75</td>
<td>GT Pipeline Reliability</td>
<td>339,522</td>
<td>339,246</td>
<td>233,315</td>
<td>233,126</td>
<td>233,126</td>
<td>233,126</td>
<td>150,220</td>
</tr>
<tr>
<td>67</td>
<td>GT Station Reliability</td>
<td>146,401</td>
<td>130,454</td>
<td>126,445</td>
<td>126,445</td>
<td>126,445</td>
<td>126,445</td>
<td>59,191</td>
</tr>
<tr>
<td>84</td>
<td>GT Gas Gathering System Manage</td>
<td>1,665</td>
<td>1,564</td>
<td>196</td>
<td>184</td>
<td>184</td>
<td>184</td>
<td>773</td>
</tr>
<tr>
<td>98</td>
<td>GT Integrity Management</td>
<td>87,469</td>
<td>87,722</td>
<td>127,945</td>
<td>128,315</td>
<td>128,315</td>
<td>128,315</td>
<td>58,850</td>
</tr>
<tr>
<td>2H</td>
<td>GT PL Safety Enhance Plan- Cap</td>
<td>0</td>
<td>0</td>
<td>49,271</td>
<td>47,300</td>
<td>47,300</td>
<td>47,300</td>
<td>1,601</td>
</tr>
<tr>
<td>3K</td>
<td>Gas Trans RemEDIATE Corrosion 2</td>
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<td>0</td>
<td>57,545</td>
<td>57,545</td>
<td>57,545</td>
<td>57,545</td>
<td>22,317</td>
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<tr>
<td>3L</td>
<td>Gas Trans Storage Wells 3</td>
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<td>0</td>
<td>12,966</td>
<td>13,453</td>
<td>13,453</td>
<td>13,453</td>
<td>6,363</td>
</tr>
<tr>
<td>2J</td>
<td>GT&amp;D Impl Regulatory Change 4</td>
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<td>0</td>
<td>0</td>
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<td>0</td>
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<td><strong>685,714</strong></td>
<td><strong>698,072</strong></td>
<td><strong>682,899</strong></td>
<td><strong>313,666</strong></td>
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<tr>
<td></td>
<td><strong>StanPac</strong></td>
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<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
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<td>8,499</td>
<td>9,459</td>
<td>8,760</td>
<td>9,459</td>
<td>8,760</td>
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<td><strong>710,312</strong></td>
<td><strong>694,473</strong></td>
<td><strong>707,531</strong></td>
<td><strong>691,659</strong></td>
<td><strong>314,649</strong></td>
</tr>
</tbody>
</table>

1 Dollars in new cost model

2 MWC 3K was created in 2015 to separate corrosion related work within MWC 75 to promote greater visibility.

3 MWC 3L was created in 2015 to separate corrosion related work within MWC 76 to promote greater visibility.

4 MWC 2J has actuals without budget as it includes carryover PSEP close-out costs.
### TABLE 2-2

#### 2016 GAS STORAGE, PIPELINE SAFETY, INTEGRITY AND RELIABILITY O&M ACTIVITIES

**BUDGET BY MAJOR WORK CATEGORY**

**REPORTING PERIOD JANUARY 1 TO JUNE 30, 2016**

*(THOUSANDS OF 2016 DOLLARS)*

<table>
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<tr>
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<td>9,631</td>
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<td>0</td>
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<td>0</td>
<td>4,702</td>
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<tr>
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<td>5,895</td>
<td>6,616</td>
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<td>4,265</td>
<td>3,583</td>
<td></td>
</tr>
<tr>
<td>GJ</td>
<td>Gas Transmission Mitigate Corr</td>
<td>9,144</td>
<td>6,616</td>
<td>6,616</td>
<td>4,265</td>
<td>4,265</td>
<td>3,583</td>
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<tr>
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<td><strong>634,541</strong></td>
<td><strong>551,409</strong></td>
<td><strong>244,260</strong></td>
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<tr>
<td><strong>StanPac</strong></td>
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<td></td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>34</td>
<td>Maintain Gas Trans-Subsidiary</td>
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</table>

**Gas Transmission Expense- Including StanPac**

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<th></th>
<th><strong>478,082</strong></th>
<th><strong>406,745</strong></th>
<th><strong>638,987</strong></th>
<th><strong>554,949</strong></th>
<th><strong>638,987</strong></th>
<th><strong>554,949</strong></th>
<th><strong>244,739</strong></th>
</tr>
</thead>
</table>

1 While the annual expense budget as of 6/30 has not changed, the expectation is that by the end of the year budgets will be modified to reflect the CPUC adopted amounts.

2 Dollars in new cost model

3 MWCs KE and KF contain actuals without budget as these MWCs hold the remaining PSEP Expense construction close-out costs.

4 MWC GJ was created in 2015 to separate corrosion mitigation work from within MWC HP to promote greater visibility.

5 Gas Transmission Integrity Management expenses are recorded in MWC II and HP. The creation of MWC HP was necessitated for accounting purposes by the authorization of a one-way balancing account for Gas Transmission Integrity Management expense in Gas Accord V. PG&E will continue to spend in the one-way balancing account per the final GT&S decision.
PACIFIC GAS AND ELECTRIC COMPANY
GAS TRANSMISSION AND STORAGE SAFETY REPORT
NO. 2016-02

REPORTING PERIOD
JULY 1 – DECEMBER 31, 2016

IN COMPLIANCE WITH CPUC DECISION 16-06-056

SUBMITTED MARCH 1, 2017
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I. 2015 Transmission Integrity Management – Assessment Plan – PG&E
Introduction and Background

This Gas Transmission and Storage (GT&S) Safety Report is submitted in compliance with the California Public Utilities Commission (CPUC or Commission) Decision (D.) 16-06-056 in Pacific Gas and Electric Company’s (PG&E or the Company) 2015 GT&S Rate Case Application (A.) 13-12-012. Pursuant to Conclusion of Law 112, PG&E will continue preparing and serving this report on a semi-annual basis, consistent with the requirements in the Gas Accord V Decision.1

This safety report (GT&S Safety Report No. 2016-02) reflects the reporting period of July 1 through December 31, 2016, and is being served on the directors of the Commission’s Safety and Enforcement Division, the Energy Division, the service list in the 2011 GT&S Rate Case proceeding (A.09-09-013), and the service list in the 2015 GT&S Rate Case proceeding (A.13-12-012).

Pipeline Safety Enhancement Plan

Decision (D.) 12-12-030, issued December 28, 2012, approved Phase 1 of PG&E’s Pipeline Safety Enhancement Plan (PSEP). OP 10 of D.12-12-030 required PG&E to submit quarterly compliance reports on PSEP activities through the end of Phase 1 (2014). Consistent with prior GT&S semi-annual reports, PG&E continues to include PSEP activities through December 31, 2016 in this report. PG&E has included in Appendix B an updated list of PSEP projects that were completed in the reporting period, under construction or yet to begin construction. Included in Appendix C is a table that provides PSEP costs from inception to date broken down by month and by activity.

1 Ordering Paragraph (OP) 5 of D.11-04-031 directed PG&E to prepare, on a semi-annual basis, a “Gas Transmission and Storage Safety Report” (GT&S Safety Report) containing information to address each of the eight requirements in Appendix C of the Decision.
Summary

For 2016, PG&E’s total recorded spending exceeded $1.3 billion in capital expenditures and expenses for GT&S related activities.\(^2\) PG&E’s annual budget as of December 31, 2016 was adjusted due to modifications based on new information including the Commission’s 2015 GT&S Rate Case Decision, identification of emergent work, changes in cost estimates, and/or changes in execution schedules.

Capital

For 2016, PG&E expected to spend $763.2 million for Gas Transmission (GT) Capital Major Work Categories (MWC) (not including StanPac Projects of $8.8 million). The total recorded capital spend through December 31, 2016 was $730.9 million: $721.7 million for safety and reliability related capital and $9.2 million for StanPac projects. See Table 1 below for a summary of the capital costs described above. See Table 2-1 in Section 2 for further details.

Expense

For 2016, PG&E expected to spend $486.7 million for GT Expense MWCs, not including $3.5 million for StanPac projects. The total recorded expense spend through December 31, 2016 was $569.3 million: $567.2 million for safety and reliability related expense and $2.1 million for StanPac. See Table 1 below for a summary of the expense costs described above. See Table 2-2 in Section 2 for further details.

\(^2\) All 2016 recorded costs in this report are as of January 9, 2017. There is a potential for additional adjustments that could impact the final costs related to GT&S related activities. If any adjustments materially change the reported costs, PG&E will provide an update in the 2017-01 GT&S Safety Report.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Costs</th>
<th>Annual Budget 1/1/16</th>
<th>Adjusted Annual Budget as of 12/31/16</th>
<th>Recorded Spend 7/1-12/31</th>
<th>YTD Recorded 12/31</th>
<th>2016 Adopted/Imputed</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Capital</td>
<td>685.7</td>
<td>763.2</td>
<td>408.0</td>
<td>721.7</td>
<td>699.6</td>
</tr>
<tr>
<td>2</td>
<td>Expense</td>
<td>532.6</td>
<td>486.7</td>
<td>300.0</td>
<td>567.2</td>
<td>416.0</td>
</tr>
</tbody>
</table>

*a Excluding StanPac. All costs presented using the new cost allocation methodology. 
*PG&E updates its annual budget during the year based on new information, which in 2016, included the Commission’s 2015 GT&S Rate Case Decision. 
*c Based on amounts adopted in D. 16-12-010; adjusted for adopted Post Test Year escalation.

For the period of July 1 to December 31, 2016, PG&E completed operations and maintenance (O&M) activities including 66,967.9 cumulative miles of pipeline inspections and 10,268 facility inspections. The pipeline inspection activities include 7,504 miles of pipeline leak surveys, 59,248 miles of pipeline patrols, 49.06 miles of pipeline hydrostatic testing work, and 166.8 miles of integrity management assessments. PG&E also validated records for 10.46 miles of pipe that would otherwise have been hydrostatically tested in 2016. The facility inspection activities include 4,436 Cathodic Protection reads, and maintenance and inspection performed on 3,549 district regulator stations and 2,283 valves. In addition, PG&E standby personnel were sent out to 5,191 individual sites to ensure pipeline safety where third parties were performing excavation work. See Table 7-1, GT Pipeline Inspection Plan, for more details on the work described above for the current reporting period.

This report also includes detailed information on 1,330 capital projects and work activities and 938 expense projects and work activities, as shown in Table 3-1.
1. **Explanation for Ranking Gas Transmission Pipeline, Storage, Safety, Integrity, Inspection, Reliability, and Operations and Maintenance Projects**

   A thorough description and explanation of the strategic planning and decision-making approach PG&E uses to determine and rank the gas storage projects, pipeline transmission safety, integrity, and reliability of its pipeline projects, O&M activities, and inspections of its gas transmission pipelines. If there has been no change in PG&E’s approach for determining and ranking which projects and activities are prioritized since the last Safety Report, the Safety Report may reference the earlier Safety Report.

**Response**

**Strategic Planning**

Similar to the planning process described in GT&S Safety Report No. 2015-02, PG&E established plans and budgets for 2016 GT capital expenditures and expenses as part of its Integrated Planning Process. Please refer to GT&S Safety Report No. 2015-02 for details on the planning process.

**Work Acceleration Following the 2015 GT&S Rate Case Decision**

On May 5, 2016, the Commission issued a proposed decision for the 2015 GT&S rate case. As a result, PG&E identified additional projects (in addition to those it had planned) to be executed in 2016 using the following criteria:

- Ability to execute in 2016
- Alignment with 2015 GT&S Proposed Decision defined scope units
- Programmatic risk assessment
- Time-sensitivity

Shortly after the Commission’s Final Decision was issued on July 1, 2016, a final proposed project list was presented to and approved by senior Gas Operations leadership.
Budgeting and Spending

2. **Explanation of Funds Budgeted and Spent for Each Major Work Category**

   The Safety Report must describe the amount of funds budgeted at the beginning of each calendar year and over the rate case period, as well as the amount spent during the reporting period and for that calendar year, for each MWC related to gas storage, pipeline safety, integrity and reliability for capital expenditures and for O&M activities. To the extent these funds are specified in the settlement or other document, such as work papers or testimony, references to where these amounts are mentioned must be provided.

**Response**

The 2016 amounts budgeted and spent under the capital and expense MWCs related to GT&S system safety, integrity, and reliability are displayed in Tables 2-1 and 2-2. PG&E also included in Table 2-1 and Table 2-2, the imputed amounts based on the 2015 GT&S Decision (D.16-12-010), Appendix D, adjusted to reflect post test-year escalation.

As previously reported, PG&E implemented a new cost allocation methodology effective January 1, 2016, referred to as the new cost model in Report No. 2016-01. This report presents all costs (adopted/imputed, budgeted and recorded) using PG&E’s new cost allocation methodology.

**2016 Budget**

PG&E’s budgets are approved by management on an annual basis in the fourth quarter of the previous year and updated as needed throughout the year. PG&E’s initial 2016 budget for GT Capital MWCs (excluding StanPac Projects of $8.8 million) was $685.7 million. PG&E’s adjusted GT Capital MWC budget as of December 31, 2016 (excluding StanPac Projects of $8.8 million) was $763.2 million. Adjustments to the GT Capital MWC budget primarily include increases in pipeline reliability, pipeline capacity, and integrity management. The GT organization utilized the framework outlined in Section 1, as described in Report No. 2015-02, and completed a risk-based reallocation of funding.

PG&E’s initial 2016 budget for GT Expense MWCs, excluding $3.5 million for StanPac projects, was $532.6 million. PG&E’s adjusted budget as of

---

3 Please refer to GT&S Safety Report 2016-01 for additional information describing the cost allocation methodology change.
December 31, 2016, excluding $3.5 million for StanPac projects, was $486.7 million. Adjustments to the GT Expense MWC budget include increases generally within reliability and general maintenance, locate and mark, corrosion control, and integrity management.

To the extent that there are material differences in the annual budget by MWC and the recorded spend at Year-End, those variance explanations can be found in the response to Section 5.

The following MWCs are excluded from this report, consistent with prior GT&S Safety Reports:

- Capital: 2F (Build IT Applications and Infrastructure), 5 (Tools & Equipment), 12 (Implement Environment Projects); 26 (GT Customer Connects), 78 (Manage Buildings), 83 (GT Work Required by Others); and

- Expense: AB (Miscellaneous Expense), AK (Manage Environmental Operations), AY (Habitat & Species Protection), CR (Manage Waste Disposal & Transportation), CX (GT Marketing, Sales & Strategy), DN (Develop and Provide Training), GF (GT & Dist Sys Mapping), GM (Manage Energy Efficiency-Non-BA), GZ (Research and Development Non-Balancing Account), JV (Maintain IT Applications and Infrastructure).
# TABLE 2-1
## 2016 GAS STORAGE, PIPELINE SAFETY, INTEGRITY, AND RELIABILITY PROJECTS CAPITAL BUDGET BY MAJOR WORK CATEGORY
### REPORTING PERIOD JULY 1 TO DECEMBER 31, 2016
#### (THOUSANDS OF 2016 DOLLARS)

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<th>MWC</th>
<th>MWC Description</th>
<th>Adopted/Imputed Amount</th>
<th>Annual Budget As of 1/1</th>
<th>Adjusted Annual Budget As of 12/31</th>
<th>Recorded Spend 7/1-12/31</th>
<th>YTD Actuals 12/31</th>
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<td>GT Pipeline Capacity</td>
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<td>116,089</td>
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<td>82,579</td>
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<td>GT Pipeline Reliability</td>
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<td>GT Gas Gathering System Manage</td>
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<td>47,300</td>
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<td>19,280</td>
</tr>
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<td>19,145</td>
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<td>54</td>
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<td><strong>685,714</strong></td>
<td><strong>763,249</strong></td>
<td><strong>408,000</strong></td>
<td><strong>721,666</strong></td>
</tr>
<tr>
<td>44</td>
<td>Gas Capital:GasTrans-Subsidiary</td>
<td>8,560</td>
<td>8,760</td>
<td>8,760</td>
<td>8,182</td>
<td>9,165</td>
</tr>
<tr>
<td></td>
<td><strong>Gas Transmission Capital- Including StanPac</strong></td>
<td><strong>708,185</strong></td>
<td><strong>694,474</strong></td>
<td><strong>772,009</strong></td>
<td><strong>416,182</strong></td>
<td><strong>730,831</strong></td>
</tr>
</tbody>
</table>

a Dollars in new cost allocation methodology.
b Based on amounts adopted in D. 16-12-010; adjusted for adopted Post Test Year escalation. Dollars in new cost allocation methodology.
c MWC 2H holds the remaining PSEP capital close-out costs.
d MWC 3K was created in 2015 to separate corrosion related work within MWC 75 to promote greater visibility.
e MWC 3L was created in 2015 to separate corrosion related work within MWC 76 to promote greater visibility.
f MWC 2J has recorded spend without budget as it includes carryover PSEP close-out costs.
<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Adopted/ Imputed Amount</th>
<th>Annual Budget As of 1/1</th>
<th>Adjusted Annual Budget As of 12/31</th>
<th>Recorded Spend 7/1-12/31</th>
<th>YTD Actuals 12/31</th>
</tr>
</thead>
<tbody>
<tr>
<td>JO</td>
<td>GT Pipeline Maintenance</td>
<td>39,714</td>
<td>25,583</td>
<td>26,788</td>
<td>12,226</td>
<td>24,803</td>
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<td>JP</td>
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<td>14,948</td>
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<td>17,898</td>
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<td>JT</td>
<td>GT Reliability &amp; General Maint. ^c</td>
<td>183,596</td>
<td>292,614</td>
<td>250,914</td>
<td>103,067</td>
<td>257,394</td>
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<td>GT Operate System</td>
<td>31,510</td>
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<td>11,346</td>
<td>7,273</td>
<td>13,761</td>
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<td>0</td>
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<td>5,444</td>
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<td>0</td>
<td>41</td>
<td>90</td>
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<tr>
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<td>G&amp;E T&amp;D Locate &amp; Mark</td>
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<td>7,074</td>
<td>10,657</td>
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<td>12,687</td>
<td>26,431</td>
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<td>II / HP</td>
<td>GT Integrity Management ^c ^f</td>
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<td>143,952</td>
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<td>148,617</td>
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</tr>
<tr>
<td><strong>StanPac</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>34</td>
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<td>3,540</td>
<td>3,540</td>
<td>1,601</td>
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<td><strong>Gas Transmission Expense- Including StanPac</strong></td>
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<td><strong>536,164</strong></td>
<td><strong>490,283</strong></td>
<td><strong>301,598</strong></td>
<td><strong>569,310</strong></td>
<td></td>
</tr>
</tbody>
</table>

^a Dollars in new cost allocation methodology.

^b Based on amounts adopted in D. 16-12-010; adjusted for adopted Post Test Year escalation. Dollars in new cost allocation methodology.

^c Includes annual budget and accounting adjustments between MWCs JT and HP.

^d MWCs KE and KF contain recorded spend without budget as these MWCs hold the remaining PSEP Expense construction close-out costs.

^e MWC GJ was created in 2015 to track corrosion mitigation work separately from MWC HP.
PACIFIC GAS AND ELECTRIC COMPANY
GAS TRANSMISSION AND STORAGE SAFETY REPORT

NO. 2017-01

REPORTING PERIOD
JANUARY 1 – JUNE 30, 2017

IN COMPLIANCE WITH CPUC DECISION 16-06-056

SUBMITTED SEPTEMBER 1, 2017
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APPENDICES

A. Table 3-1 Gas Transmission Project Capital and Expense


C. Pipeline Safety Enhancement Plan Costs – Inception, To-date

D. Low Stress Reassessment - TD-4810P-27

E. Pipeline and Hazardous Materials Safety Administration Form 7100.2-1, Annual Report for Calendar Year 2016 Natural or Other Gas Transmission and Gathering Systems – Pacific Gas and Electric Company (March 15, 2017)

Introduction and Background

This Gas Transmission and Storage (GT&S) Safety Report is submitted in compliance with the California Public Utilities Commission (CPUC or Commission) Decision (D.) 16-06-056 in Pacific Gas and Electric Company’s (PG&E or the Company) 2015 GT&S Rate Case Application (A.) 13-12-012. Pursuant to Conclusion of Law 112, PG&E will continue preparing and serving this report on a semi-annual basis, consistent with the requirements in the Gas Accord V Decision.¹

This safety report (GT&S Safety Report No. 2017-01) reflects the reporting period of January 1 through June 30, 2017. PG&E is serving this report on the directors of the Commission’s Safety and Enforcement Division (SED), the Energy Division, as well as the service lists in the 2011 and 2015 GT&S Rate Case proceedings (A.09-09-013 and A.13-12-012).

Pipeline Safety Enhancement Plan

D.12-12-030, issued December 28, 2012, approved Phase 1 of PG&E’s Pipeline Safety Enhancement Plan (PSEP). Ordering Paragraph 10 of D.12-12-030 required PG&E to submit quarterly compliance reports on PSEP activities through the end of Phase 1 (2014). Consistent with prior GT&S semi-annual reports, PG&E continues to include PSEP activities in this report. In Appendix B, PG&E has included an updated list of PSEP projects that were completed in the reporting period, under construction or yet to begin construction. In Appendix C, PG&E has included a table that provides PSEP costs from inception to date broken down by month and by activity.

¹ Ordering Paragraph 5 of D.11-04-031 directed PG&E to prepare, on a semi-annual basis, a “Gas Transmission and Storage Safety Report” containing information to address each of the eight requirements in Appendix C of the Decision.
Summary

In total, PG&E budgeted approximately $1.4 billion for 2017 in GT&S-related capital and expense.² For the first half of 2017, PG&E’s recorded spending totaled $500.1 million in capital expenditures and expense for GT&S related activities.³ Even though PG&E may underspend its budget for 2017, that budget was set above approved levels of funding from the 2015 GT&S rate case. PG&E continues to focus on executing the important safety work approved in this rate case.

Capital

PG&E’s adjusted annual budget as of June 30, 2017 was $827.8 million on GT&S related capital Major Work Categories (MWC) (not including StanPac Projects of $11 million) for 2017. The total recorded capital spending through June 30, 2017 was $286.6 million: $286.3 million for safety and reliability capital and $0.3 million for StanPac projects. See Table 1 for a summary of the capital costs described above. See Table 2-1 in Section 2 for further details.

Expense

PG&E’s adjusted annual budget as of June 30, 2017 was $568.5 million on GT&S related expense MWCs (not including StanPac Projects of $7.3 million) for 2017. The total recorded expense spending through June 30, 2017 was $216 million: $213.8 million for safety and reliability related expense and $2.2 million for StanPac projects. See Table 1 for a summary of the expense costs described above. See Table 2-2 in Section 2 for further details.

² For details on the GT&S related capital and expense MWCs that the budget and recorded spend includes in this report, see Section 2.
³ January 1-June 30, 2017 recorded costs, and 2017 annual full-year budget amounts for MWCs LU and LV reflect SAP data as of August 21, 2017. All other January 1-June 30, 2017 recorded costs in this report reflect SAP data as of July 17, 2017. All other 2017 annual full-year budget amounts reflect SAP data as of August 17, 2017. There is a potential for additional adjustments that could impact the final costs related to GT&S related activities. If any adjustments materially change the reported costs, PG&E will provide an update in the next GT&S Safety Report.
For the first half of 2017, PG&E completed operations and maintenance (O&M) activities including 60,924 cumulative miles of pipeline inspections, and 11,357 facility inspections.

The pipeline inspection activities include:

- 6,957 miles of pipeline leak surveys
- 53,880 miles of pipeline patrols
- 46 miles of pipeline hydrostatic testing work, and
- 41 miles of integrity management assessments

The facility inspection activities include:

- 5,023 Cathodic Protection reads
- Maintenance and inspections performed on 3,647 district regulator stations and 2,687 valves

In addition, PG&E standby personnel were sent out to 5,050 individual sites where third parties were performing excavation work. See Table 7-1, Gas Transmission (GT) Pipeline Inspection Plan, for more details on the work described above for the current reporting period.

This report also includes detailed information on over 1,454 capital projects and work activities and over 1,047 expense projects and work activities, as shown in Table 3-1.
1. **Explanation for Ranking Gas Transmission Pipeline, Storage, Safety, Integrity, Inspection, Reliability and Operations and Maintenance Projects**

   A thorough description and explanation of the strategic planning and decision-making approach PG&E uses to determine and rank the gas storage projects, pipeline transmission safety, integrity, and reliability of its pipeline projects, O&M activities, and inspections of its gas transmission pipelines. If there has been no change in PG&E’s approach for determining and ranking which projects and activities are prioritized since the last Safety Report, the Safety Report may reference the earlier Safety Report.

   **Response**

   **Strategic Planning**

   Similar to the planning process described in GT&S Safety Report No. 2015-02, PG&E established plans and budgets for its 2017 GT capital expenditures and expenses as part of its Integrated Planning Process. Please refer to the GT&S Safety Report No. 2015-02 for details on the planning process.
Budgeting and Spending

2. **Explanation of Funds Budgeted and Spent for Each Major Work Category**

   *The Safety Report must describe the amount of funds budgeted at the beginning of each calendar year and over the rate case period, as well as the amount spent during the reporting period and for that calendar year, for each MWC related to gas storage, pipeline safety, integrity and reliability for capital expenditures and for O&M activities. To the extent these funds are specified in the settlement or other document, such as work papers or testimony, references to where these amounts are mentioned must be provided.*

**Response**

The 2017 amounts budgeted and spent for the capital and expense MWCs related to GT system safety, integrity, and reliability are displayed in Tables 2-1 and 2-2. PG&E also included in Table 2-1 and Table 2-2, the imputed amounts based on the 2015 GT&S Decision (D.16-12-010, Appendix D), adjusted to reflect post-test-year escalation.

As previously reported, PG&E implemented a new cost allocation methodology effective January 1, 2016, referred to as the new cost model in Report No. 2016-01. This report presents all costs (adopted/imputed, budgeted, and recorded) using PG&E’s new cost allocation methodology.

**2017 Budget**

PG&E’s budgets are approved by management on an annual basis in the fourth quarter of the previous year, and updated as needed throughout the year. PG&E’s initial 2017 budget for GT Capital MWCs (excluding $11 million for StanPac Projects) was $829.3 million. PG&E’s adjusted annual budget as of June 30, 2017 (excluding $11 million for StanPac Projects) was $827.8 million. Adjustments to the GT Capital MWC budget primarily include increases in pipeline and station reliability, and gas gathering offset with a reduction to corrosion. The GT organization used the planning process framework outlined in Section 1, as described in Report No. 2015-02, and completed a risk-based reallocation of funding.

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4 Refer to GT&S Safety Report 2016-01 for additional information describing the cost allocation methodology change.
PG&E’s January 1, 2017 budget for GT Expense MWCs (excluding $7.3 million for StanPac Projects) was $570.5 million. PG&E’s adjusted annual budget as of June 30, 2017 (excluding $7.3 million for StanPac Projects) was $568.5 million.

This report organizes MWCs based on current reporting structure which may have changed over time due to various business reasons. As a result, this report introduces new MWCs from those previously reported. To preserve the adopted/imputed value connections with the Commission’s 2015 GT&S decision, PG&E has not modified imputed values for any MWC re-alignments.

The following MWCs are included in this report, consistent with prior GT&S Safety Reports:

- **Capital:** 73 (Pipeline Capacity); 75 (Pipeline Reliability); 76 (Station Reliability); 84 (Gas Gathering); 98 (Integrity Management); 2H (Pipeline Safety Enhancement Plan); 3K (Corrosion); 3L (Storage Wells); 2J (Implement Regulatory Change); 44 (Stanpac)

- **Expense:** CM (Operate System); DF (Locate & Mark); GJ (Corrosion); II/HP (Integrity Management); JO (Pipeline Maintenance); JP (Station Maintenance); JT (Reliability & General Maintenance); KE (Pipeline Safety Enhancement Plan); KF (Implement Regulatory Change); 34 (Stanpac)

The following MWCs were created in 2017 as part of a MWC/Maintenance Activity Type (MAT) re-design effort to further align the work programs to the accounting structure, and are new to this report.

- **Expense:** LV (Station Assessments); LU (Manage Critical Documents)
# Table 2-1
## 2017 Gas Storage, Pipeline Safety, Integrity and Reliability Projects Capital Budget by Major Work Category
### Reporting Period January 1 to June 30, 2017
#### (Thousands of 2017 Dollars) *(a)*

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Adopted/Imputed <em>(b)</em></th>
<th>Annual Budget 1/1/17 <em>(c)</em></th>
<th>Adjusted Annual Budget as of 6/30/17 <em>(d)</em></th>
<th>Recorded Spend 1/1-6/30</th>
</tr>
</thead>
<tbody>
<tr>
<td>73</td>
<td>GT Pipeline Capacity</td>
<td>150,050</td>
<td>184,380</td>
<td>173,972</td>
<td>49,051</td>
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<tr>
<td>75</td>
<td>GT Pipeline Reliability</td>
<td>350,883</td>
<td>289,557</td>
<td>329,384</td>
<td>112,292</td>
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<td>76</td>
<td>GT Station Reliability</td>
<td>154,499</td>
<td>134,947</td>
<td>135,756</td>
<td>46,446</td>
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<td>84</td>
<td>GT Gas Gathering System Manage</td>
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<td>1,229</td>
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<tr>
<td>98</td>
<td>GT Integrity Management</td>
<td>94,183</td>
<td>70,515</td>
<td>70,515</td>
<td>36,644</td>
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<td>2H</td>
<td>GT PL Safety Enhance Plan- Cap</td>
<td>0</td>
<td>23,658</td>
<td>23,658</td>
<td>7,723</td>
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<tr>
<td>3K</td>
<td>Gas Trans Remediate Corrosion <em>(e)</em></td>
<td>0</td>
<td>111,772</td>
<td>76,272</td>
<td>27,234</td>
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<tr>
<td>3L</td>
<td>Gas Trans Storage Wells <em>(f)</em></td>
<td>0</td>
<td>12,185</td>
<td>12,185</td>
<td>5,619</td>
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<tr>
<td>2J</td>
<td>GT&amp;D Impl Regulatory Change <em>(g)</em></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>24</td>
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<td><strong>Gas Transmission Capital</strong></td>
<td><strong>751,502</strong></td>
<td><strong>829,289</strong></td>
<td><strong>827,797</strong></td>
<td><strong>286,272</strong></td>
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<tr>
<td>44</td>
<td>Gas Capital: GasTrans-Subsidiary</td>
<td>6,392</td>
<td>10,952</td>
<td>10,952</td>
<td>278</td>
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<td><strong>Gas Transmission Capital- Including StanPac</strong></td>
<td><strong>757,894</strong></td>
<td><strong>840,241</strong></td>
<td><strong>838,749</strong></td>
<td><strong>286,550</strong></td>
</tr>
</tbody>
</table>

*(a)* All costs presented using the new cost allocation methodology.

*(b)* Based on amounts adopted in D. 16-12-010; adjusted for adopted Post Test Year escalation.

*(c)* 1/1/17 annual budget for the entire 2017 year.

*(d)* PG&E updates its annual 2017 full-year budget during the year based on new information.

*(e)* MWC 3K was created in 2015 to separate corrosion related work within MWC 75 to promote greater visibility.

*(f)* MWC 3L was created in 2015 to separate storage related work within MWC 76 to promote greater visibility.

*(g)* MWC 2J has actuals without budget as it includes carryover PSEP close-out costs.
### TABLE 2-2
2017 GAS STORAGE, PIPELINE SAFETY, INTEGRITY AND RELIABILITY O&M ACTIVITIES
BUDGET BY MAJOR WORK CATEGORY
REPORTING PERIOD JANUARY 1 TO JUNE 30, 2017
(THOUSANDS OF 2017 DOLLARS) *(a)*

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Adopted/Imputed <em>(b)</em></th>
<th>Annual Budget 1/1/17 <em>(c)</em></th>
<th>Adjusted Annual Budget as of 6/30/17 <em>(d)</em></th>
<th>Recorded Spend 1/1-6/30</th>
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</thead>
<tbody>
<tr>
<td>JO</td>
<td>GT Pipeline Maintenance</td>
<td>37,441</td>
<td>20,543</td>
<td>50,121</td>
<td>12,639</td>
</tr>
<tr>
<td>JP</td>
<td>GT Station Maintenance</td>
<td>17,825</td>
<td>14,809</td>
<td>11,243</td>
<td>8,261</td>
</tr>
<tr>
<td>JT</td>
<td>GT Reliability &amp; General Maint</td>
<td>191,202</td>
<td>298,833</td>
<td>282,997</td>
<td>106,693</td>
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<tr>
<td>CM</td>
<td>GT Operate System</td>
<td>26,842</td>
<td>15,110</td>
<td>14,130</td>
<td>6,824</td>
</tr>
<tr>
<td>KE</td>
<td>GT PL Safety Enhance Plan-Exp <em>(e)</em></td>
<td>0</td>
<td>66</td>
<td>0</td>
<td>487</td>
</tr>
<tr>
<td>KF</td>
<td>GT&amp;D Impl Regulatory Change <em>(e)</em></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>69</td>
</tr>
<tr>
<td>DF</td>
<td>G&amp;E T&amp;D Locate &amp; Mark</td>
<td>6,224</td>
<td>9,225</td>
<td>9,225</td>
<td>5,260</td>
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<tr>
<td>GJ</td>
<td>Gas Transmission Mitigate Corr <em>(f)</em></td>
<td>0</td>
<td>57,484</td>
<td>45,628</td>
<td>5,834</td>
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<tr>
<td>II / HP</td>
<td>GT Integrity Management</td>
<td>177,691</td>
<td>136,243</td>
<td>137,022</td>
<td>59,112</td>
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<tr>
<td>LU</td>
<td>GTS Station Assessments <em>(g)</em></td>
<td>0</td>
<td>8,988</td>
<td>8,988</td>
<td>2,945</td>
</tr>
<tr>
<td>LV</td>
<td>GTS Manage Critical Documts <em>(g)</em></td>
<td>0</td>
<td>9,178</td>
<td>9,178</td>
<td>5,655</td>
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<tr>
<td><strong>Gas Transmission Expense</strong></td>
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</tr>
<tr>
<td></td>
<td></td>
<td>457,225</td>
<td>570,479</td>
<td>568,532</td>
<td>213,778</td>
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<tr>
<td><strong>StanPac</strong></td>
<td></td>
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<td></td>
<td></td>
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<td>34</td>
<td>Maintain Gas Trans-Subsidiary</td>
<td>3,154</td>
<td>7,287</td>
<td>7,287</td>
<td>2,174</td>
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<td><strong>Gas Transmission Expense- Including StanPac</strong></td>
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<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>460,379</td>
<td>577,766</td>
<td>575,818</td>
<td>215,951</td>
</tr>
</tbody>
</table>

*(a)* All costs presented using the new cost allocation methodology.
*(b)* Based on amounts adopted in D. 16-12-010; adjusted for adopted Post Test Year escalation.
*(c)* 1/1/17 annual budget for the entire 2017 year.
*(d)* PG&E updates its annual 2017 full-year budget during the year based on new information.
*(e)* MWCs KE and KF represent PSEP Expense construction close-out costs.
*(f)* MWC GJ was created in 2015 to separate corrosion mitigation work from within MWC HP to promote greater visibility.
*(g)* MWC LU and LV were created in 2017 to separate station work from within MWC JT to promote greater visibility.
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6. Current Status of Legacy Top 100 ........................................................................... 21

7. Most Recent Pipeline Inspection Plan, Progress, Methods, Locations, Results and Discrepancies With Prior Records .......................................................................................................................... 22

8. Status of Compliance with Federal Code on Pipeline Integrity Management .......... 33
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This safety report (GT&S Safety Report No. 2017-02) reflects the reporting period of July 1 through December 31, 2017. PG&E is serving this report on the directors of the Commission’s Safety and Enforcement Division, the Energy Division, as well as the service lists in the 2011 and 2015 GT&S Rate Case proceedings (A.09-09-013 and A.13-12-012).

Pipeline Safety Enhancement Plan

D.12-12-030, issued December 28, 2012, approved Phase 1 of PG&E’s Pipeline Safety Enhancement Plan (PSEP). Ordering Paragraph 10 of D.12-12-030 required PG&E to submit quarterly compliance reports on PSEP activities through the end of Phase 1 (2014). Consistent with prior GT&S semi-annual reports, PG&E continues to include PSEP activities in this report. In Appendix B, PG&E has included an updated list of PSEP projects that were completed in the reporting period, under construction or yet to begin construction. As of December 31, 2017, there are two PSEP projects that have not been completed. In Appendix C, PG&E has included a table that provides PSEP costs from inception to date broken down by month and by activity.

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¹ Ordering Paragraph 5 of D.11-04-031 directed PG&E to prepare, on a semi-annual basis, a “Gas Transmission and Storage Safety Report” containing information to address each of the eight requirements in Appendix C of the Decision.
Summary

In total, PG&E budgeted approximately $1.5 billion for 2017 in GT&S-related capital and expense. PG&E’s 2017 recorded spending totaled $1.2 billion in capital expenditures and expense for GT&S related activities, aligned with approved levels of funding from the 2015 GT&S rate case. The following contributed to the underspend in budget: implementing efficient processes in the work plan, lower-than-anticipated strength test costs, cancellation of the Saratoga line extension due to updated load forecast, and shifting some work into 2018. PG&E continues to focus on executing the important safety work approved in this rate case.

Capital

PG&E’s adjusted annual budget as of December 31, 2017 was $840 million on GT&S capital Major Work Categories (MWC) (not including StanPac Projects of $11 million) for 2017. The total recorded capital spending through December 31, 2017 was $707.5 million: $703.7 million for safety and reliability capital, and $3.8 million for StanPac projects. See Table 1 for a summary of the capital costs described above. See Table 2-1 in Section 2 for further details.

Expense

PG&E’s adjusted annual budget as of December 31, 2017 was $629.3 million on GT&S expense MWCs (not including StanPac Projects of $7.3 million) for 2017. The total recorded expense spending through December 31, 2017 was $488.8 million: $485.2 million for safety and reliability related expense, and $3.6 million for StanPac projects. See Table 1 for a summary of the expense costs described above. See Table 2-2 in Section 2 for further details.

---

2 For details on the GT&S related capital and expense MWCs that are included in this report, see Section 2.

3 All recorded costs, and 2017 annual full-year budget amounts reflect SAP data as of January 9, 2018. There is a potential for additional adjustments that could impact the final costs related to GT&S activities. If any adjustments materially change the reported costs, PG&E will provide an update in the next GT&S Safety Report.
For the second half of 2017, PG&E completed operations and maintenance (O&M) activities including 48,182 cumulative miles of pipeline inspections, and 9,424 facility inspections.

The pipeline inspection activities include:
- 7,064 miles of pipeline leak surveys;
- 40,765 miles of pipeline patrols;
- 207 miles of pipeline hydrostatic testing work; and
- 146 miles of Integrity Management (IM) assessments.

The facility inspection activities include:
- 4,554 Cathodic Protection reads; and
- Maintenance and inspections performed on 2,742 district regulator stations and 2,128 valves.

In addition, PG&E standby personnel were sent out to 5,070 individual sites where third parties were performing excavation work. See Table 7-1, Gas Transmission (GT) Pipeline Inspection Plan, for more details on the work described above for the current reporting period.

This report also includes detailed information on over 1,194 capital projects and work activities and over 1,113 expense projects and work activities, as shown in Table 3-1.

---

**TABLE 1**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Costs (a)</th>
<th>Annual Budget 1/1/17 (b)</th>
<th>Adjusted Annual Budget as of 12/31/17(c)</th>
<th>Recorded Spend 7/1-12/31</th>
<th>YTD Recorded 12/31</th>
<th>Annual Adopted/Imputed(d)</th>
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<tr>
<td>1</td>
<td>Capital</td>
<td>829.3</td>
<td>840.0</td>
<td>418.2</td>
<td>703.7</td>
<td>748.8</td>
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<tr>
<td>2</td>
<td>Expense</td>
<td>622.8</td>
<td>629.3</td>
<td>258.7</td>
<td>485.2</td>
<td>462.0</td>
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</table>

(a) Excluding StanPac and CEMA costs. All numbers presented using the new cost allocation methodology.
(b) 1/1/17 annual budget for the entire 2017 year, including shareholder funded dollars. Due to order realignment in the second half of 2017, the annual budget and adjusted annual budget have been updated.
(c) PG&E updates its annual 2017 full-year budget during the year based on new information.
(d) Based on amounts adopted in D. 16-12-010 converted to the new cost allocation methodology at the MAT and MWC levels for comparability; adjusted for adopted Post Test Year escalation. Excludes StanPac.
1. **Explanation for Ranking Gas Transmission Pipeline, Storage, Safety, Integrity, Inspection, Reliability and Operations and Maintenance Projects**

   A thorough description and explanation of the strategic planning and decision-making approach PG&E uses to determine and rank the gas storage projects, pipeline transmission safety, integrity, and reliability of its pipeline projects, O&M activities, and inspections of its gas transmission pipelines. If there has been no change in PG&E’s approach for determining and ranking which projects and activities are prioritized since the last Safety Report, the Safety Report may reference the earlier Safety Report.

   **Response**

   **Strategic Planning**

   Similar to the planning process described in GT&S Safety Report No. 2015-02, PG&E established plans and budgets for its 2017 GT capital expenditures and expenses as part of its Integrated Planning Process. Please refer to the GT&S Safety Report No. 2015-02 for details on the planning process.
Budgeting and Spending

2. **Explanation of Funds Budgeted and Spent for Each Major Work Category**

   The Safety Report must describe the amount of funds budgeted at the beginning of each calendar year and over the rate case period, as well as the amount spent during the reporting period and for that calendar year, for each MWC related to gas storage, pipeline safety, integrity and reliability for capital expenditures and for O&M activities. To the extent these funds are specified in the settlement or other document, such as work papers or testimony, references to where these amounts are mentioned must be provided.

   **Response**

   The 2017 amounts budgeted and spent for the capital and expense MWCs related to GT&S safety, integrity, and reliability are displayed in Tables 2-1 and 2-2. PG&E also included in Table 2-1 and Table 2-2, the imputed amounts based on the 2015 GT&S Decision (D.16-12-010, Appendix D), adjusted to reflect post-test-year escalation.

   As previously reported, PG&E implemented a new cost allocation methodology effective January 1, 2016, referred to as the new cost model in Report No. 2016-01. This report presents all costs (adopted/imputed, budgeted, and recorded) using PG&E’s new cost allocation methodology.

   **2017 Budget**

   PG&E’s budgets are approved by management on an annual basis in the fourth quarter of the previous year, and updated as needed throughout the year. PG&E’s initial 2017 budget for GT Capital MWCs (excluding $11 million for StanPac Projects) was $829.3 million. PG&E’s adjusted annual budget as of December 31, 2017 (excluding $11 million for StanPac Projects) was $840.0 million. Adjustments to the GT Capital MWC budget primarily include increases in pipeline and storage wells, offset by a reduction to corrosion. The GT organization used the planning process framework outlined in Section 1, as described in Report No. 2015-02, and completed a risk-based reallocation of funding.

   PG&E’s initial 2017 budget for GT Expense MWCs (excluding $7.3 million for StanPac Projects) was $622.8 million. PG&E’s adjusted annual budget as of

---

4 Refer to GT&S Safety Report 2016-01 for additional information describing the cost allocation methodology change.
December 31, 2017 (excluding $7.3 million for StanPac Projects) was $629.3 million. Adjustments to the GT Expense MWC budget primarily include increases in pipeline maintenance and station maintenance, offset by a reduction to reliability and corrosion.

To the extent that there are material differences in the initial 2017 annual budget by MWC and the recorded spend at Year-End, those variance explanations can be found in the response to Section 5.

This report organizes MWCs based on current reporting structure which may have changed over time due to various business reasons. As a result, this report introduces new MWCs from those previously reported. To preserve the adopted/imputed value connections with the Commission’s 2015 GT&S decision, PG&E has not modified imputed values for any MWC re-alignments.

The following MWCs are included in this report, consistent with prior GT&S Safety Reports:

- **Capital:** 73 (Pipeline Capacity); 75 (Pipeline Reliability); 76 (Station Reliability); 84 (Gas Gathering); 98 (Integrity Management); 2H (Pipeline Safety Enhancement Plan); 3K (Corrosion); 3L (Storage Wells); 2J (Implement Regulatory Change); 44 (Stanpac)
- **Expense:** CM (Operate System); DF (Locate & Mark); GJ (Corrosion); II/HP (Integrity Management); JO (Pipeline Maintenance); JP (Station Maintenance); JT (Reliability & General Maintenance); KE (Pipeline Safety Enhancement Plan); KF (Implement Regulatory Change); 34 (Stanpac)

The following MWCs were created in 2017 as part of a MWC/Maintenance Activity Type (MAT) re-design effort to further align the work programs to the accounting structure, and are new to this report.

- **Expense:** AH (Maint Gas Storage Fac); LV (Station Assessments); LU (Manage Critical Documents)
<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Adopted/Imputed (b)</th>
<th>Annual Budget 1/1/17 (c)</th>
<th>Adjusted Annual Budget as of 12/31/17 (d)</th>
<th>Recorded Spend 7/1-12/31</th>
<th>YTD Recorded 12/31</th>
</tr>
</thead>
<tbody>
<tr>
<td>73</td>
<td>GT Pipeline Capacity</td>
<td>148,335</td>
<td>184,380</td>
<td>173,972</td>
<td>70,595</td>
<td>119,646</td>
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<td>75</td>
<td>GT Pipeline Reliability</td>
<td>365,621</td>
<td>288,769</td>
<td>328,596</td>
<td>194,705</td>
<td>311,525</td>
</tr>
<tr>
<td>76</td>
<td>GT Station Reliability</td>
<td>138,896</td>
<td>135,735</td>
<td>136,543</td>
<td>69,427</td>
<td>117,386</td>
</tr>
<tr>
<td>84</td>
<td>GT Gas Gathering System Manage</td>
<td>1,721</td>
<td>2,075</td>
<td>5,856</td>
<td>3,981</td>
<td>5,312</td>
</tr>
<tr>
<td>98</td>
<td>GT Integrity Management</td>
<td>94,183</td>
<td>70,515</td>
<td>70,515</td>
<td>40,877</td>
<td>70,687</td>
</tr>
<tr>
<td>2H</td>
<td>GT PL Safety Enhance Plan- Cap</td>
<td>0</td>
<td>23,858</td>
<td>23,858</td>
<td>7,152</td>
<td>14,884</td>
</tr>
<tr>
<td>3K</td>
<td>Gas Trans RemEDIATE Corrosion(e)</td>
<td>0</td>
<td>111,772</td>
<td>76,272</td>
<td>10,535</td>
<td>37,701</td>
</tr>
<tr>
<td>3L</td>
<td>Gas Trans Storage Wells(f)</td>
<td>0</td>
<td>12,185</td>
<td>24,385</td>
<td>21,006</td>
<td>26,625</td>
</tr>
<tr>
<td>2J</td>
<td>GT&amp;D Impl Regulatory Change(g)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>(88)</td>
<td>(64)</td>
</tr>
</tbody>
</table>

**Gas Transmission Capital**

|                          | 748,756 | 829,289 | 839,997 | 418,189 | 703,701 |

**Gas Transmission Capital**

| StanPac                | 44      | 6,392   | 10,952  | 10,952  | 3,540   | 3,818   |

**Gas Transmission Capital- Including StanPac**

|                          | 755,148 | 840,241 | 850,949 | 421,729 | 707,519 |

---

(a) All costs presented using the new cost allocation methodology. Excludes CEMA costs.
(b) Based on amounts adopted in D. 16-12-010 converted to the new cost allocation methodology at the MAT and MWC levels for comparability; adjusted for adopted Post Test Year escalation.
(c) 1/1/17 annual budget for the entire 2017 year, including shareholder funded dollars. Due to order realignment in the second half of 2017, the annual budget and adjusted annual budget have been updated.
(d) PG&E updates its annual 2017 full-year budget during the year based on new information.
(e) MWC 3K was created in 2015 to separate corrosion related work within MWC 75 to promote greater visibility.
(f) MWC 3L was created in 2015 to separate storage related work within MWC 76 to promote greater visibility.
(g) MWC 2J has recorded costs without budget as it includes carryover PSEP close-out costs.
### Table 2-2

2017 Gas Storage, Pipeline Safety, Integrity and Reliability O&M Activities

Budget by Major Work Category

Reporting Period July 1 to December 31, 2017

(Thousands of 2017 Dollars) (a)

<table>
<thead>
<tr>
<th>MWC</th>
<th>MWC Description</th>
<th>Annual Adopted/ Imputed (b)</th>
<th>Annual Budget 1/1/17 (c)</th>
<th>Adjusted Annual Budget as of 12/31/17 (d)</th>
<th>Recorded Spend 7/1-12/31</th>
<th>YTD Recorded 12/31</th>
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<tr>
<td>JO</td>
<td>GT Pipeline Maintenance</td>
<td>34,172</td>
<td>20,543</td>
<td>53,221</td>
<td>14,147</td>
<td>26,597</td>
</tr>
<tr>
<td>JP</td>
<td>GT Station Maintenance</td>
<td>17,825</td>
<td>14,809</td>
<td>17,243</td>
<td>6,951</td>
<td>15,212</td>
</tr>
<tr>
<td>JT</td>
<td>GT Reliability &amp; General Maint</td>
<td>195,257</td>
<td>320,763</td>
<td>302,377</td>
<td>122,107</td>
<td>232,861</td>
</tr>
<tr>
<td>CM</td>
<td>GT Operate System (e)</td>
<td>32,510</td>
<td>31,895</td>
<td>30,914</td>
<td>16,231</td>
<td>29,893</td>
</tr>
<tr>
<td>KE</td>
<td>GT PL Safety Enhance Plan-Exp (f)</td>
<td>0</td>
<td>66</td>
<td>0</td>
<td>398</td>
<td>885</td>
</tr>
<tr>
<td>KF</td>
<td>GT&amp;D Impl Regulatory Change (f)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>37</td>
<td>106</td>
</tr>
<tr>
<td>DF</td>
<td>G&amp;E T&amp;D Locate &amp; Mark</td>
<td>6,224</td>
<td>9,225</td>
<td>9,225</td>
<td>4,319</td>
<td>9,579</td>
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<tr>
<td>GJ</td>
<td>Gas Transmission Mitigate Corr (g)</td>
<td>0</td>
<td>59,885</td>
<td>48,028</td>
<td>12,489</td>
<td>19,781</td>
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<tr>
<td>II / HP</td>
<td>GT Integrity Management</td>
<td>176,056</td>
<td>136,243</td>
<td>137,022</td>
<td>68,844</td>
<td>128,729</td>
</tr>
<tr>
<td>LU</td>
<td>GTS Station Assessments (h)</td>
<td>0</td>
<td>8,988</td>
<td>8,988</td>
<td>1,718</td>
<td>4,663</td>
</tr>
<tr>
<td>LV</td>
<td>GTS Manage Critical Documts (i)</td>
<td>0</td>
<td>9,178</td>
<td>9,178</td>
<td>3,937</td>
<td>7,895</td>
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<tr>
<td>AH</td>
<td>Maint Gas Storage Fac (i)</td>
<td>0</td>
<td>11,204</td>
<td>13,123</td>
<td>6,523</td>
<td>9,045</td>
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<tr>
<td>Gas Transmission Expense</td>
<td>462,044</td>
<td>622,798</td>
<td>629,320</td>
<td>258,701</td>
<td>485,247</td>
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<tr>
<td>StanPac</td>
<td>Maintain Gas Trans-Subsidiary</td>
<td>3,154</td>
<td>7,287</td>
<td>7,287</td>
<td>1,411</td>
<td>3,584</td>
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<tr>
<td>Gas Transmission Expense- Including StanPac</td>
<td>465,199</td>
<td>630,084</td>
<td>636,607</td>
<td>260,112</td>
<td>488,831</td>
<td></td>
</tr>
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</table>

(a) All costs presented using the new cost allocation methodology. Excludes CEMA costs.

(b) Based on amounts adopted in D. 16-12-010 converted to the new cost allocation methodology at the MAT and MWC levels for comparability; adjusted for adopted Post Test Year escalation.

(c) 1/1/17 annual budget for the entire 2017 year, including shareholder funded dollars.

(d) PG&E updates its annual 2017 full-year budget during the year based on new information.

(e) MWC CM records some costs directly dedicated Receiver Cost Centers; Annual Budgets and Adjusted Annual Budgets are trued-up to match recorded spend per CFCA/NCA balancing account guidelines.

(f) MWC KE and KF represent PSEP Expense construction close-out costs.

(g) MWC GJ was created in 2015 to separate corrosion mitigation work within MWC HP to promote greater visibility.

(h) MWCs LU and LV were created in 2017 to separate station work withing MWC JT to promote greater visibility.

(i) MWC AH was created in 2017 to capture Expense-related programs for PG&E’s underground storage field operations.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

REBUTTAL TESTIMONY OF BENNIE BARNES

ASSET FAMILY – TRANSMISSION PIPE
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A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Bennie Barnes. This testimony responds to the direct testimony of the Office of Ratepayer Advocates (ORA), Chapter 5; The Utility Reform Network (TURN), Chapters 5A and 5B; the Indicated Shippers (IS), Chapter 5; the California State University (CSU) system; and the Office of the Safety Advocate (OSA), Chapter 1.

Q 2 Do parties generally criticize Pacific Gas and Electric Company's (PG&E or the Company) showing regarding the Transmission Pipe Asset Family?

A 2 Parties do not offer any general criticism regarding the Transmission Pipe Asset Family.

Q 3 Do parties make recommendations concerning specific projects and programs?

A 3 Yes, parties make recommendations concerning a number of PG&E’s forecast projects and programs.

Q 4 Does PG&E dispute any of the parties’ recommendations?

A 4 Yes, PG&E disputes certain recommendations. PG&E addresses parties’ recommendations in Section D.

The programs described in Chapter 5 are designed to ensure the safety and integrity of PG&E’s approximately 6,600 miles of transmission pipe, as well as ensure appropriate responses to pipe failures. No party disputes the need to perform the work in these programs. To the extent there are differences among the parties, they relate to cost, scope, and pace of the programs.

---

1 ORA-05.
2 IS-1, Chapter 5.
3 CSU-1.
4 OSA-1.
Q 5 Does PG&E have any adjustments to its forecasts as a result of this rebuttal testimony?

A 5 Yes, as described in the relevant rebuttal sections below, PG&E’s forecast recommendation is adjusted for the following expense programs:

• Traditional ILI Runs Program;
• Public Awareness Program; and
• Class Location Change Program.

B. Summary of Parties’ Positions

Q 6 Please summarize parties’ recommendations.

A 6 PG&E’s application forecast and the parties’ recommendations are set forth in Table 5-1 (2019 expense), Table 5-2A (2019-2021 capital expenditures), and Table 5-2B (2016-2018 capital expenditures) below. In addition, Table 5-3 summarizes PG&E Transmission Pipe programs and parties’ positions.

Q 7 Please describe the two tables for capital expenditures.

A 7 Table 5-2A reflects all the capital expenditure reductions recommended by ORA, IS and a portion of the recommendations TURN makes for the years 2019-2021. Table 5-2B reflects the capital expenditure recommendations by TURN Chapter 5B for the years 2016-2018.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Program</th>
<th>Major Work Category (MWC)</th>
<th>Filed Forecast</th>
<th>Current Forecast</th>
<th>ORA&lt;sup&gt;(c)&lt;/sup&gt; Forecast</th>
<th>Proposed Reductions</th>
</tr>
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<tr>
<td>1</td>
<td>In-Line Inspection (ILI)</td>
<td>34, HP</td>
<td>$125,820</td>
<td>$(1,339)</td>
<td>$124,481</td>
<td>$(38,080)</td>
</tr>
<tr>
<td>2</td>
<td>Direct Assessments (DA)</td>
<td>HP</td>
<td>35,107</td>
<td>–</td>
<td>35,107</td>
<td>(17,554)</td>
</tr>
<tr>
<td>3</td>
<td>Hydrostatic Testing</td>
<td>34, GM, HP, JT</td>
<td>155,702</td>
<td>(19,399)</td>
<td>136,303</td>
<td>(10,183)</td>
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<td>4</td>
<td>Pipe Replacements</td>
<td>JT</td>
<td>4,111</td>
<td>(19)</td>
<td>4,092</td>
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<td>5</td>
<td>Earthquake Fault Crossings</td>
<td>JT</td>
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<td>6</td>
<td>Geo-Hazard Threat Identification and Mitigation</td>
<td>HP, JT</td>
<td>2,841</td>
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<tr>
<td>7</td>
<td>Programs to Support Transmission</td>
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<td>14,248</td>
<td>–</td>
<td>14,248</td>
<td>–</td>
</tr>
<tr>
<td>8</td>
<td>Emergency Response</td>
<td>JT</td>
<td>5,281</td>
<td>(906)</td>
<td>4,375</td>
<td>–</td>
</tr>
<tr>
<td>9</td>
<td>Class Location Change</td>
<td>JT</td>
<td>3,305</td>
<td>(1,124)</td>
<td>2,181</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Shallow/Exposed Pipe (Including Water and Levee Crossings)</td>
<td>34, JT</td>
<td>1,061</td>
<td>52</td>
<td>1,113</td>
<td>–</td>
</tr>
<tr>
<td>10</td>
<td>Work Required by Others (WRO)</td>
<td>JT</td>
<td>716</td>
<td>(1)</td>
<td>715</td>
<td>(87)</td>
</tr>
<tr>
<td>11</td>
<td>Pipe Investigations and Field Engineering</td>
<td>JT</td>
<td>8,743</td>
<td>(3)</td>
<td>8,740</td>
<td>–</td>
</tr>
<tr>
<td>12</td>
<td>Other</td>
<td>34, II</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>13</td>
<td>Total Expense</td>
<td></td>
<td>$358,307</td>
<td>$(22,728)</td>
<td>$335,568</td>
<td>$(65,904)</td>
</tr>
</tbody>
</table>

<sup>(a)</sup> PG&E errata as of August 17.

<sup>(b)</sup> This is a disallowance.

<sup>(c)</sup> Reductions are from ORA’s testimony. In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.

<sup>(d)</sup> Also reflected in the PG&E Errata column are adjustments made by PG&E to its forecast as a result of this rebuttal testimony to the Traditional ILI Runs, Public Awareness, and Class Location Change Programs.
<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ILI</td>
<td>98</td>
<td>$213,526</td>
<td>$220,235</td>
<td>$226,708</td>
<td>$(71,175)</td>
<td>$(73,412)</td>
<td>$(75,569)</td>
<td>$118,431</td>
<td>$122,152</td>
<td>$125,742</td>
<td>$(85,400)</td>
<td>$(88,100)</td>
<td>$(90,700)</td>
</tr>
<tr>
<td>2</td>
<td>Hydrostatic Testing</td>
<td>44</td>
<td>49,897</td>
<td>51,465</td>
<td>52,978</td>
<td>(10,474)</td>
<td>(10,524)</td>
<td>(10,833)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>3</td>
<td>Pipe Replacements &lt;sup&gt;a&lt;/sup&gt;</td>
<td>75</td>
<td>47,935</td>
<td>51,850</td>
<td>42,879</td>
<td>(3,660)</td>
<td>(7,712)</td>
<td>(6,639)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>4</td>
<td>Earthquake Fault Crossings</td>
<td>75</td>
<td>12,231</td>
<td>12,616</td>
<td>12,986</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>5</td>
<td>Geo-Hazard Threat Identification and Mitigation</td>
<td>75</td>
<td>4,487</td>
<td>4,628</td>
<td>4,764</td>
<td>(4,313)</td>
<td>(4,448)</td>
<td>(4,579)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>6</td>
<td>Emergency Response</td>
<td>75</td>
<td>55,410</td>
<td>60,233</td>
<td>57,584</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7</td>
<td>Class Location Change &lt;sup&gt;b&lt;/sup&gt;</td>
<td>75</td>
<td>5,498</td>
<td>5,636</td>
<td>5,773</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>8</td>
<td>Shallow/Exposed Pipe (Including Water and Levee)</td>
<td>44</td>
<td>25,446</td>
<td>26,246</td>
<td>27,017</td>
<td>(4,122)</td>
<td>(4,252)</td>
<td>(4,376)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>9</td>
<td>Gas Gathering</td>
<td>84</td>
<td>3,971</td>
<td>4,096</td>
<td>4,216</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>10</td>
<td>WRO</td>
<td>83</td>
<td>27,866</td>
<td>28,742</td>
<td>29,587</td>
<td>(8,718)</td>
<td>(8,993)</td>
<td>(9,257)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>11</td>
<td>Total Capital Expenditures</td>
<td></td>
<td>$446,270</td>
<td>$465,747</td>
<td>$464,493</td>
<td>$(102,463)</td>
<td>$(109,341)</td>
<td>$(111,253)</td>
<td>$(118,431)</td>
<td>$(122,152)</td>
<td>$(125,742)</td>
<td>$(95,400)</td>
<td>$(98,100)</td>
<td>$(100,700)</td>
</tr>
</tbody>
</table>

<sup>a</sup> Includes Errata increasing the forecast by $21, $22, and $23 in 2019, 2020, and 2021, respectively ('000s).

<sup>b</sup> Includes Errata decreasing the forecast by $1 in 2019 ('000s).

<sup>c</sup> Reductions are from ORA's testimony. In ORA's testimony, ORA's recommended amounts do not reflect PG&E's errata.
### TABLE 5-2B
SUMMARY OF 2016-2018 CAPITAL EXPENDITURES FORECAST – PG&E AND TURN
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Program</th>
<th>Sub-Program</th>
<th>Maintenance Activity Type (MAT) Code</th>
<th>PG&amp;E(^{(a)})</th>
<th>TURNS ()</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Pipe Replacements(^{(a)})</td>
<td>Vintage Pipe Replacement</td>
<td>75E</td>
<td>$93,383</td>
<td>$107,418</td>
</tr>
<tr>
<td>2</td>
<td>Geo-Hazard Mitigation</td>
<td>Geo-Hazard Mitigation</td>
<td>75J</td>
<td>4,531</td>
<td>2,100</td>
</tr>
<tr>
<td>3</td>
<td>Total Capital</td>
<td></td>
<td></td>
<td>$97,914</td>
<td>$109,518</td>
</tr>
</tbody>
</table>

\(^{(a)}\) There are no errata for Chapter 5 capital expenditures for 2016-2018. PG&E’s capital expenditures reflect the Vintage Pipe Replacement sub-program only, and includes Standard Pacific Gas Line, Inc. (StanPac) (MAT Code 44A) as part of the 2017 Forecast. TURN relied on PG&E’s response to TURN_015, Question 1, for their recommendations.
**TABLE 5-3**

**PG&E TRANSMISSION PIPE ASSET FAMILY PROGRAMS,**
**SUMMARY OF PG&E’S REBUTTAL TO PARTIES’ RECOMMENDATIONS/ISSUES**
**(FINANCIALS IN TABLES 5-1, 5-2A AND 5-2B)**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Program</th>
<th>PG&amp;E Proposal</th>
<th>Summary of PG&amp;E Rebuttal to Parties’ Key Recommendations/Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ILI</td>
<td>Continuation of 12-year upgrade program with a goal of 4,266 miles upgraded by 2026 and first-time inspection by 2027. 18 upgrade projects per year of rate case period and 2,126 miles inspected over rate case period.</td>
<td>Recommendation to defer ILI Upgrades to the next rate case and still achieve completion on the Commission approved 12-year plan is flawed. (ORA and CSU). Recommendation to remove ILI Runs and associated ILI Direct Examination and Repair (DE&amp;R) for runs that do not have re-assessments due during the rate case period, or are not required by law, ignores risk profile. (ORA only). Claim that the ILI Upgrade scope would require an increase in ILI equipment inventory or capable staff is incorrect because PG&amp;E does not own ILI equipment and uses contractors who own the ILI equipment. (CSU only). Recommendation of reducing the ILI Capital Upgrades Program by 50 percent is unfounded. Recommendation for forecasting methodology for Traditional ILI Runs is reasonable, but requires correction. Recommendation to extend the ILI Capital Upgrades, and, therefore, extend the Traditional ILI Runs Program adversely affects compliance requirements. Recommendation to reduce Non-Traditional ILI expenses is not reasonable. Recommendation to reduce In-Line Inspection Direct Exam and Repair is not reasonable.</td>
</tr>
<tr>
<td>2</td>
<td>DA</td>
<td>304 miles of External Corrosion Direct Assessment (ECDA) over rate case period. 3.5 miles of Internal Corrosion Direct Assessment (ICDA) over rate case period.</td>
<td>Assumptions that DA forecast miles should be lower because of PG&amp;E’s ILI Program assessment miles is incorrect and causes analysis errors. Methodology for reducing ECDA assessment miles by using year 2017 as a basis was flawed because PG&amp;E must complete HCA assessment miles when they are due. Methodology used to calculate the number of digs per ECDA project would result in inadequate funding to meet regulatory obligations. Proposal to defund the ICDA Program and track costs in a memorandum account for consideration in the next rate case is without merit.</td>
</tr>
<tr>
<td>Line No.</td>
<td>Program</td>
<td>PG&amp;E Proposal</td>
<td>Summary of PG&amp;E Rebuttal to Parties' Key Recommendations/Issues</td>
</tr>
<tr>
<td>---------</td>
<td>---------</td>
<td>---------------</td>
<td>---------------------------------------------------------------</td>
</tr>
<tr>
<td>3</td>
<td>Hydrostatic Testing Program (Consistent with requirements of Decision (D.) 11-06-017 and D.12-12-030, and accepted assessment method required by 49 CFR 192, Subpart O)</td>
<td>For D.11-06-017, estimated 111 miles to hydrostatically test over rate case period, focus on replacing or strength testing pipe that lacks a Traceable, Verifiable, and Complete record of a test for pipe that is in highest population density around pipeline. For TIMP pressure tests, estimated 128 miles to test pipe with either unstable manufacturing threats or the elevated Stress Corrosion Cracking (SCC) threat.</td>
<td>Exclusion of higher cost projects to determine a unit cost for expense pipe replacements in lieu of hydrotesting is unreasonable. Cost estimating model for capital pipe replacements in lieu of Hydrostatic Testing uses inconsistent data, making the model unreliable. Cost estimating model for expense Hydrostatic Testing uses inconsistent data, making the model unreliable.</td>
</tr>
<tr>
<td>Line No.</td>
<td>Program</td>
<td>PG&amp;E Proposal</td>
<td>ORA</td>
</tr>
<tr>
<td>---------</td>
<td>---------</td>
<td>---------------</td>
<td>-----</td>
</tr>
<tr>
<td>6</td>
<td>Geo-Hazard Threat Identification and Mitigation (Ongoing study to identify and mitigate effect of Geo-Hazard threat across the system.)</td>
<td>Maintains a data collection, monitoring and action plan development pace, and expense mitigations pace that addresses the higher risk sites during the rate case period. Estimated capital mitigation of 10 sites where pipelines have a confirmed Geo-Hazard threat over rate case period.</td>
<td>Assertion that one high cost project should be excluded to reduce capital mitigation unit costs is unfounded.</td>
</tr>
<tr>
<td>7</td>
<td>Programs to Support Integrity Management</td>
<td>Root Cause and Risk Analysis.</td>
<td>No recommendations/issues.</td>
</tr>
<tr>
<td>8</td>
<td>Emergency Response</td>
<td>Automate 80 valves over rate case period. Maintain Public Awareness Program. Continue valve replacements to address inoperable/hard-to-operate valves, leaking valves, previously deactivated valves or and valves with reliability issues.</td>
<td>No recommendations/issues.</td>
</tr>
<tr>
<td>Line No.</td>
<td>Program</td>
<td>PG&amp;E Proposal</td>
<td>Summary of PG&amp;E Rebuttal to Parties’ Key Recommendations/Issues</td>
</tr>
<tr>
<td>---------</td>
<td>-------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>------------------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ORA</td>
<td>TURN</td>
</tr>
<tr>
<td>9</td>
<td>Class Location Change</td>
<td>Maintain Class Location Change studies and mitigations.</td>
<td>No recommendations/issues.</td>
</tr>
<tr>
<td></td>
<td>(Title 49 CFR, Part 192.613, require ongoing determination and mitigation for changes in class.)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Shallow and Exposed Pipe (including Water and Levee Crossings)</td>
<td>Mitigation of locations that have a high LOF and are in HCAs, approximately 4.3 miles of highest risk pipe.</td>
<td>Capital cost estimating model for the Shallow and Exposed Pipe (including Water and Levee Crossings) Program uses inconsistent data, making the model unreliable. Assertion that PG&amp;E did not explain a metric for re-prioritizing Shallow and Exposed Pipe mitigations in the prior rate case is incorrect.</td>
</tr>
<tr>
<td>11</td>
<td>Gas Gathering (Divestiture of gas gathering facilities)</td>
<td>Retire approximately six idle meters per year during this rate case period.</td>
<td>Recommendations Concerning the Gas Gathering Program Are Without Merit.</td>
</tr>
<tr>
<td>12</td>
<td>WRO (Transmission pipeline or related facility removals and relocations performed by PG&amp;E at the request of third parties.)</td>
<td>Re-location projects with a program cost based on the 3-year historical average. Discontinue One-Way Balancing Account.</td>
<td>Use of a more up-to-date program average forecast methodology is unjustified. Recommendation for discontinuance of the WRO one-way balancing account has unreasonable stipulations.</td>
</tr>
<tr>
<td>Line No.</td>
<td>Program</td>
<td>PG&amp;E Proposal</td>
<td>Summary of PG&amp;E Rebuttal to Parties’ Key Recommendations/Issues</td>
</tr>
<tr>
<td>---------</td>
<td>--------------------------------------------------</td>
<td>-----------------------------------------------------------</td>
<td>---------------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td>Pipe Investigations and Field Engineering</td>
<td>Continue at the pace PG&amp;E has historically had to perform this work.</td>
<td>ORA: No recommendations/issues.</td>
</tr>
<tr>
<td></td>
<td>(Common costs associated with performing various pipeline issue investigations and field engineering of pipeline repair work.)</td>
<td></td>
<td>TURN: Recommendations concerning the Pipe Investigations and Field Engineering Program are unjustified.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>IS: No recommendations/issues.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>OSA: No recommendations/issues.</td>
</tr>
</tbody>
</table>
C. PG&E’s Proposed Two-Way Transmission Integrity Management Program

Balancing Account and Gas Statutes, Regulations and Rules Memorandum

Account (GSRRMA) Should Be Authorized, and the Transmission Integrity
Management Program Memorandum Account (TIMPMA) Should Be
Discontinued

Q 8 What parties disputed PG&E’s recommendation for a two-way Transmission
Integrity Management Program Balancing Account (TIMPBA)?
A 8 ORA, TURN and CSU disputed PG&E’s recommendation for a two-way
TIMPBA.

Q 9 What do the parties recommend?
A 9 All three parties recommend that PG&E’s TIMPBA accounting treatment
remain the same, that is to say that PG&E should continue to use a one-way
TIMPBA.5

Q 10 What was the basis for ORA’s one-way TIMPBA recommendation?
A 10 ORA claims that PG&E’s concerns about the uncertainty surrounding
Pipeline and Hazardous Materials Safety Administration’s (PHMSA) final
rule and General Order (GO)-112F’s new High Consequence Area (HCA)
definition are unfounded because PG&E’s existing TIMPMA is sufficient to
recover any additional costs posed by new regulatory requirements and that
these costs can be reviewed in PG&E’s next Gas Transmission and Storage
(GT&S) Rate Case.6

Q 11 Are PG&E’s concerns regarding the uncertainty of the TIMP work required
by GO-112Fs new HCA justified?
A 11 Yes. PG&E stated in Chapter 5 Prepared Testimony:

PG&E is in the process of identifying new HCAs and will incorporate
those new HCAs into its integrity assessment plan for assessments in
2018 and beyond.7

At the time of writing the prepared testimony, PG&E was in the early
stages of identifying the new HCAs, which at that time still had to have
threats identified so that proper assessment methods could be identified.

As noted in testimony, we could not know what costs would be involved in

5 ORA-05, p. 11, lines 5-7; CSU-1, p. 2; TURN, Chapter 5A, p. 16, lines 5-7.
6 ORA-05, p. 11, lines 7-12.
7 PG&E Prepared Testimony, Chapter 5, p. 5-6, lines 3-5.
assessing these new HCAs until 2018, and, therefore, could not know upon filing of the 2019 GT&S Rate Case what those additional costs may be.

Q 12 Are PG&E’s concerns about the uncertainty of PHMSA’s final rule justified?
A 12 Yes. PG&E cannot overstate the potential impact of the upcoming PHMSA rule changes. The industry has used the term, “gas and gathering pipeline mega rule” because the amount of change proposed for 49 CFR, Part 192 is the largest that PHMSA has undertaken since the inception of Part 192. It is so large that PHMSA has decided to break it into three parts, as PG&E described in a discovery response. The expansion of the integrity management portion of the new rule is expected for publication in June of 2019. As such, there is a high degree of uncertainty that makes a two-way TIMPBA necessary.

Q 13 Does ORA recommend a funding mechanism to address additional TIMP costs incurred by the new PHMSA regulations that may be implemented?
A 13 Yes. ORA used its own Hydrotest forecasting model to produce its recommended expenses for PG&E’s TIMP Pressure Test Program. In doing so, ORA recommends a 2019 Test Year (TY) forecast of $66.9 million, an approximate $2.7 million increase in PG&E’s proposed forecast of $64.282 million for the program. ORA then suggests that:

These additional funds should help mitigate any additional costs incurred by the new regulations.

Q 14 Does ORA offer any analysis showing how they determined that a $2.7 million increase would be sufficient to mitigate any additional TIMP costs incurred by new regulations?
A 14 No, they do not.
Q 15 Does PG&E believe $2.7 million will address the additional TIMP costs PHMSA may impose?

---


9 ORA-038, Question 06a.

10 ORA-05, p. 10, lines 3-6 and Table 5-3.

11 ORA-05, p. 11, lines 16-17.
No. While PG&E cannot forecast the new TIMP costs, given the scope of
the potential regulatory changes, it seems unlikely that $2.7 million will
address additional costs that PHMSA may impose. The scope of PHMSA
regulatory changes affects both HCAs (TIMP) and non-HCAs. The two-way
TIMP Balancing Account addresses the additional costs due to TIMP
regulatory changes and the Gas Statutes Regulations and Rules
Memorandum Account (GSRRMA) addresses additional costs for non-TIMP
related regulatory changes. It should be noted that none of the intervenors
dispute the need for the GSRRMA.

What is the basis for TURN’s one-way TIMP balancing account
recommendation?

TURN states that:

Nothing has changed since PG&E’s last unsuccessful request that
would address the concerns that caused the Commission to reject a
2-way account.12

Is TURN’s statement that “nothing has changed” true?

No. As stated above, the pending PHMSA rule changes with regards to
HCAs may have a very large impact. There is a high degree of uncertainty
that makes a two-way TIMPBA necessary.

Does TURN offer a mechanism for recovery of TIMP costs PG&E would
incur due to pending regulations?

Yes. TURN recommends that the TIMPMA created as a result of
D.16-06-056 be retained. TURN argues that:

This TIMP MA fully addresses PG&E’s arguments based on regulatory
uncertainty….13

Do you agree with TURN’s recommendation to retain the TIMPMA?

No. In addition to the discussion above, TIMP work is required under
Subpart O. A TIMPMA only allows PG&E to track costs for new TIMP
statutes or rules, after which, PG&E must file a separate application to
recover the incurred costs. This results in the need for PG&E to redistribute
other program adopted funds to cover the required Subpart O work.

A two-way TIMP balancing account would ensure that PG&E can perform

12 TURN, Chapter 5A, p. 17, lines 4-5.
13 TURN, Chapter 5A, p. 17, lines 16-17.
Q 20  Are there other elements the Commission should consider when evaluating PG&E’s proposal for a two-way TIMPBA that would not be covered by the TIMPMA?

A 20  Yes. First, the additional reason that PG&E needs a two-way balancing account is to:

- Enable PG&E to complete mitigations and conduct re-assessments as required based on assessment findings. When assessments are conducted, those assessments produce various mitigations. PG&E has forecast mitigations in its various TIMP programs for this rate case filing based on historical findings. However, until assessments are completed, the amount of mitigation work is highly uncertain. Under Subpart O, certain findings have required remediation time frames. A two-way balancing account will enable PG&E to have adequate funding to comply with Subpart O.

Second, authorization of a two-way TIMPBA is consistent with the Commission’s approval of a two-way balancing account for Southern California Gas Company (SoCalGas). The Commission authorized a two-way balancing account for TIMP expenditures in SoCalGas’ 2012 and 2016 General Rate Cases (GRC). PG&E has provided details from those decisions in its prepared testimony.

Q 21  Considering a two-way TIMP balancing account was approved for SoCalGas, did ORA, CSU or TURN provide any meaningful explanation as to why PG&E should be treated any differently?

A 21  No. Neither ORA, CSU, nor TURN, acknowledges that both PG&E and SoCalGas are subject to all of the same issues regarding TIMP-related work. Both utilities are required to comply with Subpart O, and both will be impacted by the new requirements imposed by the pending GO-112F’s new HCA definition and PHMSA rule changes. In light of the fact that both

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14 See PG&E Chapter 2 rebuttal testimony, sponsored by Mr. Singh, for additional discussion regarding balancing and memorandum accounts.

15 PG&E Prepared Testimony, Chapter 5, p. 5-9, lines 17-26.

16 PG&E Prepared Testimony, Chapter 5, p. 5-8, line 20 to p. 5-9, line 7.
utilities are impacted similarly, the Commission should authorize a two-way TIMP balancing account for TIMP costs for PG&E.\textsuperscript{17}

Q 22 What is PG&E’s recommendation after considering the arguments made by parties in their direct testimony?

A 22 PG&E continues to recommend that the Commission approve a two-way TIMP balancing account, approve the GSRRMA for non-TIMP regulatory changes, and, if the two-way TIMP balancing account is approved, discontinue the TIMP memorandum account.\textsuperscript{18}

Q 23 If the Commission does not approve a two-way TIMP balancing account, what is PG&E’s position regarding the discontinuation of the TIMP memorandum account?

A 23 Should the Commission deny PG&E’s request for a two-way TIMP balancing account and instead continue the one-way TIMP balancing account, the TIMP memorandum account should continue as well to address new TIMP statutes or rules.

D. Response to Parties’ Recommendations Concerning Specific Programs or Projects

1. In-Line Inspection

a. Parties’ Recommendations Concerning the ILI Program Are Unjustified

Q 24 What parties disputed PG&E’s cost forecasts for the ILI Program?

A 24 ORA, TURN, IS, and CSU disputed PG&E’s cost forecast for the ILI Program.

Q 25 How do you respond to these positions and criticisms?

A 25 Table 5-4 summarizes PG&E’s rebuttal to parties’ ILI recommendations.

\textsuperscript{17} See PG&E Chapter 2 rebuttal testimony, sponsored by Mr. Singh, for additional discussion regarding balancing accounts.

\textsuperscript{18} If the two-way TIMP balancing account is not approved, the TIMP memorandum account should not be discontinued, as discussed in PG&E’s Chapter 17B rebuttal testimony, sponsored by Mr. Pinn.
### TABLE 5-4
### SUMMARY OF PG&E’S ILI PROGRAM REBUTTAL

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<th>Section</th>
<th>Party</th>
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<td>ORA and CSU</td>
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<tr>
<td>2</td>
<td>ORA</td>
<td>ORA’s recommendation to remove ILI Runs and associated ILI DE&amp;R for runs that do not have re-assessments due during the rate case period, or are not required by law, ignores risk profile.</td>
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<tr>
<td>3</td>
<td>CSU</td>
<td>CSU’s claim that the ILI Upgrade scope would require an increase in ILI equipment inventory or capable staff is incorrect because PG&amp;E does not own ILI equipment and uses contractors who own the ILI equipment.</td>
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<td>4</td>
<td>TURN</td>
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<td>5</td>
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<td>6</td>
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<td>TURN’s recommendation to extend the ILI Capital Upgrades, and, therefore, Extend the Traditional ILI Runs Program, adversely effects compliance requirements.</td>
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<td>9</td>
<td>IS</td>
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<tr>
<td>10</td>
<td>IS</td>
<td>IS’ recommendations of forecast reduction to ILI Expenses is flawed.</td>
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</tbody>
</table>

#### b. ORA’s and CSU’s Recommendation to Defer ILI Upgrades to the Next Rate Case and Still Achieve Completion on the Commission-Approved 12-Year Plan Approved by the Commission Is Flawed

**Q 26** What does ORA recommend regarding cost forecasts for the capital ILI Upgrade Program?

**A 26** ORA recommends that the 2019 capital ILI Upgrade forecast be reduced from $214 million to $142 million, a reduction of approximately $72 million.\(^{19}\) CSU agrees with and supports this recommendation.\(^{20}\)

**Q 27** How does ORA justify such a large annual reduction?

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\(^{19}\) ORA-05, p. 26, Table 5-18.

\(^{20}\) CSU-1, p. 5.
ORA recommends that PG&E achieve this reduction by deferring 18 ILI Upgrade projects to the next rate case period, reducing the scope of work during this rate case period from 18 to 12 upgrade projects per year.21

Q 28 Does ORA contest the 12-year pace for the ILI Upgrade Program that was already authorized by the Commission in PG&E’s 2015 GT&S Rate Case?22

A 28 No. Instead, ORA believes that PG&E can still achieve the 12-year pace by pushing out 18 projects into the next rate case.23

Q 29 Will PG&E be able to complete the ILI Upgrade Program at the 12-year pace if 18 projects are deferred to the next rate case?

A 29 No. PG&E identified the number of ILI Upgrade projects that needed to be completed over the remainder of the 12-year period to develop its forecast of 18 projects annually to achieve completion in 12 years. Deferring 18 projects to the next rate case period, as ORA suggests, will result in a significant increase in the next rate case period for the ILI Upgrade Program in order for PG&E to achieve the 12-year pace authorized by the Commission.

Q 30 Does ORA provide support for the deferral of 18 projects?

A 30 Yes, ORA states that the average annual ILI Upgrade mileage PG&E forecasts for the 2019 GT&S Rate Case period is higher than the average of any other year previously in PG&E’s ILI Upgrade Program. ORA further states that PG&E is accelerating work on specific pipelines in the 2019-2021 rate case, rather than spreading the workload more evenly between 2019-2026,24 which may strain resources. ORA also recommends that PG&E wait to complete ILI Upgrades until such time that a pipeline section is due for re-assessment under 49 CFR, Subpart O.25

Q 31 Is PG&E “accelerating work on specific pipelines” in this rate case period?

21 ORA-05, p. 23, lines 6-8.
22 D.16-06-056, mimeo, p. 441, Conclusion of Law 10.
23 ORA-05, p. 23, lines 6-11.
24 ORA-05, p. 24, lines 12-14.
25 ORA-05, p. 25, lines 10-13 and fn’s 57 and 58.
A 31 No. PG&E is forecasting a completion pace of 18 projects per year in order to complete the program on the 12-year authorized pace. PG&E is not forecasting an acceleration of the authorized pace.

Q 32 Do the high number of miles for ILI Upgrade for this rate case period demonstrate that PG&E has accelerated ILI Upgrade work?

A 32 No, ORA’s analysis related to ILI Upgrade miles and its potential for straining of resources is flawed.

Q 33 How is it flawed?

A 33 First, and most important, the amount of work associated with ILI Upgrades cannot and should not be related to miles. Rather, it is based on projects. This is the reason that PG&E’s forecast for the ILI Upgrade Program is based on a cost-per-project basis, and does not use the length of projects as a forecasting basis.26

Second, ORA seems to suggest that PG&E accelerated completing certain higher mile pipeline sections during this rate case period and that those miles can be evenly spread over two rate case periods in order to spread the costs over a longer period of time. This cannot be done, however, because individual projects cannot be split to even out the pipeline miles across years. Furthermore, adding more projects counts to the outer years will do more to strain resources than maintaining the pace of 18 projects per year.

Q 34 Please explain your first, and most important, point further.

A 34 The main point is that forecasting the amount of work and costs associated with ILI Upgrades is not mileage dependent. Whether a project is 100 miles long or 10 miles long, the actual cost and work requirements could be nearly the same or there could even be a higher cost for the 10-mile project. ILI Upgrade cost and the work associated with the projects are driven by capital improvements to make the pipelines piggable. The upgrade project includes installing pig launchers and receivers in appropriate locations to introduce and remove the cleaning and ILI tools from the inside of the pipeline. It also includes replacing certain segments of pipe, valves, fittings or other appurtenances that, if left in the system, would obstruct the movement of the

26 PG&E Prepared Testimony, Chapter 5, p. 5-30, lines 3-8.
tool through the pipeline. To illustrate, please see Figures 5-1 and 5-2. Both of these project examples are for the same diameter pipe. Figure 5-1 shows that both the 100-mile and the 10-mile projects have launchers/receivers to install, a valve replacement, and the same length of pipe to be replaced. These projects will be approximately the same cost even though the lengths are significantly different. In Figure 5-2, the 100-mile long project only requires a launcher/receiver to be installed. The 10-mile long project has the same upgrade requirements as the 10-mile project in Figure 1. The 10-mile long project will cost more even though it is 10 percent of the length of the 100-mile long project. These examples demonstrate how it is incorrect to use a length relationship to correlate with the amount of work associated with ILI Upgrades.

**FIGURE 5-1**
ILI UPGRADE: 100 MILES VERSUS 10 MILES WITH SAME WORK REQUIREMENTS

**FIGURE 5-2**
ILI UPGRADE: 100 MILES VERSUS 10 MILES WITH DIFFERENT WORK REQUIREMENTS

Q 35 Should PG&E wait to complete ILI Upgrades until such time that a pipeline section is due for re-assessment under 49 CFR, Subpart O?
No. First, as PG&E explained in Chapter 5 Prepared Testimony and
demonstrated in Chapter 5 workpapers, the reasoning for performing the ILI
Upgrade projects that were prioritized for the rate case period are
risk-based,\textsuperscript{27} which goes beyond simply waiting for re-assessment intervals
to be reached.

Second, as PG&E also explained in Chapter 5 Prepared Testimony:
ILI is the most reliable pipeline integrity assessment tool currently
available to natural gas pipeline operators to assess the internal and
external condition of transmission line pipe.\textsuperscript{28}

As such, performing the condition assessments with ILI is preferred
where possible.

Please summarize PG&E’s recommendation regarding ILI upgrades.
PG&E recommends that the Commission continue to approve PG&E’s
12-year ILI upgrade pace that was authorized in the 2015 GT&S Rate Case
decision, completing upgrade projects at the pace of approximately
18 per year.

c. ORA’s Recommendation to Remove ILI Runs and Associated ILI
DE&R for Runs That Do Not Have Re-Assessments Due During the
Rate Case Period, or Are Not Required by Law, Ignores Risk Profile

What forecast is ORA recommending for Traditional ILI Runs,
Non-Traditional ILI Runs, and the ILI DE&R portions of the ILI Program?

For the Traditional ILI Runs Program, ORA recommends $42 million in 2019
dollars, as compared to PG&E’s $66 million in 2019 dollars.\textsuperscript{29} For the
Non-Traditional ILI Program, ORA recommends $16 million in 2019 dollars,
as compared to PG&E’s $20 million in 2019 dollars.\textsuperscript{30} For the ILI DE&R
Program, ORA recommends $29 million in 2019 dollars, as compared to
PG&E’s $39 million in 2019 dollars.\textsuperscript{31} In total for the ILI expense programs,
ORA recommends $87 million in expenses in 2019 dollars, as compared to

\textsuperscript{27} PG&E Prepared Testimony, Chapter 5, p. 5-25, lines 13-17; and PG&E WP 5-41,
Workpaper Table 5-6.

\textsuperscript{28} PG&E Prepared Testimony, Chapter 5, p. 5-20, lines 20-22.

\textsuperscript{29} ORA-05, p. 28, lines 12-13.

\textsuperscript{30} ORA-05, p. 29, lines 16-17.

\textsuperscript{31} ORA-05, p. 31, lines 14-16.
PG&E’s $125 million, a reduction of approximately $38 million in 2019 dollars.32

Q  38 What is ORA’s rationale for such a large ILI expense reduction?
A  38 ORA’s rationale for all three programs is based on one of the similar arguments that was used for the ILI Upgrades Capital Program. Specifically, ORA suggests that PG&E should wait to complete Traditional ILI and Non-Traditional ILI Runs and the associated ILI DE&R, until such time that a pipeline section is due for re-assessment under 49 CFR, Subpart O.33

Q  39 Is there a flaw in this analysis?
A  39 Yes. First, as PG&E explained in Chapter 5 Prepared Testimony, and demonstrated in Chapter 5 workpapers, the reasoning for performing the Traditional and Non-Traditional ILI Runs and the associated ILI DE&R that are prioritized for the rate case period are risk-based,34 which goes beyond simply waiting for re-assessment intervals to be reached.

Second, as PG&E also explained in Chapter 5 Prepared Testimony:

ILI is the most reliable pipeline integrity assessment tool currently available to natural gas pipeline operators to assess the internal and external condition of transmission line pipe.35

As such, performing the condition assessments with ILI is preferred, where possible.

d. CSU’s Claim That the ILI Upgrade Scope Would Require an Increase in ILI Equipment Inventory or Capable Staff Is Incorrect Because PG&E Does Not Own ILI Equipment and Uses Contractors Who Own the ILI Equipment

Q  40 Does CSU give any justification for agreeing with ORA’s reduction?
A  40 Yes. CSU states that an:

________________________

32 Reductions are from ORA’s testimony. In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
33 ORA-05, p. 27, line 20 to p. 28, line 3; ORA-05, p. 29, lines 7-9; and ORA-05, p. 30, lines 13-14.
34 PG&E Prepared Testimony, Chapter 5, p. 5-25, lines 13-17 and PG&E WP 5-41, Workpaper Table 5-6.
35 PG&E Prepared Testimony, Chapter 5, p. 5-20, lines 20-22.
average rate of 374 miles inspected per year is more than twice 
\((374/180 = 208\%)\) the highest number of miles completed in the 
documented period (180 in 2017).

Then, CSU claims that:

Any increase in pace of inline inspections would logically require an 
increased inventory of equipment and a larger staff trained and capable 
of doing the inspection work.

Q 41 Are CSU’s claims about an increase in ILI equipment inventory or capable 
staff correct?

A 41 No. First, their calculations of an average of 374 miles a year 
\((1,122/3 = 374)\) are based on the number of miles that PG&E proposes as 
capital upgrades, and not “inspections,” as stated by CSU. Second, PG&E 
does not own or operate any ILI tools themselves. PG&E hires ILI vendors 
that own and operate the tools. PG&E has not included any forecasts for 
purchasing tools or hiring any additional staff in this case.

Q 42 Please summarize PG&E’s recommendation regarding ILI upgrades and the 
straining of resources.

A 42 PG&E recommends that the Commission continue to approve PG&E’s 
12-year ILI upgrade pace that was authorized in the 2015 GT&S Rate 
Case decision.

e. TURN’s Recommendation of Reducing the ILI Capital Upgrades 
Program by 50 Percent Is Unfounded

Q 43 What does TURN recommend for the ILI Upgrades Program?

A 43 TURN has two recommendations. First, TURN recommends that:

PG&E be authorized to continue its ILI Upgrade work at the rate of 
9 projects per year.

Second, TURN recommends an:

Approximately 11% lower cost per project than forecast by PG&E.

The combination of these recommendations results in ILI Upgrades 
forecast recommendations of approximately $95.1 million, $98.1 million, and

36 CSU-1, p. 4.
37 CSU-1, p. 4.
38 TURN, Chapter 5A, p. 2, lines 5-6.
39 TURN, Chapter 5A, p. 2, line 8.
$101.0 million in 2019, 2020, and 2021, respectively. These are reductions of approximately $118.4 million, $122.2 million, and $125.7 million for the respective years.

Q 44 How does TURN determine that a pace of nine projects per year is appropriate?

A 44 TURN states that:

PG&E is proposing a tremendous acceleration of the program compared to the work that PG&E has been able to perform in 2012-2017.

TURN also states that:

PG&E’s forecast that it will complete 18 projects in each of the three upcoming years doubles its highest number of annual upgrade projects to date, a target reached only in 2015 and 2016.

TURN continues with:

These results raise serious doubts whether PG&E will even be able to achieve a pace that exceeds the highest number of annual projects it has performed in the last six years.

Q 45 Is PG&E proposing an acceleration of the program, compared to the work that PG&E has been able to perform in 2012-2017?

A 45 No. PG&E is proposing to complete 18 projects per year in the 2019-2021 rate case period, which is in line with the 12-year ILI Upgrade plan adopted in D.16-06-056. Starting in 2019, PG&E will have 150 more ILI Upgrade projects to complete. With eight years left in the 12-year program, 18 projects per year is the average number of projects PG&E will need to complete the program in the Commission-adopted 12-year period (150/8 = 18.75 or ~18).

Q 46 Does PG&E have any doubts that it is capable of achieving this pace?

A 46 No. As stated in the response to TURN-003 Q12:

PG&E has not had any problems obtaining qualified individuals, either company employees or contractor employees, to do other required work associated with the ILI Upgrade program.

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40 TURN, Chapter 5A, p. 2, lines 8-9 and table.
41 TURN, Chapter 5A, p. 3, lines 21-23.
42 TURN, Chapter 5A, p. 4, lines 7-8.
43 TURN, Chapter 5A, p. 4, lines 12-13.
44 TURN-003, Question 12c.
Q 47 Does TURN make any other criticism of PG&E’s ILI Upgrades Program?
A 47 Yes. TURN states:

PG&E has already upgraded much of its highest risk pipe in the
over 50% of the program that will be completed by the end of 2018.45

Q 48 How did TURN come to this conclusion?
A 48 TURN provided Table 2 in their testimony showing the "ILI Upgrades as a
Percent of PG&E Goal."46 In this table, TURN calculated the percentage of
mileage completed for the prescribed timeframe versus PG&E’s overall
upgrades goal. Seemingly, TURN used the first two lines of the table
showing “Through 2016” (42%) and “2017-2018 Planned” (11%) to conclude
that over 50 percent of the program will be completed by the end of 2018.

Q 49 Is this conclusion correct?
A 49 No. As stated in PG&E’s rebuttal to ORA above, the amount of work
associated with ILI Upgrades cannot, and should not, be related to miles.
Instead, the amount of work should be related to the number of projects.
Through 2018, PG&E will have only completed 86 of the 236 ILI upgrade
projects. With 150 projects left to complete after the end of 2018, PG&E will
only be approximately 36 percent complete at the end of 2018 (86 + 150 = 236, 86/236 = 0.3644 or ~36 percent).

Q 50 How did TURN determine that an 11 percent reduction in cost per project
was appropriate?
A 50 TURN used data from PG&E’s response to data request TURN-018,
Question 1, to create four separate cost-per-project categories, based on
the number of miles of the upgrade project.47 TURN then used those
values, and applied them to the forecasted projects over the rate case
period to determine a subtotal forecast for all projects within the program.
Last, TURN then divided that subtotal by the number of projects to resemble
PG&E’s cost-per-project methodology, and yielded a cost per project
forecast of approximately $9.7 million, a reduction of approximately

45 TURN, Chapter 5A, p. 5, lines 11-12.
46 TURN, Chapter 5A, p. 5, Table 2.
47 TURN, Chapter 5A, p. 9, Figure 2 and fn 18.
11 percent from PG&E’s cost per project forecast of approximately $10.9 million. 48

Q 51 Did PG&E identify any issues with TURN’s ILI Upgrades forecast methodology?

A 51 Yes. Footnote number 18, on page 9 of TURN’s Chapter 5A testimony, states that TURN “only include[d] projects for which PG&E provided length estimates.” 49 This is an incorrect use of this data. There are several line items with “N/A” in the “Project Length (Miles)” columns which represent costs of an upgrade project, and should have been included in TURN’s analysis.

Q 52 Can you explain why some line items had “N/A” for length values?

A 52 Yes. An example can be found in PG&E’s workpapers page WP 5-158, and used again in PG&E’s response to data request TURN-018, Question 1. Lines 78-81 represent the total costs of one project, project 108-041. 50 In this instance, only line 78 has a value in the “Project Length (Miles)” column, while lines 79-81 do not. This is because the subsequent three lines represent the costs captured in different order numbers used on the same upgrade section. Mileage could only be counted once, thus the reason PG&E put “N/A” in the “Project Length (Miles)” column. TURN does not account for the total project costs when they eliminate the line items with “N/A” in the “Project Length (Miles)” column.

Q 53 What does PG&E recommend based on its review of TURN’s analysis?

A 53 PG&E recommends that the Commission adopt PG&E’s forecast pace of 18 projects per year, as it aligns with the 12-year upgrade plan adopted in D.16-06-056. PG&E also recommends that the Commission reject TURN’s erroneous cost-per-project analysis, and adopt PG&E’s appropriately calculated cost-per-project.

48 TURN, Chapter 5A, p. 9, lines 6-12.
49 TURN, Chapter 5A, p. 9, fn 18.
50 PG&E WP 5-158, Workpaper Table 5-36, lines 78-81.
f. TURN’s Recommendation for Forecasting Methodology for
   Traditional ILI Runs is Reasonable, but Requires Correction

Q 54 What is TURN’s forecast methodology recommendation for the expense
   Traditional ILI Runs Program?
A 54 TURN provides their own Traditional ILI Run forecasting methodology which
   is based on the average cost per length times diameter (LxD) in five specific
   LxD buckets. 51 Using their methodology, TURN recommends a reduction to
   PG&E’s Traditional ILI Runs 2019 TY forecast of approximately
   $5.8 million. 52

Q 55 Does TURN state why their forecasting methodology is appropriate?
A 55 Yes. TURN claims that PG&E’s cost curve used to forecast the Traditional
   ILI Runs Program has an, “R-squared value of just 3.4%,” which if used “will
   lead to inaccurate results.” 53 In response, TURN provides Figure 3, which
   states the, “Average Cost per LxD for Traditional ILI Runs.” TURN’s
   justification for using this is that:

   While one curve to fit all of the historical data points was not able to
   provide a reasonable fit for forecasting future project costs, examining
   costs by size (LxD) illustrates relatively large “fixed” costs for short/small
   pipe which decrease significantly for large/long sections of pipe. 54

Q 56 Were there any issues PG&E identified with the data that TURN used in
   their forecast methodology?
A 56 Yes. TURN used the data from PG&E’s response to data request
   TURN-002, Question 8, to conduct their analysis. 55 In PG&E’s review of
   this data response, PG&E identified that it inadvertently had multiple line
   items for five different projects that should have been combined. This is a
   mistake on PG&E’s part, and was corrected in a revised data response sent
   to TURN, subsequent to the issuance of TURN’s testimony. 56

51 TURN, Chapter 5A, p. 13, Figure 3.
52 TURN, Chapter 5A, p. 13, line 17.
53 TURN, Chapter 5A, p. 12, lines 16 and 20.
54 TURN, Chapter 5A, p. 13, lines 5-8.
55 TURN, Chapter 5A, p. 12, fn 27.
56 TURN-002, Question 08, Revision 01.
Q 57 Did PG&E re-evaluate TURN’s forecast methodology based on the corrected data?

A 57 Yes. Please see Figure 5-3 below for the corrected Average Cost per LxD for Traditional ILI Runs for the same buckets determined by TURN.

FIGURE 5-3
TRADITIONAL ILI RUNS: AVERAGE COST PER LxD FOR TRADITIONAL ILI RUNS

Q 58 What would the 2019 TY forecast be for the Traditional ILI Runs Program if the updated costs per LxD were applied using TURN’s methodology?

A 58 Using the corrected average costs per LxD for Traditional ILI Runs, the 2019 TY forecast for the Traditional ILI Runs Program would be approximately $65.7 million, a reduction of approximately $1.0 million of PG&E’s original forecast of approximately $66.7 million.\(^{57}\)

Q 59 What does PG&E recommend based on the aforementioned analysis?

A 59 PG&E acknowledges the relatively low R-squared value of its forecast cost curve. PG&E finds TURN’s forecasting methodology to be reasonable.

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\(^{57}\) PG&E’s original forecast of $66.7 million for Traditional ILI Runs includes approximately $0.6 million for StanPac (MAT Code 34A). TURN Chapter 5A does not account for StanPac in the PG&E forecast. (TURN, Chapter 5A, p. 14, Table 6).
PG&E is not opposed to using TURN’s methodology so long as it incorporates the data corrections provided by PG&E.

g. TURN’s Recommendation to Extend the ILI Capital Upgrades, and, Therefore, Extend the Traditional ILI Runs Program, Adversely Affects Compliance Requirements

Q 60 What pace recommendation does TURN make associated with the Traditional ILI Runs Program?
A 60 In conjunction with the recommendation to reduce the capital ILI Upgrades Program, TURN recommends that the Traditional ILI Run Program be reduced accordingly. When combined with TURN’s forecast methodology reduction recommendation, this results in a recommended forecast of approximately $44.0 for 2019, a reduction of approximately $22.7 million of PG&E’s original forecast of approximately $66.7 million.

Q 61 Does TURN state why their pace reduction is appropriate?
A 61 Yes. TURN associates their Traditional ILI Runs Program pace reduction with their recommendation to reduce the pace of the capital ILI Upgrades Program. As such, the same reasons they give for their recommendation to slow the pace of the ILI Upgrades Program would apply.

Q 62 What would be the key effects on the Traditional ILI Runs Program, assuming project-per-year ILI Upgrades Program pace recommended by TURN was adopted?
A 62 As stated in PG&E’s response to data request TURN-019, Question 4, and reiterated by TURN in its testimony, TURN’s recommended ILI Upgrades pace would reduce the first-time assessments in Traditional ILI Runs Program by 50 percent. PG&E’s Workpaper Table 5-4, on workpaper pages WP-5-38 through WP 5-39, list 75 forecasted inspection projects, of which, 44 of them are first-time inspections. Adopting TURN’s recommendation would mean that PG&E would have to eliminate approximately 22 of the 44 first-time inspections. If PG&E were not able to inspect these sections using ILI, PG&E would be required to use a different assessment method in order to comply with the requirements of 49 CFR 192, Subpart O. TURN’s recommendation only accounts for the

58 TURN, Chapter 5A, p. 11, lines 11-12 and fn 22.
reduction of forecast using ILI as the assessment method, but does not
provide recovery using a different assessment method.
Q 63 What does PG&E recommend, based on its review of TURN's
recommendation of extending the ILI Capital Upgrades Program, and its
adverse effects on compliance requirements?
A 63 PG&E recommends that the Commission reject TURN's recommenda-
tion of extending the ILI Capital Upgrades Program, and adopt PG&E's forecast pace of 18 projects per year, as it aligns with the 12-year upgrade pace adopted in D.16-06-056, and provides cost recovery for HCA assessments required by 49 CFR, Part 192, Subpart O.

h. TURN's Recommendation to Reduce Non-Traditional ILI Expenses Is Not Reasonable
Q 64 What does TURN recommend for the Non-Traditional ILI Program?
A 64 TURN recommends a 2019 forecast of approximately $18.8 million, a reduction of approximately $1.0 million from PG&E's original forecast of approximately $19.8 million.59
Q 65 Does TURN state why their reduction is appropriate?
A 65 Yes. TURN agrees with PG&E's forecasting methodology, but "incorporates 2017 data, which creates a more robust data set."60
Q 66 Does TURN explain how including 2017 makes the dataset more robust?
A 66 No.
Q 67 What does PG&E recommend?
A 67 PG&E recommends that the Commission reject TURN's use of 2017 data, and adopt PG&E's original 2019 TY forecast of approximately $19.8 million. PG&E based its original forecast on the information it had available at the time.

i. TURN's Recommendation to Reduce ILI DE&R Is Not Reasonable
Q 68 What does TURN recommend for the ILI DE&R Program?
A 68 TURN recommends a 2019 forecast of approximately $36.2 million, a reduction of approximately $2.7 million from PG&E's original forecast of approximately $38.9 million.61

59 TURN, Chapter 5A, p. 15, Table 7.
60 TURN, Chapter 5A, p. 14, lines 18-20.
61 TURN, Chapter 5A, p.16, Table 8.
Q 69 Does TURN state why their reduction is appropriate?
A 69 Yes. TURN states two reasons their reduction is appropriate. First, TURN approves PG&E’s forecast methodology, however, “incorporates 2017 cost and dig data to create a more robust data set.”\(^{62}\) Second, TURN removes a function in PG&E’s workpaper that rounds up a forecast number of digs.\(^{63}\)

Q 70 Does TURN explain how including 2017 dig and cost data makes the dataset more robust?
A 70 No.

Q 71 Does PG&E agree with removing the function in its workpaper that rounds up a forecast number of digs?
A 71 Yes.

Q 72 What would PG&E’s forecast be if the rounding function was removed?
A 72 The rounding function has negligible effect when removed. The whole-dollar 2019 TY forecast for the ILI DE&R was originally $38,958,879. Removing the function yields TY forecast of $38,949,340, a reduction of approximately $9,500.

Q 73 What does PG&E recommend?
A 73 PG&E recommends the Commission reject TURN’s use of 2017 data, and adopt a 2019 forecast of approximately $38.9 million, which includes removal of the rounding function for determining the forecast number of digs. PG&E based its original forecast on the information it had available at the time.

j. IS’ Recommendation to Extend the ILI Capital Upgrades Program From 12 Years to 15 Years Is Flawed

Q 74 What does IS recommend for the ILI Upgrade Program?
A 74 IS has two recommendations. First, IS recommends that PG&E:

\[\text{[I]Increase the time length or pace of the ILI program in this GT&S to }\]
\[\text{15 years from 12 years.}\] \(^{64}\)

Second, associated with the extended pace of the program, IS recommends a 40 percent reduction in PG&E’s capital forecast for

\(^{62}\) TURN, Chapter 5A, p. 15, lines 13-14.

\(^{63}\) TURN, Chapter 5A, p. 15, lines 14-15.

\(^{64}\) IS-1, Chapter 5, p. 5-11, lines 6-7.
2019-2021. This results in a forecast of approximately $128.1 million, $132.1 million, and $136.0 million in 2019, 2020, and 2021, respectively.\(^{65}\)

**Q 75** How does IS determine a pace extension is appropriate?

**A 75** IS states that:

\[ \text{Increasing the number of years to complete the ILI retrofits will result in a pace that is reasonable given PG&E is now proposing to expand the total mileage within the ILI program in this case.}^{66}\]

**Q 76** Did PG&E propose to expand the total mileage within the ILI Upgrades Program in this case?

**A 76** Yes. As stated in PG&E’s prepared testimony, since the last rate case, PG&E identified an additional 24 sections (237 miles) that can be made traditionally-piggable, due to ILI technology improvements.\(^{67}\)

**Q 77** Is PG&E proposing to include these 24 additional sections in its 12-year plan?

**A 77** Yes. As stated in PG&E’s prepared testimony, PG&E plans to keep the overall end milestone with these added sections. The 12-year pace with the additional projects is reflected in the forecast for this rate case period.\(^{68}\)

**Q 78** How does IS justify a 40 percent reduction to PG&E’s ILI Upgrade forecast?

**A 78** IS uses Table 5-9 in PG&E’s prepared testimony to state that there will be 2,007 miles left to be upgraded in the ILI Upgrades Program starting in 2019. IS then uses their recommendation of a 15-year plan to determine that there would be 10 years remaining in the ILI Upgrades Program starting in 2019. IS then averages the remaining 2,007 miles over the 10-year period, resulting in “approximately a pace of 201 miles per year.” IS then multiplies 201 by three to get a total mileage forecast for the 2019-2021 period, resulting in a “projected retrofit of approximately 602 miles.” IS calculates this to be “a reduction of 46%” from PG&E’s original forecast mileage of 1,122 miles (603/1122= ~54%, a ~46% reduction). Then, “to be conservative,” IS “propose[s] an adjustment to the annual ILI program cost

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\(^{65}\) IS-1, Chapter 5, p. 5-14, Table 5-4.

\(^{66}\) IS-1, Chapter 5, p. 5-11, lines 16-18.

\(^{67}\) PG&E Prepared Testimony, Chapter 5, p. 5-26, lines 13-16.

\(^{68}\) PG&E Prepared Testimony, Chapter 5, p. 5-26, lines 16-18.
during the 2019 GT&S at 60% of the Company’s request, or a 40% reduction."  

Q 79  Why does PG&E consider this recommendation flawed?
A 79  First, as stated above, the amount of work associated with ILI Upgrades cannot, and should not, be related to miles. This is the reason that PG&E’s forecast for the ILI Upgrade Program is based on a cost-per-project basis, and does not use the length of projects as a forecasting basis. IS’ forecast reduction is solely-based on miles, and not a number of projects. Second, IS built their recommendations on the presumption that there are only seven years remaining in the 12-year ILI Upgrade plan. This is not the case. PG&E’s 12-year plan started in 2015, which means there will be eight years remaining in the program starting in 2019.

Q 80  How many projects make up the 2,007 miles of pipeline left to be upgraded through the end of the program, starting in 2019?
A 80  There are 150 projects that make up the 2,007 miles of remaining pipe to be upgraded for ILI. PG&E used this number of remaining projects to determine the level of work forecast in this case (150/8 = 18.75 thus, PG&E’s proposed forecast of 18 projects per year).

Q 81  Does this include the additional 24 projects identified since the last rate case?
A 81  Yes, it does.

Q 82  Considering the 12-year plan was adopted before the 24 additional projects were identified, what would PG&E’s forecast be if the Commission were to stick to the 12-year plan for the sections only identified at the time of D.16-06-056?
A 82  If PG&E were forecasting an ILI Upgrades Program to complete 126 projects in the remainder of the 12-year program, rather than 150 (150 – 24 = 126), PG&E would reduce the number of forecast projects per year from 18 to 16 (126/8 = 15.75 or ~ 16). PG&E’s forecast for 2019-2021 would be approximately $189.8 million, $195.8 million, and $201.5 million in 2019, 2020, and 2021, respectively. Please see Table 5-5 below.

69 IS-1, Chapter 5, p. 5-12, line 21 to p. 5-13, line 9.
70 PG&E Prepared Testimony, Chapter 5, p. 5-30, lines 3-8.
### TABLE 5-5
CAPITAL ILI UPGRADES FORECAST USING 16 PROJECTS PER YEAR

#### Cost Summary Table (2019-2021)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Year</th>
<th>Forecast (2016 $, New Cost Model (NCM))</th>
<th>Escalation Factor</th>
<th>Forecast ($, NCM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2019</td>
<td>$174,369,240</td>
<td>1.089</td>
<td>$189,800,918</td>
</tr>
<tr>
<td>2</td>
<td>2020</td>
<td>$174,369,240</td>
<td>1.123</td>
<td>$195,764,346</td>
</tr>
<tr>
<td>3</td>
<td>2021</td>
<td>$174,369,240</td>
<td>1.156</td>
<td>$201,518,531</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Forecast – 2016 Base $, NCM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Average projects per year during rate case to complete upgrade program in 2026 – Not including the 24 newly-identified projects (12-year pace)</td>
</tr>
<tr>
<td>2</td>
<td>Average 2016 $, NCM Forecast/Project $10,898,078</td>
</tr>
<tr>
<td>3</td>
<td>Average Forecast Per Year $174,369,240</td>
</tr>
</tbody>
</table>

PG&E would still have to upgrade the additional 24 sections of pipeline after the completion of the original 12-year plan. If PG&E were to continue at the pace of 16 projects per year, completion of the ILI Upgrade Program would extend to 2028.

Q 83 Does IS make any other general statements supporting their capital ILI Upgrades recommendation?

A 83 Yes. IS claims that their:

[P]roposed reduction to the 2019 GT&S rate case can allow for PG&E to meet the current pace for HCA mileage of ILI retrofits but allow for a longer period to retrofit non-HCA miles of pipe, and/or those with lower IOCs.71

Q 84 How does PG&E respond to this statement?

A 84 IS' recommendation was based on an average of miles and not any specific project, however, 49 of the 54 projects PG&E forecast in the 2019-2021 period include HCAs. A reduction of 40 percent of forecasts based on miles does not account for the fact that 49 of the 54 projects forecast include HCA pipe, and, therefore IS' presumption that the proposed reduction would

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71 IS-1, Chapter 5, p. 5-11, lines 12-15.
“allow PG&E to meet the current pace for HCA mileage of ILI retrofits”\textsuperscript{72} is incorrect.

Q 85 What does PG&E recommend?

A 85 PG&E recommends that the Commission reject IS’ recommendation, and adopt PG&E’s filed forecast of 18 projects per year, keeping to the 12-year plan including the additional 24 projects newly-identified in this case. However, if the Commission were to require that PG&E extend the ILI Upgrades Program, due to the addition of the 24 new projects, PG&E recommends that the Commission adopt PG&E’s forecast of 16 projects per year, as shown in Table 5-5 above.

k. IS’ Recommendations for Forecast Reduction to ILI Expenses

Is Flawed

Q 86 Which ILI expense programs does IS provide recommendations for?

A 86 IS makes a broad recommendation for all the ILI expense programs, which include Traditional ILI Runs, Non-Traditional ILI Runs, and ILI DE&R.

Q 87 What is the nature of IS’ recommendations?

A 87 IS recommends that the ILI expense programs’ forecasts be reduced by 40 percent, resulting in a ILI expense forecast of “$75.3 million a year.”\textsuperscript{73} This is a reduction of approximately $50.2 million in 2019 from PG&E’s original forecast of approximately $125.5 million.

Q 88 How did IS determine that this reduction was appropriate?

A 88 IS applied the same 40 percent reduction calculated in their recommendation for the capital ILI Upgrades Program to all the expense ILI programs.

Q 89 Why does PG&E consider this recommendation flawed?

A 89 First, the recommendation for the 40 percent reduction to capital is flawed for the reasons mentioned above.

Second, IS presumes that there is a one-to-one relation between the capital and expense ILI programs. This is not correct.

Q 90 Can you elaborate on your second point above?

\textsuperscript{72} IS-1, Chapter 5, p. 5-11, line 13.

\textsuperscript{73} IS-1, Chapter 5, p. 5-13, lines 11-12. This reduction is erroneously listed as $75.5 million in IS-1, Chapter 5, p. 5-14, Table 5-4.
Yes. First, PG&E’s expense Traditional ILI Runs Program includes both first-time inspections and re-assessment inspections. This means that even if there is a 40 percent reduction to the number of capital projects completed, it would only have influence on the number of first-time inspections, and not yield a 40 percent reduction in the total number of Traditional ILI Runs required to be conducted. Also, the expense ILI inspections are conducted the year subsequent to the capital upgrade. This means that even if you take a reduction in the number of capital upgrades you complete in a particular year, the reduction of associated expense traditional ILI runs would not be realized until the following year. IS did not take any of these considerations into account in their recommendation.

Second, Non-Traditional ILI does not require a capital upgrade, and should not at all be associated with a recommendation in reductions associated with the Capital ILI Upgrades Program. IS did not take this into consideration in their recommendation.

Last, ILI DE&R is required on both first-time assessments and re-assessments. The digs are conducted the year subsequent to the inspection. This means that the digs are performed two years after the capital upgrade for sections being inspected for the first time. Even if you take a reduction to the number of capital ILI upgrades completed in a particular year, you would not realize a reduction in the number of digs for two years. IS did not take this into consideration in their recommendation.

If the Commission were to adopt a pace of 16 capital ILI upgrade projects per year as explained in the previous section, how would that affect the forecasts for the expense Traditional ILI Runs Program?

If the Commission were to adopt a pace of 16 capital upgrade projects per year, the assessment of four sections would be delayed until after the 2019 GT&S Rate Case period. This would result in an updated 2019 TY forecast of approximately $64.0 million for the Traditional ILI Runs Program, a reduction of approximately $2.7 million from the original forecast of approximately $66.7 million. Please see Table 5-6 below.
### TABLE 5-6
TRADITIONAL ILI RUNS FORECAST USING 16 PROJECTS PER YEAR

<table>
<thead>
<tr>
<th>Line No.</th>
<th>MAT Code</th>
<th>Unescalated Forecast (2016$, NCM)</th>
<th>Escalation Factor</th>
<th>Escalated Forecast ($, NCM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>HPB</td>
<td>$59,333,493</td>
<td>1.069</td>
<td>$63,454,673</td>
</tr>
<tr>
<td>2</td>
<td>34A</td>
<td>534,496</td>
<td>1.069</td>
<td>571,621</td>
</tr>
<tr>
<td>3</td>
<td>Total</td>
<td>$59,867,990</td>
<td>1.069</td>
<td>$64,026,294</td>
</tr>
</tbody>
</table>

#### Average Annual Cost Analysis – Initial Forecast

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>PG&amp;E Portion for Rate Case Period</td>
</tr>
<tr>
<td>2</td>
<td>StanPac Portion for Rate Case Period</td>
</tr>
<tr>
<td>3</td>
<td>Total Forecast for Rate Case Period</td>
</tr>
<tr>
<td>4</td>
<td>Annual PG&amp;E Portion</td>
</tr>
<tr>
<td>5</td>
<td>Annual StanPac Portion</td>
</tr>
<tr>
<td>6</td>
<td>6/7th of StanPac Portion</td>
</tr>
<tr>
<td>7</td>
<td>Subtotal of Annual Forecast</td>
</tr>
</tbody>
</table>

1. **Q 92** If the Commission were to adopt a pace of 16 capital upgrade projects per year, how would that affect the forecast for the expense Non-Traditional Runs Program?

2. **A 92** If the Commission were to adopt a pace of 16 capital upgrade projects per year, there would be no effect on the Non-Traditional ILI Runs Program, as there are no capital upgrades necessary to conduct Non-Traditional runs.

3. **Q 93** If the Commission were to adopt a pace of 16 capital upgrade projects per year, how would that affect the forecast for the expense ILI DE&R Program?

4. **A 93** If the Commission were to adopt a pace of 16 capital upgrade projects per year, subsequently delaying the associated inspections, PG&E estimates it would need to do approximately five fewer digs during the rate case period. This would result in TY forecast of approximately $38.55 million for the ILI DE&R Program, a reduction of approximately $0.41 million from the original forecast of approximately $38.96 million. Please see Table 5-7 below.
### TABLE 5-7
ILI DE&R FORECAST USING 16 PROJECTS PER YEAR

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Year</th>
<th>Subtotal of Expenses (2016$ NCM)</th>
<th>Escalation Rate</th>
<th>Total Expenses 2016$ NCM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2019</td>
<td>$36,044,939</td>
<td>1.069</td>
<td>$38,546,457</td>
</tr>
</tbody>
</table>

<p>| Miles Forecast for Assessment (2018-2020) (With 16 Capital Upgrade Projects Per Year) |</p>
<table>
<thead>
<tr>
<th>Program</th>
<th>Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Traditional ILI</td>
<td>1800.70</td>
</tr>
<tr>
<td>2 Non-Traditional ILI</td>
<td>27.113</td>
</tr>
<tr>
<td>3 Total Miles</td>
<td>1827.81</td>
</tr>
<tr>
<td>4 Estimated Number of Digs (2019-2021)</td>
<td>460</td>
</tr>
<tr>
<td>5 Total ILI DE&amp;R Expenses (2016$ NCM)</td>
<td>$108,134,816</td>
</tr>
<tr>
<td>6 Subtotal of Annual Expenses (2016$ NCM)</td>
<td>$36,044,939</td>
</tr>
</tbody>
</table>

1 What does PG&E recommend?
2 PG&E recommends that the Commission reject IS' recommendation on PG&E's expense ILI programs and adopt PG&E's original forecast for each expense ILI program. However, if the Commission adopts a capital ILI Upgrades pace of 16 projects per year, PG&E recommends that the Commission adopt the appropriately calculated updated forecasts provided for each of the expense ILI programs above.

2. Direct Assessment

a. Parties' Recommendations Concerning the DA Program Are Unjustified

1 What parties made recommendations for PG&E's DA Program?
2 ORA and TURN.
3 What is ORA's recommendation?
4 ORA recommends $17.6 million in 2019 dollars for expenses for the DA Program, compared to PG&E's forecast of $35.1 million, a reduction of approximately $17.6 million. Within the DA Program, ORA recommends $17.6 million in 2019 dollars for expenses for ECDA, a reduction of $13.8 million from PG&E’s forecast of $31.4 million in 2019 dollars, and ORA also recommends that all of the funding, $3.7 million in 2019 dollars,
be removed for the ICDA Program. ORA claims that PG&E did not provide sufficient detail to justify the forecast for the ICDA Program, and instead of recommending a forecast for ICDA, ORA recommends that a new memorandum account be established to track ICDA costs for review in the next GT&S Rate Case.

Q 97 What is TURN's recommendation?

A 97 TURN recommends approximately $12.76 million in total ECDA expenses for 2019, a reduction of approximately $18.63 million from PG&E's forecast of approximately $31.39 million. TURN recommends PG&E's forecast be reduced to zero for total ICDA expenses for 2019, a reduction of approximately $3.72 million. TURN recommends that PG&E shareholders “pay for 59.4 percent of the ECDA mileage for each year of the rate case” because “rate payers have already paid for 181 miles of ECDA that PG&E failed to complete.” TURN calculated the percentage by dividing 181 miles by the total of 305 miles that PG&E has forecast assessing using ECDA in the 2019-2021 rate case period. (181/305 = ~59.4 percent).

TURN recommends that PG&E shareholders pay for all ICDA expenses because:

[R]atepayers have already paid for 76 miles of [I]CDA that PG&E failed to complete, and the proposed ICDA mileage for the 2019-2021 rate case period is only a fraction of the mileage that ratepayers have previously paid for.

Q 98 How do you respond to these positions and criticisms?

A 98 PG&E discusses each of these positions and criticisms in turn. This testimony will show that parties’ recommendations are unsupported and their assumptions are incorrect. See Table 5-8 for a summary of my DA rebuttal.

74 ORA-05, p. 35, Table 5-26.
75 ORA-05, p. 41, lines 22-23.
76 TURN, Chapter 5B, p. 7, lines 6-12.
77 TURN, Chapter 5B, p. 7, line 19 to p. 8, line 1.
**TABLE 5-8**
SUMMARY OF PG&E’S DA PROGRAM REBUTTAL

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Party</th>
<th>PG&amp;E’s Rebuttal</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ORA</td>
<td>Assumptions that DA forecast miles should be lower because of PG&amp;E’s ILI Program assessment miles is incorrect and causes analysis errors.</td>
</tr>
<tr>
<td>2</td>
<td>ORA</td>
<td>Methodology for reducing ECDA assessment miles by using year 2017 as a basis was flawed because PG&amp;E must complete HCA assessment miles when they are due.</td>
</tr>
<tr>
<td>3</td>
<td>ORA</td>
<td>Methodology used to calculate the number of digs per ECDA project would result in inadequate funding to meet regulatory obligations.</td>
</tr>
<tr>
<td>4</td>
<td>ORA</td>
<td>Proposal to defund the ICDA Program and track costs in a memorandum account for consideration in the next rate case is without merit.</td>
</tr>
<tr>
<td>5</td>
<td>TURN</td>
<td>Recommendation that PG&amp;E shareholders should pay for a portion of DA work during 2019 through 2021 is inappropriate. (a)</td>
</tr>
</tbody>
</table>

(a) See Chapter 23 Rebuttal Testimony.

1. **Q 99** Does ORA agree with any part of PG&E’s DA forecast?

2. **A 99** Yes. ORA agrees that:

   - PG&E has satisfied the requirements of the 2017 GRC Settlement Agreement regarding its forecast for DA expenses and capital expenditures.  

   ORA also agrees with PG&E’s ECDA survey cost-per-mile, ECDA cost-per-dig, and ECDA digs-per-mile ratio, as used in workpapers.  

3. **Q 100** Does TURN agree with any part of PG&E’s DA forecast?

4. **A 100** TURN did not comment on the ECDA survey cost-per-mile, the ECDA digs-per-mile ratio, the ECDA cost-per-dig, ICDA survey costs, or ICDA cost-per-direct examination. TURN used PG&E’s total program forecasts as a basis from which to propose reductions.

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78 ORA-05, p. 32, lines 16-18.
79 PG&E WP 5-46, Workpaper Table 5-10, line 86.
80 ORA-05, p. 40, lines 16-18.
b. ORA’s Assumptions That DA Forecast Miles Should Be Lower Because of PG&E’s ILI Program Are Incorrect and Cause Analysis Errors

Q 101 What is the basis for ORA’s belief that PG&E’s 2019 ECDA forecast miles should be lower because of PG&E’s ILI Program?

A 101 ORA erroneously interprets PG&E’s Chapter 5 Prepared Testimony by assuming that because “more of PG&E’s transmission system is being made piggable to accommodate in-line inspections,”\(^ {81}\) the 2019 ECDA forecast assessment miles should be lower as a result.

Q 102 What portion of PG&E’s Chapter 5 Prepared Testimony is being referenced by ORA in making this error?

A 102 ORA is referencing Chapter 5 Prepared Testimony, pages 34 and 35. Specifically, it appears that ORA references two paragraphs. The first says:

> PG&E is accomplishing this by replacing-where feasible-DA, with ILI and/or hydrostatic testing, as assessment methods for HCAs.\(^ {82}\)

The second reference appears to be from a paragraph that states:

> PG&E is shifting its approach in the 2019 GT&S Rate Case toward ILI where possible and to hydrostatic testing for higher pressure pipeline subject to the SCC threat.\(^ {83}\)

Q 103 How has ORA misinterpreted these statements from testimony?

A 103 ORA is excluding the fact that testimony states that PG&E is shifting DA toward ILI, “where feasible,” and, “where possible” (as shown in the quotes referenced in the previous answer).

Q 104 Has PG&E considered ILI and/or hydrostatic testing feasibility in the development of its DA forecast assessment miles?

A 104 Yes. The forecast of DA assessment miles includes only those HCA sections that: (1) have HCA assessment or re-assessment due dates during the rate case period as required by 49 CFR 192, Subpart O; and (2) are not possible to ILI or do not need a hydrostatic test to assess for the identified threats.

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81 ORA-05, p. 36, lines 10-11.
82 PG&E Prepared Testimony, Chapter 5, p. 5-34, lines 4-6.
83 PG&E Prepared Testimony, Chapter 5, p. 5-35, lines 14-16.
Q 105 What is PG&E’s justification for having higher ECDA and ICDA miles in year 2019, than ECDA and ICDA miles in 2017?

A 105 In a response to an IS data request, PG&E provides the answer to this question. While the question and response were directed toward the ECDA Program, the same holds true for the ICDA Program.

As stated in testimony pages 5-5 through 5-6, PG&E has new requirements based on the issuance of General Order (GO) 112-F, including the process for determining high consequence areas (HCAs) for pipelines over 12 inches in diameter. As a result of this new regulation, PG&E had to incorporate new HCAs into its assessment plan, with many of these new HCAs currently being unpiggable. The increases of forecast miles within the ECDA program for 2019-2021 are a result of this regulation change.

Therefore, the numbers of both ECDA and ICDA miles in the 2019 GT&S Rate Case period are fully-justified, based on required assessment as a result of the regulatory change.

c. ORA’s Methodology for Reducing ECDA Assessment Miles by Using Year 2017 as a Basis Is Flawed

Q 106 Why is ORA using 2017 ECDA miles as a basis for their proposed 2019 ECDA forecast?

A 106 First, ORA presumed that the ILI Program would reduce the ECDA assessment miles in the 2019 GT&S Rate Case, which was shown to be incorrect earlier in this section. Second, ORA used the assessment miles from 2016 and 2017, suggesting that 2017, 17 percent less miles than 2016, would represent a downward trend in ECDA assessment miles. ORA then applied that 17 percent reduction in ECDA assessment miles to the 2019

84 "GO 112-F modified the definition of HCA as follows effective January 1, 2017: 'High Consequence Area (HCA) is defined by 49 CFR §192.903, which allows two different methods to be used towards determining locations where HCAs exist. However, in an effort to be more conservative towards ensuring the safety in areas of more densely populated areas, the Commission restricts the use of Method 2 in 49 CFR §192.903, in determining HCAs to pipeline segments of 12-inches or less. Accordingly, the Commission modifies paragraph (2) of the High Consequence Area defined by 49 CFR §192.903 to read as follows:

(2) The area within a potential impact circle of a pipeline 12-inches or less in diameter containing –

HCAs newly identified through the Commission’s restriction on Method 2 shall be scheduled for baseline assessment in accordance with 49 CFR §192.905(c) and 49 CFR §192.921(f)."

85 IS-002, Question 49 and fn 1.
forecast ECDA assessment miles, thereby reducing the ECDA assessment miles by 15 miles.86

Q 107 What is the flaw in ORA’s logic?
A 107 First, PG&E already noted in the previous section that it considered ILI feasibility in the development of its DA forecast assessment miles for the 2019 GT&S Rate Case period.

Second, PG&E must complete HCA assessments when they are due. PG&E’s ECDA assessment miles for the specific projects for HCA assessments that are due during this rate case period are shown in its workpapers.87 Those specific projects were identified because they have integrity assessment due dates that are driven by compliance with 49 CFR, Part 192, Subpart O regulations. For example, the ECDA projects that are due in 2019 have a finite number of miles (96 miles), and one cannot reduce the miles to be equivalent to any other year because the year 2019 is when the integrity assessments are due. Therefore, ORA’s recommendation to reduce the 2019 ECDA assessment miles to 74 miles should be rejected.

d. ORA’s Methodology to Calculate the Number of Digs Per ECDA Project Results in Inadequate Funding to Meet Regulatory Obligations

Q 108 What is the basis for ORA’s recommendation to reduce the ECDA Program cost forecast by reducing the number of estimated digs per project?
A 108 As stated previously, ORA agreed with PG&E’s use of 0.958 digs-per-mile. However, ORA opposes PG&E’s use of a minimum number of digs for baseline assessment (four digs) and re-assessment (two digs). ORA claims that half of PG&E’s projects do not require the four minimum digs.88 ORA’s forecast relies solely on the average 0.958 digs-per-mile, regardless of assessment type,89 which also disregards PG&E’s requirement for a minimum of two digs for ECDA re-assessments.

86 ORA-05, p. 37, lines 3-22.
87 PG&E WP 5-45 to WP 5-46, Workpaper Table 5-10.
88 ORA-05, p. 37, line 23 to p. 38, line 4.
89 ORA-05, p. 40, lines 4-7.
Q 109 Is ORA’s calculation basis for estimating the number of digs for an ECDA project justified?

A 109 No. ORA’s calculation eliminates the minimum number of digs per ECDA project, which is inconsistent with the requirements of federal code and industry standards.

PG&E explained the requirement for four digs for baseline ECDA assessments in discovery where PG&E stated:

The Code of Federal Regulations (CFR) Title 49 Section 192.925(b)(3), which is the section of regulation regarding External Corrosion Direct Assessment (ECDA) Direct Examinations, references National Association of Corrosion Engineers (NACE) standard SP0502-2008. NACE SP0502-2008 Section 5.1.3 requires one dig per region regardless of the results of the indirect inspection and pre-assessment steps.

Next, NACE SP0502-2008 Section 5.3.3.2.1 states that:

when ECDA is applied for the first time, one additional direct examination shall be performed in each ECDA region containing scheduled indications.

In addition, NACE SP0502-2008 Section 6.7.2.1 requires that:

for initial ECDA applications, at least two additional direct examinations are required for process validation.

Therefore, in accordance with CFR 49 Part 192 and NACE SP0502-2008, PG&E is required to perform a minimum of four digs on projects that include initial assessments.

PG&E explained the requirement for two digs for ECDA re-assessments in discovery where PG&E stated:

NACE SP0502-2008 Section 5.1.3 requires one dig per region regardless of the results of the indirect inspection and pre-assessment steps.

In addition, NACE SP0502-2008 Section 6.7.2 requires that

At least one additional direct examination at a randomly selected location shall be performed to provide additional confirmation that the ECDA process has been successful.

Therefore, in accordance with CFR 49 Part 192 and NACE SP0502-2008, PG&E is required to perform a minimum of two digs on projects that are re-assessments.

90 IS-002, Question 48a.

91 TURN-027, Question 7a.
Q 110 Please explain how PG&E used knowledge from NACE SP0502-2008 to develop and justify the forecast number of digs for each of PG&E's ECDA projects from 2019 through 2021.

A 110 In a response to a TURN data request, PG&E stated:

The forecast number of digs was calculated using either a minimum number of digs or the calculated digs-per-mile, whichever was greater. The minimum number of digs for a project that included first time assessments was four digs. The minimum number of digs for a project that was exclusively re-assessments was two digs.\footnote{TURN-002, Question 11c.}

Using this approach, PG&E first calculated the number of digs using 0.958 digs per mile surveyed for each forecast project. This calculated number of digs result was then compared to the aforementioned minimum digs from NACE SP0502-2008. If the number of digs using the calculated number of digs was greater than the minimum number of digs from NACE SP0502-2008, then PG&E used the calculated number of digs. If, on the other hand, the calculated number of digs result was less than the minimum digs from NACE SP0502-2008, PG&E used the minimum digs from NACE SP0502-2008. This is best demonstrated with two examples.

ECDA project, EC19-0402,\footnote{PG&E WP 5-45, Workpaper Table 5-10, line 12.} is an example of a project where the calculation of 0.958 digs per mile surveyed is greater than the minimum number of digs from NACE SP0502-2008. The survey length is 10.59 miles and this is a baseline assessment. Multiplying 0.958 by 10.59 produces a calculated number of digs of 10.15, rounded down to 10 digs. Since this is a baseline assessment, NACE SP0502-2008 requires at least four digs. Since the calculated number of digs of 10 is greater than the minimum digs of four from NACE SP0502-2008, the forecast number of digs was set at 10.

ECDA project, EC19-209,\footnote{PG&E WP 5-45, Workpaper Table 5-10, line 34.} is an example of a project where the calculation of 0.958 digs per mile surveyed is less than the minimum number of digs from NACE SP0502-2008. The survey length is 0.28 miles and this is a re-assessment. Multiplying 0.958 by 0.28 produces a calculated number of digs of .268, rounded to one dig. Since this is a re-assessment, NACE SP0502-2008 requires at least two digs. Since the calculated
number of digs of one is less than the minimum digs of two from NACE SP0502-2008, the forecast number of digs was set at two.

So, as one can see from the above analysis, using only the average 0.958 digs per mile, as ORA recommends, would be inconsistent with PG&E’s compliance with NACE SP0502-2008 and 49 CFR, Section 192.925(b)(3). As such, ORA’s recommended methodology to calculate the number of digs per ECDA project would, based on PG&E’s forecast, result in inadequate funding to meet regulatory obligations.

e. ORA’s Proposal to Defund the ICDA Program and Track Costs in a Memorandum Account for Consideration in the Next Rate Case Is Without Merit

Q 111 What is ORA proposing regarding ICDA?
A 111 ORA recommends that PG&E’s 2019 ICDA forecast of $3.7 million be adjusted to zero and that PG&E perform the planned work while tracking the costs for the work in a memorandum account.95

Q 112 Why does PG&E believe that this is without merit?
A 112 The ICDA projects that are in PG&E’s workpapers96 have assessment due dates that are required by 49 CFR, Part 192, Subpart O. The internal corrosion threat assessment due date for these have been established following regulatory requirements and must be completed by their respective due dates. As such, it is without merit to withhold adopted funding until a much later time.

Q 113 Do you agree with ORA’s recommendation to create a memorandum account for ICDA costs?
A 113 No. In addition to the discussion above, TIMP work is required under Subpart O and DA, including ICDA, is a Subpart O activity. A memorandum account would only allow PG&E to track ICDA costs, after which PG&E must file a separate application to recover the incurred costs.97

95 ORA-05, p. 41, lines 20-23.
96 PG&E WP 5-47, Workpaper Table 5-11.
97 See PG&E’s Chapter 2 rebuttal testimony, sponsored by Mr. Singh, for additional discussion regarding balancing and memorandum accounts.
Adopting ORA’s recommendation will result in the need for PG&E to redistribute funds for other work to pay for required Subpart O ICDA work. The Commission should adopt a forecast for ICDA work for reasons described herein.

Q 114 Should the Commission adopt ORA’s recommendation for a zero ICDA forecast, what is PG&E’s position regarding the memorandum account proposal?

A 114 To the extent that the Commission adopts ORA’s recommendation for a zero forecast for ICDA, PG&E reiterates its proposal that the Commission approve PG&E’s proposal to modify the TIMPBA to allow for two-way balancing account treatment to cover the costs associated with Subpart O ICDA work. Should the Commission not adopt a two-way TIMP balancing account and adopt a zero ICDA forecast, PG&E supports the need for a memorandum account to track ICDA incurred costs, as PG&E should be afforded an opportunity to recover these costs required by regulation.

f. TURN’s Recommendation that PG&E Shareholders Should Pay for a Portion of DA Work During 2019 through 2021 Is Inappropriate

Q 115 What is TURN’s recommendation regarding PG&E’s DA Program?

A 115 TURN recommends reducing PG&E’s 2019 forecast for the DA Program by $18.6 million.

Q 116 What is the basis of TURN’s recommendation?

A 116 TURN claims that PG&E did less work than the Commission approved in the 2015 GT&S Rate Case for the years 2015 through 2018. Because of this, TURN recommends that PG&E shareholders should pay for 59.4 percent of the DA work for the years this rate case covers, 2019 through 2021.

Q 117 How does PG&E respond to TURN’s recommendation?

A 117 PG&E disagrees with TURN’s recommendation and rebuts TURN’s recommendation in two chapters.

• This chapter addresses: (1) the safety implications of not performing all the DA work forecasted for 2015 through 2018; (2) the relative priority of DA work and TIMP pressure tests in HCAs; and (3) the cost of performing DA work; and
Chapter 23, “Forecast Ratemaking,” addresses the inappropriateness of TURN’s proposal that shareholders pay for 59.4 percent of DA work during this rate case period.

Q 118 What is TURN’s claim regarding PG&E’s progress of the DA programs as they relate to D.16-06-056?

A 118 TURN claims that:

[PG&E] projects to complete only 324 out of the 505 [ECDA] miles directed by the Commission...[and] 5 out of 81 of the ICDA miles....

Q 119 Is PG&E out of compliance with the D.16-06-056, with respect to the amount of work the Company plans to complete between 2015 and 2018?

A 119 No. Though the Commission adopted an expense forecast for DA in the 2015 GT&S Rate Case, the decision did not mandate any specific amount of work to complete as it did for other programs.

Q 120 Is PG&E out of compliance with 49 CFR 192, Subpart O by delaying the assessment of 181 ECDA assessment miles or 76 ICDA assessment miles?

A 120 No. PG&E did not delay the assessment of any segments due for assessment in the 2015-2018 timeframe.

Q 121 Did PG&E perform the necessary DA work to eliminate any immediate safety hazards?

A 121 Yes.

Q 122 Did TURN have any other criticisms of PG&E’s performance of its DA programs?

A 122 Yes. TURN states that:

PG&E has failed to complete the ECDA/ICDA mileage established by the Commission despite [PG&E’s] recognition of the importance of “proactively address[ing] the pipeline threat of corrosion....

Q 123 Did PG&E ignore the importance of proactively addressing the pipeline threat of corrosion by only projecting to address 324 of the 505 ECDA assessment miles or 6 of the 81 ICDA assessment miles?

A 123 No. As stated in prepared testimony, some of the DA of new transmission miles was delayed to outside of the 2015 GT&S Rate Case in order to accommodate additional TIMP pressure tests in HCAs that had become

98 TURN, Chapter 5B, p. 4, lines 18-20.
99 TURN, Chapter 5B, p. 5, lines 14-16.
higher risk due to findings from the risk analysis process. American Society of Mechanical Engineers (ASME) B31.8S, Section 6.3.1 titled, “Time Dependent Threats,” states:

[Pressure testing is appropriate for use when addressing time-dependent threats. Time-dependent threats are external corrosion, internal corrosion, stress corrosion cracking, and other environmentally assisted corrosion mechanisms.]

As such, PG&E did not ignore the importance of proactively addressing the pipeline threat of corrosion by opting to conduct TIMP pressure tests and delaying particular ECDA or ICDA assessments.

Q 124 How many miles of TIMP pressure test does PG&E plan to complete in the 2015-2018 time period?
A 124 As shown in the response to data request ORA_038, Question 1(b), PG&E completed approximately 67 miles of TIMP pressure tests from 2015-2017. PG&E plans to complete approximately an additional 17 miles of TIMP pressure tests in 2018. This is a total of approximately 84 miles over the 2015-2018 time period.

Q 125 How many miles of TIMP pressure tests did the Commission adopt in the D.16-06-056?
A 125 In the 2015 GT&S Rate Case, PG&E did not specify a number of miles that it expected to assess via TIMP pressure test, and therefore, the Commission did not adopt any level of scope for the TIMP Pressure Test Program. However, in PG&E’s 2015 GT&S Rate Case prepared testimony for Hydrostatic Testing, PG&E expressed the potential for the need of TIMP pressure tests.

Q 126 Did PG&E request cost recovery for TIMP pressure tests in the 2015 GT&S Rate Case?

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100 PG&E Prepared Testimony, p. 5-38, lines 3-6.
101 ASME B31.8S-2004, Section 6.3.1.
102 ORA-038, Question 01b.
Yes. In anticipation of the need to conduct TIMP pressure tests, PG&E allocated approximately $10.2 million for the 2015 TY to TIMP pressure tests.104

Did the Commission adopt any forecast amount for TIMP pressure tests in D.16-06-056?

Yes. As shown in Appendix I of D.16-06-056, the Commission adopted the entire 2015 TY forecast for TIMP pressure tests.105

What was the amount of expenses adopted in D.16-06-056 for the entire 2015-2018 time period for TIMP pressure tests?

In D.16-06-056, the Commission adopted approximately $42.36 million for TIMP pressure tests program over the 2015-2018 time period.106

What are PG&E’s recorded expenses through 2017, and what is PG&E’s forecast for 2018 for the TIMP Pressure Test Program?

PG&E recorded approximately $10.49 million in 2015,107 $79.46 million in 2016,108 $14.56 million in 2017,109 and forecast approximately $21.04 million in 2018.110 This totals a level of spend at approximately $125.55 million over the rate case period. This is well in excess of the approximately $42.36 million adopted by the Commission in D.16-06-056.

Does TURN account for the number of miles accessed via TIMP pressure test or the level of spend associated with TIMP pressure tests in their recommendations regarding the DA Program?

No.

Did customers benefit from the TIMP pressure tests that PG&E completed in-lieu of ECDA and ICDA assessments?

Yes.

What is PG&E’s recommendation on the reductions proposed by TURN associated with DA?
For the reasons included in this section, and those in Chapter 23 Rebuttal, the Commission should not adopt TURN's recommendation. Rather, the Commission should adopt PG&E's full forecast for DA work, based on the premise that customers benefitted from the TIMP pressure tests that PG&E completed in-lieu of ECDA and ICDA assessments.

3. Hydrostatic Testing

a. Parties' Recommendations Concerning the Hydrostatic Testing Program Are Unjustified

Q 133 Which parties made recommendations on the Hydrostatic Testing Program?
A 133 ORA and IS.

Q 134 What are parties' recommendations?
A 134 ORA recommends $145.5 million in expense forecast for the Hydrostatic Testing Program, a $10.2 million reduction compared to PG&E's forecast of $155.7 million for TY 2019. ORA also recommends capital expenditures of $39.4 million, $40.9 million, and $42.1 million in 2019, 2020, and 2021, respectively, a reduction of $31.8 million in capital expenditures over the 3-year period, compared to PG&E's forecast of $49.9 million, $51.5 million and $53.0 million in 2019, 2020, and 2021, respectively.

IS recommends a 2019 forecast of approximately $46.346 million for the Hydrostatic Testing Program, a reduction of approximately $16.774 million from PG&E's original forecast of approximately $63.120 million. IS recommends a 2019 TY forecast of approximately $47.276 million for the TIMP Pressure Test Program, a reduction of approximately $9.685 million from PG&E's original forecast of approximately $56.961 million.

A summary of PG&E's rebuttal to parties' positions is contained in Table 5-9 below.

Q 135 Do ORA's recommendations reflect PG&E's June 5, 2018 errata?
A 135 No. ORA does not use the corrected Hydrostatic Testing forecast in its recommendations. For expense, the amount in ORA's Table 5-1 for the

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111 ORA-05, p. 3, Table 5-1.
112 ORA-05, p. 6, Table 5-2.
113 IS-1, Chapter 5, p. 5-7, Table 5-2.
2019 TY forecast shows a value of $155.702 million, instead of $136.302 million.\textsuperscript{114} The details in ORA’s Table 5-3 show values of $75.199, instead of $63.120 for the Hydrostatic Testing (D.11-06-017) sub-program and $64.282, instead of $56.961 for the TIMP Pressure Tests sub-program.\textsuperscript{115} Also, the PG&E proposed amount for the 2021 capital forecast in ORA’s Table 5-2 is listed incorrectly as $52,987, instead of $52,978.\textsuperscript{116} Furthermore, the details in ORA’s Table 5-4 show values of $19.583, instead of $19.853 for the Hydrostatic Testing (D.11-06-017) sub-program.\textsuperscript{117}

\begin{table}[h]
\centering
\begin{tabular}{|c|c|p{10cm}|}
\hline
Line No. & Party & PG&E’s Rebuttal \\
\hline
1 & ORA & Exclusion of higher cost projects to determine a unit cost for expense Pipe Replacements In-Lieu of Hydrostatic Testing is unreasonable. \\
\hline
2 & ORA & Cost estimating model for capital Pipe Replacements In-Lieu of Hydrostatic Testing uses inconsistent data, making the model unreliable. \\
\hline
3 & ORA & Cost estimating model for expense Hydrostatic Testing uses inconsistent data, making the model unreliable. \\
\hline
4 & IS & Criticisms for PG&E’s expense Hydrostatic Testing programs are flawed. \\
\hline
\end{tabular}
\caption{SUMMARY OF PG&E’S HYDROSTATIC TESTING PROGRAM REBUTTAL}
\end{table}

b. ORA’s Exclusion of Higher Cost Projects to Determine a Unit Cost for Expense Pipe Replacements In-Lieu of Hydrostatic Testing Is Unreasonable

Q 136 What does ORA recommend with respect to expense Pipe Replacements In-Lieu of Hydrostatic Testing?

A 136 ORA recommends an expense forecast for Hydrostatic Testing per D.11-06-017 – Pipe Replacements In-Lieu of Hydrostatic Testing, based on a modification of PG&E’s average historical expense pipe replacements cost

\textsuperscript{114} ORA-05, p. 3, Table 5-1.
\textsuperscript{115} ORA-05, p. 10, Table 5-3.
\textsuperscript{116} ORA-05, p. 6, Table 5-2.
\textsuperscript{117} ORA-05, p. 11, Table 5-4.
data to produce an average of $0.498 million per project before escalation.

ORA suggested that two higher-cost projects should be considered outliers, and should not be used in the historical unit cost calculation.  

Q 137 What method did ORA use to make this new calculation?
A 137 ORA used the “Interquartile Range Method” to determine that the two highest values in the historic expense pipe replacement project costs should be thought of as outliers.

Q 138 Should these projects be considered outliers for purposes of forecasting costs for this program?
A 138 No, for two reasons. First, the reference used by ORA for this method points out that:

Before considering the possible elimination of these points from the data, one should try to understand why they appeared and whether it is likely similar values will continue to appear.

PG&E fully understands that these project costs—while large in comparison to the overall recorded costs—are also considered normal for this type of work and we expect these types of projects to continue to exist in the future.

Second, PG&E notes that even if the cost of these two projects were outliers, a small number of outliers is to be expected, and is not due to any anomalous condition. Outliers can be on both the low-cost side and the high-cost side of project cost estimates and PG&E included both low- and high-cost projects in its analysis. Neither high- nor low-cost projects should be excluded if the costs are expected to continue to exist in future work. It is expected that these types of projects will continue to exist in the future.

Q 139 Does PG&E agree with removing these two high cost projects from the unit cost analysis?
A 139 No. As PG&E notes above, in removing potential outliers, one must concentrate on applying the outlier concept to both the high costs in the data set, and the low costs in the data set. In PG&E’s data set referenced above,

118 ORA-05, p. 8, lines 1-9.
120 PG&E WP-5-49, Table 5-13, lines 24-42.
there are also two very low-cost projects in the list that are $0.037 million
and $0.021 million.

Q 140 If PG&E were to remove both the two highest cost projects and the
two lowest cost projects, even though they are not outliers, what is the
resulting average cost-per-project un-escalated and the forecast for
inclusion of outliers?

A 140 This would yield an un-escalated average cost per project in 2016 dollars
of $339,989. Applying this unit cost in the same manner used in PG&E’s
workpaper would produce the 2019 forecast shown in Table 5-10.

TABLE 5-10
COMPARISON OF FORECAST RESULTS CONSIDERING OUTLIERS
(2019, THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>PG&amp;E Forecast</th>
<th>PG&amp;E Forecast With Outliers Removed</th>
<th>ORA Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$13,446</td>
<td>$9,174</td>
<td>$7,927</td>
</tr>
</tbody>
</table>

Q 141 Based on ORA’s analysis and PG&E’s further analysis using a similar
approach to ORA’s, what does PG&E recommend?

A 141 PG&E continues to recommend that the Commission adopt PG&E’s 2019
expense forecast for Pipe Replacements In-Lieu of Hydrostatic Testing of
$13.4 million, because the two highest cost projects are still representative
of the types of costs PG&E could expect to see during the rate case period
for expense pipe replacements in-lieu of hydrostatic testing.

c. ORA’s Cost Estimating Model for Capital Pipe Replacements
   In-Lieu of Hydrostatic Testing Uses Inconsistent Data, Making the
   Model Unreliable

Q 142 On what does ORA base its model for capital cost estimating of Pipe
Replacements In-Lieu of Hydrostatic Testing?

A 142 ORA bases its proposed capital pipe replacement cost estimating model on
variables of length, diameter and project duration, as compared to PG&E’s
model, which uses variables of length and diameter only.122 ORA also
supports the viability of this model by suggesting that it draws on a large

122 ORA-05, p. 9, lines 4-5.
database of 180 replacement projects as compared to PG&E’s 80 projects.  

Q  143 What is PG&E’s basis for believing ORA’s model for capital cost estimating of Pipe Replacements In-Lieu of Hydrostatic Testing is unreliable?  

A  143 First, ORA added a model variable, project duration, that is not practical.  

Second, the data used to generate the model is inconsistent and unreliable.  

Q  144 Why does PG&E believe that addition of a model variable, project duration, is not practical?  

A  144 ORA presumes PG&E can easily predict project duration when it forecasts costs for projects several years in the future. That is not the case. While PG&E can broadly estimate how long it will take to complete a capital pipe replacement project, there is a wide range of possible project durations because there are wide ranging influences on project duration that PG&E does not control, making an estimate of the value for this factor impractical to apply in the manner that ORA has suggested. ORA used a simple project duration average on each capital replacement project of 170 days that was based on PG&E’s discovery response, in which PG&E provided a rough estimate of project durations for future, proposed projects, which were broad ranging. Use of a singular, average duration number to produce the final forecast shows that even ORA recognizes that to make a prediction of specific project duration so far in advance is impractical. Further, use of this singular number also means that ORA did not use duration in the final analysis as a distinguishing characteristic, making use of this factor unnecessary and misleading.  

Q  145 Did PG&E analyze the 180 projects that went into ORA’s model to identify any other discrepancies that may cause the model to be unreliable?  

A  145 Yes, and we found several discrepancies, including the following:  

1) ORA’s data for capital cost estimating of pipe replacements includes projects completed by SoCalGas/San Diego Gas & Electric Company  

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123 ORA-05, p. 9, lines 1-3.  
124 ORA-042, Question 01.
(SDG&E), and Southwest Gas Corporation (SWG), which does not properly represent project costs within PG&E’s service territory.

2) The 180 projects ORA relied on in its pipe replacement dataset dated from 2006-2017. This poses the issue of analysis crossing over PG&E’s old and new cost models. Nowhere in testimony or workpapers did ORA attempt to align cost models either within PG&E or with the other utilities.

3) Of the 180 projects relied on in ORA’s pipe replacement dataset, 15 of them were distribution replacement projects conducted by Sempra. Distribution pipe replacement projects are not representative of the costs for capital transmission pipe replacements.

4) Of the 180 projects in ORA’s pipe replacement dataset, 110 of those projects relied on cost data from PG&E’s Pipeline Safety Enhancement Plan (PSEP) Compliance Reports. The cost data in the PSEP Compliance Reports is not appropriate for use in this manner. In the PSEP Compliance Reports, PG&E provided the cost of the project at the time of the report, which correlated with the time the project went operational. The costs reported in the PSEP Compliance Reports did not account for any invoices not yet processed, nor did it account for project close out costs. Considering all costs were not recorded at the time of the reporting, the values in the report should not be used. ORA did not request information regarding final costs through discovery in this proceeding. PG&E did use final costs in development of its capital pipe replacement cost calculation model.

5) The “Project – Start Date” and “Project – End Date” values in ORA’s dataset were populated inconsistently. For the rows of data that have a “Data Source” of “Compliance Report,” “Mobilization Date” was used for

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125 ORA-05, p. 9, lines 1-3.
126 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
127 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
128 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
“Project – Start Date.” For the rows of data that have a “Data Source” of “DR-008 PG&E (2018 GT&S),” “Engineering Start Date” was used for “Project – Start Date.” Engineering Start Date and Mobilization Date are two extremely different dates, and ORA did not align these to a common “Project – Start Date” in discovery.

6) For the rows of data that have a “Data Source” of “Compliance Report,” “Tie-In Date” was used for “Project – End Date.” For the rows of data that have a “Data Source” of “DR-008 PG&E (2018 GT&S),” “Field Construction Complete Date” was used for “Project – End Date.” Tie-in Date and Field Construction Complete Date are two extremely different dates, and ORA made no effort to align these to a common “Project – End Date” in discovery.

7) ORA used its own escalation rates in an attempt to have all projects in 2016 dollars, however, the escalation rates appear flawed. Please see the table below for the capital escalation rates used by ORA versus those used by PG&E:

ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.

ORA-008, Question 01h.

ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.

Engineering Start Date is the date when engineering of the project just begins; the project is in the very early stages of project development and design. The Mobilization Date is when construction crews have actually mobilized to the field for construction. Engineering start can actually occur months to years before mobilization actually occurs.

ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.

ORA-008, Question 01i.

ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.

Tie-in Date is the date that the pipe is last welded in place. However, at this stage, Field Construction is not complete. Backfilling, coating, site mediation, etc. must still take place to reach the Field Construction Complete date. This can be weeks to months after the project is tied in.
TABLE 5-11
COMPARISON OF CAPITAL ESCALATION RATES (ORA V PG&E)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Year</th>
<th>ORA's Capital Escalation Rate (a)</th>
<th>PG&amp;E's Capital Escalation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2011-2016</td>
<td>1.0727</td>
<td>1.0968</td>
</tr>
<tr>
<td>2</td>
<td>2012-2016</td>
<td>1.1027</td>
<td>1.0410</td>
</tr>
<tr>
<td>3</td>
<td>2013-2016</td>
<td>1.0889</td>
<td>1.0452</td>
</tr>
<tr>
<td>4</td>
<td>2014-2016</td>
<td>1.0746</td>
<td>0.9890</td>
</tr>
<tr>
<td>5</td>
<td>2015-2016</td>
<td>1.032</td>
<td>0.9969</td>
</tr>
<tr>
<td>6</td>
<td>2016-2016</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>7</td>
<td>2017-2016</td>
<td>0.941</td>
<td>0.9663</td>
</tr>
</tbody>
</table>

(a) ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018 04 24 Database_Clean.xlsx.

ORA’s escalation rates are not the same escalation rates that PG&E used, causing inconsistency in forecasting, further contributing to the model’s unreliability.

Q 146 What does PG&E recommend based on analysis of ORA’s pipe replacement cost model and associated data inputs?

A 146 Due to the extensive amount of issues PG&E identified in ORA’s dataset, as well as the inclusion of duration into the model, ORA’s model is not reliable. As such, PG&E recommends that the Commission reject ORA’s recommendations of reductions for the Pipe Replacement In-Lieu of Hydrostatic Testing Program and adopt PG&E’s cost model as the basis for capital pipe replacement forecasting.

d. ORA’s Cost Estimating Model for Expense Hydrostatic Testing Uses Inconsistent Data, Making the Model Unreliable

Q 147 On what does ORA base its model for expense cost estimating for Hydrostatic Testing?

A 147 ORA bases its proposed Hydrostatic Testing expense cost estimating model on variables of length, diameter, and project duration, as compared to PG&E’s model, which uses a single variable of length. ORA also supports the viability of this model by suggesting that it draws on a

137 ORA-05, p. 9, line 16 to p. 10, line 1.
large database of 378 hydrotest projects, as compared to PG&E’s 121 projects.\textsuperscript{138}

Q 148 Why does PG&E believe that ORA’s proposed model for Hydrostatic Testing expense cost estimating uses inconsistent data and is unreliable?

A 148 First, ORA added two model variables, diameter and project duration, the latter of which is not practical. Second, the data used to generate the model is inconsistent and unreliable.

Q 149 Why does PG&E believe that addition of diameter is practical and a project duration variable is not practical?

A 149 As to diameter, PG&E did perform an early analysis of diameter and determined that the addition of diameter did not greatly improve the curve fit for hydrostatic testing, and, therefore, moved toward a simpler model instead. PG&E does not dispute the addition of diameter as a factor for hydrostatic testing expense projects. As to the use of project duration in the hydrostatic testing model, first, as with the use of this factor in ORA’s capital pipe replacement estimating model, ORA presumes that project duration can be easily predicted. This is not true. While PG&E can broadly estimate how long it will take to complete a hydrostatic testing project, there is a wide range of possible project durations because there are wide ranging influences on project duration that PG&E does not control, making an estimate of the value for this factor impractical to apply in the manner that ORA has suggested. ORA used a simple project duration average on each hydrostatic testing project of 150 days that was based on PG&E’s discovery response\textsuperscript{139} in which PG&E only provided a rough estimate of project durations for future, proposed projects, which were broad ranging. Use of a singular, average duration number to produce the final forecast shows that even ORA recognizes that to make a prediction of specific project duration so far in advance is impractical. Further, use of this singular number also means that ORA did not use duration in the final analysis as a distinguishing characteristic, making use of this factor un-necessary and misleading.

\textsuperscript{138} ORA-05, p. 9, lines 16-19.
\textsuperscript{139} ORA-042, Question 02.
Q 150 Did PG&E analyze the 378 projects that went into ORA’s model to identify any other discrepancies that may cause the model to be unreliable?

A 150 Yes, and we found several discrepancies, including the following:

1) ORA’s data for estimating hydrotests includes projects completed by SoCalGas/SDG&E and SWG, which do not properly represent project costs within PG&E’s service territory.

2) The 378 projects ORA relied on in its hydrotest dataset dated from 2011-2017. This poses the issue of analysis crossing over PG&E’s old and new cost models. Nowhere in testimony or workpapers did ORA attempt to align cost models either within PG&E or with the other utilities.

3) Of the 378 projects relied on in ORA’s hydrotest dataset, five of them were either distribution or storage projects conducted by other utilities, which are not representative of transmission hydrostatic testing costs.

4) Of the 378 projects relied on in ORA’s pipe replacement dataset, 251 of those projects relied on cost data from PG&E’s PSEP Compliance Reports. The cost data in the PSEP Compliance Reports is not appropriate for use in this manner. In the PSEP Compliance Reports, PG&E provided the cost of the project at the time of the report which correlated with the time the project went operational. The costs did not account for any invoices not yet processed, nor did it account for project close out costs. Considering all costs were not recorded at the time of the reporting, the values in the report should not be used. PG&E did use final costs in development of its capital pipe replacement cost calculation model.

_____________________________
140 ORA-05, p. 9, lines 1-3.
141 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
142 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
143 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
5) The “Project – Start Date” and “Project – End Date” values in ORA’s dataset were populated inconsistently. For the rows of data that have a “Data Source” of “Compliance Report,” “Mobilization Date” was used for “Project – Start Date.” For the rows of data that have a “Data Source” of “DR-008 PG&E (2018 GT&S),” “Engineering Start Date” was used for “Project – Start Date.” Engineering Start Date and Mobilization Date are two extremely different dates, and ORA made no effort to align these to a common “Project – Start Date” in discovery.

6) For the rows of data that have a “Data Source” of “Compliance Report,” “Tie-In Date” was used for “Project – End Date.” For the rows of data that have a “Data Source” of “DR-008 PG&E (2018 GT&S),” “Field Construction Complete Date” was used for “Project – End Date.” Tie-In Date and Field Construction Complete Date are two extremely different dates, and ORA made no effort to align these to a common “Project – End Date” in discovery.

7) ORA used its own escalation rates in an attempt to have all projects in 2016 dollars; however, the escalation rates are not representative of actual escalation. Please see the table below for the expense escalation rates used by ORA versus those used by PG&E:

______________________________

144 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
145 ORA-008, Question 01h.
146 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
147 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
148 ORA-008, Question 01i.
149 ORA Supporting Attachments for Chapter 5 (July 9, 2018), Attachment 2018-04-24 Database_Clean.xlsx.
### TABLE 5-12
COMPARISON OF EXPENSE ESCALATION RATES (ORA V PG&E)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Year</th>
<th>ORA’s Expense Escalation Rate</th>
<th>PG&amp;E’s Expense Escalation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2011-2016</td>
<td>1.0727</td>
<td>1.0708</td>
</tr>
<tr>
<td>2</td>
<td>2012-2016</td>
<td>1.1027</td>
<td>1.0506</td>
</tr>
<tr>
<td>3</td>
<td>2013-2016</td>
<td>1.0889</td>
<td>1.0318</td>
</tr>
<tr>
<td>4</td>
<td>2014-2016</td>
<td>1.0746</td>
<td>1.0115</td>
</tr>
<tr>
<td>5</td>
<td>2015-2016</td>
<td>1.032</td>
<td>1.0094</td>
</tr>
<tr>
<td>6</td>
<td>2016-2016</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>7</td>
<td>2017-2016</td>
<td>0.941</td>
<td>0.9771</td>
</tr>
</tbody>
</table>

(a) *Id.*

ORA’s escalation rates are not the same escalation rates that PG&E used, causing inconsistency in forecasting, further contributing to the model’s unreliability.

Q 151 What does PG&E recommend based on their analysis of ORA’s hydrotest cost model and their associated data inputs?

A 151 Due to the extensive amounts of issues PG&E identified in ORA’s dataset, as well as the inclusion of diameter and duration into the model, ORA’s model is not reliable. As such, PG&E recommends that the Commission reject ORA’s recommendations for the Hydrostatic Testing Program.

e. **IS’ Criticisms for PG&E’s Expense Hydrostatic Testing Programs Are Flawed**

Q 152 What are IS’ recommendations on the Hydrostatic Testing Program?

A 152 IS recommends the use of their own regression model for use of forecasting for the Hydrostatic Testing Program. Using their model, IS recommends a TY forecast of approximately $46.346 million for the Hydrostatic Testing Program, a reduction of approximately $16.774 million from PG&E’s original forecast of approximately $63.120 million. IS recommends a 2019 TY forecast of approximately $47.276 million for the TIMP Pressure Test Program, a reduction of approximately $9.685 million from PG&E’s original forecast of approximately $56.961 million.\(^{150}\)

Q 153 On what does IS base its model for expense cost estimating for Hydrostatic Testing?

---

\(^{150}\) IS-1, Chapter 5, p. 5-7, Table 5-2.
IS "conducted a regression analysis on PG&E's historical cost data, with outliers removed."\textsuperscript{151}

Did IS define an "outlier"?

Yes. IS defined an outlier as "the highest ten and lowest ten projects on a cost per mile basis."\textsuperscript{152}

Is this an appropriate way to determine outliers?

No. As stated in PG&E's rebuttal to ORA above, before considering the possible elimination of these potential outliers from the data, one should try to understand why they appeared and whether it is likely similar values will continue to appear.

Did IS provide any analysis that suggests that their outer values, either high or low, will not continue to appear?

No.

How does IS conclude that their model is more appropriate than PG&E's?

First, IS claims that their model yields an R-squared value of "0.52," which is a "significant improvement from the 0.11 R-squared factor from PG&E's model."\textsuperscript{153} Second, IS claims that PG&E's "historical data points [] are skewed."\textsuperscript{154}

Is it true that PG&E's model only yields an R-squared value of 0.11?

No. PG&E's Hydrotest model has two curves it relies on, based on the length of the project being forecasted. Each curve has its own R-squared value. IS' suggestion that PG&E only has one R-squared value, 0.11, is incorrect. In fact, neither of PG&E's R-squared values is what IS claims. The curve for projects less than 0.314 miles yields an R-squared value of 0.506, not IS' claim of 0.11. In fact, the R-squared value for projects less than 0.314 miles shows a reasonably good curve fit. This is especially important since the hydrostatic testing scope for the rate case period is predominantly made of these shorter hydrostatic test projects. The curve for projects greater than 0.314 miles yields an R-squared value of 0.098, not IS'

\textsuperscript{151} IS-1, Chapter 5, p. 5-6, lines 4-5.
\textsuperscript{152} IS-1, Chapter 5, p. 5-6, lines 5-6.
\textsuperscript{153} IS-1, Chapter 5, p. 5-6, lines 8-10.
\textsuperscript{154} IS-1, Chapter 5, p. 5-4, line 3.
claim of 0.11. Please see Figure 5-4 below for the R-squared values yielded in PG&E’s analysis.

Q 159 Is it true that PG&E’s data, referred to by IS as the “blue dots,” are skewed?
A 159 No. The blue dots as seen in both IS Figure 5-1, and PG&E’s Figure 5-4 below, are the raw data points of PG&E’s hydrostatic testing dataset. PG&E used recorded values from hydrotests completed between 2014-2016, and the only post processing that PG&E conducted was to bring all projects in to NCM Base Year (BY) dollars. No other adaptations were made.

Q 160 Would bringing all projects in to NCM BY dollars skew the data?
A 160 No. Converting all project costs to the NCM does not skew the data; rather, it allows for an apples-to-apples comparison.

FIGURE 5-4
PG&E’S ANALYSIS OF HISTORICAL COSTS | STRENGTH TEST PROJECTS

Q 161 Did IS have any other general criticisms of PG&E’s Hydrostatic Testing forecasts?
A 161 Yes. IS claims that PG&E:
[S]eeks hydrostatic costs based on a projected cost of $1.64 million per mile, more than twice the forecasted test cost in its last G&TS.\textsuperscript{155}

Q 162 How does PG&E respond to this criticism?
A 162 First, PG&E does not forecast "costs per mile" in this rate case period. Instead, it uses the cost forecasting curves/formulas that are shown in Figure 5-4 above. Second, IS claims that:
In PG&E's 2015 GT&S, it proposed a hydrostatic test cost based on a cost-per-mile of $850,000.\textsuperscript{156}
This is not correct. Rather, $850,000 per mile was the figure used by the Commission to determine PG&E's adopted program expenses for the Hydrostatic Testing Program in the 2015 GT&S Rate Case. PG&E's forecast for Hydrostatic Testing in the 2015 GT&S Rate Case was higher than the costs assumed by the Commission to establish adopted costs for the Hydrostatic Testing Program.
Q 163 What does PG&E recommend based on review of IS' recommendations and analysis?
A 163 Based on the flaws in IS' approach, PG&E recommends that the Commission reject the IS model and associated recommendations, and adopt PG&E's Hydrostatic Testing forecast based on PG&E's cost calculation curves and formulas.

4. Pipe Replacements
a. Parties' Recommendations Concerning the Pipe Replacements Program Are Unjustified
Q 164 Which parties made recommendations or had significant criticisms of the Pipe Replacements Program?
A 164 ORA and TURN.
Q 165 What was the nature of their recommendations?
A 165 ORA recommends $4.1 million\textsuperscript{157} in expense forecast for the Pipe Replacements Program, which equals PG&E's forecast of $4.1 million for

\textsuperscript{155} IS-1, Chapter 5, p. 5-1, line 24 to p. 5-2, line 2.
\textsuperscript{156} IS-1, Chapter 5, p. 5-1, lines 23-24.
\textsuperscript{157} In ORA's testimony, ORA's recommended amounts do not reflect PG&E's errata.
ORA also recommends capital expenditures of $44.2 million, $44.1 million, and $36.2 million in 2019, 2020, and 2021, respectively, a reduction of $18.0 million in capital expenditures over the 3-year period, compared to PG&E’s forecast of $47.9 million, $51.8 million, and $42.9 million in 2019, 2020, and 2021, respectively. ORA agrees with PG&E’s expense and capital forecast for the Other Pipeline Safety and Reliability Pipe Replacements sub-program. ORA also agrees with PG&E’s Vintage Pipe Replacement Program prioritization and scope. ORA’s dispute lies with the Vintage Pipe Replacement Program capital pipe replacement cost model and how it produces PG&E’s forecast.

TURN recommends allowing “into rate base [V]intage [P]ipeline [R]eplacement expenditures made in 2016-2018 only up to the amounts of the mileage completed for each pipe size category times the Commission’s authorized 2016-2018 level of cost per mile for [V]intage [P]ipeline replacements in that pipe size category” associated with the Vintage Pipe Replacement portion of the Pipe Replacements Program for 2015 through 2018 capital expenditure forecasts. A summary of PG&E’s rebuttal to parties’ positions and criticisms is contained in the Table 5-13 below.

**TABLE 5-13**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Party</th>
<th>PG&amp;E’s Rebuttal</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ORA</td>
<td>Cost estimating model for the Vintage Pipe Replacement Program is flawed.</td>
</tr>
<tr>
<td>2</td>
<td>TURN</td>
<td>Recommendation to limit the 2015-2018 capital expenditures included in rate base for the Vintage Pipe Replacement Program is inappropriate.</td>
</tr>
</tbody>
</table>

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158 ORA-05, p. 3, Table 5-1.
159 In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
160 ORA-05, p. 6, Table 5-2.
161 ORA-05, p. 12, lines 8-10.
162 ORA-05, p. 12, lines 16-17.
163 TURN, Chapter 5B, p. 3, lines 14-17.
b. ORA’s Cost Estimating Model for the Vintage Pipe Replacement Program Is Flawed

Q 166 What is ORA’s cost forecast recommendation regarding PG&E’s Vintage Pipeline Replacement Program?
A 166 ORA recommends $36.9 million, $44.1 million, and $36.2 million in 2019, 2020 and 2021, respectively, in capital expenditures for the Vintage Pipe Replacement Program,\(^{164}\) a reduction of approximately $18 million over the rate case period. ORA’s recommendation is based on using the same capital pipe replacement cost model that is referenced above for the capital Pipe Replacements In-Lieu of Hydrostatic Testing sub-program, which was previously described as a flaw.

Q 167 Do you agree with ORA’s recommended reduction in forecast for the Vintage Pipe Replacement Program?
A 167 No. As noted earlier, the model is flawed. The details behind these bases are explained above for the capital Pipe Replacements In-Lieu of Hydrostatic Testing sub-program.

c. TURN’s Recommendation to Limit the 2015-2018 Capital Expenditures Included in Rate Base for the Vintage Pipe Replacement Program Is Inappropriate

Q 168 What are TURN’s recommendations regarding PG&E’s Vintage Pipe Replacement Program?
A 168 TURN recommends allowing “into rate base Vintage Pipe Replacement expenditures made in 2016-2018 only up to the amounts of the mileage completed for each pipe size category times the authorized 2016-2018 level of cost per mile for Vintage Pipe replacements in that pipe size category” associated with the Vintage Pipe Replacement portion of the Pipe Replacements Program for 2015 through 2018 capital expenditure forecasts.

Q 169 What is the basis of TURN’s recommendation?
A 169 First, TURN acknowledges that PG&E will not complete replacement of 80 miles of Vintage Pipe Replacement over the 2015 GT&S Rate Case

\(^{164}\) ORA-05, p. 13, Table 5-5.
Second, TURN supports disallowances because of PG&E’s unit costs being higher than those unit costs used to authorized for forecast in the 2015 GT&S Rate Case decision.\textsuperscript{166}

Q 170 How does PG&E respond to TURN’s recommendation?
A 170 PG&E disagrees with TURN’s recommendation and rebuts TURN’s recommendation in two chapters:

- This chapter addresses the: (1) miles we plan to complete and why it is less than forecasted; (2) safety implications of not completing authorized miles; (3) reasonableness of costs incurred in 2015-2018; and (4) forecast for this rate case; and
- Chapter 23 Rebuttal Testimony explains why the capital disallowances TURN proposes should be rejected.

Q 171 Why are PG&E’s Vintage Pipe Replacement miles less than those authorized in the 2015 GT&S Rate Case?
A 171 As PG&E explained in Chapter 5 Prepared Testimony:

\begin{quote}
[T]here was uncertainty in the early years of the 2015 GT&S rate case period, due to final decision being received in the middle of 2016. The uncertainty in the timing of the decision created operational constraints that did not allow enough time for engineering and receipt of permits following issuance of the decision to initiate these capital projects. As PG&E was awaiting the final decision, it performed limited Vintage Pipe Replacement projects. Once the decision was issued, PG&E began to work toward project development of more Vintage Pipe Replacement projects. On average, it takes about 24 months to complete a Vintage Pipe Replacement project, due to the following reasons:

- Land acquisition;
- Long materials lead time, which can be 40 weeks;
- Complexity of projects, because the higher priority projects are targeting locations with elevated population density; and
- Environmental permitting.\textsuperscript{167}
\end{quote}

Q 172 Were there safety implications of not completing authorized Vintage Pipe Replacement miles?
A 172 No. As PG&E explained in Chapter 5 Prepared Testimony:

Performing less Vintage Pipe Replacement work did not result in a safety hazard because the condition of strains on the pipelines miles involved are continuously being monitored by PG&E’s: Leak Survey

\begin{flushright}
\footnotesize
\textsuperscript{165} TURN, Chapter 5B, p. 9, lines 11-18.  \\
\textsuperscript{166} TURN, Chapter 5B, p. 11, lines 10-17.  \\
\textsuperscript{167} PG&E Prepared Testimony, Chapter 5, p. 5-60, lines 4-19.  
\end{flushright}
Program; Geo Hazard Threat Identification Program; and Continuing Surveillance Program. Further, for the 2015-2018 GT&S Rate Case period, PG&E performed all work needed to eliminate immediate safety hazards. Although PG&E did not perform some work in this program, PG&E performed the higher priority work, and the work that PG&E did not perform did not create a safety hazard.  

Q 173 Were costs incurred in 2015 to 2018 for the Vintage Pipe Replacement Program reasonable?  
A 173 Yes. PG&E has routinely reported factors that have prevented completing Vintage Pipe Replacement projects in a more cost-effective manner through its periodic “Transmission Pipeline Compliance Report.” Full explanations can be found within each of the referenced reports. Generally speaking, the factors that affected cost effectiveness include: (1) Unidentified Pipeline Conditions, (2) Field Conditions, (3) Construction Permitting, (4) Schedule Constraints, (5) Gas System Operational Constraints, (6) Compliance Commitments, and (7) Construction Resources.  

Q 174 Has PG&E accounted for these factors in development of its Vintage Pipe Replacement Program forecast?  
A 174 Yes, by use of its cost calculation curve, which uses historical costs to generate a cost forecast for a project. Since the aforementioned factors existed for those historical project costs, they have been accounted for in development of the 2019 GT&S Rate Case forecasts for capital pipe replacements at the total program level. Therefore, the capital pipe replacement forecasts for the 2019 GT&S Rate Case are reasonable.  

Q 175 Based on analysis of TURN’s recommendation to limit the 2015-2018 capital expenditures included in rate base for the Vintage Pipe Replacement Program, what does PG&E recommend?  
A 175 PG&E recommends that all Vintage Pipe Replacement Program capital expenditures from 2015-2018 be included in rate base.

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169 PG&E Transmission Pipeline Compliance Report, Nos. 2016-01 (pp. 33-35), 2016-02 (pp. 20-21), 2017-01 (pp. 21-22), 2017-03 (pp. 20-22), 2017-04 (pp. 20-21), for example. See Attachment A at the end of this chapter, which also includes other relevant excerpts from these reports.
5. Geo-Hazard Threat Identification and Mitigation
   
a. Parties’ Recommendations Concerning Geo-Hazard Threat Identification and Mitigation Are Unjustified

Q 176 What parties commented on the Geo-Hazard Threat Identification and Mitigation Program?
A 176 ORA and TURN.

Q 177 What was the nature of their recommendations?
A 177 ORA did not recommend any expense reductions for the Geo-Hazard Threat Identification and Mitigation Program. ORA recommended $0.17 million, $0.18 million, and $0.19 million in 2019, 2020, and 2021, respectively, compared to PG&E’s forecast of $4.5 million, $4.6 million, and $4.8 million in 2019, 2020, and 2021, respectively, which is a reduction of approximately $13 million in capital expenditures over the rate case period. The recommended reduction is based on a significant reduction in unit cost, cost per project, for capital mitigations.

TURN recommends that the Commission:
[A]llow into rate base geo-hazard threat mitigation expenditures made in 2016-2018 only up to the actual number of mitigation projects times the Commission’s authorized 2016-2018 level of cost per mitigation site.170

A summary of PG&E’s rebuttal to parties’ positions is contained in Table 5-14 below.

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Party</th>
<th>PG&amp;E’s Rebuttal</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ORA</td>
<td>Assertion that one high cost project should be excluded to reduce capital mitigation unit costs is unfounded.</td>
</tr>
<tr>
<td>2</td>
<td>TURN</td>
<td>TURN’s recommendation to limit the 2015-2018 capital expenditures included in rate base for the Geo-Hazard Mitigation Program is inappropriate.</td>
</tr>
</tbody>
</table>

170 TURN, Chapter 5B, p. 3, lines 18-21.
b. ORA’s Assertion That One High Cost Project Should Be Excluded to Reduce Capital Mitigation Unit Costs Is Unfounded

Q 178 What is ORA’s basis for such a significant forecast reduction?
A 178 ORA asserts that PG&E’s unit cost for capital mitigation of approximately $1.4 million is inflated because of inclusion of one higher cost project, considering the capital mitigation on Line 021E to be an outlier.171

Q 179 Does PG&E agree that Line 021E should be an outlier and excluded from the unit cost analysis?
A 179 No. Line 021E is representative of the work that is expected in the Geo-Hazard Threat Identification and Mitigation Program capital mitigation. This capital mitigation program is one that requires an engineered mitigation to address high-risk land movement locations, and, as such, there is no specific high or low boundary that should be considered, as all capital mitigation work is needed, and not one geo-hazard threat mitigation will be similar to another; they are all engineered, based on the circumstances around each individual land movement site.

Q 180 Were all of the projects in PG&E’s workpaper supporting this program completed at the time of PG&E’s filing?172
A 180 No. Only the project for Line 021E was nearing completion and the rest of the projects were in early stages of engineering. PG&E’s workpaper, therefore, did not reflect full completed project costs for every historical project listed. PG&E reflected total historical costs available at the time of the filing in order to develop a program forecast that tracked with historical spending at the program level. This was further exemplified in PG&E’s response to a TURN data request173 that showed updated costs for completed capital mitigation projects that were not only high for Line 021E, but also included a relatively high cost for completion of a high-risk land movement mitigation on Line 210C, which was not included in the workpaper at the time of PG&E’s filing because it had not yet been identified as a high-risk location. Table 5-15 shows a comparison between PG&E’s

171 ORA-05, p. 13, lines 14-18.
172 PG&E WP 5-17s, Workpaper Table 5-45.
173 TURN-021, Question 05, Attachment 01.
original workpaper for unit cost analysis and the completed projects updated in the data response to TURN, combined with updated data for recorded costs from other PG&E discovery responses for the Geo-Hazard Threat Identification and Mitigation Program capital mitigation:

Table 5-15

**Comparison Between PG&E’s Original Geo-Hazard Workpaper (Unit Cost Analysis) and the Completed Projects Updated in the Data Response to TURN**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Order #</th>
<th>Order Description</th>
<th>PG&amp;E Workpaper 2016 $, NCM(c)</th>
<th>Completed Projects 2016 $, NCM(d)</th>
<th>Recorded Project Cost From Discovery 2016 $, NCM(e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>30983250</td>
<td>R-412 L-177A MP 68.96, Embankment Erosion</td>
<td>$41,357</td>
<td>(b)</td>
<td>$114,940</td>
</tr>
<tr>
<td>2</td>
<td>74000962/30603689</td>
<td>R-317 L-147 1.23 MI MP 0.85-1.98 Replace</td>
<td>$18,598</td>
<td>(b)</td>
<td>20,426</td>
</tr>
<tr>
<td>3</td>
<td>74012243</td>
<td>R-1031 L-210C 0.1894MI MP 22.26-22.39 Replace</td>
<td>(a)</td>
<td>$3,875,502</td>
<td>3,875,502</td>
</tr>
<tr>
<td>4</td>
<td>30884606/30861966</td>
<td>021E MP 129.7 Land Slide Mitigation</td>
<td>$6,656,979</td>
<td>(b)</td>
<td>7,144,451</td>
</tr>
<tr>
<td>5</td>
<td>30987153</td>
<td>L-300A MP 0.69 Span Support Erosion Prot</td>
<td>$37,585</td>
<td>(b)</td>
<td>43,580</td>
</tr>
<tr>
<td>6</td>
<td>74007334</td>
<td>L-132 43.63-45.23 Replace San Bruno Mtn</td>
<td>$115,879</td>
<td>(b)</td>
<td>$292,466</td>
</tr>
<tr>
<td>7</td>
<td>Total</td>
<td></td>
<td>$11,491,366</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Cost Per Project</td>
<td>(Using same Methodology as Workpaper, with Updated Recorded Costs):</td>
<td>$1,915,228</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(a) Line 210C capital mitigation had not yet been identified at time of PG&E’s filing.
(b) These projects have not been completed, and the discovery response asked for recorded costs at completion.
(c) PG&E WP 5-172, Workpaper Table 5-45.
(d) TURN-021, Question 05, Attachment 01.
(e) Combines recorded project costs from ORA-002, Question 01, Attachment 03 for recorded costs up to year 2016, and from ORA-035, Question 01, Attachment 01, Revised 01, redacted for recorded costs in year 2017.

Q 181 What does Table 5-15 show?
A 181 First, Table 5-15 shows that high cost projects are indeed a part of the mix of capital Geo-Hazard Threat mitigation projects. Second, if ORA takes into account recorded costs for all projects, using the same partially completed project mix, the cost per project is actually approximately $0.5 million per project higher than shown at the time the forecast was filed.

Q 182 Based on your assessment of updated recorded data, what do you recommend?
A 182 For all of the aforementioned reasons, I recommend that the Commission reject ORA’s exclusion of the one higher cost project from the Geo-Hazard...
Threat Identification and Mitigation Program capital mitigation unit cost, and approve of the unit cost of approximately $1.4 million, as filed by PG&E.

c. TURN’s Recommendation to Limit the 2015-2018 Capital Expenditures Included in Rate Base for the Geo Hazard Threat Identification and Mitigation Program Is Inappropriate

Q 183 What are TURN’s recommendations regarding PG&E’s Geo-Hazard Threat Identification and Mitigation Program?

A 183 TURN recommends that the Commission:

[A]llow into rate base geo-hazard threat mitigation expenditures made in 2016-2018 only up to the actual number of mitigation projects times the Commission’s authorized 2016-2018 level of cost per mitigation site.174

Q 184 What is the basis of TURN’s recommendation?

A 184 TURN asserts that PG&E deferred work that it should have done.175

Q 185 How does PG&E respond to TURN’s recommendation?

A 185 PG&E disagrees with TURN’s recommendation and rebuts TURN’s recommendation in two chapters:

• This chapter addresses the: (1) why the number of projects completed is less than forecasted, (2) safety implications of not completing forecasted number of projects; (3) reasonableness of costs incurred in 2015-2018; and (4) forecast for this rate case; and

• Chapter 23 explains why the capital disallowances TURN proposes should be rejected.

Q 186 Why was PG&E unable to complete the forecasted number of Geo-Hazard Threat Identification and Mitigation capital mitigation projects?

A 186 As PG&E explained in Chapter 5 Prepared Testimony:

PG&E anticipates completion of fewer Geo-Hazard Program capital mitigation projects than authorized because the Geo-Hazard Threat Identification process had a delayed start, due to the issuance of D.16-06-056 on July 1, 2016. The delayed threat identification meant that there was a delay identifying capital projects. Once the capital mitigation projects were identified, there was not enough time to engineer and complete the number of authorized capital mitigation projects by the end of the rate case period.

174 TURN, Chapter 5B, p. 3, lines 18-21.

175 TURN, Chapter 5B, p. 12, line 10 to p. 16, line 6.
Additionally, as discussed in Chapter 4, PG&E re-prioritized some of the program funding toward higher priority capital safety work within the Transmission Pipeline asset family. 176

Q 187 Were there safety implications for not completing the forecast number of projects?

A 187 No. As PG&E explained in Chapter 5 Prepared Testimony:

Performing less capital geo-hazard mitigation work did not result in a safety hazard because the condition of geo-hazards requiring immediate attention is discovered through PG&E’s Continuing Surveillance Program. Through that program, geo-hazards that immediately affect the safety of the pipeline, such as wash outs or landslides, are mitigated expeditiously, as a result of findings from that program. As such, for the 2015-2018 GT&S Rate Case period, PG&E performed all work needed to eliminate immediate safety hazards. Although PG&E reprioritized some work in this program, PG&E performed the highest priority work, and the work that PG&E did not perform did not create a safety hazard. 177

Q 188 Were the costs incurred between 2015-2018 reasonable?

A 188 Yes. Considering that PG&E had very limited experience with forecasting a program such as this one in the past, PG&E used the best information it had to develop a per-project forecast, based on a limited historical cost data set. Each capital geo-hazard threat mitigation requires specific engineering, and until that engineering is completed, one cannot predict what the actual cost of the mitigation will be. At the time of the 2015 GT&S Rate Case filing, PG&E did not have a list of specific project locations. Rather, it was working from a proposition that a certain number of locations would be identified for mitigation once the geo-hazard threat identification process began. Since the two projects, totaling $11 million dollars, that are being referenced by TURN 178 were specifically engineered projects to mitigate the geo-hazard threat, the total cost was reasonable and should be included in rate base, along with all other engineered capital geo-hazard threat mitigation projects.

176 PG&E Prepared Testimony, Chapter 5, p. 5-71, lines 1-11.
177 PG&E Prepared Testimony, Chapter 5, p. 5-71, lines 12-21.
178 TURN, Chapter 5B, p. 14, line 9.
6. Programs to Support Integrity Management

   a. Parties Recommendations on Forecast Methodology Are Without Merit

   Q 189 What parties commented on the Programs to Support Integrity Management?

   A 189 TURN.

   Q 190 What is TURN’s recommendation?

   A 190 For the Root Cause Analysis subprogram, TURN recommends: “the use of the last recorded year (2017) amount of $2,754,000 as the 2019 TY level expense.”\(^{179}\)

   This is a reduction of approximately $1.38 million from PG&E’s proposal of approximately $4.13 million.

   Q 191 Does TURN provide support for its recommendation?

   A 191 Yes. TURN provided Table 5B-8 titled, “Historical Root Cause Analysis Expense,”\(^{180}\) showing recorded values from 2012 through 2017. TURN states that “the two years the Company has chosen for its calculation had the highest costs of the last six years.” TURN further states “[i]t should be noted that two years can be too short a period for calculating an average as the limited data can be unrepresentative.”\(^{181}\) Last, TURN cites language from a prior GRC decision that stated, “when costs trend in one direction over three or more years, the last recorded year is appropriate for use.”\(^{182}\)

   Q 192 Are there issues in the support of TURN’s recommendation?

   A 192 Yes, several. First, the values are provided in nominal year dollars, and not 2016 base year dollars. Please see Table 5-16 below for an updated version of TURN's Table 5B-8, which uses the appropriate 2016 BY amounts.

\(^{179}\) TURN, Chapter 5B, p. 18, lines 12-13.

\(^{180}\) TURN, Chapter 5B, p. 17, Table 5B-8.

\(^{181}\) TURN, Chapter 5B, p. 17, lines 11-13.

\(^{182}\) TURN, Chapter 5B, p. 18, line 15-16.
TABLE 5-16
ROOT CAUSE ANALYSIS RECORED EXPENSES
2012-2017 (2016$ NCM)
(THOUSAND OF DOLLARS)

<table>
<thead>
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<tr>
<td>1</td>
<td>$65</td>
<td>$279</td>
<td>$1,057</td>
<td>$3,922</td>
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Second, as shown in the table above, the numbers of year-over-year decline in recorded cost is two years. There was a decline in Root Cause Analysis costs between years 2015 and 2016 and between 2016 and 2017. As shown in Table 5-16, there is not a trend showing a decline over three annual intervals, proving TURN’s argument is unsupported. Further, for the Root Cause Analysis Program, there is much variability, due to the fact that the cost for the program is greatly influenced by issues/incidents that occur in any given year. This makes the use of a single year for forecast inappropriate for Root Cause Analysis.

Q 193 What would the forecast be if PG&E incorporated 2017 recorded values into its calculation of a programmatic average?

Q 194 What is PG&E’s recommendation considering this updated analysis?
A 194 PG&E’s 2019 TY forecast of approximately $4.134 million should be adopted, using years 2015-2016 as the basis for forecast. Should the Commission choose to incorporate 2017 recorded costs in developing an adopted forecast for this program, PG&E recommends that a 3-year average be used as the basis for a 2019 TY forecast of approximately $3.715 million.

7. Emergency Response Programs
a. Parties Recommendations on the Public Awareness Program
Forecast Methodology Are Without Merit
Q 195 What sub-programs make up PG&E’s Emergency Response Programs?
A 195 PG&E’s Emergency Response Program is made up of the Public Awareness Program, Valve Automation Program, and the Valve Safety and Reliability Program.

Q 196 What parties commented on the Emergency Response programs?

A 196 TURN.

Q 197 Which sub-program does TURN have recommendations for?

A 197 TURN provides recommendations for the Public Awareness Program only. TURN does not provide a recommendation for the Valve Automation or the Valve Safety and Reliability programs under the overarching Emergency Response Program.

Q 198 What was the nature of TURN’s recommendation on the Public Awareness Program?

A 198 TURN recommends “using the last recorded year amount of $2,609,634” as the forecast for the 2019 TY.\(^{183}\) This is a reduction of approximately $1.8 million from PG&E’s proposal of approximately $4.41 million.

Q 199 Does TURN provide support for their recommendation?

A 199 Yes. TURN provided Table 5B-10 titled, “Historical Public Awareness Expenses,” showing recorded values from 2012 through 2017. TURN then states that:

A three-year average, although better than a two-year average applied by the Company in some of its calculations, is still not optimal, since it can be too short of a period to provide an accurate estimate.\(^{184}\)

TURN then uses recorded values from 2015-2017 to suggest that using 2017 recorded:

\[\text{[I]s consistent with prior decisions as the CPUC stated in D.04-07-022 and D.89-12-057 that when costs decline for three or more years it is appropriate to use the last recorded year as a base.}\(^{185}\)

Q 200 Does TURN have any other criticisms of PG&E’s forecast for the Public Awareness Program?

A 200 Yes. TURN states, “PG&E was authorized $3.558M for 2015 Test Year, but costs have not reached that level in the ensuing years.”\(^{186}\) TURN also

\(^{183}\) TURN, Chapter 5B, p. 20, line 13.

\(^{184}\) TURN, Chapter 5B, p. 19, line 23 to p. 20, line 2.

\(^{185}\) TURN, Chapter 5B, p. 20, lines 10-12.

\(^{186}\) TURN, Chapter 5B, p. 20, lines 4-5, fn omitted.
states that, “the amount for 2014 is an outlier.”\textsuperscript{187} TURN considers 2014 to be an outlier because it included the cost to send the proximity letter requested by Congresswoman Jackie Speier. TURN also supports their claim by stating:

\textit{In PG&E’s previous GT&S decision, the Commission removed $5.3 million of expenses from the 2014 forecast related to mailing the informational letters.}\textsuperscript{188}

Q 201 How does PG&E respond to TURN’s recommendation and criticisms?

A 201 PG&E acknowledges $3.558 million was adopted for the 2015 TY, and PG&E has not reached that level of spend in the ensuing years. PG&E also acknowledges the Commission’s decision to remove the costs of the informational letter in D.16-06-056. Despite these acknowledgements, PG&E does not agree with the use of 2017 recorded costs as these costs were not available at the time of PG&E’s filing. Omitting 2017 would not produce a trend of decline for a term of three or more years. As such, TURN’s recommendation should be rejected.

Q 202 What does PG&E recommend?

A 202 PG&E recommends using an average of 2015 and 2016 recorded values to determine the forecast for the 2019 TY. This method omits both the use of 2014 recorded costs that included the costs associated with the informational letter disallowed by the Commission, as well as omits the use of 2017 recorded values that were not available at the time of PG&E’s filing. This method yields a TY forecast of approximately $3.51 million, a reduction of approximately $0.9 million from PG&E’s original forecast of approximately $4.41 million. Please see Table 5-17 for the calculations of PG&E’s updated recommended forecast.

\textsuperscript{187} TURN, Chapter 5B, p. 19, line 12.

\textsuperscript{188} TURN, Chapter 5B, p. 19, lines 20-21.
8. Class Location Change

a. PG&E Partially Agrees with TURN Regarding Removal of Recurring Projects

Q 203 What parties commented on the Class Location Change Program?

A 203 TURN.

Q 204 Which Class Location Change activities does TURN have recommendations for?

A 204 TURN proposes recommendations for the Class Location Strength Testing Mitigations only. TURN does not provide a recommendation for the Class Location Studies or Class Location Pipe Replacement Mitigation.

Q 205 What is the nature of TURN’s recommendation on the Class Location Strength Testing Mitigations?

A 205 TURN recommends: “the Company’s use of a five-year average for this expense but only after excluding the anomalous non-recurring costs from 2014.”  

189 This recommendation results in a forecast of approximately $189 thousand in the 2019 TY, a reduction of approximately $1.491 million of PG&E’s original forecast.

Q 206 What are the non-recurring costs in 2014 that TURN refers to?

A 206 TURN calls out two separate orders from 2014 that they have issue with: order 41368618, “GT Classification Review – Systemwide” 190, and order 41687447, “L-131 T-172-12 MP 35.73-35.87 CLASSW0034.” 191

Q 207 Are these in fact non-recurring costs?

189 TURN, Chapter 5B, p. 22, lines 9-10.
190 PG&E WP 5-80, Workpaper Table 5-27, line 16.
191 PG&E WP 5-80, Workpaper Table 5-27, line 29.
As stated in PG&E’s response to a TURN data request, and reiterated by TURN in its testimony, the costs associated with the GT Classification Review – Systemwide order are indeed non-recurring costs.

As stated PG&E’s response to another TURN data request:

The specific project listed on Line 29 [L-131 T-172-12 MP 35.73-35.87 CLASSW0034] of WP 5-80 itself is not recurring. However, the need to perform a similar hydrotest as a mitigation of Class Location change is in fact recurring. PG&E included line 29 of WP 5-80 as a cost that is representative of what PG&E could expect in the 2019-2021 rate case period.

Can you further explain why the costs found on line 29 of WP 5-80 (L-131 T-172-12 MP 35.73-35.87 CLASSW0034) are representative of what PG&E could expect in the 2019-2021 rate case period?

Yes. 49 CFR 192.609 requires operators to evaluate their gas transmission system for Class Location change. In the event of a Class Location change, 49 CFR 192.611 requires operators to confirm the Maximum Allowable Operating Pressure (MAOP) of the pipelines in the affected area. Strength testing is used to confirm the MAOP. As a result of PG&E’s Class Location studies, PG&E was required to perform a strength test to confirm the MAOP of a section of L-131 in 2014. Line 29 of WP 5-80 shows the costs associated with that strength test. PG&E evaluates Class Location change annually, and a Class Location change anywhere on PG&E’s system would yield the need to perform a similar strength test, as was performed in 2014. As such, PG&E believes it is reasonable to include the cost of this strength test in its calculation of a programmatic average.

TURN’s recommendation also reflects the use of 2017 recorded in the 5-year average. Do you agree with this?

No. 2017 recorded figures were not available at the time of PG&E’s filing. Consistent with forecast ratemaking, the most recent BY available when PG&E prepared its filing was 2016.

Based on the above discussion, does PG&E have an updated recommendation to provide?

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192 TURN-017, Question 15.
193 TURN, Chapter 5B, p. 21, lines 15-18.
194 TURN-Oral-004, Question 01.
Yes. PG&E recommends its original proposal of utilizing a 5-year (2012-2016) programmatic average to calculate the 2019 TY forecast, however, excluding the non-recurring costs associated with the “GT Classification Review – Systemwide” order only. This analysis yields an updated forecast of approximately $0.525 million for the 2019 TY, a reduction of approximately $1.154 million of the original forecast of approximately $1.680 million. Please see Table 5-18 below for the calculations of PG&E’s updated recommended forecast.

### TABLE 5-18

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<thead>
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### 9. Shallow and Exposed Pipe (Including Water and Levee Crossings)

#### a. Parties’ Recommendations Concerning Shallow and Exposed Pipe (Including Water and Levee Crossings) Are Unjustified

Q 211 What parties have recommendations on the Shallow and Exposed Pipe (Including Water and Levee Crossings) Program?

A 211 ORA and OSA.

Q 212 What do parties recommend?

A 212 First, ORA recommends applying ORA’s capital pipe replacement cost estimating model as the forecast methodology for this program. This results in a capital expenditure reduction of $12.7 million over the 3-year rate case period. Second, ORA generally criticizes PG&E’s metric for re-prioritizing Shallow and Exposed Pipe Program work during the 2015 GT&S Rate Case period:

ORA does not oppose the pace and prioritization of projects for this rate case period.\(^{195}\)

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\(^{195}\) ORA-05, p. 14, lines 18-19.
PG&E acknowledges and agrees with ORA that we used the proper pace and prioritization of projects for the 2019 GT&S Rate Case period. We will rebut the last two points.

OSA stated that the:

Commission should order PG&E to explain why it currently does not plan to mitigate two specific segments of exposed pipelines in the City of Lafayette as part of its pipeline maintenance program. Additionally, PG&E should provide a timeframe in which it plans to address this issue.196

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Party</th>
<th>PG&amp;E’s Rebuttal</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ORA</td>
<td>Capital cost estimating model for the Shallow and Exposed Pipe (Including Water and Levee Crossings) Program uses inconsistent data, making the model unreliable.</td>
</tr>
<tr>
<td>2</td>
<td>ORA</td>
<td>Assertion that PG&amp;E did not explain a metric for re-prioritizing Shallow and Exposed Pipe mitigations in the 2015 GT&amp;S Rate Case is incorrect</td>
</tr>
<tr>
<td>3</td>
<td>OSA</td>
<td>Recommendation on particular exposed pipe segments on PG&amp;E’s Gas Transmission System addressed.</td>
</tr>
</tbody>
</table>

b. ORA’s Capital Cost Estimating Model for the Shallow and Exposed Pipe (Including Water and Levee Crossings) Program Uses Inconsistent Data, Making the Model Unreliable

Q 213 What is ORA’s cost forecast recommendation regarding PG&E’s Shallow and Exposed Pipe Program?

A 213 ORA recommends $21.3 million, $22.0 million, and $22.6 million in 2019, 2020 and 2021, respectively, in capital expenditures for the Shallow and Exposed Pipe Program,197 a reduction of approximately $12.7 million over the rate case period. ORA agrees with PG&E’s expense forecast of approximately $1.1 million198 for this program.199 ORA’s capital forecast reduction is based on using the same capital pipe replacement cost model

196 OSA-1, Chapter 1, p. 1-1, lines 17-20.
197 ORA-05, p. 6, Table 5-2.
198 In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
199 ORA-05, p. 3, Table 5-1.
that is referenced above for the capital Pipe Replacements In-Lieu of
Hydrostatic Testing sub-program, which was described as flawed.

Q 214 Do you agree with ORA’s recommended reduction in capital forecast for the
Shallow and Exposed Pipe Program?
A 214 No. As described above for the capital Pipe Replacements In-Lieu of
Hydrostatic Testing sub-program, the capital pipe replacement cost
estimating model uses inconsistent data, making the model unreliable.

c. ORA’s Assertion That PG&E Did Not Explain a Metric for
Re-Prioritizing Shallow and Exposed Pipe Mitigations in the 2015
GT&S Rate Case Is Incorrect

Q 215 What is ORA’s criticism concerning re-prioritization of Shallow and Exposed
Pipe Program work in the 2015 GT&S Rate Case period?
A 215 ORA generally criticizes PG&E for apparently lacking a metric to determine
the highest priority safety work that was done instead of Shallow and
Exposed Pipe Program work in the 2015 GT&S Rate Case period,
making it difficult to evaluate re-prioritization of this work during the rate
case period.

Q 216 Does PG&E believe it has provided sufficient explanation of the methods it
used to re-prioritize safety work within the 2015 GT&S Rate Case period?
A 216 Yes.
Q 217 Please explain what supports this assertion.
A 217 PG&E, in its Chapter 4 Prepared Testimony, explained and supported the
methods it used to re-prioritize safety work within the 2015 GT&S Rate Case
period. PG&E used the RIBA scoring process that is described in the
Investment Planning Process in Chapter 4 Prepared Testimony on
pages 4-11 through 4-15. The RIBA scoring process enables making risk
based investment decisions to generally complete higher risk work before
lower risk work.

d. OSA’s Recommendation on Particular Exposed Pipe Segments on
PG&E’s Gas Transmission System Is Addressed

Q 218 What was the nature of OSA’s recommendations?
A 218 OSA stated that the:

200 ORA-05, p. 15, lines 1-6.
Commission should order PG&E to explain why it currently does not plan to mitigate two specific segments of exposed pipelines in the City of Lafayette as part of its pipeline maintenance program. Additionally, PG&E should provide a timeframe in which it plans to address this issue.201

Q 219 Can PG&E explain which two segments OSA is raising questions about, and why, PG&E currently does not plan to mitigate them as part of its pipeline maintenance program?

A 219 Yes. OSA is asking this question with regard to L-191-1 MP 25.496 – 25.504 (Segment 1) and L-191-1 MP 26.115 – 26.132 (Segment 2).

In the 2019 GT&S Rate Case, PG&E prioritized the Shallow and Exposed Pipe Program mitigation projects, based on Figure 5-11 on page 5-104 of Prepared Testimony. As stated on page 5-104 in Prepared Testimony:

In this rate case period, PG&E forecasts mitigation of locations that have a high LOF and are in HCAs [High COF].202

Q 220 What risk score did these two specific segments receive based on Figure 5-11?

A 220 Segment 1 received a Medium Likelihood of Failure (LOF) score and a Medium Consequence of Failure (COF) score. Segment 2 received a Medium LOF score and a High COF score. Neither segment received both a High LOF and COF score, and as such, was not proposed to be mitigated within the 2019 GT&S Rate Case period.

Q 221 What is the timeframe in which PG&E plans to address the issues?

A 221 PG&E plans to move forward with the mitigation of Segment 1, and currently plans to complete the mitigation in 2019. PG&E will continue to monitor Segment 2 in the Shallow and Exposed Pipe Program, and it will prioritize the segment against the rest of the segments in the program using Figure 5-11 on page 5-104.

201 OSA-1, Chapter 1, p. 1-1, lines 17-20.

202 PG&E Prepared Testimony, Chapter 5, p. 5-104, lines 8-9.
10. Gas Gathering

a. Parties’ Recommendations Concerning the Gas Gathering Program Are Without Merit

Q 222 What parties commented on the Gas Gathering Program?
A 222 ORA had a general recommendation, but did not recommend a specific forecast.

Q 223 What does ORA recommend?
A 223 ORA suggested that there is uncertainty about how many meters PG&E could complete during the 2019 GT&S Rate Case period, based on its rate of historical completion. As such, ORA recommended that PG&E file an annual Tier 1 Advice Letter (AL) describing progress for this program, including how many meters were retired and their cost. They also provided an alternative to include this information with PG&E’s “Annual Risk Spending Accountability Reports.”

Q 224 Based on ORA’s recommendation, what does PG&E recommend?
A 224 PG&E does not agree that a Tier 1 AL is the appropriate avenue of reporting the Gas Gathering Program’s progress. Tier 1 ALs are used primarily for cost recovery. Considering ORA does not recommend a forecast reduction, PG&E does not agree a Tier 1 AL is warranted. In addition, the structure of the Annual Risk Spending Accountability Report is yet to be determined, but is generally geared more towards reporting on risk reduction per dollar spent, than it is for general program progress. The Annual Risk Spending Accountability Report is not an appropriate report for the type of information ORA is requesting. If ORA wants to track PG&E’s progress on this program throughout the 2019-2021 time period, PG&E would be happy to respond to an ORA data request.

Since ORA does not dispute PG&E’s forecast, PG&E recommends that the Commission adopt PG&E’s forecast for Gas Gathering.

203 ORA-05, p. 17, lines 2-8.
11. Work Required by Others

a. Parties’ Recommendations Concerning the WRO Program Are Unjustified

Q 225 What parties commented on the WRO Program?
A 225 ORA and IS.

Q 226 What does ORA recommend?
A 226 ORA recommends reducing both the capital and expense WRO programs.

ORA recommends a forecast of approximately $19.15 million, $19.75 million, and $20.33 million in 2019, 2020 and 2021 capital expenditures, respectively, and a forecast of approximately $0.63 million in 2019 expenses for the WRO Program. Both capital and expense were reduced by ORA’s use of a 3-year program average using recorded costs between 2015 and 2017. Also, ORA supports PG&E’s recommendation to discontinue the WRO balancing account, “provided that ORA’s recommended forecast, or similar forecast, is adopted.”

Q 227 What does IS recommend?
A 227 IS recommends a $10 million reduction to PG&E’s 2019 capital WRO program. This calculates to forecast of $17.87 million forecast. IS did not have a recommendation for the expense WRO Program.

### TABLE 5-20
SUMMARY OF PG&E’S SHALLOW AND EXPOSED PIPE PROGRAM REBUTTAL

<table>
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<tr>
<th>Line No.</th>
<th>Party</th>
<th>PG&amp;E’s Rebuttal</th>
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<tbody>
<tr>
<td>1</td>
<td>ORA, IS</td>
<td>Use of a more up-to-date program average forecast methodology is unjustified.</td>
</tr>
<tr>
<td>2</td>
<td>ORA</td>
<td>Recommendation for discontinuance of the WRO one-way balancing account has unreasonable stipulations.</td>
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</table>

204 ORA-05, p. 18, lines 10-12.
205 IS-1, Chapter 5, p. 5-15, lines 17-18.
b. Parties’ Use of a More Up-to-Date Program Average Forecast

Methodology Is Unjustified

Q 228 What was the nature of ORA’s recommendation regarding forecasting methodology?

A 228 ORA recommended the use of an annual average program forecast, based on recorded costs between 2015 and 2017,\textsuperscript{206} rather than recorded costs from years 2013-2015; the forecast methodology used by PG&E.

Q 229 Why did PG&E use years 2013-2015 annual average program cost as its forecasting methodology?

A 229 As stated in PG&E’s Chapter 5 Prepared Testimony:

Year 2016 was not used in this analysis because Net costs were not yet available for 2016. This is a result of the WRO process which has PG&E first performing the work and then receiving compensation for the work sometimes well after the work is completed and the gross costs for projects are recorded.\textsuperscript{207}

At the time of filing, PG&E also did not yet have 2017 recorded costs. The most recent recorded year available when PG&E prepared its filing was the 2016 BY.

Q 230 Does ORA have any other criticisms of PG&E’s forecast?

A 230 Yes. ORA claims that:

[R]ecorded costs in 2013 through 2015 on which PG&E bases its forecast represent relatively-high cost years compared to 2011, 2012, 2016 or 2017. PG&E’s forecast, therefore, is likely too high.\textsuperscript{208}

Q 231 Does ORA provide any support proving that the spending levels of 2013 through 2015 were not to be expected in this rate case period?

A 231 No.

Q 232 Does PG&E agree with ORA that the 2019 capital WRO forecast is “likely too high” because it is based on 2013 through 2015 recorded costs?

A 232 No. As stated in Chapter 5 Prepared Testimony

WRO is difficult to forecast in advance, as the obligations arise from requirements imposed on PG&E by another agency.\textsuperscript{209}

\textsuperscript{206} ORA-05, p. 17, lines 18-21.
\textsuperscript{207} PG&E Prepared Testimony, Chapter 5, p. 5-114, fn 65.
\textsuperscript{208} ORA-05, p. 18 line 18 to p. 19, line 3.
\textsuperscript{209} PG&E Prepared Testimony, Chapter 5, p. 5-113, lines 22-23.
WRO is highly variable, and as shown in ORA’s Table 5-10, PG&E has experienced net costs in its capital WRO program ranging from as low as approximately $6 million up to as high as approximately $32 million. PG&E has experienced recorded values higher than its 2019 forecast, and as such, PG&E does not agree that its 2019 forecast of approximately $27.87 million is too high.

Q 233 What impacts does ORA’s recommendation have on the 2019 capital and expense forecasts for the WRO Program?

A 233 ORA’s recommendation on the capital WRO Program would reduce PG&E’s original 2019 forecast of approximately $27.87 million by approximately $8.72 million to approximately $19.15 million. ORA’s recommendation on the expense WRO Program would reduce PG&E’s original 2019 forecast of approximately $715 thousand by approximately $87 thousand to approximately $628 thousand.

Q 234 What method does IS’ use to derive a forecast?

A 234 IS calculated an annual average for the capital WRO Program for 2016-2018, using PG&E’s recorded costs for 2016, along with PG&E’s forecasts for 2017 and 2018. This calculated average was stated as “$17 million per year.” IS states that the Company’s 2019 GT&S cost “of $27.9M is more than $10 million higher than this amount.” IS recommends $10 million in reductions, and claims:

This reduces the projected capital expenditures in 2019-2021 down to a level that is reasonably consistent with the three-year average over the 2016-2018 period.

Q 235 Does IS provide any support that the spending levels of 2013 through 2015, of which, PG&E bases its capital WRO forecast, were not to be expected in this rate case period?

A 235 No.

Q 236 What impacts do the IS’ recommendations have on the 2019 capital and expense forecasts for the WRO Program?

---

210 In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
211 IS-1, Chapter 5, p. 5-15, lines 12-14.
212 IS-1, Chapter 5, p. 5-15, lines 14-15.
213 IS-1, Chapter 5, p. 5-15, lines 18-20.
IS’ recommendation on the capital WRO Program would reduce PG&E’s original 2019 forecast of approximately $27.87 million by $10 million to approximately $17.87 million. IS did not have a recommendation for the expense WRO Program.

Based on the parties’ arguments, what is PG&E’s recommendation?

PG&E recommends that the Commission adopt PG&E’s original 2019 forecasts of approximately $27.87 million in capital expenditures, and approximately $715 thousand in expenses for the WRO Program. These forecasts and the cost estimating methodology used reflect the highly variable nature of WRO.

ORA’s Recommendation for Discontinuance of a WRO One-Way Balancing Account Has Unreasonable Stipulations

What is the nature of the existing WRO balancing account?

In D16-06-056, the Commission required PG&E to:

[Establish a one-way balancing account to track the difference between the capital expenditure amounts adopted in this decision and the portion of costs assigned to customers over the 2015 GT&S rate cycle.]

Did the Commission give a reason this requirement was necessary?

Yes. The Commission saw the need for a balancing account due to the:

Large number of High Speed Rail projects included in the forecast and the fact that no master agreement has yet been approved by the Commission.

Does the uncertainty of High Speed Rail projects exist in PG&E’s 2019-2021 forecasts for the capital WRO Program?

No. As stated in Chapter 5 Prepared Testimony, PG&E is using the historical average annual cost for developing its WRO forecast, and not a specific forecast for the High-Speed Rail projects.

What was the nature of ORA’s recommendation regarding the WRO one-way balancing account?

---

216 PG&E Prepared Testimony, Chapter 5, p. 5-114, lines 21-29.
ORA supported PG&E’s recommendation to discontinue the WRO balancing account, ‘provided that ORA’s recommended forecast, or similar forecast, is adopted.”

Q 242 Does ORA state the need of the WRO balancing account if ORA’s recommendation is not adopted?

A 242 Yes. ORA argues if their recommendation is not adopted that:

   The use of a balancing account would protect ratepayers in case the amount of [WRO] falls short of PG&E’s forecast.

Q 243 How do you respond?

A 243 As discussed in Chapter 5 Prepared Testimony, the WRO Program is dependent on work required by third parties. As with all programs, in some instances PG&E will spend more, and in others less, than originally anticipated. This is a result of normal business and does not justify the need to continue a balancing account.

Q 244 Based on the nature of the existing WRO balancing account and PG&E’s forecasting methodology for the 2019 GT&S Rate Case WRO forecast, what does PG&E recommend?

A 244 Considering PG&E eliminated the uncertainty of High Speed Rail projects in its 2019-2021 forecast, PG&E recommends that the Commission adopt PG&E’s forecast and discontinue the WRO balancing account for the 2019-2021 time period. PG&E’s recommendation comports with use of the “similar forecast” conditions in ORA’s recommendation to discontinue the WRO One-Way Balancing Account.

12. Pipeline Investigations and Field Engineering

a. Parties’ Recommendations Concerning the Pipe Investigations and Field Engineering Program Are Unjustified

Q 245 What parties commented on the Pipe Investigations and Field Engineering Program?

References:

217 ORA-05, p. 18, lines 10-12.
218 ORA-05, p. 19, lines 4-6.
219 PG&E Prepared Testimony, Chapter 5, p. 5-111, lines 2-3.
220 See PG&E’s Chapter 2 rebuttal testimony, sponsored by Mr. Singh, for additional discussion regarding balancing and memorandum accounts.
What does TURN recommend for the Pipe Investigations and Field Engineering Program?

TURN recommends:

[T]he use of a five-year average of the most recent years (2013-2017) resulting in a cost of $5,562,000.

This recommendation is approximately $1.159 million less than PG&E’s originally submitted forecast of approximately $6.721 million for the 2019 TY.

Does TURN provide support for their recommendation?

Yes. TURN provides Table 5B-13 titled, “Historical Pipeline Investigations Expense,” showing recorded values from 2013 to 2017. TURN states that they:

[A]gree [ ] with the use of an average for this cost but considers a larger sampling size for the average to be more appropriate.

Does TURN offer any other arguments against PG&E’s Pipeline Investigations and Field Engineering Program’s forecast?

Yes. TURN states that PG&E’s 2019 TY forecast of $6.725 million:

[]is significantly higher than three of the previous 5 years and more than double the $2.994M costs incurred in 2017. A larger sample size of years would lessen the impact of the unusually high 2016 costs.

Does TURN provide support as to why it believes 2016 costs are “unusually high?”

No.

What comments do you have on TURN’s recommendation?

First, 2017 costs should not be included in the analysis of the reasonableness of PG&E’s forecast because 2017 costs were not available at the time of PG&E’s filing. Consistent with forecast ratemaking, the most recent BY available when PG&E prepared its filing was 2016. Second, TURN fails to acknowledge that the level of spend in 2016, $8.648 million, is just as significantly higher than PG&E’s 2019 TY forecast as other years are.

---

221 TURN, Chapter 5B, p. 25, lines 4-5.
222 TURN, Chapter 5B, p. 24, lines 1-2.
223 TURN, Chapter 5B, p. 24, lines 12-15.
lower. There is no evidence to show that PG&E would not experience the 2016 level of spend during the 2019-2021 rate case period.

Q 251 What is PG&E’s recommendation?

A 251 PG&E recommends the Commission adopt the originally filed 2019 TY forecast of approximately $6.721 million. This forecast was determined using the information PG&E had available at the time of the original submittal, and is reasonable, based on the fluctuating level of spend the program has experienced.

E. Conclusion

Q 252 Do you have any concluding remarks?

A 252 Yes. Based on my Chapter 5 Prepared Testimony, along with adjustments agreed to in this rebuttal, PG&E’s Chapter 5 forecasts are reasonable and should be adopted.

Q 253 Does this conclude your rebuttal testimony?

A 253 Yes, it does.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

ATTACHMENT A

EXCERPTS FROM PG&E’S TRANSMISSION PIPELINE

COMPLIANCE REPORTS:

NO. 2016-01, NO. 2016-02,

NO. 2017-01, NO. 2017-03 AND NO. 2017-04
PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION PIPELINE COMPLIANCE REPORT

NO. 2016-01

REPORTING PERIOD
JANUARY 1, 2015 – SEPTEMBER 30, 2016

IN COMPLIANCE WITH CPUC DECISION 16-06-056

SUBMITTED OCTOBER 31, 2016
PACIFIC GAS AND ELECTRIC COMPANY  
TRANSMISSION PIPELINE  
COMPLIANCE REPORT  
NO. 2016-01  
REPORTING PERIOD  
JANUARY 1, 2015 – SEPTEMBER 30, 2016  
IN COMPLIANCE WITH CPUC DECISION 16-06-056  
SUBMITTED OCTOBER 31, 2016  

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Introduction

On July 1, 2016, the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 16-06-056 in Pacific Gas and Electric Company's (PG&E or the Company) 2015 Gas Transmission and Storage (GT&S) rate case (Application (A.) 13-12-012). Ordering Paragraph (OP) 11 of the decision directs PG&E to serve quarterly compliance reports of PG&E’s transmission pipeline work, including Strength Testing,¹ Pipe Replacement, and In-Line Inspection (ILI). Per OP 11, Transmission Pipeline Compliance Reports shall generally follow the format set forth in Attachment D of the Pipeline Safety Enhancement Plan (PSEP) D.12-12-030, and shall include all costs recorded to these programs, such that they provide an accurate and complete record of all costs at the project and program level. OP 11 of D.16-06-056 requires that:

Pacific Gas and Electric Company shall file a quarterly compliance report of its transmission pipeline work, including pressure test, pipe replacement, and ILI. The report shall generally follow the format in Attachment D of Decision 12-12-030 and shall include all costs recorded to these programs, such that they provide an accurate and complete record of all costs at the project and program level. Consistent with the joint stipulation on Reporting and Communications between PG&E and the Office of Ratepayer Advocates, the format and content of the report may be revised by a working group to ensure that the report is useful to parties. PG&E’s first compliance filing shall cover the period between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter. The report shall be served on the Commission’s Safety and Enforcement Division, Energy Division, and on the service list of this proceeding.

Transmission Pipeline Compliance Report (Report) No. 2016-01 is submitted in compliance with the directive set forth in OP 11 and reflects the reporting period of January 1, 2015 to September 30, 2016. This report is being served on the Commission’s Safety and Enforcement Division, Energy Division and the service list of the 2015 GT&S rate case proceeding (A.13-12-012).

¹ “Strength test” is also referred to as the Hydrotect Program.
Decision-Making Process

1. Project Planning and Prioritization of Work

   Describe PG&E’s project planning process including how the projects were and are being scheduled and sequenced and what measures were and are being taken to conduct the work in a cost effective manner.

Response

   Gas Operations completes its multi-year planning by following PG&E’s Integrated Planning process. PG&E used its Integrated Planning process as described in this Requirement to make risk-informed decisions when establishing the 2015 and 2016 Plan. When determining the final forecast for each program or project in the portfolio during the Integrated Planning process, consideration is given to risk as well as other factors such as: classification of work, system constraints, work readiness, and financial constraints.

   The annual Integrated Planning process is led by PG&E’s Finance and Risk Department and is followed by all Lines of Business (LOB). This process provides the framework for how PG&E will accomplish its strategic initiatives. The Executive Guidance forum starts the annual process and provides the strategic focus for the Company, followed by Session D (Risk and Compliance), and Sessions 1 and 2. The Integrated Planning process incorporates the Executive Guidance and information from Session D to develop the 5-year strategic plan (Session 1) and the 2-year detailed work plan (Session 2).
The Executive Guidance is provided by the Chief Executive Officer to the Senior Leadership team at the beginning of each calendar year and results in the Company’s strategic focus for the next five years. Executive Guidance sets the direction for the Company.

Session D is completed at the beginning of each calendar year and provides an assessment of enterprise, operational, and compliance risks. The Session D deliverables include: a Risk Register, which highlights the top risks to the organization; a Session D presentation; and an executive session. During the executive session, senior PG&E officers across all LOBs discuss top risks and compliance requirements, progress made in risk reduction, and commitments to specific objectives of the Enterprise and Operational Risk Management and compliance programs.

Session 1 (S-1) is completed during the middle of the year following the completion of Session D. S-1 outlines PG&E’s multi-year strategic plan and includes a high-level, multi-year forecast. The S-1 process includes a written strategic plan and meetings of senior PG&E officers across all LOBs to discuss work needs and priorities. Through these meetings and the information contained in the strategic plans, leaders determine priorities for the Company as a whole.
achieve its strategic goals and provide feedback to LOB leaders on their strategic plans. Once these plans are approved, strategic plans for each LOB are finalized.

Session 2 (S-2) is completed in the second half of the year after the completion of S-1. S-2 outlines PG&E’s execution plan and includes a multi-year work plan and forecast at a more detailed level than provided in S-1. The S-2 process includes a written work plan and meetings of senior PG&E officers across all LOBs to discuss work needs and priorities. Through these meetings and the information contained in the execution plans, leaders determine priorities for the Company as a whole to achieve its execution plan. Once these plans are approved, detailed 2-year work plans are finalized.

Establishing the 2015 and 2016 Plan

1. Investment Planning Process

The Asset Program Owners, working with the Asset Family Owners (AFO), submit a list of proposed projects to Investment Planning for portfolio-level prioritization across all assets and programs. Investment Planning leads the process to develop a multi-year investment plan that is informed by risk and considers constraints. The objective of this prioritization is for Gas Operations to address its higher risks with its chosen mitigation programs given constraints including compliance requirements, obligations to serve, resources, system availability, executability, and affordability. To accomplish this objective, Investment Planning leads the following steps, which includes the Risk Informed Budget Allocation process:

a. Classification

The first step in the Investment Planning process is to classify projects or programs. This step identifies the key drivers for the work, which are used during prioritization with the risk scores for each project or program. Classifications include, but are not limited to: Mandatory; Regulatory Compliance; Commitment; and Work Requested by Others (WRO).

b. Program and Project Risk Scoring

The next step in the Investment Planning process is to risk score the respective projects or programs. There is a distinction in purpose between the Risk Register risk score, developed during Session D, and the Program and Project risk score. The purpose of the Gas Operations
Risk Register risk score is to rank and prioritize high consequence and low frequency risks at the asset level. The purpose of the Program and Project risk score is to relatively capture the consequence and likelihood scores for Safety, Environmental, and Reliability, based on the worst reasonable direct impact of not investing in the program or project. The Program and Project risk scoring process uses a framework to assess consequence and likelihood that is aligned with the framework utilized in the development of the Gas Operations Risk Register.

c. Program and Project Risk Score Validation
   The next step is to validate the Program and Project risk score. To facilitate consistent application of risk scores within and across asset families, Investment Planning conducts calibration sessions with AFOs. In addition, Investment Planning conducts analysis to validate that the Program and Project risk scores are aligned with the Gas Operations Risk Register risk scores.

d. Preliminary Portfolio
   Next, based on the classification and calibrated risk scoring for projects or programs, Investment Planning builds a preliminary investment portfolio by first including all Mandatory, WRO, and Commitment work, and then includes programs ranked by their respective Program and Project risk score.

e. Constraints Analysis
   Once the preliminary investment portfolio is compiled, Investment Planning collects information on constraints. Investment Planning then recommends adjustments to the preliminary portfolio based on these constraints prior to the Investment Decision Meetings.

f. Investment Decision Meetings
   Investment Planning then conducts a series of Investment Decision Meetings including the AFOs to analyze the portfolio and make any adjustments to the portfolio based on risks and constraints. These adjustments are typically in the form of increases or decreases to the scope of a program, or acceleration or deceleration of the pace of a program. Investment Planning is responsible for providing portfolio
analysis and facilitating the meetings; however, AFOs are accountable for making investment decisions.

2. Reprioritization Due to Timing of the 2015 GT&S rate case decision

Gas Transmission re-prioritized the investment portfolio in 2015 and 2016 due to the timing of the 2015 GT&S rate case decision. The result was a portfolio that included execution of mandatory work, moderated construction and incorporated more design and engineering work.

In re-planning the portfolio, the Gas Transmission organization utilized the same framework, outlined above, to reallocate funding for projects informed by risk.

Project Planning and Scheduling

Once the Plan is approved, project teams maintain schedules for each approved project that incorporate resource availability and constraint information including, but not limited to:
1) Environmental constraints and permitting duration;
2) Land acquisition requirements and duration;
3) Materials availability;
4) Engineering/design duration;
5) Pipeline clearance and coordination with other planned gas transmission work and maintenance activities;
6) Customer impact and communication; and
7) Construction resource availability.

Within the Project Management organization, projects are grouped into Workstreams based upon the work type for each program (e.g., Strength Test, Pipe Replacement, and ILI). On a weekly basis, Project Managers meet with key stakeholders to validate schedule information across the entire Workstream and address issues. These Workstream reviews enable functional organizations—such as: Engineering and Integrity Management; Land and Environmental Permitting; Sourcing; Compressed Natural Gas/Liquefied Natural Gas (CNG/LNG); and Construction—to identify opportunities to align project schedules and resource availability.

When individual functional constraints affect multiple projects across transmission work, the Workstreams seek to align these projects to execute concurrently. For example, during the summer of 2016, a series of strength
testing, valve automation and ILI upgrade projects were impacted by the same constraints associated with taking a clearance on Line 402 near Redding. The radial feed configuration of the pipeline and the presence of large commercial customer load necessitated a single clearance with significant CNG/LNG support. Each Workstream successfully aligned the project schedules to execute concurrent construction activities.

Planning activities focus upon the identification of opportunities to align work across the Workstreams. These include both sequencing work schedules in geographic areas and concurrent construction of co-located work.

The above described activities to schedule and sequence projects directly support the conduct of work in a cost effective manner. In addition, PG&E undertakes a range of other activities that support the completion of work in a cost effective manner including:

- Construction Management and Inspection oversight of construction activities that monitor and ensure work quality;
- Early constructability input from internal and ex construction resources, including internal and external construction resources;
- Development and maintenance of a standardized project delivery methodology with associated controls and governance oversight; and
- Bulk materials procurement, management of long-lead materials orders, and supplier quality oversight.
open houses; and sending brochures and other publication. These activities were extended across all Gas Transmission programs’ construction activities.

4) Improved Traffic Management Planning:

The PMO has improved the quality and consistency of: traffic management planning; supporting permit documentation; and overseeing activities for appropriate execution in the field.

5) Improved Pipeline Clearance Management:

The PMO has improved the alignment of project scheduling as it relates to ongoing gas system operations. The PMO helps plan construction activities such that it avoids peak winter demand and high commercial activity periods (e.g., agricultural harvesting, drying).

6) Customer Outage Management:

The PMO works with Gas Operations to increase its CNG/LNG equipment fleet. This enables the program to conduct construction-related pipeline outages with minimal, if any, impact to customer service. The PMO helps improve project planning steps to identify customers’ gas load demand requirements, and to integrate this information into project schedules by identifying the need for CNG/LNG. The PMO evaluates the availability of sufficient equipment to: meet customer demand; minimize planned customer outages; and reduce most, if not eliminate, unplanned customer outages.
Budget and Spending

8. Factors Impacting Cost Effectiveness

Describe any factors, either internal or external, that may have prevented or affected PG&E from conducting the work in a more cost effective manner. Quantify the cost impact of such factors.

Response

PG&E summarizes primary cost drivers associated with Strength Testing, Pipe Replacement and In-Line Inspection programs that have in many cases resulted in significantly higher actual costs than the amounts adopted in D.16-06-056. As part of ongoing project management activities, PG&E’s transmission pipeline programs have consistently identified project uncertainties and implemented risk mitigation activities. Despite these efforts, PG&E has not been able to fully mitigate the potential impact of cost uncertainties. Table 8-1, below, summarizes the cost variances associated with each program, followed by programmatic variance explanations.
## TABLE 8-1
UNITS AND COSTS BY PROGRAM
(DOLLARS SHOWN IN THOUSANDS)

<table>
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<tbody>
<tr>
<td>1</td>
<td>In-Line Tool Upgrades (capital)</td>
<td>6BC, 6OA</td>
<td>61 miles</td>
<td>187 miles</td>
<td>N/A</td>
<td>$85,238</td>
<td>$67,476</td>
<td>$136,711</td>
<td>186 miles</td>
<td>$237,561</td>
<td>N/A</td>
<td>$1,108,870</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2</td>
<td>In-Line Inspections (exempted)</td>
<td>N/A</td>
<td>365 miles</td>
<td>254 miles</td>
<td>N/A</td>
<td>$16,212</td>
<td>$15,158</td>
<td>$34,349</td>
<td>377 miles</td>
<td>$14,518</td>
<td>N/A</td>
<td>$1,108,870</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>3</td>
<td>ILU Repair &amp; Replacement</td>
<td>HRI</td>
<td>77 digs</td>
<td>77 digs</td>
<td>N/A</td>
<td>$13,310</td>
<td>$10,126</td>
<td>$30,506</td>
<td>124 digs</td>
<td>$3,153</td>
<td>N/A</td>
<td>$31,820</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>4</td>
<td>Pipeline Replacement (capital)</td>
<td>TSE, TSH, TM, TNO</td>
<td>24 miles</td>
<td>24 miles</td>
<td>N/A</td>
<td>$177,962</td>
<td>$106,841</td>
<td>$31,503</td>
<td>13 miles</td>
<td>$209,318</td>
<td>N/A</td>
<td>$103,180</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>6</td>
<td>Strength Testing (exempted)</td>
<td>MPF, JTC (30A)</td>
<td>170 miles</td>
<td>170 miles</td>
<td>$643/mile</td>
<td>$1,428,800</td>
<td>$1,428,800</td>
<td>$1,428,800</td>
<td>$1,428,800</td>
<td>$201,130</td>
<td>$1,428,800</td>
<td>$1,428,800</td>
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<td>$1,428,800</td>
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1. D-14-KH-009 (OF 2) requires PG&E to conduct hydrostatic testing for 170 miles of transmission pipe per year. Table 8-1 presents the adopted unit cost of $643/mile per mile for hydrotesting, and then multiplies that adopted unit cost by 170 miles to derive an annual "total adopted program cost" of $175,609 million. This derived number differs from the actual hydrotesting costs adopted by the Commission and presented in Requirement 8, which excludes any costs to test previously untested pipe (1050 pipe ($105.2 million) and 1027.8 million dollars for 2015 and 2016, respectively).

2. There were no adopted unit costs for the ILU upgrade program in the Decision. For ILU upgrades cannot have unit costs as each project has a uniquely engineered scope. For example, a single project can have several valves replaced or no valves replaced, along with the addition of a branch line and reverse to make the line piggable. Therefore, an upgrade project could be 1 mile or 10 miles and still be the same cost.

For the Vintage Pipe program, no adopted unit costs are provided at the program level as the Decision provided for three groupings of unit costs based on pipe diameter.

For ILU Direct Exam and Repair, the unit cost was based on an average cost per dig taking into account whether the dig location was rural, urban, or a combination of the two. Therefore, a singular unit cost per dig does not apply.

3. Adopted amounts include MAT 44A for Vintage Pipe: Class Location and Shallow Pipe.

4. Adopted amount January 2016 through September 2016 reflects costs provided to include three quarters of the year.

5. Column (i) is the sum of Column (a) plus Column (h). Column (j) reflects the costs for the current compliance reporting period.

6. Rate Case Uhra only shows miles for Traditional In-Line Inspections. The rates used for Non-Traditional ILU and IL of Casing was based on number of projects and not miles. The numbers of projects for Non-Traditional ILU increased in MPF from 6 projects in 2015 and 15 projects in 2016. Respectively, IL of Casing (included in MPF) has 4 projects each in 2015 and 2016. Costs for MPF are not included in the actual costs which totals to $1,428,800 during the reporting period.

7. Unit Cost was derived from recorded costs referenced in Table 29-1 (see Balancing Account and Base Expense (Without Burdened) values in Column (c)) and completed units in column J of Table 8-1. Unit Cost is represented in rear cost model.
Strength Testing Variances

PG&E’s strength testing during 2015 and 2016 has focused on addressing:

- Meeting compliance deadlines to address integrity threats identified by PG&E’s Integrity Management assessment procedures; and
- Untested pipeline segments in High Consequence Areas (HCA) included within the National Transportation Safety Board’s (NTSB) recommendation to PG&E.

These “IM-flagged” and NTSB8 pipeline segments are significantly shorter in length on average than in prior years and primarily located in densely-populated urban areas. Since much of the cost of a strength test is a fixed cost, the unit cost is significantly impacted by the test length, and somewhat affected by test location. PG&E currently plans to complete a series of longer tests in 2017 and 2018, incorporating “IM-flagged” and NTSB pipeline segments where practical. This approach has the effect of increasing the number of miles of pipe tested and reducing the overall test cost-per-mile. This approach is taken to target achievement of the 680 miles mandated in the Decision. The long line testing is in-line with PG&E’s risk approach as it balances the need to target short segments of “NTSB” mileage while eliminating greater amount of risk to the system (complying with the CPUC directive to have a valid test record for all untested pipe) by testing long sections of untested pipe and in the most cost effective manner. This approach will minimally lengthen the amount of time it will take to complete testing of the shorter and higher unit cost “NTSB” pipeline segments.

Vintage Pipe Replacement Variances

The timing of D.16-06-056 and uncertainty regarding approved funding prompted PG&E to reduce the amount of budget allocated to the vintage pipe replacement construction in 2015 and 2016. Project approval during the reporting period remained consistent with risk-based prioritization procedures outlined in response to Requirement 1. The reduced spend was also caused by project delays on three pipe replacement projects on Line 105N and Line 105C due to increased permitting durations, and the delay of four lower risk pipeline retirement

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8 HCA and Class 3 and 4, non-HCA pipe that does not have a traceable, verifiable, and complete record of a strength test.
projects on Line 107. Since the issuance of D.16-06-056, PG&E is working on constructing several complex and high-cost vintage pipe replacement projects in urban areas in 2017 and 2018.

During the reporting period PG&E’s Pipe Replacement team has identified factors that have prevented completing work in a more cost effective manner, including:

1) Unidentified Pipeline Conditions:
   Factors such as additional engineering and construction activities, including the repair and replacement of pipe, valves and fittings due to condition, construction obstructions, and re-engineering due to previously unidentified non-PG&E structures or other utilities (i.e., increased construction duration and costs) on projects R-824, R-309A, R-503, and R-332 in urban environments.

2) Geographical Field Conditions:
   Factors such as: high water table, trench dewatering costs, poor or weak soil, restrictive permitting conditions, site specific contamination, and restrictive waste disposal requirements. For example, pipe replacement project R-503, on Line 50A in Gridley, incurred additional unanticipated costs totaling $12.8 million to address groundwater that included the pumping, handling and disposal of approximately 55 million gallons of groundwater.
   In addition increased costs associated with construction in dense urban environments, including additional traffic control, restrictive working space, poor soil and handling of contaminated soil (i.e., increased construction durations and costs) on projects R-503, R-824, and R-309A.

3) Permitting:
   Factors such as increased permitting conditions and restricted work hours to avoid road/lane closures during heavy commute hours (i.e., compacted construction schedules) on project R-309A.

4) Schedule Constraints:
   Management of construction schedules to meet schedule commitments (e.g., internal integrity management compliance dates for the remediation of pipeline anomalies identified through ILI, with associated increased construction and land acquisition costs on projects R-503, R-599A, R-009, and R-824).
5) Gas System Operational Constraints:

Schedule changes driven from operational constraints on PG&E’s gas system which delayed and extended clearance activities on project R-332.

**ILI Upgrade Variances**

During the reporting period PG&E has experienced significantly higher-than-planned costs associated with ILI Upgrade. Cost drivers have included:

- Increased land acquisition purchase prices and Temporary Construction Easement (TCE) fees due to limited location alternatives and accelerated project timelines on projects I-043, I-048B, and I-049A.
- Changes in construction schedules, including acceleration to meet planned inspection timelines on project I-043E and delays to resolve permitting issues with local permitting agencies and hydraulic constraints on Peninsula pipelines on project I-048B.
- Higher-than-planned costs of pipeline excavation and re-configuration to avoid underground utilities and structures on projects I-041G, and I-056F, and additional shoring due to weak soils on project I-129A.
- Higher-than-planned costs associated with ground water management on projects I-048B, I-44A, and I-044C; and
- Higher-than-planned costs of pipeline re-configuration requirements due to lower navigation tolerances of newer inspection tools on project I-056F.

**ILI Variances**

During the reporting period the ILI Inspections have incurred higher-than-planned costs associated with inspection tools becoming lodged in the pipeline during inspection runs, requiring removal via cut-out. These cut-out operations require separate mobilizations and replacement of pipeline features that impede the passage of the ILI tool. Over the course of this reporting period, PG&E has seen a higher number of cut-out operations than in previous years due to the number of inspections using newer multi-diameter tools. PG&E is currently evaluating the effect of potential cut-outs on future forecasting of first time inspections.

In addition, to meet Integrity Management program compliance deadlines, the ILI Inspection Program has undertaken a series of non-traditional ILI inspections of creek crossings and freeway crossings that have significantly-increased costs.
Non-traditional ILI is nearly three times more costly than a traditional ILI and inspections on a per-mile basis.

**ILI Direct Exam and Repair Variances**

During the reporting period, ILI Direct Exam and Repair ("Digs") unit costs have been higher than expected due to the following factors:

- Challenges in acquiring the necessary field data on a timely basis to facilitate repair decisions;
- Additional assessment and analysis determined necessary to complete repair decisions consistent with PG&E’s Repair Standard;
- Local permits requiring the use of non-native backfill for wet spoils (e.g., when using hydro-excavation as opposed to mechanical excavation);
- Increased incidence of welded sleeve repair decisions, in preference to “flat-top” welds to achieve proper sleeve fit-up. Instead, clearances are being implemented to reduce line pressure to zero psig prior to flat-topping of welds; and
- Increased incidence of repair decisions requiring the removal of benign linear indications and minor tooling marks upon application of judgment within PG&E’s Repair Standard.
9. **Procurement Policy and Practices**

Describe PG&E’s procurement policy and practices for pipe and other materials used for projects. Was a competitive bidding process used? If not, explain why. Describe what factors PG&E considers in procuring material ranked by importance. Identify the manufacturer(s) or suppliers of the pipe used for the replacement projects and for any material that cost more than $100,000 per item.

**Response**

PG&E procures relevant materials as specified for Strength Testing, Pipe Replacement, and ILI, including pipes, valves, fittings, and repair materials, such as steel and composite sleeves. PG&E uses Power Advocate software to conduct Request for Proposals (RFP), which aids PG&E to make supplier selections in a consistent manner. The supplier can also use Power Advocate to respond to RFPs and upload documents.

The selection qualification is a multi-disciplinary team effort, and it includes input from internal key stakeholders including Gas Operations.

Factors considered in procuring materials, ranked by level of importance, are:

1) **Technical:**
   - PG&E mandates that technical requirements as prescribed by Gas Operations, codes and standards must be met.

2) **Quality:**
   - PG&E mandates that quality requirements as prescribed by the LOB codes and standards must be met. The Supplier Quality Team evaluates and scores this requirement. The scoring and evaluation process may include audits and application of the PG&E Product Qualification Process.

3) **Safety:**
   - PG&E’s Contractor Safety Team evaluates and scores outside supplier safety qualifications.

4) **Commercial/Pricing:**
   - PG&E attempts to procure an item at the best pricing option.

5) **Credit Risk:**
   - PG&E evaluates the prospective supplier’s financial stability for RFPs that will exceed $20 million prior to beginning the bidding process. Should PG&E determine the supplier to be credit worthy, PG&E engages the supplier in the bidding process.
18. Potential Enhancements to Phase 2 Planning and Budgeting

How will the work PG&E conducts in Phase 1 influence how PG&E will plan and estimate the costs of its proposed projects for Phase 2?

Response

This requirement is specific to PG&E’s PSEP proceeding (D.12-12-030) and is not applicable to the GT&S Rate Case.
19. Cost Impacts of Unexpected or Unforeseen Items

What, if any, significant unexpected or unforeseen items did PG&E encounter in undertaking the projects and what were the resulting cost impacts on a project-by-project basis?

Response

Unlike PSEP, PG&E did not forecast specific projects in the GT&S rate case. Rather, it forecast costs for Strength Tests, Pipe Replacement, and ILI on a programmatic-basis, using various forecast methodologies. For purposes of responding to this directive, PG&E used projects for which the original job estimates are greater than $10 million where it has fully documented risk information and the ability to cross reference the base line information. PG&E has summarized primary cost drivers associated with these projects that have, in these cases, resulted in significantly-higher total actual-project costs, than the budgeted amount. Therefore, the analysis of these projects revealed the most significant unexpected or unforeseen items encountered in the reporting period.

Table 19-1 in the Appendix provides:

- PG&E’s most recent project-level analysis for the most impactful of unexpected or unforeseen items that have affected the projects completed in 2015-2016 YTD with over 10 percent cost variance and the resulting cost impacts;¹² and
- An identification of ways in which PG&E is addressing these risks on an ongoing-basis by incorporating the lessons learned into project delivery processes.

Project selection criteria:

1) Projects were mobilized between January 1, 2015 and September 30, 2016, and the original Job Estimate was over $10 million;

2) Projects that have cost variances equal to or greater than 10 percent of original Job Estimate; cost variance is derived from total cost since the inception of the order, which may include costs prior to reporting period, to the completion of the project; and

3) A detailed explanation of why the overrun occurred.

¹² Impacts are determined using the information in the Change Orders issued after completion of Job Estimate.
The cost variances of these projects were primarily driven by materialized risks during project execution.

For projects completed in 2015-2016 YTD, PG&E identified that “Scope Change after Issue for Bid (IFB),”13 “Unsuitable Soil Conditions,”14 and “High Volume Surface/Groundwater”15 caused the greatest cost increases. The total impact of these risks represented significant cost variances to the original budgeted amount of the project. These risks are discussed further below.

• Scope Change After IFB:
  – This risk has significant impacts to both cost and schedule of projects in pipe replacement and test. It has several contributing factors, including additional scope and engineering modifications identified after the completion of construction drawings, which were issued for bid; and estimate corrections. The most common resultant changes were additional replacement, excavation, sniff holes, bell holes and/or welding. The changes were generally requested by counties, cities, or other agencies, such as CalTrans or other utilities. Another significant cost driver that changed the work plan after estimating is when a city or county requires project work hours in street locations to begin at 9 a.m. and end by 3 p.m. to avoid creating traffic problems. By the time traffic control is set up or taken down, there may only be four to five productive work hours, potentially doubling the length and cost of a project.

• Unsuitable Soil Conditions
  – Impacts related to this risk affected projects in pipe replacement. Both cost and schedule implications were realized on impacted projects. Unanticipated unstable soils required additional backfill, shoring or other measures; while unanticipated rock could impact productivity of trenching, boring or drilling.

13 Addition of project scope including, but not limited to replacement/test length or valve quantities, after approval of the Job Estimate.
14 Unsuitable soil may require additional shoring or other measures.
15 Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g., limited working hours, limited access, delays in issuance, etc.) may be experienced resulting in schedule and/or cost impacts.
• High-Volume Surface/Groundwater
  – This risk has several contributing factors, including a higher volume of groundwater encountered during construction and unplanned water management costs (e.g., permit changes, more tanks, trucking, treatment, disposal, TCEs). Impacts related to this risk affected some Pipeline Replacement projects, which resulted in cost and schedule impacts.

**TABLE 19-2**  
**DESCRIPTION OF TABLE 19-1 COLUMN REFERENCE**

<table>
<thead>
<tr>
<th>Column Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line #</td>
<td>Reference number for this report.</td>
</tr>
<tr>
<td>Order Number</td>
<td>Financial system of record reference number to track specific costs, e.g., on individual projects and provided in workpapers supporting PG&amp;E Gas Transmission Application for projects commonly resulting from project split or addition.</td>
</tr>
<tr>
<td>Project Description</td>
<td>Order Description for strength test, pipe replacement, ILI, and upgrades for ILI.</td>
</tr>
<tr>
<td>Region</td>
<td>Region where line is located.</td>
</tr>
<tr>
<td>Risk</td>
<td>Categorization of risk factor affecting the project.</td>
</tr>
<tr>
<td>Description</td>
<td>Description of risk factor.</td>
</tr>
<tr>
<td>Cost Impact ($)</td>
<td>Impact of risk to project cost.</td>
</tr>
<tr>
<td>Comments</td>
<td>Description of how risk factor materialized.</td>
</tr>
</tbody>
</table>
20. **Program Amount Authorized and Spent**

   *Provide a table showing the total amount authorized for recovery from ratepayers and the total amount spent by PG&E year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).*

**Response**

Table 20-1 included in the Appendix depicts the total amount of spend by PG&E in 2015 and 2016 YTD by month, as well as the corresponding annual (2015 and 2016) adopted/imputed program amount for the following programs: Strength Test Program (including both the portions in base expense and Transmission Integrity Management Program (TIMP) expense balancing account); TIMP capital balancing account; ILI portion of the TIMP expense balancing account; and the programs associated with pipe replacement.

As mentioned in the Introduction, PG&E changed its method for allocating overhead costs. Starting in 2016, expense spend receives certain overheads, while capital and balancing account spend receive all overheads. Refer to Figure 29-2 for additional information. In response to Requirement 20, in Table 20-1, for base expense spend—which refers to spending outside of the Transmission Integrity Management Program Balancing Account (TIMPBA)—PG&E provides both the current overhead view used for internal reporting purposes, as well as base expense costs as if they had been fully-burdened, to allow for a direct comparison to the capital and balancing account spend and the adopted/imputed program amount shown in Requirement 20.
21. Shareholder Costs Absorbed

Provide a table showing the total amount of costs that shareholders will absorb year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).

Response

Table 21-1 included in the Appendix depicts the total amount of spend by PG&E in 2015 and 2016 YTD by month, annual (2015-2018) adopted/imputed program amount, and shareholder funded costs for the Strength Test program (including both the portions in base expense and TIMP expense balancing account), TIMP capital balancing account, ILI portion of the TIMP expense balancing account; and the pipe replacement programs with shareholder-funded spend.

In response to Requirement 21, in Table 21-1, for base expense spend—which refers to spending outside of the TIMP Balancing Account—PG&E provides both the certain overhead view used for internal reporting purposes, as well as base expense costs as if they had been fully burdened, to allow for a direct comparison to the capital and balancing account spend and the adopted/imputed program amount shown in Requirement 21.

With respect to the dollars funded by shareholders, PG&E expects a significant portion, if not all, of the spending on Strength Test, Pipe Replacement, and ILI programs to be included as safety-related spending for purposes of calculating the $850 million penalty adopted in the San Bruno penalty decision. Table 21-1 will be adjusted pending the results of the Phase II decision.
22. Forecast vs. Actual Mileage – Replacements

Provide a table showing the total mileage of pipe PG&E forecast to replace in R.11-02-019 and the mileage PG&E has replaced year-to-date. Identify the location, Line #, milepost, Class of the pipe replaced. Indicate whether the pipe is located in a High Consequence Area.

Response

For the current reporting period, PG&E has replaced approximately 13.09 miles of gas transmission pipeline. Table 22-1 below provides the total pipeline miles associated with vintage pipe, class location, shallow pipe, and other pipeline safety investment. Table 22-2 included in the Appendix provides total mileage of pipe PG&E has replaced for the reporting period, identifying the location, Line number, milepost, class of the pipe replaced, and whether the pipe is located in a HCA.

### TABLE 22-1
TOTAL PIPELINE MILES REPLACED – ADOPTED AND ACTUAL MILEAGE
JANUARY 1, 2015 – SEPTEMBER 30, 2016

<table>
<thead>
<tr>
<th>Pipe Replacement</th>
<th>2015</th>
<th>2016</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vintage Pipe</td>
<td>20.0</td>
<td>20.0</td>
<td>40.0</td>
</tr>
<tr>
<td>Class Location</td>
<td>1.97</td>
<td>1.97</td>
<td>3.94</td>
</tr>
<tr>
<td>Shallow/Exposed Pipe</td>
<td>2.50</td>
<td>2.50</td>
<td>5.00</td>
</tr>
<tr>
<td>Other Pipeline Safety Investment</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total Adopted:</strong></td>
<td><strong>24.47</strong></td>
<td><strong>24.47</strong></td>
<td><strong>48.94</strong></td>
</tr>
<tr>
<td>Actual Miles</td>
<td>4.71</td>
<td>8.38</td>
<td>13.09</td>
</tr>
<tr>
<td>Column Name</td>
<td>Description</td>
<td></td>
<td></td>
</tr>
<tr>
<td>----------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line #</td>
<td>Reference number for this report.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Order Number</td>
<td>Financial system of record reference number to track specific costs, e.g., on individual projects and provided in workpapers supporting PG&amp;E Gas Transmission Application for projects commonly resulting from project split or addition.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Description</td>
<td>Order Description for ILI, upgrades for Strength Test, Pipe Replacement, and ILI, for Pipe Replacement and Strength Testing.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MAT</td>
<td>Maintenance Activity Type (MAT) represents a complete, distinct, sub-process of major work category. MATs are designated by three-character alphanumeric codes. The first two digits of the MAT are the MWC. A MAT can only be assigned to one MWC.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Miles Completed</td>
<td>Miles of pipeline replaced.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line</td>
<td>Pipeline identifier.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MP1</td>
<td>Beginning project mile point.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>MP2</td>
<td>Ending project mile point.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>City</td>
<td>Location of project.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>HCA</td>
<td>Project includes a High Consequence Area.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Class Code</td>
<td>Class of pipeline included in project.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tie-In Date</td>
<td>For ILI and pipeline testing and replacement projects, the tie-in date is the date the pipe became operational and the project was completed.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION PIPELINE
COMPLIANCE REPORT

NO. 2016-02

REPORTING PERIOD
OCTOBER 1, 2016 – DECEMBER 31, 2016

IN COMPLIANCE WITH CPUC DECISION 16-06-056

SUBMITTED JANUARY 30, 2017
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Introduction

On July 1, 2016, the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 16-06-056 in Pacific Gas and Electric Company’s (PG&E or the Company) 2015 Gas Transmission and Storage (GT&S) rate case (Application (A.) 13-12-012). Ordering Paragraph (OP) 11 of the decision directs PG&E to serve quarterly compliance reports of PG&E’s transmission pipeline work, including Strength Testing,1 Pipe Replacement, and In-Line Inspection (ILI). OP 11 of D.16-06-056 requires that:

Pacific Gas and Electric Company shall file a quarterly compliance report of its transmission pipeline work, including pressure test, pipe replacement, and ILI. The report shall generally follow the format in Attachment D of Decision 12-12-030 and shall include all costs recorded to these programs, such that they provide an accurate and complete record of all costs at the project and program level. Consistent with the joint stipulation on Reporting and Communications between PG&E and the Office of Ratepayer Advocates, the format and content of the report may be revised by a working group to ensure that the report is useful to parties. PG&E’s first compliance filing shall cover the period between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter. The report shall be served on the Commission’s Safety and Enforcement Division, Energy Division, and on the service list of this proceeding.

This Transmission Pipeline Compliance Report (Report) No. 2016-02 is submitted in compliance with the directive set forth in OP 11 and reflects the reporting period of October 1, 2016 to December 31, 2016. The Report is being served on the Commission’s Safety and Enforcement Division, Energy Division and the service list of the 2015 GT&S rate case proceeding (A.13-12-012).

Report Format

The report requirements set forth in Attachment D of the Pipeline Safety Enhancement Plan (PSEP) decision were framed to address specific issues relevant to the PSEP proceeding, which, in several ways, differ from the 2015 GT&S rate case proceeding.

1 “Strength test” is also referred to as the Hydrotest Program.
This Transmission Pipeline Compliance Report is organized to address each of the applicable requirements outlined in Attachment D of D.12-12-030 regarding the transmission pipeline programs: Strength Testing, Pipe Replacement, and ILL. This Report includes all costs recorded to programmatic Maintenance Activity Types (MAT) associated with the required transmission pipeline programs.

As described in Transmission Pipeline Compliance Report No. 2016-01, PG&E has implemented a new cost model. This Report and future reports will present all costs (adopted/imputed and recorded) using PG&E’s new cost model. For the reporting period of October 1, 2016 through December 31, 2016, Table 1 provides a summary of the recorded costs incurred.

### TABLE 1
ADOPTED 2016 GT&S EXPENSE AND CAPITAL COMPARED TO RECORDED COSTS BY PROGRAM
OCTOBER 1, 2016 – DECEMBER 31, 2016
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Programs</th>
<th>2016 Adopted / Imputed</th>
<th>Recorded Oct-Dec 2016</th>
<th>Recorded 2016 YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Strength Testing</td>
<td>$ 89,110</td>
<td>$ 23,823</td>
<td>$ 132,896</td>
</tr>
<tr>
<td>In-Line Inspection</td>
<td>$ 32,099</td>
<td>$ 33,479</td>
<td>$ 99,952</td>
</tr>
<tr>
<td>Pipeline Replacement</td>
<td>$ -</td>
<td>$ 118</td>
<td>$ 237</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 121,209</td>
<td>$ 57,421</td>
<td>$ 233,085</td>
</tr>
<tr>
<td><strong>Capital</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>In-Line Inspection</td>
<td>$ 91,561</td>
<td>$ 29,971</td>
<td>$ 139,163</td>
</tr>
<tr>
<td>Pipeline Replacement</td>
<td>$ 177,105</td>
<td>$ 28,658</td>
<td>$ 119,691</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 268,666</td>
<td>$ 58,629</td>
<td>$ 258,854</td>
</tr>
</tbody>
</table>

(a) 2016 adopted funding has been imputed by PG&E, consistent with the adopted Post Test-Year increase specified in D.16-12-010, Appendix E and Appendix I.

---

2 For a detailed explanation of the cost model change, refer to the response to Requirement 29 of the Transmission Pipeline Compliance Report No. 2016-01.

3 All 2016 recorded costs in this Report are current as of January 9, 2017. There is a potential for additional adjustments that could impact the final costs related to the three transmission pipeline programs. If any adjustments materially change the reported costs, PG&E will provide an update in the 2017-01 report.
Decision-Making Process

1. Project Planning and Prioritization of Work

   Describe PG&E’s project planning process including how the projects were and are being scheduled and sequenced and what measures were and are being taken to conduct the work in a cost effective manner.

Response

   Gas Operations completes its multi-year planning by following PG&E’s Integrated Planning process. PG&E’s Integrated Planning process and project planning and scheduling remain consistent with the descriptions previously provided in PG&E’s Gas Transmission Pipeline Compliance Report 2016-01.^4^ When determining the final forecasts for each program or project in the portfolio during the annual Integrated Planning process, consideration is given to risk as well as classification of work, system constraints, work readiness, and financial constraints.

Project Planning and Scheduling

   PG&E’s Strength Testing, Pipe Replacement, and ILI Upgrade schedules in the fourth quarter of 2016 reflect a planned seasonal reduction in work to minimize the operational impact of executing work that requires system clearances during the winter period (fourth quarter). Work is typically planned to be completed prior to the winter period in order to reduce weather-related construction risk, and the potential impact of the uncertain availability of clearances as colder weather increases heating-driven demand. In the fourth quarter of 2016:

   - PG&E successfully completed an increased number of ILI Inspections, and ILI Direct Exam and Repair projects compared to prior quarters in 2016.
   - Consistent with PG&E’s work execution model, each program successfully aligned project schedules to execute concurrent construction activities.

Planning activities focus on the identification of opportunities to align work across the programs. These include both sequencing work schedules in geographic areas and concurrent construction of co-located work.

---

^4^ See Appendix A – Requirement 1: Integrated Planning Process, for the process outlined in the 2016-01 report.
The activities to schedule and sequence projects described above directly support the conduct of work in a cost effective manner. In addition, PG&E undertakes a range of other activities that support the completion of work in a cost effective manner including:

- Construction management and inspection oversight of construction activities that monitor and ensure work quality;
- Early constructability input from internal and external construction resources;
- Development and maintenance of a standardized project delivery methodology with associated controls and governance oversight; and
- Bulk materials procurement, management of long-lead materials orders, and supplier quality oversight.
Resource Procurement and Oversight

2. Resource Planning

Explain how PG&E decided whether to do the work in-house (e.g., use own employees and equipment) or contract the work out to other parties.

Response

PG&E’s resource planning process remains consistent with the description previously provided in the Gas Transmission Pipeline Compliance Report No. 2016-01 to complete gas transmission work on a timely basis.\(^5\) During this reporting period, PG&E made the decision to allocate 5 of 18 bundles\(^6\) of 2017 construction projects to internal Gas Transmission General Construction resources based upon an assessment of the bundle’s schedule uncertainty and the magnitude of the required construction resources. This will result in PG&E contracting the remaining 13 bundles to external resources.

---

5 Refer to Appendix B – Requirement 2: Resource Planning Process for a description of the resource planning process provided in Requirement 2 of the 2016-01 report.

6 PG&E “bundles” construction to align projects that would otherwise be executed separately. The objective is to maximize the use of limited resources and improve overall success of the project.
In addition to being used by field crews for construction management activities, Unifier is now also used by engineering teams to approve and resolve issues for construction drawings and obtain project authorizations. In 2016, Unifier was expanded to include Project Delivery System (PDS) Cost Controls to its capabilities. PDS Project Cost Controls include Advanced Authorization, Project Authorization, and Contingency Release and Reauthorizations. It also sets preventative controls around potential change orders and does not allow the project to exceed the Job Estimate amount without proper approvals.
Factors Impacting Cost Effectiveness

Describe any factors, either internal or external, that may have prevented or affected PG&E from conducting the work in a more cost effective manner. Quantify the cost impact of such factors.

Response

As part of ongoing project management activities, PG&E’s transmission pipeline programs have consistently identified project uncertainties and implemented risk mitigation activities. Despite these efforts, PG&E has not been able to fully mitigate the potential impact of cost uncertainties. Primary cost drivers that impacted the cost efficiency of work associated with Strength Testing, Pipe Replacement and In-Line Inspection programs are listed in the tables below. While not an exhaustive list, in many cases, these cost drivers resulted in significantly higher actual costs than the amounts adopted in D.16-06-056 and D.16-12-010. Table 8-1, below, summarizes the cost variances associated with each program, followed by Table 8-2 through Table 8-5, listing certain primary cost drivers for work completed during the reporting period, along with available variance explanations at the program level.
**TABLE 8-1**

**UNITS AND COSTS BY PROGRAM**

(DOLLARS SHOWN IN THOUSANDS)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>In-Line Tool Upgrades</td>
<td>98C, 44A</td>
<td>187 miles</td>
<td>N/A</td>
<td>$91,561</td>
<td>22.9 miles</td>
<td>107.2 miles</td>
<td>$ 29,970.59</td>
<td>$ 139,162.58</td>
<td>N/A</td>
<td>[g]</td>
<td>$47,802</td>
</tr>
<tr>
<td>2</td>
<td>In-Line Inspections</td>
<td>HPB</td>
<td>254 miles</td>
<td>N/A</td>
<td>$21,994</td>
<td>124.97 miles</td>
<td>259.5</td>
<td>$ 16,074.86</td>
<td>$ 50,749.29</td>
<td>N/A</td>
<td>[g]</td>
<td>$28,755</td>
</tr>
<tr>
<td>3</td>
<td>ILI Direct Exam &amp; Repair</td>
<td>HPI</td>
<td>77 digs</td>
<td>N/A</td>
<td>$10,105</td>
<td>36 digs</td>
<td>160 digs</td>
<td>$ 17,404.64</td>
<td>$ 49,202.27</td>
<td>N/A</td>
<td>[g]</td>
<td>$39,097</td>
</tr>
<tr>
<td>4</td>
<td>Pipeline Replacement</td>
<td>75E, 75H, 75M, 75O, 75T, J6</td>
<td>24 miles</td>
<td>N/A</td>
<td>$177,105</td>
<td>1.45 miles</td>
<td>9.48 miles</td>
<td>$ 28,658.05</td>
<td>$ 119,691.10</td>
<td>N/A</td>
<td>[g]</td>
<td>($57,414)</td>
</tr>
<tr>
<td>5</td>
<td>Strength Testing (expense)</td>
<td>HPF / JFC/ 34A</td>
<td>170 miles</td>
<td>$840/k/mile</td>
<td>$89,110</td>
<td>27.13 miles</td>
<td>88.64 miles</td>
<td>$ 23,823.36</td>
<td>$ 132,895.98</td>
<td>$1,499,285/k/m</td>
<td>[4]</td>
<td>$43,786</td>
</tr>
</tbody>
</table>

---

### Notes:

1. There were no adopted unit costs for the ILI Upgrade program in 2016.
2. Adopted amounts include MAT 44A (StanPac) for Vintage Pipe, Class Location and Shallow Pipe.
3. Rate Case Units only show miles for Traditional In-Line Inspections. The rate case for Non-Traditional ILI and ILI of Casings was based on number of projects and not miles. In 2016, there were 15 projects for Non-Traditional ILI (included in MAT HPB) and 4 projects for ILI Casings (included in MAT HPG). Recorded costs for MAT HPG ($315,000 during Q4 2016) are not included in the Table 8-1 above.
4. Unit Costs were derived from recorded costs referenced in Table 20-1 (see Balancing Account and Base Expense values in Column 2016 YTD) and completed units in column G of Table 8-1.
5. All costs presented using PG&E’s new cost allocation methodology.
6. 2016 adopted funding has been imputed by PG&E, consistent with the adopted Post Test-Year Increase specified in D. 16-12-010, Appendix E and Appendix I.

---

The table above provides a breakdown of units and costs by program, with columns for adoption/imbution amount, units completed, and recorded costs. Each entry is detailed with specific metrics such as MAT codes, units, and costs, along with variances to total and unit costs.
Strength Testing Cost Variances

PG&E's strength testing during the fourth quarter of 2016 focused on addressing:

- Meeting compliance deadlines to address integrity threats identified by PG&E’s Integrity Management (IM) assessment procedures (“IM-flagged”); and
- Untested pipeline segments in High Consequence Areas (HCA) included within the National Transportation Safety Board's (NTSB) recommendation to PG&E.

These “IM-flagged” and NTSB\textsuperscript{14} pipeline segments are significantly shorter in length on average than segments strength tested in prior years and are primarily located in densely-populated urban areas. Since much of the cost of a strength test is a fixed cost, the unit cost is significantly impacted by the test length, and somewhat affected by test location. PG&E currently plans to complete a series of longer tests in 2017 and 2018, incorporating “IM-flagged” and NTSB pipeline segments where practical. This approach will have the effect of increasing the number of miles of pipe tested and reducing the overall test cost-per-mile. This approach will be undertaken to target achievement of the 680 strength test miles mandated in D.16-06-056. The long-line testing is in-line with PG&E's risk-based decision-making approach. PG&E is balancing the need to target numerous short segments of “NTSB” mileage with the overall goal of reducing risk to the transmission pipeline system (complying with the Commission's directive to have a valid test record for all untested pipe) by testing long sections of untested pipe in the most cost-effective manner. This approach results in a longer timeframe for completing testing of the shorter and higher unit cost “NTSB” pipeline segments.

Table 8-2 provides detail regarding certain projects in this reporting period where strength test unit costs in the period have been higher than expected:

\textsuperscript{14} HCA and Class 3 and 4, non-HCA pipe that does not have a traceable, verifiable, and complete record of a strength test.
TABLE 8-2  
COST IMPACTS TO SELECT STRENGTH TEST PROJECTS

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>T-1052</td>
<td></td>
<td></td>
</tr>
<tr>
<td>T-1141C</td>
<td>$766K $3.3M</td>
<td>Urban construction requires:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1) Additional traffic control measures and night work to minimize impact of lane closures.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2) Additional shoring and engineered designs.</td>
</tr>
<tr>
<td>T-1141C</td>
<td>$530K</td>
<td>1) Large pipeline diameter.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2) Increased water management costs.</td>
</tr>
<tr>
<td>T-1026C</td>
<td></td>
<td></td>
</tr>
<tr>
<td>T-1196</td>
<td>$840K $2.4M</td>
<td>Additional scope identified in field, such as:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1) ILI anomaly validation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2) Casing removal.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3) Valve replacement</td>
</tr>
<tr>
<td></td>
<td></td>
<td>4) Pipeline configuration to complete testing.</td>
</tr>
<tr>
<td>T-1196</td>
<td>$225K</td>
<td>Multiple clearances and tie-in activities required to meet timing of large agricultural customer demand.</td>
</tr>
<tr>
<td>T-1125</td>
<td>$70K</td>
<td>CNG support and associated staging costs.</td>
</tr>
</tbody>
</table>

**Vintage Pipe Replacement Cost Variances**

During the reporting period, projects were approved in alignment with risk-based prioritization procedures outlined in response to Requirement 1. The reduced spend was also caused by project delays on three pipe replacement projects on Line 105N and Line 105C due to increased permitting durations, and the delay of four lower risk pipeline retirement projects on Line 107. Since the issuance of D.16-06-056, PG&E has been continuing to work on constructing several complex and high-cost vintage pipe replacement projects in urban areas planned for 2017 and 2018.

Table 8-3 provides detail regarding select projects where certain primary cost drivers relating to vintage pipe replacement have prevented completing work in a more cost effective manner during the current reporting period:
TABLE 8-3
COST IMPACTS TO SELECT VINTAGE PIPE REPLACEMENT PROJECTS

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>R-008B</td>
<td>$200K</td>
<td>Schedule Constraints: a) Increased costs associated with changing construction plans to meet safety commitments e.g., integrity management compliance dates for the remediation of pipeline anomalies identified through ILI or gas leak detection; and b) Increased costs associated with external agencies’ requirements to construct project in two separate phases e.g., multiple mobilization, demobilization and site restoration activities.</td>
</tr>
<tr>
<td>RT-879</td>
<td>$26K</td>
<td></td>
</tr>
<tr>
<td>R-349B</td>
<td>$260K</td>
<td></td>
</tr>
<tr>
<td>R-824</td>
<td>$200K</td>
<td>Geographical Field Conditions: Uncertainty in estimating soil handling, water haulage, and disposal costs in urban environment.</td>
</tr>
<tr>
<td>R-008B</td>
<td>$200K</td>
<td>Permitting and Land Rights: Factors such as increased agricultural labor rates and market rates for agricultural produce increased costs to acquire temporary construction easements in agricultural areas.</td>
</tr>
<tr>
<td>R 303</td>
<td>$300K</td>
<td>Gas System Operational Constraints: Schedule changes driven from operational constraints on PG&amp;E’s gas system which delayed and extended clearance activities.</td>
</tr>
<tr>
<td>R 309B</td>
<td>$2.2M</td>
<td>Costs to acquire construction land rights and construction easements adjacent to existing pipeline along urban/commercial highway corridor.</td>
</tr>
</tbody>
</table>

ILI Upgrade Cost Variances

During the current reporting period PG&E has experienced significantly higher-than-planned costs associated with ILI Upgrade as described in Table 8-4:
TABLE 8-4
COST IMPACTS TO SELECT IN-LINE INSPECTION UPGRADE PROJECTS

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>I-111B I-111C</td>
<td>$200K(^{(a)})</td>
<td>Changes in construction schedules and assignment of construction resources, when internal resources have been required to respond to higher priority, emergent work.</td>
</tr>
<tr>
<td>I-11E</td>
<td>$200K</td>
<td>1) Addressing variances in pipeline condition (e.g., identification of anomaly (linear indication) at clearance point). 2) Configuration from engineered project scope.</td>
</tr>
<tr>
<td>I-257</td>
<td>$70K</td>
<td>1) Addressing variances in pipeline condition (e.g., identification of anomaly (linear indication) at clearance point). 2) Removal of pipeline liquids.</td>
</tr>
<tr>
<td>I-110B</td>
<td>$100K</td>
<td>Conducting clearances e.g., water entering pipe during clearance, requiring dewatering drying and extension of schedule.</td>
</tr>
<tr>
<td>I-110C</td>
<td>$50K</td>
<td>Delays in completing dewatering of line.</td>
</tr>
<tr>
<td>I-100C I-100E</td>
<td>$82K $112K</td>
<td>Challenges in anticipating costs associated with hydrovac excavation and handling of associated wet spoils.</td>
</tr>
</tbody>
</table>

\(^{(a)}\) Combined impact on costs for the two projects.

**In-Line Inspection Cost Variances**

During the reporting period, the In-Line Inspections incurred higher-than-planned costs associated with inspection tools becoming lodged in the pipeline during inspection runs thus requiring removal via cut-out. These cut-out operations require separate mobilization and replacement of pipeline features that impede the passage of the ILI tool. Over the course of this reporting period, PG&E has seen a higher number of cut-out operations than in previous years due to the number of inspections using newer multi-diameter tools. PG&E is currently evaluating the effect of potential cut-outs on future forecasting of first time inspections.

In addition, to meet Integrity Management program compliance deadlines, the In-Line Inspection Program has undertaken a series of non-traditional In-Line inspections of creek crossings and freeway crossings that have significantly increased costs when compared to traditional In-Line Inspection runs. Non-traditional ILI is nearly three times more costly than a traditional In-Line
inspection on a per-mile basis. Integrity Management compliance deadlines required expedited construction schedules and complex clearance planning to maintain peninsula operational requirements.

   See Table 8-5 for a brief description of impacts to efficiency for select projects:

<table>
<thead>
<tr>
<th>TABLE 8-5</th>
</tr>
</thead>
<tbody>
<tr>
<td>COST IMPACTS TO SELECT IN-LINE INSPECTION PROJECTS</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>I-359B</td>
<td>$200K</td>
<td>Changes in construction schedules and assignment of construction resources, when internal resources have been required to respond to higher priority, emergent work.</td>
</tr>
<tr>
<td>I-11E</td>
<td>$200K</td>
<td>1) Addressing variances in pipeline condition (e.g., identification of anomaly (linear indication) at clearance point). 2) Configuration from engineered project scope.</td>
</tr>
<tr>
<td>I-257</td>
<td>$1.1M</td>
<td>1) Extended clearances. 2) Inspection tool rental. 3) Additional clearance support costs.</td>
</tr>
<tr>
<td>I-077</td>
<td>$925K</td>
<td>1) Repair of damaged tool. 2) Multiple cleaning runs. 3) Remobilizations.</td>
</tr>
<tr>
<td>I-136B</td>
<td>1.4M</td>
<td></td>
</tr>
<tr>
<td>I-110C</td>
<td>$50K</td>
<td>Delays in completing dewatering of line.</td>
</tr>
<tr>
<td>I-100C</td>
<td>$82K</td>
<td>Challenges in anticipating costs associated with hydrovac excavation and handling of associated wet spoils.</td>
</tr>
<tr>
<td>I-100E</td>
<td>$11K</td>
<td></td>
</tr>
</tbody>
</table>

**ILI Direct Exam and Repair Cost Variances**

During the current reporting period, ILI Direct Exam and Repair ("Digs") unit costs have been generally higher than expected due to the following factors:

1) Winter rain negatively impacted site conditions or triggered environmental or city requirements. This resulted in reduced construction productivity and schedule delays;
2) Challenges related to site specific conditions e.g., remote mountainous locations or environmentally sensitive areas;
3) Additional site restoration and traffic control requirements imposed by local jurisdictions;
4) Challenges in acquiring the necessary field data on a timely basis to facilitate repair decisions;
5) Additional assessment and analysis necessary to complete repair decisions consistent with PG&E’s Repair Standard;
6) Local permits that required the use of non-native backfill for wet spoils (e.g., when using hydro-excavation as opposed to mechanical excavation);
7) Increased incidence of welded sleeve repair decisions, in preference to “flat-top” welds to achieve proper sleeve fit-up. Instead, clearances were being implemented to reduce line pressure to zero psig prior to flat-topping of welds; and
8) Increased incidence of repair decisions requiring the removal of benign linear indications and minor tooling marks upon application of engineering judgment within PG&E’s Repair Standard.
9. Procurement Policy and Practices

Describe PG&E’s procurement policy and practices for pipe and other materials used for projects. Was a competitive bidding process used? If not, explain why. Describe what factors PG&E considers in procuring material ranked by importance. Identify the manufacturer(s) or suppliers of the pipe used for the replacement projects and for any material that cost more than $100,000 per item.

Response

PG&E procures relevant materials as specified for Strength Testing, Pipe Replacement, and ILI, including pipes, valves, fittings, and repair materials, such as steel and composite sleeves. PG&E uses Power Advocate software to conduct Request for Proposals (RFP), which aids PG&E to make supplier selections in a consistent manner. The supplier can also use Power Advocate to respond to RFPs and upload documents.

The selection qualification is a multi-disciplinary team effort, and it includes input from internal key stakeholders including Gas Operations. The successful supplier is chosen based on the factors described below. All of these critical factors are significant for consideration of suppliers, but the ranking of importance of these factors may be adjusted depending on what is being procured.

1) Technical

   PG&E mandates that technical requirements as prescribed by Gas Operations, codes and standards must be met.

2) Quality

   PG&E mandates that quality requirements as prescribed by the Line of Business (LOB) codes and standards must be met. The Supplier Quality Team evaluates and scores this requirement. The scoring and evaluation process may include audits and application of the PG&E Product Qualification Process.

3) Safety

   PG&E evaluates and scores outside supplier safety qualifications.

4) Commercial/Pricing

   PG&E attempts to procure an item at the best pricing option.

5) Credit Risk

   PG&E evaluates the prospective supplier’s financial stability for RFPs that will exceed $20 million.
20. **Program Amount Authorized and Spent**

*Provide a table showing the total amount authorized for recovery from ratepayers and the total amount spent by PG&E year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).*

**Response**

Table 20-1 depicts the total amount of spend by PG&E in 2016 YTD by month, as well as the corresponding 2016 annual adopted/imputed program amount for the following programs: Strength Test Program (including both the portions in base expense and Transmission Integrity Management Program (TIMP) expense balancing account), TIMP capital balancing account, ILI portion of the TIMP expense balancing account, and the programs associated with pipe replacement.21

---

21 See Appendix I – Requirement 20: Table 20-1 Adopted and Recorded Spend.
21. Shareholder Costs Absorbed

Provide a table showing the total amount of costs that shareholders will absorb year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).

Response

Table 21-1 depicts the total amount of spend by PG&E in 2016 YTD by month, annual (2015-2018) adopted/imputed program amount, and shareholder funded costs for the Strength Test program (including both the portions in base expense and TIMP expense balancing account), TIMP capital balancing account, ILI portion of the TIMP expense balancing account, and the pipe replacement programs with shareholder-funded spend.22

On December 5, 2016, the Commission issued the 2015 GT&S Phase II decision (D.16-12-010), which finalized the treatment of the $850 million penalty adopted in the San Bruno penalty decision (D.15-04-024) and ruled that much of PG&E's pipeline work is safety related, and therefore, shareholder funded up to the penalty amount.23 To ensure that amounts debited to the Shareholder-Funded Account are properly recorded, including expenditures relating to the San Bruno Penalty, PG&E is required to submit an annual report each May pursuant to Section 6 of General Order 96-B.24

22 See Appendix J – Requirement 21: Table 21-1 Shareholder Absorbed Costs.
23 For lists of safety programs and associated penalties, refer to D.16-12-010, Appendix G, Table 1 and Table 2.
22. Forecast vs. Actual Mileage – Replacements

Provide a table showing the total mileage of pipe PG&E forecast to replace in R.11-02-019 and the mileage PG&E has replaced year-to-date. Identify the location, Line #, milepost, Class of the pipe replaced. Indicate whether the pipe is located in a High Consequence Area.

Response

For the current reporting period, PG&E replaced approximately 1.5 miles of gas transmission pipeline. Table 22-1 below provides the total pipeline miles adopted and replaced during the reporting period associated with vintage pipe, class location, shallow pipe, and other pipeline safety investment. Table 22-2 provides a breakdown of the total mileage of pipe PG&E has replaced for the reporting period by location, line number, milepost, class of the pipe replaced, and whether the pipe is located in a HCA. \(^{25}\)

**TABLE 22-1**

<table>
<thead>
<tr>
<th>Pipe Replacement</th>
<th>2016 Adopted Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vintage Pipe</td>
<td>20.0</td>
</tr>
<tr>
<td>Class Location</td>
<td>1.97</td>
</tr>
<tr>
<td>Shallow/Exposed Pipe</td>
<td>2.50</td>
</tr>
<tr>
<td>Other Pipeline Safety Investment</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total Adopted:</strong></td>
<td><strong>24.47</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Q4 2016</th>
<th>2016 YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual Miles</td>
<td>1.45</td>
<td>9.49</td>
</tr>
</tbody>
</table>

\(^{25}\) See Appendix K – Requirement 22: Table 22-2 Pipeline Replacement Completed Project Detail.
<table>
<thead>
<tr>
<th>Column Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line #</td>
<td>Reference number for this report.</td>
</tr>
<tr>
<td>Order Number</td>
<td>Financial system of record reference number to track specific costs, e.g., on individual projects and provided in workpapers supporting PG&amp;E Gas Transmission Application for projects commonly resulting from project split or addition.</td>
</tr>
<tr>
<td>Project Description</td>
<td>Order Description for ILI, upgrades for Strength Test, Pipe Replacement, and ILI, for Pipe Replacement and Strength Testing.</td>
</tr>
<tr>
<td>MAT</td>
<td>Maintenance Activity Type (MAT) represents a complete, distinct, sub-process of major work category. MATs are designated by three-character alphanumeric codes. The first two digits of the MAT are the MWC. A MAT can only be assigned to one MWC.</td>
</tr>
<tr>
<td>Miles</td>
<td>Miles of pipeline replaced.</td>
</tr>
<tr>
<td>Line</td>
<td>Pipeline identifier.</td>
</tr>
<tr>
<td>MP1</td>
<td>Beginning project mile point.</td>
</tr>
<tr>
<td>MP2</td>
<td>Ending project mile point.</td>
</tr>
<tr>
<td>City</td>
<td>Location of project.</td>
</tr>
<tr>
<td>HCA</td>
<td>Project includes a High Consequence Area.</td>
</tr>
<tr>
<td>Class Code</td>
<td>Class of pipeline included in project.</td>
</tr>
<tr>
<td>Tie-In Date</td>
<td>For ILI and pipeline testing and replacement projects, the tie-in date is the date the pipe became operational and the project was completed.</td>
</tr>
</tbody>
</table>
PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION PIPELINE
COMPLIANCE REPORT

NO. 2017-01

REPORTING PERIOD
JANUARY 1, 2017 – MARCH 31, 2017

IN COMPLIANCE WITH CPUC DECISION 16-06-056

SUBMITTED MAY 1, 2017
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Introduction

On July 1, 2016, the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 16-06-056 in Pacific Gas and Electric Company’s (PG&E or the Company) 2015 Gas Transmission and Storage (GT&S) rate case (Application (A.) 13-12-012). Ordering Paragraph (OP) 11 of the decision directs PG&E to serve quarterly compliance reports of PG&E’s transmission pipeline work, including Strength Testing, Pipe Replacement, and In-Line Inspection (ILI). OP 11 of D.16-06-056 requires that:

Pacific Gas and Electric Company shall file a quarterly compliance report of its transmission pipeline work, including pressure test, pipe replacement, and ILI. The report shall generally follow the format in Attachment D of Decision 12-12-030 and shall include all costs recorded to these programs, such that they provide an accurate and complete record of all costs at the project and program level. Consistent with the joint stipulation on Reporting and Communications between PG&E and the Office of Ratepayer Advocates, the format and content of the report may be revised by a working group to ensure that the report is useful to parties. PG&E’s first compliance filing shall cover the period between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter. The report shall be served on the Commission’s Safety and Enforcement Division, Energy Division, and on the service list of this proceeding.

This Transmission Pipeline Compliance Report (Report) No. 2017-01 is submitted in compliance with the directive set forth in OP 11 and reflects the reporting period of January 1, 2017 to March 31, 2017. The Report is being served on the Commission’s Safety and Enforcement Division, Energy Division and the service list of the 2015 GT&S rate case proceeding (A.13-12-012).

Report Format

The report requirements set forth in Attachment D of the Pipeline Safety Enhancement Plan (PSEP) decision were framed to address specific issues relevant to the PSEP proceeding, which, in several ways, differ from the 2015 GT&S rate case proceeding.

This Transmission Pipeline Compliance Report is organized to address each of the applicable requirements outlined in Attachment D of D.12-12-030 regarding the
transmission pipeline programs: Strength Testing, Pipe Replacement, and ILI. This Report includes all costs recorded to programmatic Maintenance Activity Types (MAT) associated with the required transmission pipeline programs.

As described in Transmission Pipeline Compliance Report No. 2016-01, PG&E has implemented a new cost model. This Report and future reports will present all costs (adopted/imputed and recorded) using PG&E’s new cost model. For the reporting period of January 1, 2017 through March 31, 2017, Table 1 provides a summary of the recorded costs incurred.

### TABLE 1
ADOPTED 2017 GT&S EXPENSE AND CAPITAL EXPENDITURES COMPARED TO RECORDED COSTS BY PROGRAM JANUARY 1, 2017 – MARCH 31, 2017 (THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Programs</th>
<th>2017 Adopted / Imputed (a)</th>
<th>Recorded Jan-Mar 2017</th>
<th>Recorded 2017 YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Strength Testing</td>
<td>$ 100,766</td>
<td>$ 11,885</td>
<td>$ 11,885</td>
</tr>
<tr>
<td>In-Line Inspection</td>
<td>$ 57,712</td>
<td>$ 18,366</td>
<td>$ 18,366</td>
</tr>
<tr>
<td>Pipeline Replacement</td>
<td>-</td>
<td>$ 21</td>
<td>$ 21</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 158,478</td>
<td>$ 30,272</td>
<td>$ 30,272</td>
</tr>
<tr>
<td><strong>Capital</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>In-Line Inspection</td>
<td>$ 94,183</td>
<td>$ 14,064</td>
<td>$ 14,064</td>
</tr>
<tr>
<td>Pipeline Replacement</td>
<td>$ 181,601</td>
<td>$ 18,480</td>
<td>$ 18,480</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 275,784</td>
<td>$ 32,544</td>
<td>$ 32,544</td>
</tr>
</tbody>
</table>

(a) 2017 adopted funding has been imputed by PG&E, based on the adopted Post Test-Year increase specified in D.16-12-010, Appendix E and Appendix I.

1 For a detailed explanation of the cost model change, refer to the response to Requirement 29 of the Transmission Pipeline Compliance Report No. 2016-01.

2 All 2017 recorded costs in this Report are as of April 10, 2017. There is a potential for additional adjustments that could impact the final costs related to the three transmission pipeline programs. If any adjustments materially change the reported costs, PG&E will provide an update in the 2017-02 report.
Decision-Making Process

1. Project Planning and Prioritization of Work

   Describe PG&E’s project planning process including how the projects were and are being scheduled and sequenced and what measures were and are being taken to conduct the work in a cost effective manner.

Response

   Gas Operations completes its multi-year planning by following PG&E’s Integrated Planning process. PG&E’s Integrated Planning process and project planning and scheduling remain consistent with the descriptions previously provided in PG&E’s Gas Transmission Pipeline Compliance Report 2016-01. When determining the final forecasts for each program or project in the portfolio during the annual Integrated Planning process, consideration is given to risk as well as classification of work, system constraints, work readiness, and financial constraints.

   Project Planning and Scheduling

   Planned construction activities within the first quarter are typically less than other calendar quarters due to the anticipated impacts of seasonally wet and cold winter weather. Cold weather materially increases gas system operational volumes due to heating demand. Higher gas system operational volumes increase the potential impact of cost and schedule risks associated with executing Strength Testing, Pipe Replacement, and ILI work that requires system clearances including, clearance availability, clearance management, and customer support including Liquefied Natural Gas/Compressed Natural Gas (LNG/CNG). Wet weather can materially impact cost range and schedule risks, including construction site safety, excavation productivity due to groundwater intrusion, groundwater management and disposal, and environmental restrictions. Consequently, the scheduling and sequencing of first quarter construction work is largely driven by its criticality (e.g., immediate pipeline repairs, remaining work with first quarter compliance due dates, the closeout of construction activities that span across the prior year end, and the readiness of construction work suited to winter execution—i.e., with limited system operational impacts and weather

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related risk). The first quarter is also a key period for the remaining planned 2017 construction work, with planning activities being focused on the identification of new work and the maintenance of existing opportunities to align work across programs. These alignment opportunities include sequencing work schedules in geographic areas or on specific gas system segments that have concurrent construction work with opportunities to bundle. PG&E currently maintains 18 work bundles involving 98 individual projects with 2017 construction work. During the first quarter of 2017, 12 individual projects mobilized across five work bundles.

During the first quarter of 2017, PG&E also undertook the following activities that are expected to directly support the conduct of work in a cost effective manner:

- Validated and updated existing three-year project-level work plans, including Strength Test, Pipe Replacement, and ILI programs. This activity was designed to increase the maturity of the existing 2017, 2018, and 2019 work plans and to support the inputs to PG&E’s annual Integrated Planning S-1 Process in the second quarter of 2017;
- Initiated identification of potential Strength Testing, Pipe Replacement, and ILI programs efficiencies; and
- Commenced pilot of project gate reviews for pipeline replacement projects late February of 2017, with a forecast spend greater than $1 million.\(^4\) In addition, PG&E undertook a range of other ongoing activities but not limited to:

- Construction management and inspection oversight of construction activities that monitor and ensure work quality;
- Early input from internal and external construction resources;
- Development and maintenance of a standardized project delivery methodology with associated controls and governance oversight; and
- Bulk materials procurement, management of long-lead materials orders, and supplier quality oversight.

\(^4\) Authorization and funding of projects is released in stages upon completion of ‘gate reviews’. Gate reviews validate that the project has completed specific deliverables at key development milestones.
2. Resource Planning

   Explain how PG&E decided whether to do the work in-house (e.g., use own employees and equipment) or contract the work out to other parties.

Response

   PG&E’s resource planning process remains consistent with the description previously provided in the Gas Transmission Pipeline Compliance Report No. 2016-01 to complete gas transmission work on a timely basis. During this reporting period, PG&E identified two additional project bundles of 2017 construction projects. These newly bundled projects were assigned to contractors rather than internal Gas Transmission General Construction (GTGC) resources based upon an assessment of GTGC existing construction commitments and resource availability. During the first quarter of 2017, PG&E reassigned one bundle from one contractor to another contractor based upon additional review of contractor work plans and associated estimates. Changes in individual project schedules affected two previously identified bundles: one assigned to GTGC was disbanded due to the divergence of the individual project schedules with the work allocation on the remaining 2017 work rescheduled until closer to mobilization; the other bundle included work that is now scheduled for 2018 and will be adjusted upon a review of the 2018 portfolio later this year. Of the current 18 bundles of 2017 work, four are assigned to GTGC, and 14 are assigned to external contractors.

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5 Refer to Appendix B – Requirement 2: Resource Planning Process for a description of the resource planning process provided in Requirement 2 of the 2016-01 report.

6 PG&E “bundles” construction work to align projects that would otherwise be executed separately. The objective is to maximize the use of limited resources and improve overall success of the project.
8. Factors Impacting Cost Effectiveness

Describe any factors, either internal or external, that may have prevented or affected PG&E from conducting the work in a more cost effective manner. Quantify the cost impact of such factors.

Response

Primary cost drivers that impacted the cost efficiency of work associated with Strength Testing, Pipe Replacement and ILI programs are listed in the tables below. As part of ongoing project management activities, PG&E’s transmission pipeline programs have consistently identified project uncertainties and implemented risk mitigation activities. Despite these efforts, PG&E has not been able to fully mitigate the potential impact of cost uncertainties. While not an exhaustive list, in many cases, these cost drivers resulted in individual projects incurring increased costs when compared to amounts adopted in D.16-06-056 and D.16-12-010. Table 8-1, below, summarizes the cost variances associated with each program, followed by Table 8-2 through Table 8-6, listing certain primary cost drivers for work completed during the reporting period, along with variance explanations at the program level.
**TABLE 8-1**  
UNITS AND COST EXPENDITURES BY PROGRAM  
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>In-Line Upgrades (capital)</td>
<td>98C, 44A</td>
<td>20 projects</td>
<td>N/A</td>
<td>$ 94,183</td>
<td>0.00</td>
<td>0.00</td>
<td>$ 14,046</td>
<td>$ 14,046</td>
<td>N/A</td>
<td>($90,137)</td>
<td>N/A</td>
</tr>
<tr>
<td>2</td>
<td>In-Line Inspections (expense)[2]</td>
<td>HPB</td>
<td>284 miles</td>
<td>N/A</td>
<td>$ 57,712</td>
<td>21</td>
<td>21</td>
<td>$ 8,815</td>
<td>$ 8,815</td>
<td>N/A</td>
<td>($48,897)</td>
<td>N/A</td>
</tr>
<tr>
<td>3</td>
<td>ILI Direct Exam &amp; Repair</td>
<td>HPi</td>
<td>97 digs</td>
<td>N/A</td>
<td>$ 18,646</td>
<td>15</td>
<td>15</td>
<td>$ 8,038</td>
<td>$ 8,038</td>
<td>N/A</td>
<td>-</td>
<td>N/A</td>
</tr>
<tr>
<td>4</td>
<td>Pipeline Replacement (capital and expense)</td>
<td>75E, 75H, 75M, 75O, 75T,75P, 75Q, 75R, 75S, J15</td>
<td>25 miles</td>
<td>N/A</td>
<td>$ 181,601</td>
<td>0.02</td>
<td>0.02</td>
<td>$ 18,496</td>
<td>$ 18,496</td>
<td>N/A</td>
<td>($163,105)</td>
<td>N/A</td>
</tr>
<tr>
<td>5</td>
<td>Strength Testing (expense)</td>
<td>HPF / JTC / 34A</td>
<td>170 miles</td>
<td>$8.40/km</td>
<td>$ 100,766</td>
<td>13</td>
<td>13</td>
<td>$ 11,882</td>
<td>$ 11,882</td>
<td>$907/km [6]</td>
<td>($88,864)</td>
<td>$67.02/km</td>
</tr>
</tbody>
</table>

[1] There were no adopted unit costs for the ILI Upgrade program in D.16-06-005.
[2] ILI upgrades cannot have unit costs as each project has a uniquely engineered scope. For example, a single project can have several valves replaced or no valves replaced, along with the addition of a launcher and receiver to make the line piggable. Therefore, an upgrade project could be 1 mile or 10 miles and still be the same cost.
[3] For the Pipeline Replacement Program, no adopted unit costs are provided at the program level as the Decision provided for three groupings of unit costs based on pipe diameter.
For ILI Direct Exam and Repair, the unit cost was based on an average cost per dig taking into account whether the dig location was rural, urban, or a combination of the two. Therefore, a singular unit cost per dig does not apply.
[5] Rate Case Units only show miles for Traditional In-Line Inspections. The rate case units for Non-Traditional ILI and ILI of Casings was based on number of projects and not miles.
[6] Unit Cost was derived from recorded costs referenced in Table 20-1 (see Balancing Account and Base Expense values in Column 2017 YTD) and completed units in column G of Table 8-1.
[7] All costs are presented in PG&E’s new cost model.
[8] 2017 adopted funding has been imputed by PG&E, consistent with the adopted Post Test-Year increase specified in D. 16-12-010, Appendix E and Appendix I.
**Strength Testing Cost Variances**

Factors that impact cost effectiveness of PG&E’s strength testing typically include:

- **Length of Test:** There are significant fixed costs associated with executing a Hydrotest (e.g., fabrication of test heads, clearance execution, and water management). The cost effectiveness of a test, measured on a unit cost basis, increases significantly as test length increases.

- **Location:** Test location materially impacts costs associated with traffic management, water disposal, environmental permitting, and construction area utilization.

- **Construction Work Plan:** PG&E has previously demonstrated significant construction efficiencies when tests can be executed in series along an extended contiguous pipeline distance (i.e., elimination of multiple mobilization costs and reduction of water management costs through re-use). During the first quarter of 2017, PG&E mobilized six individual tests, of which three (T-1266, T-1267, and T-1268 on L-215) are being executed by GTGC as part of a six-project bundle in the Patterson area. One additional strength test (T-1152 as part of the uprate of DFM-7203-01) was also completed near Firebaugh. Table 8-2 provides detail regarding impacts to cost efficiency of projects in this reporting period:
### TABLE 8-2
COST IMPACTS TO SELECT STRENGTH TEST PROJECTS

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
</table>
| T-1266, T-1267, and T-1268 | $1.85M | Traffic Control: Proposed road closures were not approved by city and county agencies. Approved plans required additional flagging resources ($180K).
| | | Pipeline Clearance: Customer demand limited the ability to take a single clearance on the three test sections, requiring additional clearance support between each test segment ($500K).
| | | Construction Efficiency: Reduced ability to sequence construction resources efficiently as each of the three projects were released to construction individually rather than together due to the design complexity and time needed to complete the design drawings ($600K).
| | | Weather: Reduced productivity due to wet weather, including fog delays, to allow for line of sight on traffic control, dewatering of excavations, and mitigating vehicles from tracking mud out of construction areas onto roadways ($420K).
| | | Location: Additional outreach to non-PG&E customers; relocation and lodging costs for crew; additional support to execute night work ($150K).
| T-1152 | $500K | Customer Outage Support (LNG/CNG): Additional mobilizations and excavation required due to rescheduling of work from Q4 2016 due to prioritization of available CNG resources ($300K). In addition costs to provide CNG support were higher than planned due to 1) the far distance from a refueling station, which required additional trucking and 2) significantly higher customer usage during the outage period ($200K).
| T-1232A | $67K | Location: Additional travel/lodging due to desert location ($10K); additional water tank storage costs ($57K).

**Pipe Replacement Cost Variances**

Factors that particularly affect the cost effectiveness of PG&E’s pipe replacement include:

- **Unidentified Pipeline Conditions**: Additional engineering and construction activities required to repair/replace pipe, valves and fittings due to condition and construction obstructions due to unidentified non-PG&E structures and other utilities;
- **Construction Permitting**: Increased and/or restrictive permitting conditions affecting work hours, traffic management, or the means and methods of construction;
• Compliance commitments: Acceleration of design and construction schedules to meet compliance can dictate compressed construction schedules, higher land costs, and construction during wet winter weather; and

• Field Conditions: Excavation-related factors such as high water table, poor/weak soils, and contaminated soil handling and disposal requirements.

During the reporting period, Pipe Replacement focused, among other projects, on the construction progress of projects within dense urban areas, including: the tunneling of a new 30-inch diameter pipeline under 640 feet of Interstate 880 in Newark (R-149, L-153) to enable the removal of an existing span across that freeway; the commencement of replacing two miles of a 24-inch diameter pipeline along Alemany Blvd. in San Francisco (R-414, L-109); and the replacement of pipeline segments within a San Jose gas transmission station (R-514, L-100 & L-300A).

Table 8-3 provides detail regarding impacts to cost efficiency of projects in this reporting period:

### TABLE 8-3
COST IMPACTS TO VINTAGE PIPE REPLACEMENT PROJECTS

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>R-514</td>
<td>$500K</td>
<td>Construction Resources: Complexity of construction work plan required augmenting GTGC resources with a contractor to complete the work.</td>
</tr>
<tr>
<td>R-149</td>
<td>$1.3M</td>
<td>Unidentified Pipeline Conditions: Additional construction duration and resources to resolve and clear an unexpected obstruction encountered during MicroTunnel operations.</td>
</tr>
<tr>
<td>R-149</td>
<td>$1.8M</td>
<td>Field Conditions: Project encountered obstruction during tunneling. Specialized shoring needed to stop infiltration of groundwater into pit during the obstruction removal operation.</td>
</tr>
<tr>
<td>R-307</td>
<td>$460K</td>
<td>Construction Permitting: Carryover cost for final land agreement related to this project, which was completed in 2014.</td>
</tr>
<tr>
<td>R-978</td>
<td>$894K</td>
<td>Field Conditions: To address emergency leak repair in Redwood Valley, rerouting of 125 feet of pipeline and retirement of existing pipeline section was required.</td>
</tr>
</tbody>
</table>
ILI Upgrade Cost Variances

Factors that can particularly impact ILI Upgrade projects include:

- Limited location alternatives for tool launchers and receivers, requiring resolution of land acquisition purchase prices and Temporary Construction Easement (TCE) fees and receivers;
- Accelerated project timelines;
- Schedule constraints to meet planned inspection timelines, requiring resolution of permitting issues with local permitting agencies;
- Hydraulic constraints on pipelines;
- Additional pipeline excavation and re-configuration to avoid other underground utilities and structures, particularly in stations; and
- Pipeline re-configuration requirements due to lower navigation tolerances of newer inspection tools.

During the reporting period, ILI Upgrade has focused on completing the retrofit of SP-5 (I-052C), mobilizing 85 percent of the I-102 L-300B projects, and the engineering and planning for 2017 and 2018 execution projects.

Table 8-4 provides detail regarding impacts to cost efficiency of projects in this reporting period:

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>I-043G</td>
<td>$70K</td>
<td>Schedule delay to complete hydrotest activities on newly installed pipe and associated clearance extension.</td>
</tr>
<tr>
<td>I-110A</td>
<td>$300K</td>
<td>Reduced productivity due to wet weather and increased dewatering costs.</td>
</tr>
</tbody>
</table>

In-Line Inspection Cost Variances

Factors that can particularly impact ILI Inspection projects include:

- Compliance Requirements: Compliance deadlines can require the implementation of expedited construction schedules and complex clearance planning to meet gas system operational requirements particularly on the San Francisco peninsula.
• The use of non-traditional ILI tools particularly at creek and freeway crossings (Non-traditional ILI is nearly three times more costly than a traditional ILI on a per-mile basis).

• Tool Inspection Operations: In 2016, PG&E experienced an increased number of cut-out operations than in previous years due to newer multi-diameter tools (i.e., inspection tools becoming lodged in the pipeline during inspection runs requiring removal via cut-out). These cut-out operations require separate mobilization and replacement of pipeline features which impede the passage of the ILI tool. PG&E is currently evaluating the effect of potential cut-outs on future forecasting of first time inspections.

During the reporting period, ILI has focused on the remediation of pipeline obstructions identified during 2016, along with the execution of planned 2017 inspections totaling 22.1 miles on L-021 in Sonoma, L-191 in Contra Costa County, and L-132 on the San Francisco Peninsula. ILI has also incorporated the use of Electro Magnetic Acoustic Transducer (EMAT) inspection technology, specifically to assess the longitudinal seam welds on certain pipelines.

Table 8-5 provides detail regarding impacts to cost efficiency of projects in this reporting period:

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>I-135</td>
<td>$750K</td>
<td>Inspection Scope: Costs to facilitate additional inspection using Electro Magnetic Acoustic Transducer, or EMAT, technology on L-300B to assess the longitudinal seam weld on the pipeline and assess for Stress Corrosion Cracking.</td>
</tr>
<tr>
<td>I-241</td>
<td>$250K</td>
<td>Tool Inspection Operations: Additional cleaning runs required to enable inspection tool to complete inspection, which increased construction duration and resources used.</td>
</tr>
<tr>
<td>I-027</td>
<td>$480K</td>
<td>Tool Inspection Operations: Costs to locate obstruction on L-132 that prevented initial September 2016 inspection. An intelligent gauge tool was successful in pinpointing the obstruction, which will be removed prior to the planned inspection rerun in May.</td>
</tr>
</tbody>
</table>
ILI Direct Exam and Repair Cost Variances

Factors that particularly impact ILI Direct Exam and Repair ("ILI Digs") projects include:

- **Pipeline Condition**: Incidence of immediate anomalies (inspection indicates wall loss greater than 70 percent) which can trigger additional pipeline assessment procedures, with a greater likelihood of welded sleeve or cut-out repairs per PG&E’s repair standard;

- **Field Conditions**: Dig location (e.g., urban, suburban, or rural) can materially affect a range of cost factors including paving removal/remediation, ability to use native backfill, sufficiency of construction area, extent of traffic management, groundwater management and disposal, environmental permitting, and construction hours permitting; and

- **Schedule Constraints**: Acceleration of permitting or excavation schedules to meet compliance commitments or mitigate gas system constraints (e.g., where immediate anomalies trigger operationally significant gas system pressure reductions).

   During the current reporting period, ILI Digs construction was focused on completing dig assessments and repairs identified from 2016 and prior year ILI inspections (including L-300B, DFM-0126-01, L-138, L-147, DFM-0617-06, and L-101).

   Table 8-6 provides detail regarding impacts to cost efficiency of projects in this reporting period:
<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>ID-80</td>
<td>$390K</td>
<td>Field Conditions: Dewatering of five excavations due to high water table. Local water discharge was not available and required trucking to disposal site ($270K). Pipe Condition: Additional excavation and construction required to complete cut-outs at each location based upon assessment of pipeline anomaly ($120K).</td>
</tr>
<tr>
<td>RT-882</td>
<td>$595K</td>
<td>Pipeline Condition: Multiple anomalies required supplemental assessment and resulted in 15 ‘clockspring’ repairs across four extended excavation sites with additional sand blasting required to assess the anomalies ($170K). Field Conditions: Remote site location and wet weather conditions increased environmental and construction costs ($265K). Schedule Constraints: System pressure reductions necessitated expedited assessment and repair schedules, including cross-compression, to enable repair activities ($160K).</td>
</tr>
<tr>
<td>RT-945</td>
<td>$520K</td>
<td>Pipeline Condition: Cut-out repair was required to address identified pipeline anomaly ($330K Construction, $130K Clearance). Schedule Constraints: Project was expedited to minimize potential cold-weather impact to S.F. Peninsula gas system ($35K). Field Conditions: Additional traffic control was required to safely execute the clearance. Rain caused delays with the clearance ($25K).</td>
</tr>
<tr>
<td>ID-36</td>
<td>$440K</td>
<td>Pipeline Condition: Additional pipeline inspection assessments were required to characterize 18 mechanical damage anomalies, and to determine and execute repair decision ($275K). Field Conditions: Groundwater management and disposal costs (average 20K gallons per day), reduced productivity due to limited availability, distance to and change of central TCE site, and wet weather impact to coating activities ($165K).</td>
</tr>
<tr>
<td>ID-70</td>
<td>$350K</td>
<td>Other: Additional construction standby to support GTGC welding crew during save-a-valve failure event ($150K). Pipeline Condition: Additional construction resources to execute cut-out repair ($200K).</td>
</tr>
<tr>
<td>ID-67</td>
<td>$295K</td>
<td>Pipeline Condition: Additional construction resources to execute cut-out repair ($107K). Field conditions: Additional site restoration costs and delay to meet agreement with private property owner ($188K).</td>
</tr>
</tbody>
</table>
9. Procurement Policy and Practices

Describe PG&E’s procurement policy and practices for pipe and other materials used for projects. Was a competitive bidding process used? If not, explain why. Describe what factors PG&E considers in procuring material ranked by importance. Identify the manufacturer(s) or suppliers of the pipe used for the replacement projects and for any material that cost more than $100,000 per item.

Response

PG&E procures relevant materials as specified for Strength Testing, Pipe Replacement, and ILI programs, including pipes, valves, fittings, and repair materials, such as steel and composite sleeves. PG&E uses Power Advocate software to conduct the competitive bidding process for most high dollar gas pipe, valve, and fitting (PVF) materials. Request for Proposals (RFP) that are used for these bidding events aid PG&E to make supplier selections in a consistent manner. The supplier can also use Power Advocate to respond to RFPs and upload documents.

The selection qualification is a multi-disciplinary team effort, and it includes input from internal key stakeholders including Gas Operations. The successful supplier is chosen based on the factors described below. All of these critical factors are significant for consideration of suppliers, but the ranking of importance of these factors may be adjusted depending on what is being procured.

1) Technical
   PG&E mandates that technical requirements as prescribed by Gas Operations, codes and standards must be met.

2) Quality
   PG&E mandates that quality requirements as prescribed by the LOB codes and standards must be met. The Supplier Quality Team evaluates and scores this requirement. The scoring and evaluation process may include audits and application of the PG&E Product Qualification Process.

3) Safety
   PG&E evaluates and scores outside supplier safety qualifications.

4) Commercial/Pricing
   PG&E attempts to procure an item at the best pricing option.
20. Program Amount Authorized and Spent

*Provide a table showing the total amount authorized for recovery from ratepayers and the total amount spent by PG&E year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).*

**Response**

Table 20-1 depicts the total amount of spend by PG&E in the first quarter of 2017 by month, as well as the corresponding 2017 annual adopted/imputed program amount for the following programs: Strength Test Program (including both the portions in base expense and Transmission Integrity Management Program (TIMP) expense balancing account), TIMP capital balancing account, ILI portion of the TIMP expense balancing account, and the programs associated with pipe replacement.¹⁹

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¹⁹ See Appendix H – Requirement 20: Table 20-1 Adopted and Recorded Expenditures.
21. Shareholder Costs Absorbed

Provide a table showing the total amount of costs that shareholders will absorb year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).

Response

Table 21-1 summarizes shareholder cost in the first quarter of 2017 by month, annual (2015-2018) adopted/imputed program amount, and shareholder funded costs for the Strength Test program (including both the portions in base expense and TIMP expense balancing account), TIMP capital balancing account, ILI portion of the TIMP expense balancing account, and the pipe replacement programs with shareholder-funded spend.\(^\text{20}\)

On December 5, 2016, the Commission issued the 2015 GT&S Phase II decision (D.16-12-010), which finalized the treatment of the $850 million penalty adopted in the San Bruno penalty decision (D.15-04-024) and ruled that much of PG&E’s pipeline work is safety related, and therefore, shareholder funded up to the penalty amount.\(^\text{21}\) To ensure that amounts debited to the Shareholder-Funded Account are properly recorded, including expenditures relating to the San Bruno Penalty, PG&E is required to submit an annual report each May pursuant to Section 6 of General Order 96-B.\(^\text{22}\)

\(^{20}\) See Appendix I – Requirement 21: Table 21-1 Shareholder Absorbed Costs.

\(^{21}\) For lists of safety programs and associated penalties, refer to D.16-12-010, Appendix G, Table 1 and Table 2.

22. **Forecast vs. Actual Mileage – Replacements**

*Provide a table showing the total mileage of pipe PG&E forecast to replace in R.11-02-019 and the mileage PG&E has replaced year-to-date. Identify the location, Line #, milepost, Class of the pipe replaced. Indicate whether the pipe is located in a High Consequence Area.*

**Response**

For the current reporting period, PG&E replaced approximately 0.02 miles of gas transmission pipeline. Table 22-1 below provides the total pipeline miles adopted and replaced during the reporting period associated with vintage pipe, class location, shallow pipe, and other pipeline safety investment. Table 22-2 provides a breakdown of the total mileage of pipe PG&E has replaced for the reporting period by location, line number, milepost, class of the pipe replaced, and whether the pipe is located in a High Consequence Area (HCA).23

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**TABLE 22-1**

**TOTAL PIPELINE MILES REPLACED – ADOPTED AND ACTUAL MILEAGE**

**JANUARY 1, 2017 – MARCH 31, 2017**

<table>
<thead>
<tr>
<th>Pipe Replacement</th>
<th>2017 Adopted Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vintage Pipe</td>
<td>20.0</td>
</tr>
<tr>
<td>Class Location</td>
<td>1.97</td>
</tr>
<tr>
<td>Shallow/Exposed Pipe</td>
<td>3.40</td>
</tr>
<tr>
<td>Other Pipeline Safety Investment</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total Adopted:</strong></td>
<td><strong>25.37</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pipe Replacement</th>
<th>2017 Actual Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Q1 2017</td>
</tr>
<tr>
<td>Vintage Pipe</td>
<td>–</td>
</tr>
<tr>
<td>Class Location</td>
<td>–</td>
</tr>
<tr>
<td>Shallow/Exposed Pipe</td>
<td>–</td>
</tr>
<tr>
<td>Other Pipeline Safety Investment</td>
<td>0.02</td>
</tr>
<tr>
<td><strong>Total Replaced:</strong></td>
<td><strong>0.02</strong></td>
</tr>
</tbody>
</table>

---

<table>
<thead>
<tr>
<th>Column Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line #</td>
<td>Reference number for this report.</td>
</tr>
<tr>
<td>Order Number</td>
<td>Financial system of record reference number to track specific costs, e.g., on individual projects and provided in workpapers supporting PG&amp;E Gas Transmission Application for projects commonly resulting from project split or addition.</td>
</tr>
<tr>
<td>Project Description</td>
<td>Order Description for ILI, upgrades for Strength Test, Pipe Replacement, and ILI, for Pipe Replacement and Strength Testing.</td>
</tr>
<tr>
<td>MAT</td>
<td>MAT represents a complete, distinct, sub-process of major work category. MATs are designated by three-character alphanumeric codes. The first two digits of the MAT are the MWC. A MAT can only be assigned to one MWC.</td>
</tr>
<tr>
<td>Miles</td>
<td>Miles of pipeline replaced.</td>
</tr>
<tr>
<td>Line</td>
<td>Pipeline identifier.</td>
</tr>
<tr>
<td>MP1</td>
<td>Beginning project mile point.</td>
</tr>
<tr>
<td>MP2</td>
<td>Ending project mile point.</td>
</tr>
<tr>
<td>City</td>
<td>Location of project.</td>
</tr>
<tr>
<td>HCA</td>
<td>Project includes a High Consequence Area.</td>
</tr>
<tr>
<td>Class Code</td>
<td>Class of pipeline included in project.</td>
</tr>
<tr>
<td>Tie-In Date</td>
<td>For ILI and pipeline testing and replacement projects, the tie-in date is the date the pipe became operational and the project was completed.</td>
</tr>
</tbody>
</table>
PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION PIPELINE
COMPLIANCE REPORT

NO. 2017-03

REPORTING PERIOD
JULY 1, 2017 – SEPTEMBER 30, 2017

IN COMPLIANCE WITH CPUC DECISION 16-06-056

SUBMITTED OCTOBER 30, 2017
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TRANSMISSION PIPELINE  
COMPLIANCE REPORT  
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REPORTING PERIOD  
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Introduction

On July 1, 2016, the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 16-06-056 in Pacific Gas and Electric Company’s (PG&E or the Company) 2015 Gas Transmission and Storage (GT&S) rate case (A.13-12-012). Ordering Paragraph (OP) 11 of the decision directs PG&E to serve quarterly compliance reports of PG&E’s transmission pipeline work, including Strength Testing, Pipe Replacement, and In-Line Inspection (ILI):

Pacific Gas and Electric Company shall file a quarterly compliance report of its transmission pipeline work, including pressure test, pipe replacement, and ILI. The report shall generally follow the format in Attachment D of Decision 12-12-030 and shall include all costs recorded to these programs, such that they provide an accurate and complete record of all costs at the project and program level. Consistent with the joint stipulation on Reporting and Communications between PG&E and the Office of Ratepayer Advocates, the format and content of the report may be revised by a working group to ensure that the report is useful to parties. PG&E’s first compliance filing shall cover the period between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter. The report shall be served on the Commission’s Safety and Enforcement Division, Energy Division, and on the service list of this proceeding.

This Transmission Pipeline Compliance Report (Report) No. 2017-03 is submitted in compliance with this directive and reflects the reporting period of July 1, 2017 to September 30, 2017.

Report Format

The Report requirements set forth in Attachment D of the Pipeline Safety Enhancement Plan (PSEP) decision were framed to address specific issues relevant to the PSEP proceeding, which, in several ways, differ from the 2015 GT&S rate case proceeding.

This Report is organized to address each of the applicable requirements outlined in Attachment D of D.12-12-030 regarding the transmission pipeline programs: Strength Testing, Pipe Replacement, and ILI. This Report includes all costs recorded to Maintenance Activity Types (MAT) associated with the required transmission pipeline programs. In the next quarterly Report to be filed in January 2018, PG&E will include
updated presentations for Tables 20 and 21 that will cover 2015 through December 2017.

As described in Transmission Pipeline Compliance Report No. 2016-01, PG&E has implemented a new cost model.\textsuperscript{1} This Report and future reports will present all costs (adopted/imputed and recorded) using PG&E’s new cost model. For the reporting period of July 1, 2017 through September 30, 2017, Table 1 provides a summary of the recorded costs incurred.\textsuperscript{2}

\textsuperscript{1} For a detailed explanation of the cost model change, refer to the response to Requirement 29 of the Transmission Pipeline Compliance Report No. 2016-01.

\textsuperscript{2} All 2017 recorded costs in this Report are as of October 9, 2017.
TABLE 1
ADOPTED 2017 GT&S EXPENSE AND CAPITAL EXPENDITURES COMPARED TO RECORDED COSTS BY PROGRAM
JULY 1, 2017 – SEPTEMBER 30, 2017
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Programs</th>
<th>2017 Adopted / Imputed (a)</th>
<th>Recorded Jul-Sept 2017</th>
<th>Recorded 2017 YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Strength Testing</td>
<td>$97,255</td>
<td>$40,505</td>
<td>$79,585</td>
</tr>
<tr>
<td>In-Line Inspection</td>
<td>$57,712</td>
<td>$16,800</td>
<td>$51,983</td>
</tr>
<tr>
<td>Pipeline Replacement</td>
<td>$2,744</td>
<td>$1,244</td>
<td>$1,506</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$157,711</td>
<td>$58,549</td>
<td>$133,074</td>
</tr>
<tr>
<td><strong>Capital</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Strength Testing</td>
<td>$26,825</td>
<td>$11,890</td>
<td>$27,273</td>
</tr>
<tr>
<td>In-Line Inspection</td>
<td>$94,182</td>
<td>$20,990</td>
<td>$50,923</td>
</tr>
<tr>
<td>Pipeline Replacement</td>
<td>$187,089</td>
<td>$61,384</td>
<td>$121,561</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$308,096</td>
<td>$94,264</td>
<td>$199,757</td>
</tr>
</tbody>
</table>

(a) 2017 adopted funding has been imputed by PG&E, consistent with the adopted Post Test-Year increase specified in D.16-12-010, Appendix E and Appendix I.
Decision-Making Process

1. Project Planning and Prioritization of Work

Describe PG&E’s project planning process including how the projects were and are being scheduled and sequenced and what measures were and are being taken to conduct the work in a cost effective manner.

Response

PG&E’s Gas Operations organization follows PG&E’s Integrated Planning process. PG&E’s Integrated Planning process and project planning and scheduling remain consistent with the descriptions previously provided in PG&E’s Gas Transmission Pipeline Compliance Report 2016-01. When determining the final forecasts for each program or project in the portfolio during the annual Integrated Planning process, consideration is given to risk as well as classification of work, system constraints, work readiness, and financial constraints.

Project Planning and Scheduling

Planned construction within the third quarter of 2017 consisted of the ramping up of construction activities across all workstreams. There are typically fewer weather-related construction delays in the third quarter compared to the first quarter. There is continued focus on obtaining encroachment permits for fourth quarter planned work.

During the third quarter of 2017, PG&E also undertook the following activities to conduct work in a cost effective manner:

- Validated and updated the existing 2017-2019 project-level work plans, including Strength Test, Pipe Replacement, and ILI programs;
- Continued to identify and implement potential process improvements and efficiencies across the Strength Testing, Pipe Replacement, and ILI programs; and
- Submitted 18 Pipeline Replacement Program projects for gate review, of which all 18 projects were approved.

---


4 Authorization and funding of projects is released in stages upon completion of “gate reviews.” Gate reviews validate that the project has completed specific deliverables at key development milestones.
Resource Procurement and Oversight

2. Resource Planning

   Explain how PG&E decided whether to do the work in-house (e.g., use own employees and equipment) or contract the work out to other parties.

Response

   PG&E’s resource planning process remains consistent with the description previously provided in the Gas Transmission Pipeline Compliance Report No. 2016-01 to complete gas transmission work on a timely basis.\(^5\)

   For construction, PG&E uses both its internal workforce and contract resources. Typically, PG&E’s internal workforce completes about 30 percent of the transmission work. In 2017, when possible, PG&E has attempted to bundle work being done on the same asset or in the same geographical area to reduce costs (e.g., costs related to mobilization, clearance support, and staging yards).

   During this reporting period, PG&E identified 24 work bundles involving 134 individual projects scheduled for 2017 construction. Of the 24 bundles, seven are assigned to Gas Transmission General Construction (GTGC) and 17 are assigned to external contractors. We are currently working to identify bundling opportunities for 2018 construction.

Budget and Spending

8. Factors Impacting Cost Effectiveness

Describe any factors, either internal or external, that may have prevented or affected PG&E from conducting the work in a more cost effective manner. Quantify the cost impact of such factors.

Response

The primary cost drivers that impacted the cost efficiency of work associated with Strength Testing, Pipe Replacement and ILI programs are listed in the tables below. As part of ongoing project management activities, PG&E's transmission pipeline programs identify project uncertainties and implement risk mitigation activities. Despite these efforts, PG&E has not been able to fully mitigate the potential impact of cost uncertainties. While not an exhaustive list, in many cases, these cost drivers resulted in individual projects incurring increased costs when compared to amounts adopted in D.16-06-056 and D.16-12-010. Table 8-1, below, summarizes the cost variances associated with each program. Table 8-2 through Table 8-6 lists certain primary cost drivers for work completed during the reporting period, along with variance explanations at the program level.
### TABLE 8-1

**UNITS AND COST EXPENDITURES BY PROGRAM**

*(THOUSANDS OF DOLLARS)*

<table>
<thead>
<tr>
<th>Ref Line</th>
<th>Program</th>
<th>MAT code</th>
<th>2017 Adopted Units</th>
<th>Adopted/Imputed Unit Cost 2017 <em>(a)</em></th>
<th>Adopted/Imputed Amount 2017 <em>(b)</em></th>
<th>Units Completed July - Sept 2017 <em>(c)</em></th>
<th>Units Completed 2017 YTD <em>(d)</em></th>
<th>Recorded Costs July - Sept 2017 <em>(e)</em></th>
<th>Recorded Costs 2017 YTD <em>(f)</em></th>
<th>Unit Costs 2017 <em>(g)</em></th>
<th>Variance to Total Cost 2017 <em>(h)</em></th>
<th>Variance to Unit Cost <em>(i)</em></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>In-Line Upgrades (capital)</td>
<td>98C, 44A</td>
<td>20 projects</td>
<td>N/A</td>
<td>$94,182</td>
<td>0</td>
<td>54</td>
<td>$20,990</td>
<td>$50,923</td>
<td>N/A</td>
<td>$43,299</td>
<td>N/A</td>
</tr>
<tr>
<td>2</td>
<td>In-Line Inspections (expenses)†</td>
<td>HPB, HPR, 34A</td>
<td>284 miles</td>
<td>N/A</td>
<td>$38,966</td>
<td>64</td>
<td>192</td>
<td>$11,334</td>
<td>$30,879</td>
<td>N/A</td>
<td>$8,088</td>
<td>N/A</td>
</tr>
<tr>
<td>3</td>
<td>LI Direct Exam &amp; Repair</td>
<td>HPI</td>
<td>97 digs</td>
<td>N/A</td>
<td>$18,746</td>
<td>28</td>
<td>67</td>
<td>$5,566</td>
<td>$21,105</td>
<td>N/A</td>
<td>$2,359</td>
<td>N/A</td>
</tr>
<tr>
<td>4</td>
<td>Pipeline Replacement (capital and expenses)</td>
<td>75E, 75H, 75M, 75Q, 75T, 75P, 75S, 75R, 75S, JT7, JT4, 44A, HPM, 34A</td>
<td>25 miles</td>
<td>N/A</td>
<td>$189,833</td>
<td>4</td>
<td>4</td>
<td>$63,076</td>
<td>$123,096</td>
<td>N/A</td>
<td>$66,737</td>
<td>N/A</td>
</tr>
<tr>
<td>5</td>
<td>Strength Testing (capital / expense) †</td>
<td>HPF / JTC 75N / 34A</td>
<td>170 miles</td>
<td>$840/km/mile</td>
<td>$124,080</td>
<td>135</td>
<td>172</td>
<td>$52,395</td>
<td>$106,689</td>
<td>$102/km [4]</td>
<td>$(17,222)</td>
<td>$182/km [4]</td>
</tr>
</tbody>
</table>

**Notes:**

1. There were no adopted unit costs for the ILI Upgrade Program in D.16-06-056.
   - ILI upgrades cannot have unit costs as each project has a uniquely engineered scope. For example, a single project can have several valves replaced or no valves replaced, along with the addition of a launcher and receiver to make the line piggable. Therefore, an upgrade project could be 1 mile or 10 miles and still be the same cost.
   - For the Pipeline Replacement Program, no adopted unit costs are provided at the program level as the Decision provided for three groupings of unit costs based on pipe diameter.
   - For ILI Direct Exam and Repair, the unit cost was based on an average cost per dig taking into account whether the dig location was rural, urban, or a combination of the two. Therefore, a singular unit cost per dig does not apply.
2. The source of adopted funding for 2015 is D.16-06-056, Appendix D-Tables 1 and 2, and Appendix I-Tables 1 and 2. 2016-2018 adopted funding has been imputed by PG&E, consistent with the adopted Post Test-Year increase specified in Appendix E and Appendix I of D.16-12-010.
3. Rate case units only show miles for Traditional In-Line Inspections. The rate case units for Non-Traditional ILI and ILI of Casings are based on number of projects, not miles. As a result of the MAT realignment effort, MAT HPB tracks Traditional ILI Inspections and MAT HPR tracks Non-Traditional ILI Inspections.
4. Unit Cost was derived from recorded costs referenced in Table 20-1 and completed units in Column G of Table 8-1.
5. All costs are presented in PG&E's new cost model.
6. 2017 Adopted funding has been imputed by PG&E, consistent with the adopted Post Test-Year increase specified in D.16-12-010, Appendix E and Appendix I.
Strength Testing Cost Variances

Factors that impact cost effectiveness of PG&E’s strength testing typically include:

- Length of Test: There are significant fixed costs associated with executing a Strength Test (e.g., fabrication of test heads, clearance execution, and water management). The cost effectiveness of a test, measured on a unit cost basis, increases significantly as test length increases.
- Location: Test location materially impacts costs associated with traffic management, water disposal, environmental permitting, and construction area utilization.
- Construction Work Plan: PG&E has previously demonstrated significant construction efficiencies when tests can be executed in series along an extended contiguous pipeline distance (i.e., elimination of multiple mobilization costs and reduction of water management costs through re-use). In the third quarter of 2017, the majority of the strength tests conducted was extended contiguous pipeline distance.

Table 8-2 provides detail regarding impacts to cost efficiency of projects in this reporting period:

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>T-1143</td>
<td>$1.2M</td>
<td>The project incurred additional construction costs in comparison to other projects conducted in Q3. It was necessary to split this test into two sections versus one extended contiguous pipeline test. Additionally, further construction costs were incurred due to a necessary partial dewater (removing water) and replacement (refilling water) of the pipe.</td>
</tr>
</tbody>
</table>

Pipe Replacement Cost Variances

Factors that particularly affect the cost effectiveness of PG&E's pipe replacement include:

- Unidentified Pipeline Conditions: Additional engineering and construction activities required to repair/replace pipe, valves and fittings due to condition and construction obstructions due to unidentified non-PG&E structures and other utilities;
• Construction Permitting: Increased and/or restrictive permitting conditions affecting work hours, traffic management, or the means and methods of construction;
• Compliance commitments: Acceleration of design and construction schedules to meet compliance can dictate compressed construction schedules, higher land costs, and construction during wet winter weather; and
• Field Conditions: Excavation-related factors such as high water table, poor/weak soils, and contaminated soil handling and disposal requirements.

During this reporting period, Pipe Replacement focused on, among other projects, the progress of construction projects within dense urban areas including: the replacement of pipeline segments within Ralston Blvd (R 401, DFM-0208-01) a heavily traveled roadway in the Bay Area city of Belmont which requires daily set-up and takedown of traffic control within eight hour shifts. The daily set up and take down of the traffic control measures and conflicts with unknown/unmarked utilities reduced actual construction time. One lane is required to stay open for traffic allowing for a reduced work area. Project R-349 on L-101 is currently tunneling a new 24 inch diameter pipeline that extends 488 feet in length and runs under San Francisquito Creek in Palo Alto which will enable the removal of an existing creek crossing. The crossing presently conflicts with a levee improvement project. Additionally, pipeline replacement project R-532 (L-118A and L-118D) immediately encountered extremely high levels of groundwater (GW) that precipitated the need for a redesign in third quarter to modify the installation method from “open trench/jack and bore” to include horizontal directional drilling in the areas where GW made open trenching prohibitive.

Table 8-3 provides detail regarding impacts to cost efficiency of select projects of the 26 conducted in this reporting period:
### TABLE 8-3
COST IMPACTS TO SELECT VINTAGE PIPE REPLACEMENT PROJECTS

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>R-401</td>
<td>$1.6M</td>
<td>Additional construction duration due to unanticipated field conditions/work hours restrictions which resulted in additional traffic control, extended project and overhead costs.</td>
</tr>
<tr>
<td>R-349</td>
<td>$250K</td>
<td>Additional construction duration due to unanticipated field conditions which resulted in additional extended project and overhead costs.</td>
</tr>
<tr>
<td>R-532</td>
<td>$850K</td>
<td>Additional construction duration and resources to modify pipe design/installation method to mitigate higher than expected volumes of groundwater.</td>
</tr>
</tbody>
</table>

**ILI Upgrade Cost Variances**

Factors that can particularly impact ILI Upgrade projects include:

- Limited location alternatives for tool launchers and receivers, requiring resolution of land acquisition purchase prices and Temporary Construction Easement fees;
- Schedule constraints to meet planned inspection timelines, requiring resolution of permitting issues with local permitting agencies;
- Hydraulic constraints on pipelines;
- Additional pipeline excavation and re-configuration to avoid other underground utilities and structures, particularly in stations; and
- Pipeline re-configuration requirements due to lower navigation tolerances of newer inspection tools.

During this reporting period, PG&E had the following projects in construction: I-101 upgrade project on L-300A, I-104 upgrade project on L-177A/L-189, I-100 upgrade project on L-142N and I-352 upgrade project on L-307A. PG&E expects to complete the projects referenced above by end of fourth quarter 2017.

Table 8-4 provides detail regarding impacts to cost efficiency of select projects in this reporting period:
TABLE 8-4
COST IMPACTS ON SELECT IN-LINE INSPECTION UPGRADE PROJECTS

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>I 104E</td>
<td>$11K</td>
<td>Construction costs and travel costs were reduced due to bundling of project activities.</td>
</tr>
<tr>
<td>I 104F</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**In-Line Inspection Cost Variances**

Factors that can particularly impact ILI Inspection projects include:

- **Compliance Requirements:** Compliance deadlines can require the implementation of expedited construction schedules and complex clearance planning to meet gas system operational requirements particularly on the San Francisco peninsula.

- **The use of non-traditional ILI tools, particularly at creek and freeway crossing locations.** Traditional ILI includes having to use a launcher and receiver to test miles of pipe and consequently there are only two areas to dig, construct and backfill. In contrast, a non-traditional ILI includes having to use pressure control fittings at multiple launch points, dig multiple holes, backfill and restore at multiple locations. The cost per mile can consequently be much higher for a non-traditional ILI.

- **Debris friction:** When pipelines have a large amount of debris or high friction, additional measures such as hydraulic or liquid cleaning need to be taken to remove debris and/or lubricate the pipeline to aid in tool passage.

- **Tool Inspection Operations:** If an inspection tool becomes lodged it requires a cut-out. These cut-out operations require separate mobilization for and replacement of pipeline features that impede the passage of the ILI tool.

During this reporting period, ILI has completed 64 miles of inspection and planning six miles on L-142N in Bakersfield and 54 miles on L-300B in Tehachapi. ILI has also incorporated the use of Electro Magnetic Acoustic Transducer inspection technology, specifically to assess the longitudinal seam welds on certain pipelines.

Table 8-5 provides detail regarding impacts to cost efficiency of select projects in this reporting period:
<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>I-357</td>
<td>$450K</td>
<td>During Q1 of 2017, a tool became lodged in the pipeline due to an unmapped, unpiggable Pressure Control Fitting. The feature was cutout and the tool runs commenced. Due to the recent hydrotest (2016) on the pipeline, the pipeline had a buildup of flash rust creating metal debris and high friction for the tools. Liquid cleaning is planned for Q2 of 2018 with inspection following in Q4 of 2018.</td>
</tr>
<tr>
<td>I-110E</td>
<td>$750K</td>
<td>Due to the black powder issue in the adjacent system (corresponding with project ID I-413), additional hydraulic pipeline cleaning measures were taken to ensure protection of district regulator filters and eliminate heavy buildup in front of inspection tools. Pipeline cleaning was completed in May 2017. ILI Inspections were completed in July 2017.</td>
</tr>
</tbody>
</table>

**ILI Direct Exam and Repair Cost Variances**

Factors that particularly impact ILI Direct Exam and Repair (“ILI Digs”) projects include:

- **Pipeline Condition**: Incidence of immediate anomalies (inspection indicates wall loss greater than 70 percent) can trigger additional pipeline assessment procedures with a greater likelihood of welded sleeve or cut-out repairs per PG&E’s repair standard;
- **Field Conditions**: Dig location (e.g., urban, suburban, or rural) can materially affect a range of cost factors including paving removal/remediation, ability to use native backfill, sufficiency of construction area, extent of traffic management, groundwater management and disposal, environmental permitting, and construction hours permitting; and
- **Schedule Constraints**: Acceleration of permitting or excavation schedules to meet compliance commitments or mitigate gas system constraints (e.g., where immediate anomalies trigger operationally significant gas system pressure reductions).

During the third quarter of 2017, ILI Digs construction addressed dig assessments and repairs identified from a 2017 ILI run (L-191/SP5) alongside those remaining from 2016 and prior year ILI inspections (including L-101, L-21D, L-138, L-300B, and L-0140-01).

Table 8-6 provides detail regarding impacts to cost efficiency of select projects in this reporting period:
## TABLE 8-6
COST IMPACTS TO SELECT ILI DIRECT EXAM AND REPAIR PROJECTS

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>ID 75</td>
<td>$300K</td>
<td>Higher than expected construction costs due to environmental factors encountered. Additional Non-destructive examination was required which included laser scan and enhanced Wet Fluorescent Magnetic Particle Examination. This is necessary to characterize the target indication, including the depth. In addition, more ground water was encountered than anticipated.</td>
</tr>
<tr>
<td>ID 84</td>
<td>$200K</td>
<td>Additional costs incurred due to the location of these digs. All locations that required extensive traffic control resulted in higher than expected third party contracts and support as well as limited construction hours. Extensive traffic control contributes to limited construction time as the set up and take down for traffic control is included in the construction time allotted by the city/county.</td>
</tr>
<tr>
<td>ID 83</td>
<td>$185K</td>
<td>Productivity factors included extended excavation durations due to encountering concrete layer under pavement and foreign utilities in the excavation zone.</td>
</tr>
</tbody>
</table>
19. Cost Impacts of Unexpected or Unforeseen Items

What, if any, significant unexpected or unforeseen items did PG&E encounter in undertaking the projects and what were the resulting cost impacts on a project-by-project basis?

Response

Unlike PSEP, PG&E did not forecast specific projects in the 2015 GT&S rate case. Rather, it forecast costs for Strength Tests, Pipe Replacement, and ILI on a programmatic basis, using various forecast methodologies. For purposes of responding to this requirement, PG&E used projects in which the original job estimates are greater than $10 million. For the current reporting period, there were no projects completed with job estimates greater than $10 million.
20. **Program Amount Authorized and Spent**

*Provide a table showing the total amount authorized for recovery from ratepayers and the total amount spent by PG&E year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).*

**Response**

Table 20-1 depicts the total amount of spending by PG&E as well as the corresponding annual adopted/imputed program amount for the following programs: Strength Test Program (including both the portions in base expense and Transmission Integrity Management Program (TIMP) expense balancing account), TIMP capital balancing account, ILI portion of the TIMP expense balancing account, and the programs associated with capital and expense pipe replacement.24

---

24 See Appendix N – Requirement 20: Table 20-1 Adopted and Recorded Expenditures.
22. Forecast vs. Actual Mileage – Replacements

Provide a table showing the total mileage of pipe PG&E forecast to replace in R.11-02-019 and the mileage PG&E has replaced year-to-date. Identify the location, Line #, milepost, Class of the pipe replaced. Indicate whether the pipe is located in a High Consequence Area.

Response

For the current reporting period, PG&E replaced approximately 3.81 miles of gas transmission pipeline. Table 22-1 below provides the total pipeline miles adopted and replaced during the reporting period associated with vintage pipe, class location, shallow pipe, and other pipeline safety investment. Table 22-2 provides a breakdown of the total mileage of pipe PG&E has replaced for the reporting period by location, line number, milepost, class of the pipe replaced, and whether the pipe is located in a High Consequence Area (HCA).  

<table>
<thead>
<tr>
<th>Pipe Replacement</th>
<th>2017 Adopted Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vintage Pipe</td>
<td>20.00</td>
</tr>
<tr>
<td>Class Location</td>
<td>1.97</td>
</tr>
<tr>
<td>Shallow/Exposed Pipe</td>
<td>3.40</td>
</tr>
<tr>
<td>Other Pipeline Safety Investment</td>
<td>0.00</td>
</tr>
<tr>
<td><strong>Total Adopted:</strong></td>
<td><strong>25.37</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pipe Replacement</th>
<th>2017 Actual Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Q1 2017</td>
</tr>
<tr>
<td>Vintage Pipe</td>
<td>–</td>
</tr>
<tr>
<td>Class Location</td>
<td>–</td>
</tr>
<tr>
<td>Shallow/Exposed Pipe</td>
<td>–</td>
</tr>
<tr>
<td>Other Pipeline Safety Investment</td>
<td>0.02</td>
</tr>
<tr>
<td><strong>Total Replaced:</strong></td>
<td>0.02</td>
</tr>
</tbody>
</table>

---


5-AtchA-89
-46-
<table>
<thead>
<tr>
<th>Column Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line #</td>
<td>Reference number for this Report.</td>
</tr>
<tr>
<td>Order Number</td>
<td>Financial system of record reference number to track specific costs, e.g., on individual projects and provided in workpapers supporting PG&amp;E Gas Transmission Application for projects commonly resulting from project split or addition.</td>
</tr>
<tr>
<td>Project Description</td>
<td>Order Description for ILI, upgrades for Strength Test, Pipe Replacement, and ILI, for Pipe Replacement and Strength Testing.</td>
</tr>
<tr>
<td>MAT</td>
<td>MAT represents a complete, distinct, sub-process of major work category. MATs are designated by three-character alphanumeric codes. The first two digits of the MAT are the MWC. A MAT can only be assigned to one MWC.</td>
</tr>
<tr>
<td>Miles</td>
<td>Miles of pipeline replaced.</td>
</tr>
<tr>
<td>Line</td>
<td>Pipeline identifier.</td>
</tr>
<tr>
<td>MP1</td>
<td>Beginning project mile point.</td>
</tr>
<tr>
<td>MP2</td>
<td>Ending project mile point.</td>
</tr>
<tr>
<td>City</td>
<td>Location of project.</td>
</tr>
<tr>
<td>HCA</td>
<td>Project includes a HCA.</td>
</tr>
<tr>
<td>Class Code</td>
<td>Class of pipeline included in project.</td>
</tr>
<tr>
<td>Tie-In Date</td>
<td>For ILI and pipeline testing and replacement projects, the tie-in date is the date the pipe became operational and the project was completed.</td>
</tr>
</tbody>
</table>
PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION PIPELINE COMPLIANCE REPORT

NO. 2017-04

REPORTING PERIOD
OCTOBER 1, 2017 – DECEMBER 31, 2017

IN COMPLIANCE WITH CPUC DECISION 16-06-056

SUBMITTED JANUARY 30, 2018
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Introduction

On July 1, 2016, the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 16-06-056 in Pacific Gas and Electric Company’s (PG&E or the Company) 2015 Gas Transmission and Storage (GT&S) rate case (A.13-12-012). Ordering Paragraph (OP) 11 of the decision directs PG&E to serve quarterly compliance reports of PG&E’s transmission pipeline work, including Strength Testing, Pipe Replacement, and In-Line Inspection (ILI):

Pacific Gas and Electric Company shall file a quarterly compliance report of its transmission pipeline work, including pressure test, pipe replacement, and ILI. The report shall generally follow the format in Attachment D of Decision 12-12-030 and shall include all costs recorded to these programs, such that they provide an accurate and complete record of all costs at the project and program level. Consistent with the joint stipulation on Reporting and Communications between PG&E and the Office of Ratepayer Advocates, the format and content of the report may be revised by a working group to ensure that the report is useful to parties. PG&E’s first compliance filing shall cover the period between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter. The report shall be served on the Commission’s Safety and Enforcement Division, Energy Division, and on the service list of this proceeding.

This Transmission Pipeline Compliance Report (Report) No. 2017-04 is submitted in compliance with this directive and reflects the reporting period of October 1, 2017 to December 31, 2017.

Report Format

The Report requirements set forth in Attachment D of the Pipeline Safety Enhancement Plan (PSEP) decision were framed to address specific issues relevant to the PSEP proceeding, which, in several ways, differ from the 2015 GT&S rate case proceeding.

This Report is organized to address each of the applicable requirements outlined in Attachment D of D.12-12-030 regarding the transmission pipeline programs: Strength Testing, Pipe Replacement, and ILI. This Report includes all costs recorded to Maintenance Activity Types (MAT) associated with these three transmission pipeline programs. As indicated in the previous quarterly Report, PG&E has included updated
presentations of Tables 20-1 and 21-1 in this report covering 2015 through December 2017.

All costs presented in this report (adopted/imputed and recorded) use the cost model PG&E implemented on January 1, 2016.¹ For the reporting period of October 1, 2017 through December 31, 2017, Table 1 provides a summary of the recorded costs incurred for the three transmission pipeline workstreams that are addressed in this report.² The 2017 data presented in this report is preliminary as of January 9, 2018 as PG&E is in the process of closing the financial books for 2017.

¹ For a detailed explanation of the cost model change, refer to the response to Requirement 29 of the Transmission Pipeline Compliance Report 2016-01.
² All recorded costs in this Report are as of January 9, 2018, and include Catastrophic Event Memorandum Account eligible orders.
## TABLE 1
ADOPTED 2017 GT&S EXPENSE AND CAPITAL EXPENDITURES COMPARED TO RECORDED COSTS BY PROGRAM
OCTOBER 1, 2017 – DECEMBER 31, 2017
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Programs</th>
<th>2017 Adopted / Imputed (a)</th>
<th>Recorded Oct-Dec 2017</th>
<th>Recorded 2017 YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Expense</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Strength Testing</td>
<td>$ 97,255</td>
<td>$ 19,775</td>
<td>$ 101,605</td>
</tr>
<tr>
<td>In-Line Inspection</td>
<td>$ 57,712</td>
<td>$ 19,238</td>
<td>$ 71,210</td>
</tr>
<tr>
<td>Pipeline Replacement</td>
<td>$ 2,744</td>
<td>$ 1,324</td>
<td>$ 2,856</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 157,711</td>
<td>$ 40,337</td>
<td>$ 175,671</td>
</tr>
<tr>
<td><strong>Capital</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Strength Testing</td>
<td>$ 26,825</td>
<td>$ 10,802</td>
<td>$ 37,369</td>
</tr>
<tr>
<td>In-Line Inspection</td>
<td>$ 94,182</td>
<td>$ 18,018</td>
<td>$ 88,941</td>
</tr>
<tr>
<td>Pipeline Replacement</td>
<td>$ 187,089</td>
<td>$ 49,634</td>
<td>$ 190,405</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$ 308,096</td>
<td>$ 78,454</td>
<td>$ 296,715</td>
</tr>
</tbody>
</table>

---

(a) 2017 adopted funding has been imputed by PG&E, consistent with the adopted Post Test-Year increase specified in D.16-12-010, Appendix E and Appendix I.
Decision-Making Process

1. Project Planning and Prioritization of Work

Describe PG&E’s project planning process including how the projects were and are being scheduled and sequenced and what measures were and are being taken to conduct the work in a cost effective manner.

Response

PG&E’s Gas Operations organization follows PG&E’s Integrated Planning process. PG&E’s Integrated Planning process and project planning and scheduling remain consistent with the descriptions previously provided in PG&E’s Gas Transmission Pipeline Compliance Report 2016-01. When determining the final forecasts for each program or project in the portfolio during the annual Integrated Planning process, consideration is given to risk as well as classification of work, system constraints, work readiness, and financial constraints.

Project Planning and Scheduling

Planned construction in the fourth quarter of 2017 consisted of continuing construction activities across all workstreams. There was continued focus on obtaining encroachment permits for 2018 planned work.

During the fourth quarter of 2017, PG&E also undertook the following activities to conduct work in a cost effective manner:

- Validated and updated the existing 2017-2019 project-level work plans, including Strength Test, Pipe Replacement, and ILI programs;
- Continued to identify potential process improvements and implement efficiencies across the Strength Testing, Pipe Replacement, and ILI programs.

---

2. Resource Planning

   Explain how PG&E decided whether to do the work in-house (e.g., use own employees and equipment) or contract the work out to other parties.

Response

PG&E's resource planning process remains consistent with the description previously provided in the Gas Transmission Pipeline Compliance Report 2016-01 to complete gas transmission work on a timely basis.\footnote{Refer to Appendix B – Requirement 2: Resource Planning Process for a description of the resource planning process provided in Requirement 2 of the 2016-01 Report.}

For construction, PG&E uses both its internal workforce and contract resources. Typically, PG&E’s internal workforce completes about 30 percent of the transmission work. In 2017, when possible, PG&E has bundled work being done on the same asset or in the same geographical area to reduce costs (e.g., costs related to mobilization, clearance support, and staging yards). By the end of fourth quarter 2017, approximately 23 work bundles were identified for 2018 construction.
Budget and Spending

8. Factors Impacting Cost Effectiveness

Describe any factors, either internal or external, that may have prevented or affected PG&E from conducting the work in a more cost effective manner. Quantify the cost impact of such factors.

Response

The primary cost drivers that impacted the cost efficiency of work associated with Strength Testing, Pipe Replacement and ILI programs are listed in the tables below. As part of ongoing project management activities, PG&E’s transmission pipeline programs identify project uncertainties and implement risk mitigation activities. In the fourth quarter of 2017, PG&E completed 66 projects in the three programs associated with this report and including ten ILI direct examination and repairs. PG&E has had success in 2017 reducing costs and limiting cost overruns on projects. However, PG&E has not been able to fully mitigate the potential impact of cost uncertainties. While not an exhaustive list, in some cases, these cost drivers resulted in individual projects incurring increased costs when compared to amounts adopted in D.16-06-056 and D.16-12-010. Of the 66 projects PG&E completed in the fourth quarter 2017, five experienced a job estimate overrun greater than 10% as depicted in Table 11-1. Table 8-1, below, summarizes the cost variances associated with each program, including direct examination and repair. Tables 8-2 through Table 8-6 list certain primary cost drivers for work completed during the reporting period, along with variance explanations at the program level.
### TABLE 8-1
UNITS AND COST EXPENDITURES BY PROGRAM
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>In-Line Tool Upgrades (capital)</td>
<td>98C, 44A</td>
<td>148 miles N/A</td>
<td>$94,182</td>
<td>100</td>
<td>154 miles $18,018</td>
<td>$68,941 N/A</td>
<td>$25,241 N/A</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>In-Line Inspections (expense)(8)</td>
<td>HPB, HPR, 34A</td>
<td>241 miles N/A</td>
<td>$38,996</td>
<td>75</td>
<td>267 miles $11,420</td>
<td>$42,298 N/A</td>
<td>$3,322 N/A</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>ILI Direct Exam &amp; Repair</td>
<td>HPi</td>
<td>97 digs N/A</td>
<td>$18,746</td>
<td>14</td>
<td>81 gigs $7,871</td>
<td>$28,922 N/A</td>
<td>$10,176 N/A</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Pipeline Replacement (capital and expense)</td>
<td>75E, 75H, 75M, 75O, 75T, 75P, 75Q, 75R, 75S, JT6, JT4, 44A, HPF, 34A</td>
<td>25 miles N/A</td>
<td>$189,833</td>
<td>1</td>
<td>5 miles(10)</td>
<td>$50,958</td>
<td>$193,261 N/A</td>
<td>$3,428 N/A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Strength Testing (2) (capital / expense)</td>
<td>HPF / JTC / JTM / 75N / 34A</td>
<td>170 miles $8.40/km</td>
<td>$124,080</td>
<td>72</td>
<td>253 miles $19,775</td>
<td>$101,605</td>
<td>$402K/mi (4)</td>
<td>($22,75)</td>
<td>($43K/mi (4))</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- (1) There were no adopted unit costs for the ILI Upgrade program in D.16-06-056. ILI upgrades cannot have unit costs as each project has a uniquely engineered scope. For example, a single project can have several valves replaced or no valves replaced, along with the addition of a launcher and receiver to make the line piggable. Therefore, an upgrade project could be 1 mile or 10 miles and still be the same cost. For the Pipeline Replacement Program, no adopted unit costs are provided at the program level as the decision were provided for three groupings of unit costs based on pipe diameter. For ILI Direct Exam and Repair, the unit cost was based on an average cost per dig taking into account whether the dig location was rural, urban, or a combination of the two. Therefore, a singular unit cost per dig does not apply.

- (2) The source of adopted funding for 2015 is D.16-06-056, Appendix D-Tables 1 and 2, and Appendix l-Tables 1 and 2. 2016-2018 adopted funding has been imputed by PG&E, consistent with the adopted Plan Test-Year increase specified.

- (3) Rate Case Units only show miles for Traditional In-Line Inspections. The rate case units for Non-Traditional ILI and ILI of Casings was based on number of projects and not miles. As of the completion of the MAT realignment effort, MAT HPB tracks Traditional ILI inspections and MAT HPR tracks Non-Traditional ILI inspections.

- (4) Recorded costs are referenced in Table 20-1 (see Balancing Account and Base Expense values in Column 2017 YTD) and completed units in column G of Table 8-1.

- (5) All costs are presented in PG&E’s new cost model.

- (6) Shareholder Absorbed Costs associated with the $650M penalty reflects the relevant programs per D.16-06-056, Appendix G.

- (7) Maintenance-Activity Type Code JTM added to scope of strength testing profile based on PG&E’s 2015 GT & $ Rate Case, Chapter 4A (D.11-06-017). YTD 2017 amount includes adjustments for JTM projects in Q1 and Q2 of 2017. See Table 23-3 for additional project detail.

- (8) 2017 adopted unit costs have been corrected from projects to miles for the In-Line Tool Upgrades program. Because D.16-06-056 did not specify an adopted mileage amount to complete per year, PG&E has had to impute miles based on the application of the decision. Units completed for the reporting period and YTD are reported in miles.

- (9) In addition to the 267 miles of in-line inspection completed to MAT codes 98C and 44A, there were 41 miles completed in-line inspection in separate work orders (MAT codes JTT and 73A).

- (10) In addition to the 5 miles of pipe replacement recorded to MATs 75E, 75H, 75M, 75O, 75T, 75P, 75Q, 75R, 75S, JT6, JT4, 44A, HPF, 34A, 15 miles of replacement were completed under separate work orders (MAT codes 26A, 73A, 75J, 84D, AH1, JTB). 20 miles of pipe were retired under separate work orders (MAT codes 75E, 84D, 79K, 750, 3K5 and 44A).
**Strength Testing Cost Variances**

Factors that impact cost effectiveness of PG&E’s strength testing typically include:

- **Length of Test**: There are significant fixed costs associated with executing a Strength Test (e.g., fabrication of test heads, clearance execution, and water management). Cost per unit decreases as test length increases.
- **Location**: Test location materially impacts costs associated with traffic management, water disposal, environmental permitting, and construction area utilization.
- **Construction Work Plan**: PG&E has previously demonstrated significant construction efficiencies when tests can be executed in series along an extended contiguous pipeline distance (i.e., elimination of multiple mobilization costs and reduction of water management costs through re-use). In the fourth quarter of 2017, the majority of the strength tests conducted were extended contiguous pipeline distance including T-1230A, T-1231A, T-1255, T-1290 and T-1385.

Table 8-2 provides detail regarding impacts to cost efficiency of strength test projects in this reporting period:

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>N/A</td>
<td>N/A</td>
<td>While the factors above are typical findings in overruns, PG&amp;E did not experience any overruns exceeding 10 percent in the area of strength test for 13 projects.</td>
</tr>
</tbody>
</table>

**Pipe Replacement Cost Variances**

Factors that particularly affect the cost effectiveness of PG&E’s pipe replacement include:

- **Unidentified Pipeline Conditions**: Additional engineering and construction activities required to repair/replace pipe, valves and fittings due to condition and construction obstructions due to unidentified non-PG&E structures and other utilities;
• Construction Permitting: Increased and/or restrictive permitting conditions affecting work hours, traffic management, or the means and methods of construction;
• Compliance commitments: Acceleration of design and construction schedules to meet compliance requirements can dictate compressed construction schedules, higher land costs, and construction during wet winter weather; and
• Field Conditions: Excavation-related factors such as high water table, poor/weak soils, and contaminated soil handling and disposal requirements.

During this reporting period, PG&E undertook two vintage pipe replacement or retirement projects that illustrate the type of drivers that can cause cost variances in excess of plan.

Table 8-3 provides detail regarding impacts to cost efficiency of vintage pipe replacement projects in this reporting period:

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>L-107 M22.34</td>
<td>$1.243M</td>
<td>Ground water, soil conditions, pipeline cleaning, a two-year permitting process and biological mitigation expenses contributed to the cost impacts of this project.</td>
</tr>
<tr>
<td>L-401</td>
<td>$11K</td>
<td>Gas Transmission Construction Management inspection costs were higher than the original budget estimate and contributed to the overrun.</td>
</tr>
</tbody>
</table>

**ILI Upgrade Cost Variances**

Factors that can particularly impact ILI Upgrade projects include:

• Limited location alternatives for tool launchers and receivers, requiring resolution of land acquisition purchase prices and Temporary Construction Easement fees;
• Schedule constraints to meet planned inspection timelines, timely resolution of permitting issues with local permitting agencies;
• Hydraulic constraints on pipelines;
• Additional pipeline excavation and re-configuration to avoid other underground utilities and structures, particularly in stations; and
Pipeline re-configuration requirements due to lower navigation tolerances of newer inspection tools.

During this reporting period, PG&E had the following projects in construction: I-100I L-142N MP 10.84-13.70 ILI Upgrade, I-101A L-300A MP 203.02 PLS 3A ILI Upgrade Launcher PB-18, I-101B L-300A MP 203.02-218.73 ILI Upgrade PB-18, I-101C L-300A Mojave Station ILI Upgrade PB-18, I-101D L-300A MP 218.73-237.5 ILI Upgrade PB-18, I-101E L-300A RCV 237.50A ILI Upgrade PB-18, I-101F L-300A MP 237.5-256.21 ILI Upgrade, PB-18, I-101G L-300A MP 256.21 PLS 4A ILI Upgrade Receiver PB-18, I-104A L-177A ILI Upgrade Launcher (Cummings Creek) PB-08, I-104B L-177A ILI Upgrade Receiver (HBPP) PB-08, I-104C L-177A ILI Upgrade Bypass Tompkins Hill Reg Station, I-104I L-177A MP 182.39-187.28 ILI Upgrade PB-08, I-352A L-307A L-134A ILI Upgrade Spreckles Meter Station Launcher PB-13, I-352B L-307A MP 0.00-12.05 ILI Upgrade PB-13, I-352C L-307B MP 8.63-16.92 ILI Upgrade PB-13, I-352D L-134B ILI Upgrade Arbios Bypass PB-13, I-352E L-134B MP 0-5.43 ILI Upgrade PB-13 and I-352F L-134B ILI Upgrade Receiver PB-13.

Table 8-4 provides detail regarding impacts to cost efficiency of ILI upgrade projects in this reporting period:

### TABLE 8-4
**COST IMPACTS ON IN-LINE INSPECTION UPGRADE PROJECTS**

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>HUM04I 177A</td>
<td>$245K</td>
<td>Final permit conditions required biological monitoring at specific locations which were not included in original job estimate. Project schedule extended due to site conditions requiring additional labor costs.</td>
</tr>
<tr>
<td>I-352F</td>
<td>$970K</td>
<td>The actual costs for engineering, permitting, material purchase and other pre-construction activities exceeded the job estimate.</td>
</tr>
</tbody>
</table>

### In-Line Inspection Cost Variances
Factors that can particularly impact ILI Inspection projects include:

- **Compliance Requirements:** Compliance deadlines can require the implementation of expedited construction schedules and complex clearance planning to meet gas system operational requirements particularly on the San Francisco peninsula.
The use of non-traditional ILI tools, particularly at creek and freeway crossing locations. Traditional ILI includes having to use a launcher and receiver to test miles of pipe and consequently there are only two areas to dig, construct and backfill. In contrast, a non-traditional ILI includes having to use pressure control fittings at multiple launch points, dig multiple holes, backfill and restore at multiple locations. The cost per mile can consequently be much higher for a non-traditional ILI.

- Debris friction: When pipelines have a large amount of debris or high friction, additional measures such as hydraulic or liquid cleaning need to be taken to remove debris and/or lubricate the pipeline to aid in tool passage.

- Tool Inspection Operations: If an inspection tool becomes lodged it requires a cut-out. These cut-out operations require separate mobilization for and replacement of pipeline features that impede the passage of the ILI tool.

During this reporting period, ILI has completed 115 miles of inspection. ILI has also incorporated the use of Electro Magnetic Acoustic Transducer inspection technology, specifically to assess the longitudinal seam welds on certain pipelines. During this reporting period, PG&E had the following projects in construction: I-027 L-132 MP 11.55-31.93 Pigging & Analysis, I-424 L-105A MP 45.65-45.85 Non-Traditional ILI, I-422 L-065 MP 0-1.00 Non-Traditional ILI, I-439 L-050A MP 2.54-2.55 Non-Traditional ILI, I-102 J L-300B MP 203.07-256.64 ILI Pigging & Analysis, I-423 DFM-1519-04 MP 0.025-0.188 Non-Traditional ILI, I-451 L-021F MP 12.14-12.16 Non-Traditional ILI, I-446 L-021G MP 12.12-12.16 Non-Traditional ILI, I-429 L-021E MP 93.54-114.89 ILI Re-Inspection and R-300D L-407 ILI Pigging & Analysis.

Table 8-5 provides detail regarding impacts to cost efficiency of ILI projects in this reporting period:

<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>I-451</td>
<td>$239K</td>
<td>Labor allocation rates rose by 70 percent from the time of the original job estimate.</td>
</tr>
</tbody>
</table>

TABLE 8-5
COST IMPACTS TO IN-LINE INSPECTION PROJECTS
ILI Direct Exam and Repair Cost Variances

Factors that particularly impact ILI Direct Exam and Repair (“ILI Digs”) projects include:

- Pipeline Condition: Incidence of immediate anomalies (inspection indicates wall loss greater than 70 percent) can trigger additional pipeline assessment procedures with a greater likelihood of welded sleeve or cut-out repairs per PG&E’s repair standard;

- Field Conditions: Dig location (e.g., urban, suburban, or rural) can materially affect a range of cost factors including paving removal/remediation, ability to use native backfill, sufficiency of construction area, extent of traffic management, groundwater management and disposal, environmental permitting, and construction hours permitting; and

- Schedule Constraints: Accelerating permitting or excavation schedules to meet compliance commitments or to mitigate gas system constraints (e.g., where immediate anomalies trigger operationally significant gas system pressure reductions).

In the fourth quarter, PG&E completed ten digs associated with direct examination and repair. For the quarter, these digs exceeded planned costs.

Table 8-6 provides detail regarding impacts to cost efficiency of ILI direct exam and repair projects in this reporting period:
<table>
<thead>
<tr>
<th>Project</th>
<th>Impact on Project Costs</th>
<th>Factors Impacting Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT-946 L-101 MP32.34 &amp; 32.40</td>
<td>$141K</td>
<td>The project was located in a highly congested area that required extensive traffic control. The cut-outs caused the project to incur additional costs to excavate sniff holes to fabricate and hydrotest tie-in pieces.</td>
</tr>
<tr>
<td>L-132</td>
<td>$527K</td>
<td>This project required extensive excavation which included removal of a large portion of Caltrans sound wall.</td>
</tr>
<tr>
<td>L-57A</td>
<td>$593K</td>
<td>Project had several locations which required expedited mobilization adding cost to the project.</td>
</tr>
<tr>
<td>L-177A</td>
<td>$860K</td>
<td>Higher costs can be associated with the required immediate mobilization in order to return the pipeline to normal operation since TROP (Temporary Reduction of Pressure) was put on the line. Repairs included weld repairs and clearance which resulted in additional costs. Clearances required additional internal and external resources. Sites were located in remote locations.</td>
</tr>
<tr>
<td>L-119C MP 0.00-6.69</td>
<td>$404K</td>
<td>Higher costs can be associated with the required immediate mobilization in order to return the pipeline to normal operation since TROP was put on the line. Repairs included weld repairs and clearance which resulted in additional costs. Clearances required additional internal and external resources.</td>
</tr>
<tr>
<td>L-177A IU MP 88.83-163.04</td>
<td>$178K</td>
<td>These sites required immediate mobilization to restore the pipeline pressure. These types of mobilizations add to project costs. Projects were located in remote locations.</td>
</tr>
<tr>
<td>L-21E</td>
<td>$562K</td>
<td>High project costs can be attributed to the resources required to perform cut-outs. Additional internal and external labor was required in order to perform the clearances and restore the pipeline to normal operation. Additionally, the project incurred standby costs for equipment and shoring due to project delay caused by the North Bay fires.</td>
</tr>
<tr>
<td>DFM-0140-01</td>
<td>$505K</td>
<td>Project had numerous sites, each requiring separate clearances. There were two emergency clearances required which added to the cost. Additionally, all sites required extensive traffic control.</td>
</tr>
<tr>
<td>L-119C MP 1.11 &amp; 1.72</td>
<td>$244K</td>
<td>Higher costs can be associated with the required immediate mobilization in order to return the pipeline to normal operation since TROP was put on the line. Repairs required welding and clearances which resulted in additional costs.</td>
</tr>
<tr>
<td>L-124A</td>
<td>$67K</td>
<td>This project required immediate mobilization in order to restore L-124 to normal operation since a TROP was put on the line.</td>
</tr>
</tbody>
</table>
19. **Cost Impacts of Unexpected or Unforeseen Items**

What, if any, significant unexpected or unforeseen items did PG&E encounter in undertaking the projects and what were the resulting cost impacts on a project-by-project basis?

**Response**

Unlike PSEP, PG&E did not forecast specific projects in the 2015 GT&S rate case. Rather, it forecast costs for Strength Tests, Pipe Replacement, and ILI on a programmatic basis, using various forecast methodologies. For purposes of responding to this requirement, PG&E used projects in which the original job estimates are greater than $10 million. For the current reporting period, there were no projects completed with job estimates greater than $10 million.
20. Program Amount Authorized and Spent

Provide a table showing the total amount authorized for recovery from ratepayers and the total amount spent by PG&E year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).

Response

Table 20-1 depicts the total amount of spending by PG&E as well as the corresponding annual adopted/imputed program amount for the following programs: Strength Test Program (including both the portions in base expense and Transmission Integrity Management Program (TIMP) expense balancing account), TIMP capital balancing account, ILI portion of the TIMP expense balancing account, and the programs associated with capital and expense pipe replacement.22

This report includes updated presentations of Table 20-1 for 201523 and 2016 to provide consistency with the presentation of 2017 data, which was updated beginning with Report 2017-02. The primary factors that drove these changes include: (1) changes to the adopted/imputed amounts resulting from the 2017 GRC decision (D.17-05-013), (2) prior reports did not include hydrotest capital or shallow/exposed pipe expense, and (3) PG&E completed its MWC/MAT realignment process in the second quarter of 2017 within PG&E’s financial system of record. All recorded data reflects SAP data, for the three-year period ending December 2017, as of January 9, 2018.


23 The updated presentation of 2015 data is presented in PG&E’s old cost model as the conversion to PG&E’s new cost model became effective in 2016.
22. Forecast vs. Actual Mileage – Replacements

Provide a table showing the total mileage of pipe PG&E forecast to replace in R.11-02-019 and the mileage PG&E has replaced year-to-date. Identify the location, Line #, milepost, Class of the pipe replaced. Indicate whether the pipe is located in a High Consequence Area.

Response

For the current reporting period, PG&E replaced approximately 0.58 miles of gas transmission pipeline. Table 22-1 below provides the total pipeline miles adopted and replaced during the reporting period associated with vintage pipe, class location, shallow pipe, and other pipeline safety investment. Table 22-2 provides a breakdown of the total mileage of pipe PG&E has replaced for the reporting period by location, line number, milepost, class of the pipe replaced, and whether the pipe is located in a High Consequence Area (HCA).28

<table>
<thead>
<tr>
<th>Pipe Replacement</th>
<th>2017 Adopted Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vintage Pipe</td>
<td>20.00</td>
</tr>
<tr>
<td>Class Location</td>
<td>1.97</td>
</tr>
<tr>
<td>Shallow/Exposed Pipe</td>
<td>3.40</td>
</tr>
<tr>
<td>Other Pipeline Safety Investment</td>
<td>0.00</td>
</tr>
<tr>
<td><strong>Total Adopted:</strong></td>
<td><strong>25.37</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pipe Replacement</th>
<th>Q1 2017</th>
<th>Q2 2017</th>
<th>Q3 2017</th>
<th>Q4 2017</th>
<th>2017 YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vintage Pipe</td>
<td>–</td>
<td>0.37</td>
<td>2.05</td>
<td>0.52</td>
<td>2.94</td>
</tr>
<tr>
<td>Class Location</td>
<td>–</td>
<td>–</td>
<td>1.11</td>
<td>–</td>
<td>1.11</td>
</tr>
<tr>
<td>Shallow/Exposed Pipe</td>
<td>–</td>
<td>–</td>
<td>0.51</td>
<td>–</td>
<td>0.51</td>
</tr>
<tr>
<td>Other Pipeline Safety Investment</td>
<td>0.04</td>
<td>0.22</td>
<td>0.17</td>
<td>0.06</td>
<td>0.49</td>
</tr>
<tr>
<td><strong>Total Replaced:</strong></td>
<td>0.04</td>
<td>0.59</td>
<td>3.84</td>
<td>0.58</td>
<td>5.05</td>
</tr>
</tbody>
</table>

---

<table>
<thead>
<tr>
<th>Column Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line #</td>
<td>Reference number for this Report.</td>
</tr>
<tr>
<td>Order Number</td>
<td>Financial system of record reference number to track specific costs, e.g., on individual projects and provided in workpapers supporting PG&amp;E Gas Transmission Application for projects commonly resulting from project split or addition.</td>
</tr>
<tr>
<td>Project Description</td>
<td>Order Description for ILI, upgrades for Strength Test, Pipe Replacement, and ILI, for Pipe Replacement and Strength Testing.</td>
</tr>
<tr>
<td>MAT</td>
<td>MAT represents a complete, distinct, sub-process of MWC. MATs are designated by three-character alphanumeric codes. The first two digits of the MAT are the MWC. A MAT can only be assigned to one MWC.</td>
</tr>
<tr>
<td>Miles</td>
<td>Miles of pipeline replaced.</td>
</tr>
<tr>
<td>Line</td>
<td>Pipeline identifier.</td>
</tr>
<tr>
<td>MP1</td>
<td>Beginning project mile point.</td>
</tr>
<tr>
<td>MP2</td>
<td>Ending project mile point.</td>
</tr>
<tr>
<td>City</td>
<td>Location of project.</td>
</tr>
<tr>
<td>HCA</td>
<td>Project includes a HCA.</td>
</tr>
<tr>
<td>Class Code</td>
<td>Class of pipeline included in project.</td>
</tr>
<tr>
<td>Tie-In Date</td>
<td>For ILI and pipeline testing and replacement projects, the tie-in date is the date the pipe became operational and the project was completed.</td>
</tr>
</tbody>
</table>

Pursuant to OP 2 of D.16-06-056, PG&E is required to replace 20 miles of vintage pipeline in 2018. PG&E will provide an update on its progress in replacing 20 miles of vintage pipeline, along with any challenges and risks to completing that scope of work, in its report for the first quarter of 2018.
TABLE 20-1 ADOPTED AND RECORDED EXPENDITURES
FOR 2015 THROUGH 2017
### TABLE 20-1

ADOPTED AND RECORDED EXPENDITURES (THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Program</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TRPA Water Capital</td>
<td>59,953</td>
<td>59,140</td>
<td>94,902</td>
<td>96,052</td>
<td>362,147</td>
</tr>
<tr>
<td>Non-Traditional in-line Inspections</td>
<td>3,033</td>
<td>13,130</td>
<td>13,950</td>
<td>16,250</td>
<td>46,116</td>
</tr>
<tr>
<td>TRPA Water Surface</td>
<td>32,330</td>
<td>31,110</td>
<td>53,710</td>
<td>50,616</td>
<td>153,159</td>
</tr>
<tr>
<td>Non-Traditional in-line Inspections (S)</td>
<td>2,149</td>
<td>1,152</td>
<td>1,150</td>
<td>1,167</td>
<td>5,618</td>
</tr>
<tr>
<td>BJ Wells</td>
<td>2,435</td>
<td>1,172</td>
<td>2,435</td>
<td>2,435</td>
<td>6,372</td>
</tr>
<tr>
<td>Non-Traditional BJ - Direct Examinations and Repairs</td>
<td>11,613</td>
<td>1,057</td>
<td>18,869</td>
<td>1,048</td>
<td>38,856</td>
</tr>
<tr>
<td>Hydrotest Capital</td>
<td>25,556</td>
<td>18,146</td>
<td>30,825</td>
<td>27,522</td>
<td>106,555</td>
</tr>
<tr>
<td>Hydrotest Expense</td>
<td>9,178</td>
<td>9,984</td>
<td>9,996</td>
<td>9,996</td>
<td>39,030</td>
</tr>
<tr>
<td>Hydrotest - TRPA Balancing Account</td>
<td>851</td>
<td>851</td>
<td>851</td>
<td>851</td>
<td>3,404</td>
</tr>
<tr>
<td>Hydrotest - Base</td>
<td>75,286</td>
<td>75,286</td>
<td>75,286</td>
<td>75,286</td>
<td>301,144</td>
</tr>
<tr>
<td>Pipelayer Capital</td>
<td>176,180</td>
<td>183,217</td>
<td>187,090</td>
<td>198,961</td>
<td>755,406</td>
</tr>
<tr>
<td>Pipelayer</td>
<td>173,051</td>
<td>169,048</td>
<td>164,011</td>
<td>147,608</td>
<td>653,718</td>
</tr>
<tr>
<td>Gas location</td>
<td>7,185</td>
<td>17,877</td>
<td>18,977</td>
<td>18,816</td>
<td>54,956</td>
</tr>
<tr>
<td>Shovel/Pipe/Flow/Pipe</td>
<td>18,244</td>
<td>18,059</td>
<td>18,955</td>
<td>19,955</td>
<td>75,169</td>
</tr>
<tr>
<td>Capital/Repair</td>
<td>1,592</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Use Capital Repair</td>
<td>1,592</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Pipe Replacement 75</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Pipe Replacement in lieu of Line Replacing</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Direct Asset</td>
<td>3,5</td>
<td>5</td>
<td>37</td>
<td>17</td>
<td>5</td>
</tr>
<tr>
<td>Pipe Replacement Expense</td>
<td>3,565</td>
<td>2,638</td>
<td>2,748</td>
<td>2,809</td>
<td>10,731</td>
</tr>
<tr>
<td>Hydrotest - Field</td>
<td>2,551</td>
<td>2,630</td>
<td>2,748</td>
<td>2,809</td>
<td>10,731</td>
</tr>
<tr>
<td>Hydrotest - Field in lieu of Line Replacing</td>
<td>3,565</td>
<td>2,638</td>
<td>2,748</td>
<td>2,809</td>
<td>10,731</td>
</tr>
<tr>
<td>pipe</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Hydrotest - Field in lieu of Line Replacing</td>
<td>3,565</td>
<td>2,638</td>
<td>2,748</td>
<td>2,809</td>
<td>10,731</td>
</tr>
<tr>
<td>pipe</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

1. In 2015, PG&E completed its LHD Code Realignment effort. The LHD Codes are identified in this table represent the actual costs incurred and post realignment. To better align projects with work programs based on PG&E's accounting structure, recorded costs associated with LHD Capital Repair, LHD Pipe Explaining, and LHD Asset are reclassified across Vantage, Obs Local, Shallow Expanding Pipe and Capital Repair.

2. The source of additional funding for 2015 is 16:16/06/05, Appendix D Table 1.3 and Appendix D Table 1.3. 2015-2016 adopted funding has been updated by PG&E, consistent with the adopted Post Year increase as posted in Appendix E and Appendix E Table 3.16:04:06/05

3. The adopted/paid and recorded amounts for TRPA Water Capital, Vantage, Obs Local, and Shallow Expanding Pipe include funding for TRPA (MAT-I) Reimbursement for 2015.

4. The adopted/paid and recorded amounts for TRPA Water Capital, Obs Local, and Shallow Expanding Pipe include funding for TRPA (MAT-I). The adopted/paid and recorded amounts for Obs Local, and Shallow Expanding Pipe include funding for Obs Local, and Shallow Expanding Pipe Capital Repair.

5. A&G records include amounts, are capitalized in the GRC and disclosed in the GRC.
### TABLE 3-1
### ADOPTED AND RECORDED EXPENDITURES (THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Program</th>
<th>MA²</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Total</th>
<th>2015 YTD</th>
<th>2016 YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td>59,483</td>
<td>93,549</td>
<td>94,682</td>
<td>99,632</td>
<td>102,427</td>
<td>342,247</td>
<td>136,217</td>
<td>6,780</td>
</tr>
<tr>
<td>Traditional In-Line Inspection</td>
<td>59,483</td>
<td>93,549</td>
<td>94,682</td>
<td>99,632</td>
<td>102,427</td>
<td>342,247</td>
<td>136,217</td>
<td>6,780</td>
</tr>
<tr>
<td>Non-Traditional In-Line Inspection</td>
<td>59,483</td>
<td>93,549</td>
<td>94,682</td>
<td>99,632</td>
<td>102,427</td>
<td>342,247</td>
<td>136,217</td>
<td>6,780</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>59,483</td>
<td>93,549</td>
<td>94,682</td>
<td>99,632</td>
<td>102,427</td>
<td>342,247</td>
<td>136,217</td>
<td>6,780</td>
</tr>
</tbody>
</table>

**Notes:**

1. The source of adoption for funding for 2015 is O. Bd. 32, No.5, Appendix G, Table 1 and 2. For 2015-2018, adopted funding has been imputed by MDE, consistent with the adopted Post Test Year increase specified in Appendix E and Appendix G O. Bd. 32/2015.

2. The adopted and recorded amounts for TRAP II, Capital, Vintage, Class Locations, and Shallow Pipe include funding for StormHunt (MA 44A).

3. The adopted and recorded amounts for TRAP II, Expense, Hydrotest - Base, Repair Costs, and Repair Replacements do not include funding for StanPac (MA 34A).

4. The adopted and recorded amounts for Hydrotest - Base reflect updates to benefits as a result of the 2017 IRC Code changes (5.17-5.01(3)). The 2017 IRC Code changes and M&G amounts are forth in the Settlement as shown in MA 44B (PET & RIC), page 4-15.

5. M&G costs, including benefits, are reported in the IRC and allocated to DBS.

6. All amounts are presented in PSE&G's new cost model, with the exception of 2015 as PSE&G did not convert to the new cost model until 2018.

7. Subtotal variance due to rounding.

---

5-AtchA-113
AppM-2
### TABLE 20-1
**ADOPTED AND RECORDED EXPENDITURES (THOUSANDS OF DOLLARS)**

<table>
<thead>
<tr>
<th>Program</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Total</th>
<th>2017Q1</th>
<th>2017Q2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Water System</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Capital</strong></td>
<td>59,983</td>
<td>51,249</td>
<td>94,198</td>
<td>96,912</td>
<td>246,427</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Traditional in Line Expenditure</strong></td>
<td>56,750</td>
<td>78,224</td>
<td>80,588</td>
<td>82,448</td>
<td>281,800</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Non-Traditional in Line Expenditure</strong></td>
<td>3,253</td>
<td>13,126</td>
<td>13,799</td>
<td>14,324</td>
<td>40,512</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TRM Position</strong></td>
<td>68,212</td>
<td>93,451</td>
<td>108,152</td>
<td>110,572</td>
<td>381,357</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-Program</td>
<td>2,489</td>
<td>2,954</td>
<td>2,308</td>
<td>2,489</td>
<td>9,280</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Traditional - Direct Examinations and Repairs</strong></td>
<td>3,220</td>
<td>3,712</td>
<td>3,799</td>
<td>3,865</td>
<td>13,590</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Non-Traditional - Direct Examinations and Repairs</strong></td>
<td>11,585</td>
<td>10,917</td>
<td>12,676</td>
<td>13,086</td>
<td>48,264</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydrotest Capital</strong></td>
<td>5,256</td>
<td>16,245</td>
<td>17,312</td>
<td>18,105</td>
<td>58,920</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydrotest Expenditure</strong></td>
<td>93,726</td>
<td>93,803</td>
<td>91,227</td>
<td>90,395</td>
<td>378,453</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydrotest - TRM Balancing Account</strong></td>
<td>9,047</td>
<td>9,764</td>
<td>9,904</td>
<td>10,095</td>
<td>37,816</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydrotest - Base</strong></td>
<td>82,680</td>
<td>83,060</td>
<td>81,220</td>
<td>80,300</td>
<td>340,284</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pipe Replacement - Capital</strong></td>
<td>377,300</td>
<td>193,237</td>
<td>163,049</td>
<td>193,981</td>
<td>870,656</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pipe Replacement - Expense</strong></td>
<td>38,320</td>
<td>80,451</td>
<td>91,132</td>
<td>92,038</td>
<td>301,931</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Water System Pipe Replacement</strong></td>
<td>9,386</td>
<td>11,539</td>
<td>12,308</td>
<td>12,512</td>
<td>45,745</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydrotest Pipe/Exposed Pipe</strong></td>
<td>16,264</td>
<td>18,664</td>
<td>19,488</td>
<td>19,646</td>
<td>74,044</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pipe Replacement - Capital</strong></td>
<td>13,048</td>
<td>10,918</td>
<td>9,901</td>
<td>10,095</td>
<td>43,952</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pipe Replacement - Expense</strong></td>
<td>2,500</td>
<td>2,975</td>
<td>3,463</td>
<td>3,865</td>
<td>12,700</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pipe Replacement in Line of Hydrating</strong></td>
<td>1,303</td>
<td>1,303</td>
<td>1,303</td>
<td>1,303</td>
<td>5,210</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pipe Replacement - Expense</strong></td>
<td>3,210</td>
<td>3,210</td>
<td>3,210</td>
<td>3,210</td>
<td>12,840</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pipe Replacement - Expense</strong></td>
<td>1,100</td>
<td>1,100</td>
<td>1,100</td>
<td>1,100</td>
<td>4,400</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pipe Replacement - Expense</strong></td>
<td>2,250</td>
<td>2,250</td>
<td>2,250</td>
<td>2,250</td>
<td>8,750</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>377,300</td>
<td>193,237</td>
<td>163,049</td>
<td>193,981</td>
<td>870,656</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1. All amounts are presented in PG&E's new cost model with the exception of 2015 as PG&E did not convert to the new cost model until 2016.
2. Subtotal variance due to rounding.
PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX N

REQUIREMENT 21:

TABLE 21-1 SHAREHOLDER ABSORBED COSTS

FOR 2015 THROUGH 2017
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total FTE Capital</td>
<td>$56,799</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Net decrease in capital</td>
<td>($11,616)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Less: net decrease in capital due to Incomi...</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Total 5-AtchA-116</td>
<td>$45,183</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Shareholder Information for 5-AtchA-116**

<table>
<thead>
<tr>
<th>Date</th>
<th>Capital (as of)</th>
<th>Current Year (as of)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>5-AtchA-116</td>
<td>$45,183</td>
</tr>
<tr>
<td>2016</td>
<td>5-AtchA-116</td>
<td>$45,183</td>
</tr>
<tr>
<td>2017</td>
<td>5-AtchA-116</td>
<td>$45,183</td>
</tr>
</tbody>
</table>

**Appendix**

*5-AtchA-116*
<table>
<thead>
<tr>
<th>Year</th>
<th>Cost 9,10</th>
<th>YTD</th>
<th>January</th>
<th>February</th>
<th>March</th>
<th>April</th>
<th>May</th>
<th>June</th>
<th>July</th>
<th>August</th>
<th>September</th>
<th>October</th>
<th>November</th>
<th>December</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>5,100.00</td>
<td>56,500.00</td>
<td>138,22</td>
<td>298,03</td>
<td>9,371</td>
<td>33,799</td>
<td>4,116</td>
<td>3,712</td>
<td>26,145</td>
<td>108,051</td>
<td>41,471</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>2016</td>
<td>5,100.00</td>
<td>56,500.00</td>
<td>138,22</td>
<td>298,03</td>
<td>9,371</td>
<td>33,799</td>
<td>4,116</td>
<td>3,712</td>
<td>26,145</td>
<td>108,051</td>
<td>41,471</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Total** | 10,200.00 | 113,000.00 | 276,44 | 596,06 | 19,742 | 67,598 | 8,228| 7,424 | 52,290| 216,102| 82,942    | 35,742 | 35,742   | 35,742   |

**Notes:**
1. The data is based on the principles outlined in the appendix.
2. The amounts represent the costs associated with the various programs.
3. The data includes all relevant costs associated with the programs.
4. The data is presented in USD.
5. The data is presented on a quarterly basis.
6. The data includes all relevant costs associated with the programs.
7. The data is presented in USD.
8. The data includes all relevant costs associated with the programs.
9. The data is presented on a quarterly basis.
10. The data includes all relevant costs associated with the programs.
11. The data is presented in USD.
12. The data includes all relevant costs associated with the programs.
13. The data is presented on a quarterly basis.
14. The data includes all relevant costs associated with the programs.
15. The data is presented in USD.
16. The data includes all relevant costs associated with the programs.
17. The data is presented on a quarterly basis.
18. The data includes all relevant costs associated with the programs.
19. The data is presented in USD.
20. The data includes all relevant costs associated with the programs.
21. The data is presented on a quarterly basis.
22. The data includes all relevant costs associated with the programs.
23. The data is presented in USD.
24. The data includes all relevant costs associated with the programs.
25. The data is presented on a quarterly basis.
26. The data includes all relevant costs associated with the programs.
27. The data is presented in USD.
28. The data includes all relevant costs associated with the programs.
29. The data is presented on a quarterly basis.
30. The data includes all relevant costs associated with the programs.
31. The data is presented in USD.
32. The data includes all relevant costs associated with the programs.
33. The data is presented on a quarterly basis.
34. The data includes all relevant costs associated with the programs.
35. The data is presented in USD.
36. The data includes all relevant costs associated with the programs.
37. The data is presented on a quarterly basis.
38. The data includes all relevant costs associated with the programs.
39. The data is presented in USD.
40. The data includes all relevant costs associated with the programs.
41. The data is presented on a quarterly basis.
42. The data includes all relevant costs associated with the programs.
43. The data is presented in USD.
44. The data includes all relevant costs associated with the programs.
45. The data is presented on a quarterly basis.
46. The data includes all relevant costs associated with the programs.
47. The data is presented in USD.
48. The data includes all relevant costs associated with the programs.
49. The data is presented on a quarterly basis.
50. The data includes all relevant costs associated with the programs.
51. The data is presented in USD.
52. The data includes all relevant costs associated with the programs.
53. The data is presented on a quarterly basis.
54. The data includes all relevant costs associated with the programs.
55. The data is presented in USD.
56. The data includes all relevant costs associated with the programs.
57. The data is presented on a quarterly basis.
58. The data includes all relevant costs associated with the programs.
59. The data is presented in USD.
60. The data includes all relevant costs associated with the programs.
61. The data is presented on a quarterly basis.
62. The data includes all relevant costs associated with the programs.
63. The data is presented in USD.
64. The data includes all relevant costs associated with the programs.
65. The data is presented on a quarterly basis.
66. The data includes all relevant costs associated with the programs.
67. The data is presented in USD.
68. The data includes all relevant costs associated with the programs.
69. The data is presented on a quarterly basis.
70. The data includes all relevant costs associated with the programs.
71. The data is presented in USD.
72. The data includes all relevant costs associated with the programs.
73. The data is presented on a quarterly basis.
74. The data includes all relevant costs associated with the programs.
75. The data is presented in USD.
76. The data includes all relevant costs associated with the programs.
77. The data is presented on a quarterly basis.
78. The data includes all relevant costs associated with the programs.
79. The data is presented in USD.
80. The data includes all relevant costs associated with the programs.
81. The data is presented on a quarterly basis.
82. The data includes all relevant costs associated with the programs.
83. The data is presented in USD.
84. The data includes all relevant costs associated with the programs.
85. The data is presented on a quarterly basis.
86. The data includes all relevant costs associated with the programs.
87. The data is presented in USD.
88. The data includes all relevant costs associated with the programs.
89. The data is presented on a quarterly basis.
90. The data includes all relevant costs associated with the programs.
91. The data is presented in USD.
92. The data includes all relevant costs associated with the programs.
93. The data is presented on a quarterly basis.
94. The data includes all relevant costs associated with the programs.
95. The data is presented in USD.
96. The data includes all relevant costs associated with the programs.
97. The data is presented on a quarterly basis.
98. The data includes all relevant costs associated with the programs.
99. The data is presented in USD.
100. The data includes all relevant costs associated with the programs.
101. The data is presented on a quarterly basis.
102. The data includes all relevant costs associated with the programs.
103. The data is presented in USD.
104. The data includes all relevant costs associated with the programs.
105. The data is presented on a quarterly basis.
106. The data includes all relevant costs associated with the programs.
107. The data is presented in USD.
108. The data includes all relevant costs associated with the programs.
109. The data is presented on a quarterly basis.
110. The data includes all relevant costs associated with the programs.
111. The data is presented in USD.
112. The data includes all relevant costs associated with the programs.
113. The data is presented on a quarterly basis.
114. The data includes all relevant costs associated with the programs.
115. The data is presented in USD.
116. The data includes all relevant costs associated with the programs.
117. The data is presented on a quarterly basis.
118. The data includes all relevant costs associated with the programs.
119. The data is presented in USD.
120. The data includes all relevant costs associated with the programs.
121. The data is presented on a quarterly basis.
122. The data includes all relevant costs associated with the programs.
123. The data is presented in USD.
124. The data includes all relevant costs associated with the programs.
125. The data is presented on a quarterly basis.
126. The data includes all relevant costs associated with the programs.
127. The data is presented in USD.
128. The data includes all relevant costs associated with the programs.
129. The data is presented on a quarterly basis.
130. The data includes all relevant costs associated with the programs.
131. The data is presented in USD.
132. The data includes all relevant costs associated with the programs.
133. The data is presented on a quarterly basis.
134. The data includes all relevant costs associated with the programs.
135. The data is presented in USD.
136. The data includes all relevant costs associated with the programs.
137. The data is presented on a quarterly basis.
138. The data includes all relevant costs associated with the programs.
139. The data is presented in USD.
140. The data includes all relevant costs associated with the programs.
141. The data is presented on a quarterly basis.
142. The data includes all relevant costs associated with the programs.
143. The data is presented in USD.
144. The data includes all relevant costs associated with the programs.
145. The data is presented on a quarterly basis.
146. The data includes all relevant costs associated with the programs.
147. The data is presented in USD.
148. The data includes all relevant costs associated with the programs.
149. The data is presented on a quarterly basis.
150. The data includes all relevant costs associated with the programs.
151. The data is presented in USD.
152. The data includes all relevant costs associated with the programs.
153. The data is presented on a quarterly basis.
154. The data includes all relevant costs associated with the programs.
155. The data is presented in USD.
156. The data includes all relevant costs associated with the programs.
157. The data is presented on a quarterly basis.
<table>
<thead>
<tr>
<th>Program</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>ITIL</td>
<td>10,939</td>
<td>9,548</td>
<td>9,283</td>
<td>8,529</td>
<td>38,405</td>
</tr>
<tr>
<td>Non ITIL</td>
<td>9,703</td>
<td>8,249</td>
<td>6,992</td>
<td>6,471</td>
<td>28,477</td>
</tr>
<tr>
<td>Total</td>
<td>20,642</td>
<td>17,847</td>
<td>16,275</td>
<td>14,999</td>
<td>77,882</td>
</tr>
</tbody>
</table>

**Notes:**
- N/A: Not applicable
- N/A: Not available

**Table: SHAREHOLDER ABSORBED COSTS (THOUSANDS OF DOLLARS)**

<table>
<thead>
<tr>
<th>Account</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Traditional - Inspections</td>
<td>2,628</td>
<td>2,930</td>
<td>3,033</td>
<td>3,101</td>
<td>12,793</td>
</tr>
<tr>
<td>Traditional - Hydrotesting</td>
<td>35,803</td>
<td>33,414</td>
<td>34,226</td>
<td>37,139</td>
<td>130,682</td>
</tr>
</tbody>
</table>

**Notes:**
- N/A: Not applicable
- N/A: Not available
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

REBUTTAL TESTIMONY OF LARRY D. KENNEDY

ASSET FAMILY – STORAGE
A. Introduction........................................................................................................................................6-1

B. Summary of Parties’ Positions...........................................................................................................6-1

C. Response to Parties’ Recommendations Concerning Specific Programs or Projects

   1. WELL – Reworks and Retrofits ........................................................................................................6-3
      a. TURN and IS Recommend Reducing PG&E’s Forecast for Reworks and Retrofits (MAT 3L3) ................6-4
      b. TURN and IS Recommendation Regarding PG&E’s Proposed Special Attrition Adjustment ..................6-6
      c. ORA Recommends Reducing the 2018 Capital Expenditure Forecast for the WELL – Reworks and Retrofits Program ...............................6-6

   2. New Storage Wells.............................................................................................................................6-9

   3. WELL – Integrity Inspections and Surveys.......................................................................................6-11

   4. Storage Well Decommissioning .......................................................................................................6-12

   5. OSA Recommendations....................................................................................................................6-14
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

REBUTTAL TESTIMONY OF LARRY D. KENNEDY

ASSET FAMILY – STORAGE

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.
A 1 My name is Larry D. Kennedy Jr. This testimony responds to the direct testimony of the Office of Ratepayer Advocates (ORA), 1 The Utility Reform Network (TURN), 2 Indicated Shippers (IS), 3 Calpine Corporation (Calpine), Commercial Energy (CE), and Office of the Safety Advocate (OSA). 4 Pacific Gas and Electric Company (PG&E) summarizes parties’ positions in Section B.

Q 2 Do parties generally criticize PG&E’s showing regarding Gas Storage?
A 2 Parties do not offer any general criticism regarding Gas Storage.

Q 3 Do parties make recommendations concerning specific projects and programs?
A 3 Yes, the parties listed above make recommendations concerning a number of PG&E’s forecast projects and programs.

Q 4 Does PG&E dispute any of these recommendations?
A 4 Yes, PG&E disputes certain of these recommendations. PG&E addresses each parties’ recommendations in this chapter in Section C.

B. Summary of Parties’ Positions

Q 5 Please provide a summary of the parties’ recommendations.
A 5 PG&E’s application forecast and the parties’ recommendations are set forth in Table 6-1 (2019 Expense), and Tables 6-2 (2018-2021 Capital) below.

1 ORA-14B/C and ORA-11.
2 TURN, Chapter 6.
3 IS-1.
4 OSA-1.
### TABLE 6-1
SUMMARY OF 2019 EXPENSE FORECAST – PG&E AND TURN
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>MWC</th>
<th>PG&amp;E Current Forecast(a)</th>
<th>TURNS Reductions</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Well Integrity Management Plan (WELL) – Integrity Assessments (Surveys)</td>
<td>AH</td>
<td>$6,011</td>
<td>$(2,900)</td>
</tr>
<tr>
<td>2</td>
<td>WELL – Other</td>
<td>AH, JT</td>
<td>4,812</td>
<td>–</td>
</tr>
<tr>
<td>3</td>
<td>WELL – Reworks Integrity Assessments</td>
<td>AH</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>4</td>
<td>Total</td>
<td></td>
<td>$10,823</td>
<td>$(2,900)</td>
</tr>
</tbody>
</table>

(a) There are no errata for Chapter 6 expenses.

### TABLE 6-2
SUMMARY OF 2018-2021 CAPITAL EXPENDITURES – PG&E AND PARTIES
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
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<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>WELL – Controls and Cont. Monitoring</td>
<td>3L</td>
<td>$18,115</td>
<td>$14,524</td>
<td>$1,791</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>2</td>
<td>WELL – Repair and Replace</td>
<td>3L</td>
<td>10,313</td>
<td>3,219</td>
<td>4,405</td>
<td>$134</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>4</td>
<td>Total</td>
<td></td>
<td>$70,832</td>
<td>$178,063</td>
<td>$170,795</td>
<td>$20,154</td>
<td>$(8,967)</td>
<td>$(101,500)</td>
<td>$(104,687)</td>
<td>$(29,893)</td>
<td>$(103,239)</td>
<td>$(104,490)</td>
<td>$(39,900)</td>
<td>$(25,039)</td>
<td>$(30,990)</td>
<td>–</td>
<td>$(25,039)</td>
<td>$(30,990)</td>
<td>–</td>
</tr>
</tbody>
</table>

(a) Includes June 5 errata decreasing the forecast by $278 in 2018.
(b) Includes June 5 errata increasing the forecast by $11 in 2021.
Q 6 Are there programs that parties do not dispute?
A 6 Yes. As Tables 6-1 and 6-2 show, no party disputes PG&E’s forecast for the following programs:
- WELL – Other (MAT AH3);
- WELL – Controls and Continuous Monitoring (MAT 3L5); and
- WELL – Repair and Replace (MAT 3L4).
Q 7 Does ORA make any recommendations to reduce the forecast for the rate case period?
A 7 No, ORA does not make any recommendations regarding PG&E’s forecast for 2019 and beyond. However, ORA recommends a capital expenditure reduction for 2018.
Q 8 Are there parties that support PG&E’s proposal for a two-way Gas Storage Balancing Account (GSBA)?
A 8 Yes, TURN supports adoption of the two-way GSBA.
Q 9 Does PG&E agree with parties’ proposed reductions for the other programs?
A 9 No. For the reasons explained in Section C, PG&E does not believe any reduction is justified for the following programs:
- WELL – Reworks and Retrofits, including the post-test year (PTY) adjustment for expenses in Maintenance Activity Type (MAT) AH2;
- WELL – Integrity Assessments in MAT AH1;
- New Storage Wells; and
- Storage Well Decommissioning.

C. Response to Parties’ Recommendations Concerning Specific Programs or Projects

1. WELL – Reworks and Retrofits
Q 10 Briefly, what is the scope of the WELL – Reworks and Retrofits Program?
A 10 The Well – Reworks and Retrofits Program includes the following work:
- Reworks and Retrofits – MAT 3L3 – Capital; and
- Integrity Assessments – MAT AH2 – Expense.

Reworks and retrofits include both well rework to address reliability issues, and well retrofits to implement the Department of Oil, Gas and Geothermal Resources (DOGGR) regulations that will require storage
operators to eliminate a single point of failure at storage wells. Once the well retrofits have been completed in 2020, subsequent biennial integrity assessments, which assess the condition of the wells, transition from capital projects to expense projects. This program is more fully-discussed in PG&E's opening testimony.

Q 11 Do any parties have a recommendation regarding the WELL – Reworks and Retrofits Program?

A 11 Yes. ORA, TURN and IS have recommendations regarding this program. PG&E addresses their recommendations below. Table 6-3A summarizes parties’ recommendations regarding WELL – Reworks and Retrofits and Integrity Assessments.

### TABLE 6-3A
**SUMMARY OF RECOMMENDATIONS FOR REWORKS AND RETROFITS PROGRAM (MIILLIONS OF DOLLARS)**

<table>
<thead>
<tr>
<th></th>
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<td>(74.4)</td>
<td>(73.5)</td>
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**a. TURN and IS Recommend Reducing PG&E’s Forecast for Reworks and Retrofits (MAT 3L3)**

Q 12 What is TURN’s recommendation for WELL – Reworks and Retrofits in 2019?

A 12 TURN proposes a 2019 funding level of $76.6 million, which is a $101.5 million reduction to PG&E’s forecast.

Q 13 What is IS’ recommendation for reworks and retrofits?

A 13 IS propose a 2019 funding level of $60.9 million, which is a $74.4 million reduction.

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5 The DOGGR regulations became final on June 29, 2018.
6 PG&E Prepared Testimony, Chapter 6, Section C, p. 6-19, line 1 to p. 6-23, line 10.
7 TURN, Chapter 6, p. 4, lines 6-9.
8 IS-1, Chapter 6, p. 6-9, Table 6-2.
Q 14 What is the basis for TURN’s and the IS’ proposed reductions?

A 14 Both TURN and IS recommend that PG&E’s forecasts be reduced to reflect the final DOGGR regulations that were issued on June 29, 2018.

Q 15 Do you agree with TURN’s and IS’ recommendations for reducing PG&E’s cost forecasts?

A 15 No. While it is true that the regulations have become final and go into effect on October 1, 2018, there are various reasons why PG&E’s original forecast should be adopted:

- First, even though the regulations have been adopted, there is still uncertainty regarding whether all of PG&E’s workplans to comply with regulations will be on a 7-year schedule. Per the regulations, DOGGR must approve PG&E’s Risk Management Plan for PG&E to obtain this longer compliance period; 9

- Second, even though the regulations have been approved, the overall level of spending is predicated on PG&E’s Natural Gas Storage Strategy (NGSS) being approved. PG&E’s forecast only included a limited amount of work to complete at the Los Medanos and Pleasant Creek facilities after 2018. If the California Public Utilities Commission (CPUC or Commission) does not adopt PG&E’s NGSS or delays its implementation, compliance activities will need to take place at those two storage fields, which would increase PG&E’s costs; and

- Third, while the compliance activities may take place over a longer period of time, all storage operators in California will still need to comply and there may still be a constraint on the availability of resources to complete this work. Such constraints could put upward pressure on PG&E’s costs.

PG&E’s forecasts in these areas were reasonable when made. Neither TURN nor IS recommended changes to PG&E’s unit costs or pace of work, other than the fact that the regulations have been made final well after the time that PG&E finalized its forecasts in this proceeding.

9 14 CCR § 1726.3.
How does PG&E propose accounting for the impact to PG&E’s forecast stemming from the adoption of final DOGGR regulations that may change PG&E’s forecast from its filed rate case position?

PG&E’s proposed two-way GSBA, which TURN supports, will provide a mechanism by which to return costs to customers in the event that PG&E’s actual costs are lower than forecast.

b. TURN and IS Recommendation Regarding PG&E’s Proposed Special Attrition Adjustment

Do any parties have a recommendation regarding integrity assessments?

Yes, as shown in Table 6-3B, both TURN and IS recommend that the Commission reject PG&E’s special attrition adjustment for integrity assessments.\[^{10}\]

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<td>$(80.2)</td>
<td>$(84.3)</td>
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What is the basis for parties’ recommendation?

TURN and IS recommend that PG&E’s special PTY expense is unnecessary because of the finalized DOGGR rules.

Does PG&E agree with their recommendation?

No. For the reasons discussed in Section C.1.a., PG&E’s forecast should be adopted.

c. ORA Recommends Reducing the 2018 Capital Expenditure Forecast for the WELL – Reworks and Retrofits Program

What is ORA’s recommendation for WELL – Reworks and Retrofits?

\[^{10}\] TURN, Chapter 6, p. 5, lines 1-5.

\[^{11}\] IS-1, Chapter 6, p. 6-9, Table 6-2.
ORA proposes a 2018 capital funding level of $3.0 million for this work, which is a $9.0 million reduction to PG&E’s forecast.\textsuperscript{12} This reduction is for work at both the Los Medanos and Pleasant Creek storage fields (see Table 6-3A above).

What is the basis of ORA’s recommendation?

ORA’s proposal is based upon the assumption that only one storage well retrofit is needed at Los Medanos, and no well retrofits should be made at Pleasant Creek.

Do you agree with ORA’s recommended reductions to the 2018 forecast?

No. While the DOGGR regulations were still in the draft stage when PG&E developed its forecast, PG&E based that forecast on an expectation that the regulations would be finalized sometime in 2018.

Should PG&E’s forecast be modified?

No. As described in Section C.1.a., even though the regulations have been adopted, they still require storage operators to conform with the requirements to eliminate the single point of well failure.\textsuperscript{13} While these regulations allow for the possibility that operators could retrofit wells over a longer period of time, PG&E’s forecast was reasonable at the time it was developed, and should be adopted. Furthermore, PG&E’s proposed GSBA, which TURN supports, would provide the mechanism by which any differences between PG&E’s forecast and actual spending could be returned to, or recovered from, customers.

Why is ORA’s proposal to reduce PG&E’s forecast and only provide cost recovery for one Los Medanos well retrofit unreasonable?

At the time PG&E prepared its forecast in 2017, PG&E anticipated that the DOGGR regulations would be adopted in 2018, and included accordingly compliance activities in its forecast. That compliance forecast included two well retrofits, at both the Los Medanos and Pleasant Creek facilities, to eliminate the single point of failure. PG&E’s forecast was based on the expectation that the compliance activities would be required by the regulations. As PG&E explained in prepared testimony:

\textsuperscript{12} ORA-14B/C, p. 36, lines 13-19. The $9.0 million reduction is the difference between $26.366 million and $17.390 million.

\textsuperscript{13} 14 CCR § 1726.5.
PG&E’s forecast includes performing retrofits at two wells, each at Los Medanos and Pleasant Creek, in 2018. Performing retrofits at a portion of the wells at these two storage fields is reasonable because PG&E will be operating some of these wells until they are decommissioned.¹⁴

Q 25 Are there other reasons why ORA’s proposed reduction to PG&E’s forecast for Los Medanos is unreasonable?

A 25 Yes. ORA’s proposal to reduce the forecast is not consistent with ORA’s proposal to defer a decision on the Los Medanos facility until the end of the next rate case.¹⁵ If the Commission adopts ORA’s recommendation to keep the facility open through this rate case period, PG&E would need to commence work to perform compliance work to retrofit the storage wells to eliminate the single point of failure, including the two wells at Los Medanos that are in PG&E’s 2018 forecast.

Q 26 What is ORA’s rationale for delaying compliance work at Los Medanos as part of its NGSS recommendations?

A 26 ORA indicated the final DOGGR regulations contain a 7-year phase-in period and stated any compliance work to retrofit wells could be completed after a 3-year delay in decommissioning because retrofit projects do not take that long to complete.¹⁶

Q 27 Would the final DOGGR regulations allow a 3-year “grace period” before starting compliance work to eliminate a single point of failure?

A 27 No. While the final DOGGR regulations allow for a 7-year compliance period, storage operators must address at least 10 percent of the nonconforming wells in the first year and with an additional 15 percent of the wells addressed in each subsequent year.¹⁷ Therefore, if the Commission approves ORA’s recommendation on the Los Medanos facility, the compliance work to retrofit the facility cannot simply be delayed three years to 2021.

Q 28 Are there reasons why ORA’s recommendations for the work at the Pleasant Creek facility should not be adopted?

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¹⁴ PG&E Prepared Testimony, Chapter 6, p. 6-21, lines 14-18.
¹⁵ ORA-11, p. 2, lines 7-19.
¹⁶ ORA-11, p. 6, lines 3-10.
¹⁷ 14 CCR § 1726.3.
Yes. For support of its adjusted forecast at Pleasant Creek, ORA points to the fact that three of the seven wells at this facility were reworked since 2010 as evidence that no further work is needed on the wells there.\footnote{18}

In making this statement, and equating well reworks with retrofits, ORA appears to assume that if a well has been reworked recently, it is already in compliance with the DOGGR regulations.

Are those wells that were reworked earlier already in compliance with the now finalized DOGGR regulations?

No. The final DOGGR regulations require that storage operators eliminate the single point of failure by installing Tubing and Packer Assemblies, and completing pressure test and inspections to demonstrate integrity of the well.\footnote{19} PG&E’s testimony highlighted the distinction between a rework done for reliability purposes, and a retrofit to eliminate single point of failure.\footnote{20} In this portion of testimony, PG&E explains the additional work required with these retrofits.

### 2. New Storage Wells

Briefly, what is the purpose of the New Storage Wells Program?

The purpose of this program is to mitigate the reduced well capacity that will result from installing Tubing and Packer Assemblies, and reduced field capacity implementing PG&E’s NGSS.\footnote{21} This program is more fully-discussed in PG&E’s prepared testimony.\footnote{22}

Do any parties have a recommendation regarding the New Storage Wells Program?

Yes. TURN, IS and Calpine made recommendations regarding this program. PG&E addresses their recommendations below.

What are parties’ recommendations for New Storage Wells?

\footnote{18} ORA-14B/C, p. 38, lines 15-21.
\footnote{19} PG&E Prepared Testimony, Chapter 6, p. 6-19, line 1 to p. 6-23, line 10. All of PG&E’s storage wells will need to be retrofitted with Tubing and Packer Assemblies.
\footnote{20} PG&E Prepared Testimony, Chapter 6, p. 6-19, lines 10-33.
\footnote{21} PG&E Prepared Testimony, Chapter 6, p. 6-23, lines 12-16.
\footnote{22} PG&E Prepared Testimony, Chapter 6, p. 6-23, line 12 to p. 6-24, line 19, including Table 6-8.
As shown in Table 6-4, both IS and Calpine oppose PG&E’s plans to add new storage wells and recommend no funding for this work. That is a reduction in PG&E’s capital forecast of $25.0 million in 2019, and a reduction of $31.0 million in 2020. PG&E discusses both of these recommendations below.

**TABLE 6-4**

**PARTIES RECOMMENDATIONS REGARDING NEW STORAGE WELLS**

(MILLIONS OF DOLLARS)

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<td>$(31.0)</td>
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Q 33  What is the basis for the IS’ proposed reduction?

A 33  IS recommends that the projected cost to install new wells are no longer valid for two reasons: (1) the Final DOGGR regulations obviate the need for new storage wells; and (2) Los Medanos and Pleasant Creek should not be closed, eliminating the need for the new storage wells.23

Q 34  Do you agree with IS’ recommendation for reducing PG&E’s cost forecasts?

A 34  No. As described above in Section C.1.a, PG&E does not believe that its forecast and pace of work should be modified. As discussed in prepared testimony, the 11 new wells are needed to mitigate reduced well capacity, resulting from the DOGGR regulations, and reduced field capacity, resulting from the implementation of the NGSS.24

Q 35  What is the basis for Calpine’s proposed reduction?

A 35  Calpine claims the new wells are not needed because there is not a need for Reserve Capacity, and PG&E did not provide any evidence that these new wells would be cheaper than additional Independent Storage Provider (ISP) capacity.25

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23 IS-1, Chapter 6, p. 6-6, lines 10-23.
24 PG&E Prepared Testimony, Chapter 6, p. 6-23, lines 12-16.
Q 36 Do you agree with Calpine’s recommendation for reducing PG&E’s cost forecasts?

A 36 No. As described in PG&E’s Chapter 11 rebuttal testimony, PG&E has demonstrated the purpose of Reserve Capacity, which supports the addition of the new wells.

Q 37 How did PG&E determine that it should drill 11 wells?

A 37 PG&E utilized a model of the McDonald Island storage reservoir and engineering judgment to determine that 11 new wells were likely to be required to achieve the withdrawal capacity of 757 million cubic feet per day (MMcfd) in the 1-day-in-10-year system reliability standard, while also satisfying the new DOGGR requirements for storage well construction that protects against a single point of failure.  

3. WELL – Integrity Inspections and Surveys

Q 38 Briefly, what is the scope of the WELL – Integrity Inspections and Surveys Program?

A 38 The WELL – Integrity Inspections and Surveys Program includes the following work:

• Noise and Temperature Surveys;
• Gamma Ray Neutron Surveys; and
• Barrier Inspection Surveys.

All the activities associated with this program involve expense expenditures that are recorded in MAT AH1. This program is more fully-discussed in PG&E’s prepared testimony.

Q 39 Do any parties have a recommendation regarding integrity assessments?

A 39 Yes, TURN recommends a $2.9 million reduction to PG&E’s forecast for this program.

Q 40 What is the basis for TURNs recommendation?

A 40 TURN’s recommendation is based on a slower pace of work resulting from the final DOGGR regulations approved in June 2018.

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26 Additional explanation of this analysis is provided in ORA_023-Q01, Subparts i and ii. See Attachment A at the end of this chapter.

27 PG&E Prepared Testimony, Chapter 6, p. 6-25, line 6 to p. 6-28, line 10.

28 TURN, Chapter 6, p. 4, lines 1-3.
Q 41 Does PG&E agree with their recommendation?
A 41 No. For the reasons explained above in Section C.1.a, PG&E’s forecast should be adopted.

4. Storage Well Decommissioning

Q 42 Briefly, what is the scope of Storage Well Decommissioning?
A 42 The scope of this program is to plug and abandon all of the storage wells at the Los Medanos and Pleasant Creek facilities as part of PG&E’s NGSS. This program is more fully-discussed in PG&E’s prepared testimony.29

Q 43 What is CE’s recommendation for decommissioning costs?
A 43 CE recommends that the costs to decommission a storage well should not cost more than $200,000 per well.30 Assuming $200,000 is CE’s recommended unit cost for the work, that would be a reduction of $14.1 million and $15.7 million to PG&E’s forecasts for the work in 2022 and 2023, respectively.

Q 44 What is the basis for CE’s proposed reduction?
A 44 CE claims PG&E has substantiated its forecast. In testimony, CE states:

PG&E does not provide any data to document their cost to abandon a well is (sic) at the present time, or what such costs have been historically in recent years. However, their Table 11-1 shows substantial costs for Well Plugging and Abandonment. (Footnote omitted.) It does not appear reasonable based on my production experience that it should cost more than a million dollars to plug each of these wells in today’s dollars. Frankly, in preparing their testimony and this Natural Gas Storage Strategy, PG&E could have readily obtained estimates for the P&A costs from local Sacramento oilfield contractors.31

Q 45 Did PG&E substantiate its forecast for well abandonment costs?
A 45 Yes, PG&E’s workpapers provided a detailed showing of the cost components of well abandonment on Workpaper Table 6-22 on page WP 6-24.

Q 46 What is PG&E’s forecast based on?
A 46 The forecast is based on a combination of detailed vendor quotes and engineering estimates. In addition to Workpaper Table 6-22 on

29 PG&E Prepared Testimony, Chapter 6, p. 6-34, line 13 to p. 6-35, line 12.
31 CE, p. 22, lines 4-10.
These vendor quotes are from multiple companies with a long history in
natural gas storage well drilling and operation, such as Paul Graham Drilling
and Service, Trident Environmental and Engineering, GEO Drilling Fluids,
Baker Hughes, and Halliburton.

Q 47 Has PG&E used these companies to perform work on its storage wells?
A 47 Yes, PG&E has used all of these companies and contracted with them when
it plugged and abandoned two wells at the Los Medanos field in 2017,
as described in more detail below.

Q 48 Did CE substantiate how it arrived at a cost estimate of not more
than $200,000?
A 48 Yes, the $200,000 estimate was based on estimated work to plug and
abandon wells in Montana, and then extrapolating that estimate to perform
the same work in California.

Q 49 Does PG&E have any recent experience in abandoning wells at the
Los Medanos or Pleasant Creek storage facilities?
A 49 Yes. In 2017, PG&E abandoned two wells at the Los Medanos field.
In performing this work, PG&E followed the procedures to abandon storage
wells that are included in Public Resources Code Section 3208.

Q 50 What were the costs to abandon those wells?
A 50 The recorded cost to abandon Well 18D was $1.4 million and the recorded
cost to abandon Well 8C was $1.2 million, as shown on Table 6-5 below.
These costs closely align with PG&E’s forecast of $1.3 million in 2022.

### TABLE 6-5
RECORDED COSTS OF ABANDONING WELLS

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<td>Los Medanos 18D</td>
<td>Plugged and Abandoned</td>
<td>5772498</td>
<td>$1,411,145</td>
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<td>2</td>
<td>Los Medanos 8C</td>
<td>Plugged and Abandoned</td>
<td>5772767</td>
<td>$1,217,078</td>
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</table>

(a) ORA_035 and ORA_069, Question 01, Attachment 01.

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32 See Attachment A at the end of this chapter. In addition, the specific bids and quotes
received were provided to OSA, but that material is confidential.
Was the process to abandon those two wells similar to the work planned to abandon the remaining wells at Los Medanos and Pleasant Creek that PG&E’s forecast is based on?

Yes.

CE indicated that PG&E’s estimate of decommissioning storage wells did not include any estimate of salvage value. Did PG&E include a reduction to the forecast of decommissioning its storage wells to account for potential salvage value of equipment?

No. PG&E did not reduce its forecast to account for salvage value for two reasons: (1) some of the equipment removed from each well could be refurbished and reused later at McDonald Island; and (2) the salvage value is not a significant amount. The main components removed from the wells are the metal tubing strings inside the production casing, the downhole safety valves and the wellhead equipment. When PG&E abandoned two wells at Los Medanos in 2017, some of the wellhead equipment was retained for later use as was some of the tubing.

What is the estimate of the salvage value of the tubing in each of the wells?

The salvage value of the tubing based on current recycle prices is about $3,700 for each well at Los Medanos.34

If PG&E recognizes any salvage value during well decommissioning would it be returned to ratepayers?

Yes. PG&E would true-up its decommissioning forecast to actual costs to plug and abandon each well, including any salvage value received at the time.

5. OSA Recommendations

Does PG&E have any overarching concerns with Chapter 3 of OSA’s testimony?

Yes. PG&E believes it is important to provide a discussion of the overall regulatory framework for natural gas storage. There are numerous

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33 CE, p. 22, lines 15-17.

34 This estimate is based on a 30-foot tubing section weighing 9.3 pounds or 279 pounds per tubing section. The average well depth at Los Medanos is about 4,000 feet and the current recycle price is about $0.10/pound. 279 pounds × 133 tubing sections/well = 37,200 pounds. 37,200 pounds × $0.10 = $3,700.
regulations that govern the safe operation of natural gas storage facilities in California. In particular, the final regulations from DOGGR adopted on June 29, 2018, govern the construction and operation and maintenance of storage facilities in California. The draft regulations formed the basis of PG&E’s capital and expense forecasts in this rate case. Additionally, as PG&E explained in opening testimony, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has promoted the voluntary adoption of the American Petroleum Industry’s (API) Recommended Practice (RP) 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. PG&E has used risk management practices included in its Gas Storage Asset Management Plan that also have been incorporated in API’s RP 1171 proposed mitigation.

Lastly, PHMSA issued in December 2016 “Pipeline Safety: Safety of Underground Natural Gas Storage Facilities” Interim Final Rules that govern the construction, operation, and maintenance of storage facilities in the United States, which also incorporate these risk management practices.

As a result of and in anticipation of these and other new safety regulations, PG&E has significantly expanded the scope of its safety work related to gas storage facilities.

Q 56 Are these safety regulations contained within the NGSS Memorandum of Understanding (MOU)?

A 56 Not explicitly, but the existing regulation PHMSA Interim Final Rule and the newly-adopted DOGGR regulations govern the operation of all storage operators in the United States and California, including independent storage providers (ISP) in California.

Q 57 OSA appears to be concerned that system safety will be increased with the adoption of PG&E’s NGSS. Is this accurate?

A 57 No. The OSA testimony provides a detailed analysis of the benefits of API RP 1173, but misses a crucial point about PG&E’s NGSS that will reduce risk and improve system safety. As part of PG&E’s proposal, PG&E will plug and abandon 27 storage wells at Los Medanos and

35 PG&E Prepared Testimony, Chapter 6, p. 6-6, line 3 to p. 6-7, line 2.
36 PG&E Prepared Testimony, Chapter 6, p. 6-13, lines 11-14.
Pleasant Creek. Removing these wells from operation reduces the risk of a well failure because there are fewer wells.

OSA recommends ISPs and PG&E:

Adopt best safety management practices by commencing a program to align their operations with the standards of [API RP 1173]: Pipeline Safety Management Systems (PSMS).37

Has PG&E adopted RP 1173?

Yes, PG&E adopted API RP 1173 in 2015. PG&E’s Gas Operations, which includes our natural gas storage facilities, has developed a Safety Management System (SMS) referred to as Gas Safety Excellence, which is based on three pillars: Asset Management, Safety Culture, and Process Safety. Our SMS was designed to improve safety, manage risk, and drive continuous improvement. The Gas Safety Excellence framework helps to proactively manage the condition of gas assets, the identification and reduction of operational and enterprise risks, promote and strengthen our safety culture and the continued support of processes and procedures related to process safety, employee and contractor safety and health, security, and environmental stewardship.

In 2014, PG&E was one of the first utilities in the world to attain both the Publicly Available Specification (PAS) 55-1: 2008 and International Organization for Standardization (ISO) 55001: 2014 certifications for asset management. These certifications were awarded by the independent, internationally recognized auditor, Lloyd’s Register.

When API RP 1173 was developed, PG&E was invited to join ExxonMobil, Kinder Morgan and other gas pipeline organizations along with the National Transportation Safety Board (NTSB) and the PHMSA to help co-author the standard that provides a best-in-class framework for organizations that operate hazardous liquids and gas pipelines in response to major industry incidents.

In November 2015, PG&E successfully passed a comprehensive third-party assessment by Lloyd’s Register and received a certificate of compliance for API 1173. A rigorous review of the ten elements of API 1173 was performed consisting of an office-based assessment and field

37 OSA-1, p. 3-2, lines 8-11.
verifications. Since 2015, Lloyd’s Register conducted annual surveillance audits for API 1173. In November 2018, Lloyd’s Register will conduct a comprehensive assessment to recertify PG&E’s compliance with API 1173.

Q 59 Has PG&E performed a third-party gap analysis related to API RP 1173, as recommended by OSA?

A 59 No. Because the 10 elements of API RP 1173 align with the management system elements already in place for PG&E under its PAS 55 and ISO 55001 certifications a formal gap analysis was not conducted for API 1173. With these certifications a gap analysis is unnecessary.

Q 60 Has PG&E attained other certifications that recognize its adoption of process safety with respect to Gas Operations?

A 60 Yes. Another significant milestone was achieved in 2016 when PG&E became the world’s first utility to earn certification for RC14001®, a standard developed by the chemical industry to drive continuous improvement around process safety, the environment, health, safety and security.

Q 61 Has PG&E included API RP 1173 in its annual Gas Safety Plan reporting as recommended by OSA?

A 61 Yes. PG&E’s 2018 Gas Safety Plan refers to API RP 1173 as one of the ways we measure progress of our safety culture. The fundamental principles and elements of Gas Safety Excellence are also referenced throughout the Plan.

Q 62 OSA recommends PG&E and the ISPs:

Jointly and collaboratively develop [an SMS] framework that is applicable to their underground storage assets and operations based on the tenets and principles of API RP 1173 and supplemented by other process safety-enhancing practices such as the Occupational Safety and Health Administration’s (OSHA) Process Safety Management System. This framework should, at a minimum, address all the elements contained in API RP 1173, as adapted for underground storage, and the ISPs and PG&E should finalize it for implementation within a year of a Commission Decision on the NGSS.

Is such a process necessary?

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38 OSA-1, p. 3-2, line 12-13.
39 OSA-1, p. 3-2, lines 20-23.
41 OSA-1, p. 3-2, lines 24-33.
No. As described above, PG&E has already been implementing API RP 1173 in its gas operations, including its natural gas storage facilities. Furthermore, PG&E is an active participant in a variety of stakeholder groups and actively participates in American Gas Association (AGA), the Interstate National Gas Association of America (INGAA), the Pipeline Research Council International (PRCI). PG&E was very active with other stakeholders in the development of API RP 1171. Creating another process would be duplicative.

OSA recommends PG&E and the ISPs:

…report to the Commission annually on the plan and progress of development and implementation of the SMS related to the underground storage assets. Does PG&E already report to the Commission information about its SMS?

Yes. As described above, PG&E incorporates its progress on SMS in its annual Gas Safety Plan.

OSA recommends PG&E and the ISPs:

Identify and explicitly designate, within the SMS (pipeline and underground storage), an Accountable Officer who is ultimately responsible for the safety of personnel, business processes and activities of the organization. The Accountable Officer should be an individual with ultimate control and responsibility of the organization, full control of the financial and human resources required to maintain the SMS, and final authority over operations and safety issues.

Has PG&E already established such accountability?

Yes. Jesus Soto, Senior Vice President, Gas Operations, performs this officer function already.

OSA recommends that the Commission:

…adopt safety metrics developed in the [Safety Model Assessment Proceeding], as are applicable to their specific operations, for reporting to the Commission at a defined frequency. Is such a requirement necessary?

If the Commission has concerns with ISPs that provide market-based rates and safety, these issues can be addressed in the SMAP process, but it is

42 OSA-1, p. 3-3, lines 1-3.
43 OSA-1, p. 3-3, lines 4-10.
44 OSA-1, p. 3-18, lines 1-3.
independent of approval of PG&E’s NGSS. At this time, ISPs are not required to be part of the SMAP process because they do not file rate cases; however, should the Commission choose, they can require the ISPs to comply with the SMAP decisions and reporting requirements.

Q 66 OSA recommends PG&E and the ISPs, “In collaboration with OSA and its consultants, participate in the development of safety metrics related to safety management, and human and organizational factors” to appropriately supplement Safety Model Assessment Proceeding (S-MAP) metrics. Is there a need to supplement the S-MAP process?

A 66 To the extent that new metrics need to be developed, such collaboration could be useful, but it should be contained within the already existing S-MAP process. PG&E is an active participant in S-MAP.

Q 67 OSA discussed safety provisions and the NGSS MOU and stated:

In the recent study prepared in response to Governor Brown’s direction to assess the long-term viability of underground gas storage in California (LTVUGS Report), the California Council of Science and Technology (CCST) found that the failure rate of UGS in California is higher than the worldwide failure frequency.

Is this the complete quotation?

A 67 No. The actual text contains a key qualifier:

Although possibly artifacts of reporting or the fact that California’s larger facilities are larger than the worldwide average, the failure rate of underground gas storage in California appears to be higher than the worldwide failure frequency, which is about the same or lower than the failure frequency of oil and gas extraction operations.

In addition, OSA’s testimony disregards the fact that PG&E’s NGSS will lead to the closure of 27 storage wells in northern California, reducing the loss of containment risk.

Furthermore, the summary report provides the following conclusion:

**Conclusion 1.1:** Analysis of historic failure-rate statistics of California’s underground gas storage facilities points to a need for better risk management and improvement in regulations and practices. The Steering Committee views the new regulations

---

45 OSA-1, p. 3-18, lines 13-15.
46 OSA-1, p. 3-18, lines 11-12.
47 OSA-1, p. 3-9, lines 8-11.
proposed by DOGGR as a major step forward to reduce the risk of
derisk of underground gas storage facilities, provided they are consistently
and thoroughly applied and enforced across all storage facilities.
In the future, careful re-evaluation of failure statistics, based on
ongoing reporting and evaluation of incidents, can help determine
whether and to what degree incident reductions have indeed been
realized. (Emphasis in original.)

PG&E agrees with this conclusion, and also views the new regulations
adopted by DOGGR, as well as PHMSA, are a major step forward to reduce
the risks associated with underground gas storage facilities.

Q 68 OSA recommends that the Natural Gas Safety Plans should be verified.
Is this necessary?
A 68 No, another oversight layer does not need to be implemented.
The Commission’s Safety Enforcement Division (SED) already has the
ability to audit PG&E as needed. An additional audit process would only
be duplicative.

Q 69 OSA recommends PG&E and the ISPs adopt similar conditions that were
included in the settlement agreement authorized in Decision (D.) 06-07-010.
Do these additional requirements need to be adopted in this proceeding?
A 69 No. The OSA recommendation is duplicative. The provisions in
D.06-07-010, developed for ISPs to provide storage services to
Core Customers, already apply to ISPs (please refer to PG&E’s Chapter 11
rebuttal testimony, Section C.2.b.). Furthermore, the NGSS MOU, which
has been agreed to by the third-party storage providers, already contains
operational provisions (Section VI – ISP Responsibilities) requiring them to
be available.

Q 70 Does this conclude your rebuttal testimony?
A 70 Yes, it does.

49 LTVUGS Summary Report, p. 17.
50 OSA-1, p. 3-18, lines 16-17.
QUESTION 1

On page 11-15 of PG&E’s 2019 GT&S testimony on the Natural Gas Storage Strategy (NGSS), PG&E states, “to compensate for the withdrawal capacity that will be lost when the new DOGGR rules for well retrofits and inspections are implemented, and Los Medanos and Pleasant Creek are decommissioned, we must drill 11 new wells to meet our proposed system supply reliability standard.” (lines 4:8)

i. Please explain how PG&E arrived at 11 new wells needed at McDonald Island to support the proposed NGSS.

ii. Under the NGSS that proposes 11 new wells at McDonald Island, how much additional incremental storage capacity does PG&E project will be provided from the 11 new wells?

iii. What percentage and capacity (in MDth) of the incremental gas storage from the proposed 11 new wells at McDonald Island will be allotted to PG&E’s Core Gas Supply (CGS) and/or core customers vs. parks and loans and lending? As part of your response, please reference the workpaper or testimony where this additional incremental storage capacity amount can be found.

iv. In making the proposal that 11 new wells are needed at McDonald Island to fulfill the NGSS, please provide PG&E’s comparison analysis between the economics of adding 11 new wells at McDonald Island versus additional firm capacity contracts with ISPs or adding additional interstate pipeline capacity? If PG&E did not prepare a comparison analysis as described, please provide an explanation on the underlying reason for this and an Excel spreadsheet analysis that compares the cost of these different scenarios, including a statement of the assumptions for the analysis.

ANSWER 1

i. PG&E utilized a model of the McDonald Island storage reservoir and engineering judgment to determine that 11 new wells were likely to be required at McDonald Island to achieve the withdrawal capacity of 757 MMcf/d in the 1-day-in-10-year system reliability standard, while also satisfying the
new DOGGR requirements for storage well construction that protects against a single point of failure.

The modeling considered two well design types: tubing with a production packer (Type 1), and tubing with a production packer and a cemented inner casing string (Type 2). (The differences between the two types are illustrated in PG&E’s testimony on pages 6-19 and 6-20.) The modeling also examined an alternative to simply drilling new wells. This alternative is to plug and abandon a number of existing wells with low withdrawal rates (potentially under-performing due to interference from other existing nearby wells) and drill new wells in areas of less interference, to determine if sufficient deliverability could still be achieved while eliminating the ongoing costs associated with the low-flow wells.

Modeling showed that, using Type 2 design, eleven wells would deliver 777 MMcfd of withdrawal capacity, slightly more than the 757 MMcfd required. The margin of 20 MMcfd reflects a conservative approach that accounts for modeling imprecision, the variability of actual individual well conditions in the field, and the need to have wells offline from time to time.

For informational purposes, we also modeled the field with a mix of Type 1 and Type 2 designs. This modeling showed higher deliverability for the same number of wells. However, our forecast used a conservative assumption that all wells will require the Type 2 design. While PG&E has not yet completed its testing and analysis, based on the current known information regarding the condition of the existing 78 wells, at least 24 will require the Type 2 design. We must assess and pressure-test the remainder (54 wells) to determine the design type they will require.

Modelling also showed that plugging and abandoning 11 wells to offset the 11 new wells (the “replacement” scenario) resulted in an inability to meet the 757 MMcfd withdrawal target. The modeling results are summarized in the table below.

<table>
<thead>
<tr>
<th>Modeling Case</th>
<th>Model Calculated Gas Withdraw Rate (MMcfd)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>78 Wells</td>
</tr>
<tr>
<td>Current</td>
<td>1,051</td>
</tr>
<tr>
<td>Combination of Type 1 and Type 2 Designs</td>
<td>804</td>
</tr>
<tr>
<td>Type 2 Design Only</td>
<td>647</td>
</tr>
</tbody>
</table>

Retrofitting all 78 wells at McDonald Island with Type 2 construction would reduce the current withdrawal capacity of the field, which is 1,051 MMcfd, to 647 MMcfd. To bring the field back up over the required withdrawal capacity threshold of 757 MMcfd, 11 new wells would be added, which would bring the field’s withdrawal capacity to 777 MMcfd, assuming Type 2 well construction. The difference between the threshold and the resulting restored, incremental capacity added by the 11 new wells accounts for imprecision in the estimating process and the possibility that all wells may not be fully functional at all times.
iii. PG&E does not propose to allocate specific portions of the capacities of the new wells at McDonald Island to any particular service. The 11 new wells are required to bring overall storage capacities to the levels shown in PG&E’s workpapers in Table 3, NGSS New Capacities Allocated to Facilities, on page WP 11-5, so that those capacities can be allocated to the services shown in Table 4, NGSS New Capacities Allocated to Services, also on page WP 11-5. This additional withdrawal capacity is needed at McDonald Island to provide the required timely supply between the transmission constraints to meet PG&E’s proposed Supply Standard. This new storage would not be incremental to existing capacity, but would compensate for a portion of the capacity reductions that will occur when PG&E removes the wells at Los Medanos and Pleasant Creek from service and reconfigures the existing wells at McDonald Island to comply with the new DOGGR storage well safety regulations, which will reduce the capacity of the existing wells at McDonald Island by up to 40 percent, as stated in PG&E’s testimony from page 11-5, line 18 through page 11-6, line 5. (The projected capacity reduction is unaffected by the February 12, 2018 draft of the final DOGGR regulations.) This is consistent with the reliability-only approach to gas storage discussed in PG&E’s testimony in Chapter 11 in section A.2, PG&E Proposes a Reliability-Only Philosophy for Gas Storage Operations, beginning on page 11-2. The implementation of this approach is discussed at length in Chapter 11 of PG&E’s testimony at section B.2, Consolidate Storage Operations at McDonald Island and Convert 1 PG&E’s Share of Gill Ranch Storage to a Utility Asset, beginning on page 11-15.

Only firm service receives a capacity allocation. Parking and lending are not firm services. They are as-available services. Therefore, they receive no capacity allocation. The word “lending” is another way of referring to loans. Allocation is further explained in PG&E’s testimony at section B.3.a, Eliminate Market Center Firm Service, starting on page 11-16.

Below is a table that shows the capacities from Table 4 on page WP 11-5 of PG&E’s workpapers in energy units. It also shows the relative allocation percentages of each service. Note that the percentages do not account for seasonality. Core will share a lesser proportion of injection and withdrawal costs associated with the notional percentages shown in this table because its use of injection and storage is seasonal, whereas the new services are year-round. See workpapers at page WP 16A-45, Allocation of Storage Revenue Requirement-January, and WP 16A-53, Allocation of Storage Revenue Requirement-April, for a comparison of cost percentages per service.
iv. PG&E has not compared the economics of adding 11 new wells at McDonald Island to adding firm capacity contracts with ISPs or adding additional interstate pipeline capacity because the critical function of McDonald Island storage is not interchangeable with these other services. As explained in PG&E’s Chapter 11 testimony in section C.4, Establish a System Supply Reliability Standard, beginning at page 11-25: “The bulk of the demand in PG&E’s service territory is in the San Francisco Bay Area, and PG&E’s backbone lines have limited capacity to meet it. They are ‘constrained,’ as shown in the diagram in Figure 11-4 … While [the] ISP facilities [Wild Goose Storage, Central Valley Storage, and Lodi Storage] have a total notional deliverability of approximately 2,000 MMcf/d, their interconnections tie to Lines 400 or 401 well upstream of the Bay Area Loop, and are therefore constrained by those pipelines’ capacity…. Gill Ranch … is constrained by the capacity of the Baja pipelines. McDonald Island is the only storage facility that can deliver gas into the Bay Area Loop, downstream of the pipeline constraints. Therefore, McDonald Island is the resource that must balance the reliability needs of the system, at a volume of 757 MMcf/d.”

In short, McDonald Island storage, due to its location and function, is irreplaceable for peak day system reliability, a function PG&E alone is responsible for as system operator. Substituting firm ISP capacity contracts or additional interstate pipeline capacity for replacing McDonald Island storage capacity would put the entire gas transmission system at risk of pressure problems under peak conditions. Given this fact, the cost of adding the 11 wells at McDonald Island is not comparable to the cost of adding firm ISP capacity contracts or additional interstate pipeline capacity. Therefore, PG&E did not perform this comparison.

<table>
<thead>
<tr>
<th>Services</th>
<th>Volumetric</th>
<th>Energy</th>
<th>Percentage per Service (notional)*</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Injection (MMcfd)</td>
<td>Inventory (bcf)</td>
<td>Withdrawal (MMcfd)</td>
</tr>
<tr>
<td>Core Firm Service (G-CFS)</td>
<td>24</td>
<td>5</td>
<td>307</td>
</tr>
<tr>
<td>Inventory Management</td>
<td>200</td>
<td>5</td>
<td>300</td>
</tr>
<tr>
<td>Reserve Capacity</td>
<td>25</td>
<td>1</td>
<td>250</td>
</tr>
<tr>
<td>Parks and Loans</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>249</td>
<td>11</td>
<td>857</td>
</tr>
</tbody>
</table>

* Percentages do not account for seasonality. Core will share a lesser proportion of injection and withdrawal costs associated with the notional percentages shown in this table because its use of injection and storage is seasonal, whereas the new services are year-round. See workpapers at page WP 16A-45, Allocation of Storage Revenue Requirement-January, and WP 16A-53, Allocation of Storage Revenue Requirement-April, for a comparison of cost percentages per service.
Attachment 1 to GTS-RateCase2019_DR_OSA_002-Q10
### Table 6-22

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Quantity</th>
<th>Total ($/load)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2,500</td>
<td>7,600</td>
</tr>
<tr>
<td>2</td>
<td>5,000</td>
<td>15,000</td>
</tr>
<tr>
<td>3</td>
<td>7,500</td>
<td>22,500</td>
</tr>
<tr>
<td>4</td>
<td>10,000</td>
<td>30,000</td>
</tr>
<tr>
<td>5</td>
<td>12,500</td>
<td>37,500</td>
</tr>
<tr>
<td>6</td>
<td>15,000</td>
<td>45,000</td>
</tr>
</tbody>
</table>

**Note:** The units in 2022 represent 10 wells at Los Medanos and 3 wells at Pleasant Creek; the units in 2023 represent 10 wells at Los Medanos and 4 wells.

### Table 1. Delivery/Disposal Transportation Estimate

<table>
<thead>
<tr>
<th>Rig Type</th>
<th>Description</th>
<th>Unit Price ($/load)</th>
<th>Unit Price ($/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Drillpipe</td>
<td>50/40</td>
<td>8.75</td>
</tr>
<tr>
<td>2</td>
<td>Mud System</td>
<td>100/50</td>
<td>10.50</td>
</tr>
<tr>
<td>3</td>
<td>Safety Lifts</td>
<td>200</td>
<td>15.75</td>
</tr>
<tr>
<td>4</td>
<td>Deliveries</td>
<td>300</td>
<td>17.50</td>
</tr>
<tr>
<td>5</td>
<td>Disposal</td>
<td>400</td>
<td>18.25</td>
</tr>
</tbody>
</table>

**Total Estimate:** $13,800

### Table 2. Vendor Quote/Cost Estimates

<table>
<thead>
<tr>
<th>Item</th>
<th>Vendor Quote</th>
<th>Unit Price ($/load)</th>
<th>Unit Price ($/load)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Total = $13,748 + $5,630 = $20,000; rounded off to $20,000**

### Table 3. Tubing pickup and lay down service cost estimate

<table>
<thead>
<tr>
<th>Item</th>
<th>Vendor Quote</th>
<th>Unit Price ($/load)</th>
<th>Unit Price ($/load)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Temp Price ($/hr):** 8.75

**Total Estimate:** $5,000

### Table 4. Integrity baseline cost estimate

<table>
<thead>
<tr>
<th>Item</th>
<th>Vendor Quote</th>
<th>Unit Price ($/load)</th>
<th>Unit Price ($/load)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Total Estimate:** $86,868

### Table 5. Additional Assumptions and Notes

- **Internal Consultants/Services Subtotal:** $13,748 + $5,630 = $20,000; rounded off to $20,000
- **Internal Labors/Admin. Subtotal:** $5,000
- **External Consultants/Services Subtotal:** $2,010 + $2,600 + $3,300 + $4,845 = $10,755
- **External Labors/Admin. Subtotal:** $7,600
- **Internal Labor Rates, New Cost Model:** $1,255 + $2,400 = $3,655
- **External Labor Rates, New Cost Model:** $5,000
- **Internal Labor Rates, Existing Cost Model:** $1,255 + $2,400 = $3,655
- **External Labor Rates, Existing Cost Model:** $5,000
- **Contractor Markup:** $0
- **Total Estimate:** $150/hr
- **Total Hours:** 200
- **Calculated Hourly Rate:** $150/hr
- **Calculations:** Base Rate = Total Cost / Total Hours
- **Total Cost:** $20,000
- **Total Hours:** 200
- **Calculated Hourly Rate:** $150/hr

**Calculations:** Base Rate = Total Cost / Total Hours

- **Total Cost:** $20,000
- **Total Hours:** 200
- **Calculated Hourly Rate:** $150/hr
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

REBUTTAL TESTIMONY OF TERRY WHITE

ASSET FAMILY – FACILITIES
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A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.
A 1 My name is Terry White. This testimony responds to the direct testimony of the Office of Ratepayer Advocates (ORA),¹ The Utility Reform Network (TURN)² and Commercial Energy (CE). Pacific Gas and Electric Company (PG&E) summarizes parties’ positions in Section B.

Q 2 Do parties generally criticize PG&E’s showing regarding Asset Family – Facilities?
A 2 No, parties do not offer any general criticism regarding Asset Family – Facilities.

Q 3 Do parties make recommendations concerning specific projects and programs?
A 3 Yes, ORA and TURN make recommendations concerning several of PG&E’s forecast projects and programs. Commercial Energy makes a recommendation concerning decommissioning of Above Ground (AG) facilities for the Natural Gas Storage Strategy (NGSS).

Q 4 Does PG&E oppose any of the recommendations offered by ORA, TURN and Commercial Energy?
A 4 Yes, PG&E opposes these recommendations. PG&E addresses each parties’ recommendations in Section C.

B. Summary of Parties’ Positions

Q 5 Please provide parties’ recommendations.
A 5 PG&E’s application forecast and the parties’ recommendations are set forth in Table 7-1 (2019 expense), Table 7-2A (2019–2021 capital expenditures) and Table 7-2B (2015-2019 capital expenditures) below.

¹ ORA-07.
² TURN, Chapter 7.
TABLE 7-1
SUMMARY OF 2019 EXPENSE FORECAST – PG&E AND PARTIES
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Program</th>
<th>MAT</th>
<th>PG&amp;E Filed Forecast</th>
<th>PG&amp;E Errata(a)</th>
<th>PG&amp;E Current Forecast</th>
<th>PG&amp;E Proposed Reductions</th>
<th>ORA(b)</th>
<th>TURN</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Routine Expense Compression and Processing (C&amp;P)</td>
<td>JTY</td>
<td>$11,259</td>
<td>–</td>
<td>$11,259</td>
<td>$(3,860)</td>
<td>$(2,104)</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Routine Expense Measurement and Control (M&amp;C)</td>
<td>34A JTW</td>
<td>6,451</td>
<td>–</td>
<td>6,451</td>
<td>(2,691)</td>
<td>–</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Becker System Upgrades</td>
<td>JTI</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>M&amp;C Gas Quality Assessment</td>
<td>34A, JTW</td>
<td>1,040</td>
<td>–</td>
<td>1,040</td>
<td>(590)</td>
<td>–</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>M&amp;C Station Over Pressure Protection (OPP)</td>
<td>34A, JTW</td>
<td>1,561</td>
<td>–</td>
<td>1,561</td>
<td>–</td>
<td>–</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Enhancements Expense</td>
<td></td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Facility Integrity Management Program (FIMP) Risk Management</td>
<td>34A, JTL</td>
<td>2,752</td>
<td>$57</td>
<td>2,809</td>
<td>–</td>
<td>–</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Critical Documents</td>
<td>34A, LU1</td>
<td>3,143</td>
<td>–</td>
<td>3,143</td>
<td>–</td>
<td>(3,143)</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Engineering Critical Assessment (ECA) Phase 1 Expense</td>
<td>34A, LV1</td>
<td>4,612</td>
<td>109</td>
<td>4,720</td>
<td>–</td>
<td>–</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>ECA Phase 2 Expense</td>
<td>34A, LV2</td>
<td>1,835</td>
<td>–</td>
<td>1,835</td>
<td>–</td>
<td>–</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Station Strength Testing Expense</td>
<td>34A, JTV</td>
<td>1,014</td>
<td>–</td>
<td>1,014</td>
<td>–</td>
<td>(1,014)</td>
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</tr>
<tr>
<td>11</td>
<td>Total Expense</td>
<td></td>
<td>$33,667</td>
<td>$166</td>
<td>$33,833</td>
<td>$(7,141)</td>
<td>$(6,261)</td>
<td></td>
</tr>
</tbody>
</table>

(a) From PG&E’s errata as of August 17.
(b) Reductions are from ORA’s testimony. In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Program</th>
<th>MAT</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>PG&amp;E(a)</th>
<th>ORA</th>
<th>TURN</th>
<th>PG&amp;E(a)</th>
<th>ORA</th>
<th>TURN</th>
<th>PG&amp;E(a)</th>
<th>ORA</th>
<th>TURN</th>
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<tbody>
<tr>
<td>1</td>
<td>Routine Capital C&amp;P</td>
<td>76N</td>
<td>$38,535</td>
<td>$39,745</td>
<td>$40,914</td>
<td>–</td>
<td>–</td>
<td>–</td>
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</tr>
<tr>
<td>2</td>
<td>Emergency Shutdown (ESD) Systems Upgrade</td>
<td>76F</td>
<td>3,843</td>
<td>3,857</td>
<td>3,850</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>3</td>
<td>Install Active Fire Suppression Systems</td>
<td>76O</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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</tr>
<tr>
<td>4</td>
<td>GT Electrical Upgrades – Hinkley, Topock Compression Stations</td>
<td>76P</td>
<td>4,270</td>
<td>4,285</td>
<td>4,277</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<td>–</td>
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<td>–</td>
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<tr>
<td>5</td>
<td>Compressor Unit Control Replacement</td>
<td>76R</td>
<td>3,268</td>
<td>3,280</td>
<td>3,273</td>
<td>–</td>
<td>–</td>
<td>–</td>
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</tr>
<tr>
<td>6</td>
<td>Upgrade Station Controls</td>
<td>76T</td>
<td>2,014</td>
<td>2,022</td>
<td>2,018</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<td>–</td>
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<tr>
<td>7</td>
<td>Compressor Stations</td>
<td>76H</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<tr>
<td>8</td>
<td>Station Other</td>
<td>76I</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<tr>
<td>9</td>
<td>Compressor Replacement</td>
<td>76X</td>
<td>21,530</td>
<td>20,640</td>
<td>22,074</td>
<td>–</td>
<td>–</td>
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<tr>
<td>10</td>
<td>Compressor Retrofit Projects</td>
<td>76Y</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<td>–</td>
</tr>
<tr>
<td>11</td>
<td>Routine Capital M&amp;C</td>
<td>44A</td>
<td>18,192</td>
<td>18,763</td>
<td>19,315</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<tr>
<td>12</td>
<td>Becker System Upgrades</td>
<td>766</td>
<td>325</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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</tr>
<tr>
<td>13</td>
<td>Replace Obsolete Bristol Controllers</td>
<td>761</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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</tr>
<tr>
<td>14</td>
<td>Perform Simple Station Rebuilds</td>
<td>44A</td>
<td>6,223</td>
<td>6,246</td>
<td>6,234</td>
<td>–</td>
<td>–</td>
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<tr>
<td>15</td>
<td>Perform Complex Station Rebuilds</td>
<td>763</td>
<td>32,311</td>
<td>32,431</td>
<td>32,368</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<td>–</td>
<td>–</td>
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<td>–</td>
</tr>
<tr>
<td>16</td>
<td>Perform Transmission Terminal Upgrades</td>
<td>765</td>
<td>7,436</td>
<td>7,544</td>
<td>7,622</td>
<td>$(3,686)</td>
<td>$(3,794)</td>
<td>$(3,872)</td>
<td>$(5,010)</td>
<td>$(6,110)</td>
<td>$(5,190)</td>
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<tr>
<td>17</td>
<td>Station OPP Enhancements Capital</td>
<td>44A</td>
<td>6,139</td>
<td>6,162</td>
<td>6,150</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>(6,139)</td>
<td>(6,162)</td>
<td>(6,150)</td>
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<tr>
<td>18</td>
<td>ECA Phase 1 Capital</td>
<td>76Q</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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</tr>
<tr>
<td>19</td>
<td>ECA Phase 2 Capital</td>
<td>44A</td>
<td>287</td>
<td>575</td>
<td>595</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<td>–</td>
<td>–</td>
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<tr>
<td>20</td>
<td>Station Strength Testing Capital</td>
<td>44A</td>
<td>102</td>
<td>185</td>
<td>256</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>(1,780)</td>
<td>(1,800)</td>
<td>(1,820)</td>
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<tr>
<td>21</td>
<td>Physical Security Capital</td>
<td>76Z</td>
<td>9,392</td>
<td>9,427</td>
<td>9,409</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>22</td>
<td>Total Capital Expenditures</td>
<td>76Z</td>
<td>$153,868</td>
<td>$155,162</td>
<td>$158,355</td>
<td>$(3,687)</td>
<td>$(3,794)</td>
<td>$(3,872)</td>
<td>$(12,929)</td>
<td>$(13,072)</td>
<td>$(13,160)</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
</tbody>
</table>

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(a) There are no errata for Chapter 7 Capital Expenditures.
| Line No. | Program                                      | Sub-Program                  | MAT      | PG&E<sup>(a)</sup> | ORA | TURN    | 2015  | 2016  | 2017  | 2018  | 2019  | 2015  | 2016  | 2017  | 2018  | 2019  | 2019<sup>(b)</sup> |
|---------|----------------------------------------------|------------------------------|----------|--------------------|-----|---------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|------------------|
| 1       | GT Electrical Upgrades – Hinkely and Topock  |                              | 76P      | $44                |     |         | $224  |       | $1,085| $7,000| $4,270| $(2,730)|       |       |       |       |       |                   |
| 2       | Perform Simple Station Rebuilds              | Simple Station Rebuilds     | 763, 44A | 8,821             |     |         | 7,025 | 5,109 | 5,000 | 6,223 |       | $(4,727)| $(3,281)|       |       |       |       |       | $(4,474)         |
| 3       | Perform Complex Station Rebuilds             | Complex Station Rebuilds    | 764, 44A | 24,553            |     |         | 15,304| 37,887| 49,004| 32,311|       | (18,512)| (8,509) | (267) |       |       |       | (90,048)       |
| 4       | Compressor Replacement                        | Compressor Replacement      | 76X      | 715               |     |         | 22,661| 30,050| 12,140| 21,530|       |       |       |       |       |       |       |       | $(16,145)       |
| 5       | Upgrade Station Control                      | Gerber Station Controls     | 76T      |                   |     |         |       |       |       |       |       |       |       |       |       |       |       |                   |
| 6       | Total Capital                                |                              |          | $35,456           |     |         | $47,603| $74,639| $78,444| $66,348|       | $(6,030)| $(23,239)| $(11,790)| (267) |       |       |       | $(96,910) | $(16,145)  |

(a) There are no errata for Chapter 7 Capital Expenditures.
(b) 2019 capital disallowances proposed by TURN for projects completed in 2015-2018.
Q 6 Please describe the two tables for capital expenditures.

A 6 Table 7-2A reflects all the capital expenditure reductions recommended by ORA and a portion of the recommendations TURN makes for the years 2019-2021. Table 7-2B reflects the capital expenditure recommendations by ORA and TURN for the years 2015-2018. Table 7-2B also includes 2019 capital disallowances proposed by TURN for projects completed in 2015-2018.

Q 7 Are there programs that parties do not dispute for 2019 and beyond?

A 7 Yes. As Tables 7-1 and 7-2 show, no parties dispute PG&E’s forecast for the following programs for 2019 and beyond:

- FIMP Risk Management (Expense)³;
- Routine C&P (Capital);
- Routine M&C (Capital);
- ESD Upgrades (Capital);
- GT Electrical Upgrades Hinkley and Topock (Capital);
- Upgrade Station Control (Capital);
- Compressor Unit Control Replacements (Capital);
- Compressor Replacement (Capital);
- Becker System Upgrades (Capital); and
- M&C Station Rebuilds (Capital).

Q 8 Are there programs that parties dispute for 2015-2018 period?

A 8 Yes. ORA and TURN dispute PG&E’s capital expenditures for certain years in the 2015-2018 period for the following programs:

- GT Electrical Upgrades Hinkley and Topock (Capital);
- Upgrade Station Control (Capital);
- Compressor Replacement (Capital); and
- M&C Station Rebuilds (Capital).

Q 9 Does PG&E agree with any of ORA’s or TURN’s recommendations regarding Facilities programs?

A 9 No. For the reasons explained in Section C, PG&E does not agree with ORA’s or TURN’s recommendations regarding Facilities programs.

³ In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
C. Response to Parties’ Recommendations Concerning Specific Programs or Projects

1. C&P Systems and Components Replacements

a. Routine Expense and Capital C&P

Q 10  Briefly, what is the scope of the Routine Expense and Capital C&P Program?

A 10  The Routine Expense and Capital C&P Program includes projects that arise during normal operation of C&P facilities to maintain current levels of service and reliability. Typical projects include repair or replacement of failed or malfunctioning equipment and instrumentation, compressor unit overhauls, inspection and testing of asset components, and modifications to address equipment safety or performance issues. The routine expense and capital C&P Program is more fully discussed in PG&E’s prepared testimony.4

Q 11  What are parties’ recommendations for routine expense and capital C&P?

A 11  As shown in Table 7-3 below, ORA proposes a 2019 expense funding level of $7.4 million for routine C&P expense, which is a $3.86 million reduction to PG&E’s forecast.5 ORA does not recommend any reductions for routine C&P capital. TURN recommends $9.155 million expense funding level for 2019, a reduction of $2.104 million to PG&E’s forecast for Routine C&P Expense Program, and has no testimony on Routine C&P Capital.6 PG&E discusses each of these recommendations below.

TABLE 7-3
ROUTINE EXPENSE C&P
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Routine C&amp;P Expense</td>
<td>$11,259</td>
<td>$7,399</td>
<td>$9,155</td>
<td>$3,860</td>
<td>$2,104</td>
</tr>
</tbody>
</table>

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4 PG&E Prepared Testimony, Chapter 7, p. 7-30, line 2 to p. 7-31, line 33.
5 ORA-07, p. 7, line 6 to p. 8, line 5.
6 TURN, Chapter 7, p. 30, lines 15-16.
Q 12 What is the basis for ORA’s proposed reduction?
A 12 ORA uses a 5-year average (2012-2016),\textsuperscript{7} based on a claim that it is a better approach than PG&E’s use of a 3-year average with adjustments for large one-time projects and projects required for regulation. ORA also claims, “the effects of these additional projects are already captured in the annual recorded data.”\textsuperscript{8}

Q 13 Do you agree with ORA’s recommendations for reducing PG&E’s expense forecasts?
A 13 No. PG&E disagrees with ORA’s recommendation.

For Routine C&P expense, PG&E used a 3-year average (2014-2016) and added costs for anticipated expense projects related to Green House Gas (GHG) emissions and California Air Resources Board (CARB) Oil and Gas Regulations.\textsuperscript{9} These new regulations came in to effect in October 2017, so the costs to comply would not be reflected in a historical average. Projects to support the new regulations are not reflected in the 5-year (2013-2017) average. Hence, ORA’s recommended 5-year average should not be used in place of PG&E’s forecast methodology.

Another problem with ORA’s forecast is that ORA uses two different forecast methodologies for the same program, one method for expense (5-year average) and one method for capital (adopting PG&E’s methodology of 3-year average) as demonstrated in Table 7-4 below. There is no reason to use two different methodologies for the same program, and ORA does not provide one. Further, ORA’s inconsistent approach maximizes the reduction to the program, more so than had ORA used a consistent approach for both.

\textsuperscript{7} ORA recommends a forecast of $7.39 million based on a 5-year average using the years 2013-2017 for routine C&P expense, yet erroneously states it is based on 5-year average using 2012-2016 in the testimony. ORA-07, p. 7, lines 9-17.
\textsuperscript{8} ORA-07, p. 7, lines 6-14.
\textsuperscript{9} GHG emissions and CARB Oil and Gas Regulations (17 CCR § 95300 et seq.).
TABLE 7-4
ROUTINE EXPENSE AND CAPITAL C&P
SUMMARY OF ROUTINE C&P EXPENSE AND CAPITAL 5-YEAR AVERAGE 2013-2017
(THOUSANDS OF NOMINAL DOLLARS)

<table>
<thead>
<tr>
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<tbody>
<tr>
<td>1</td>
<td>Routine Expense C&amp;P</td>
<td>$5,167</td>
<td>$8,389</td>
<td>$6,932</td>
<td>$7,353</td>
<td>$9,155</td>
<td>$7,399</td>
<td>$11,259</td>
</tr>
<tr>
<td>2</td>
<td>Routine Capital C&amp;P</td>
<td>$52,731</td>
<td>$27,583</td>
<td>$30,973</td>
<td>$54,278</td>
<td>$40,351</td>
<td>$41,183</td>
<td>$38,535</td>
</tr>
</tbody>
</table>

(a) PG&E Prepared and Testimony, Chapter 7, p. 7-32, Tables 7-9 and 7-10.

1  Q 14 What is the basis for TURN’s proposed reduction?
2  A 14 TURN states that “the last recorded year (2017) is the most known and measurable amount and therefore appropriate to use for the forecast.”
4  TURN also claims that “PG&E’s response did not provide any actual work orders” and “the requested support for this cost was lacking.”
6  Q 15 Do you agree with TURN’s recommendations for reducing PG&E’s expense forecasts?
8  A 15 No. PG&E disagrees with TURN’s recommendation. As stated previously, for Routine C&P expense, PG&E used a 3-year average (2014-2016) and added costs for anticipated expense projects related to GHG emissions and CARB Oil and Gas Regulations. These new regulations came in to effect in October 2017. Projects to support the new regulations are not reflected in the recorded 2017 costs. Hence, TURN’s recommendation to use the last recorded year for forecasting routine C&P expense is not advisable.
15  TURN’s criticism that PG&E did not provide any actual work orders or quotes is inconsistent with the nature of expense work. Unlike capital projects, work orders for expense projects are not created three years ahead. PG&E plans the anticipated expense at the program level for rate case forecasting purposes. Detailed project costs and work orders for subsequent years, including the ones pertaining to new regulations, will be created as part of the integrated planning (S2) process.

11 TURN, Chapter 7, p. 29, lines 16-17.
12 GHG emissions and CARB Oil and Gas Regulations (17 CCR § 95300 et seq.).
In summary, what is PG&E’s position in response to ORA and TURN’s recommendations?

PG&E disagrees with ORA and TURN’s recommendations based on the reasons discussed above, and recommends that PG&E’s $11.2 million expense forecast for Routine Expense C&P Program be adopted.

b. GT Electrical Upgrades Hinkley and Topock

Briefly, what is the scope of GT Electrical Upgrades Hinkley and Topock Program?

The GT Electrical Upgrades Hinkley and Topock program funds upgrades to the electrical equipment for Hinkley and Topock Compressor Stations. The electrical equipment targeted by this program is power distribution system Switch Gear (SWGR) sections and Motor Control Center (MCC) sections. Maintaining the condition of these components is important to the reliability of the compressor station and the safety of station personnel. GT Electrical Upgrades Hinkley and Topock Program is more fully discussed in PG&E’s prepared testimony.13

What are parties’ recommendations for GT Electrical Upgrades Hinkley and Topock Program?

No party submitted an alternative forecast for this program for the 2019-2021 rate case period. ORA does not make any recommendations for 2019 and beyond. However, ORA proposes a $2.73 million capital reduction for 2018 and proposes a balancing account to track the expenditures.14

What is the basis for ORA’s proposed reduction for 2018?

ORA claims “adjusting the 2018 capital expenditures down to $4.27 million from $7 million is more consistent with [PG&E’s forecasts] for 2019-2021.”15 ORA asserts, without support, that PG&E’s forecasted expenditures of slightly over $4 million a year to perform the Hinkley upgrade is an indication of a possible resource limitation to do the work.16

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13 PG&E Prepared Testimony, Chapter 7, p. 7-35, line1 to p. 7-36, line 32.
14 ORA-07, p. 10, lines 1-9.
15 ORA-07, p. 10, lines 1-3.
16 ORA-07, p. 10, lines 3-4.
Q 20 Do you agree with ORA’s recommendations for reducing PG&E’s forecast for 2018?
A 20 No. PG&E disagrees with ORA’s recommendation. As stated in PG&E’s workpapers, PG&E is proposing an electrical upgrade at one location over two years. The total estimated cost for Hinkley is $8.5 million spread over two years at $4.3 million per year. ORA speculates that the cost of Hinkley upgrade is $4 million due to possible resource limitations, but this is not the case.

Rather, both Hinkley and Topock stations have complex scopes and electrical upgrade capital projects which typically take two to three years to complete, as the projects move through engineering, construction and close-out stages. ORA’s recommendation appears to erroneously assume that the project will only take one year to complete and at only a fraction of the total forecasted cost.

Q 21 Does ORA make any other recommendation for this program?
A 21 Yes. ORA states “because of the discrepancy in the estimates for the Topock and Hinkley upgrades [it] recommends the California Public Utilities Commission [CPUC or Commission] require PG&E to set up a one-way balancing account to track the expenditures for the GT Electrical Upgrades to balance the ratepayer’s protection with the uncertainty in PG&E’s work plans.”

Q 22 Do you agree with ORA’s recommendations for a one-way balancing account for GT Electrical Upgrades Program?
A 22 No. PG&E disagrees with ORA’s recommendation. ORA states that “[t]he large discrepancy between the $5.8 million for Topock upgrades and $12.5 million for Hinkley upgrades is inconsistent with PG&E’s testimony that ‘Both Hinkley and Topock stations have similar designs, were constructed in the 1950s and contain the originally installed electrical

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17 PG&E WP 7-54 to WP 7-55.
18 ORA-07, p. 10, lines 3-4.
19 ORA-07, p. 10, lines 5-9.
ORA claims that as a result there is uncertainty in PG&E’s work plans and recommends a one-way balancing account.

ORA’s claim regarding the large discrepancy between the forecasts for Hinkley and Topock reflects ORA’s misunderstanding of the forecasts. As stated previously in A20, ORA compares one year (2018) of Topock costs to three years of Hinkley costs (2019-2021). ORA’s recommendation takes into account only the 2018 capital forecast and not the total cost for the entire capital project for Topock. The project costs are typically spread over multiple years as the project moves from engineering to construction and close out stages. PG&E has a defined scope of work identified for both Hinkley and Topock stations. The total estimated scope and costs for the electrical upgrade project at Topock is comparable to the estimated forecast scope and cost for Hinkley. This program will continue until the targeted obsolete SWGR and MCC sections are replaced. As part of the project planning, the engineering resources will evaluate the level of obsolescence to be addressed, operational improvements required, and will determine if there are cost efficiencies through bundling by upgrading more SWGRs or MCCs on a project-by-project basis. The number of SWGR and MCC sections and the pace of replacement for this Electrical Upgrade are well-defined. This demonstrates that ORA’s concerns about “uncertainties” do not support a balancing account.

Q  What is your conclusion based on the parties’ proposed recommendations for GT Electrical Upgrades at Hinkley and Topock?
A  For the reasons discussed above, ORA’s forecast recommendations for GT Electrical Upgrades Hinkley and Topock program for the 2015-2018 Rate Case period should be rejected, PG&E’s GT Electrical Upgrades Hinkley and Topock Program capital forecast of $4.3 million per year for 2019-2021 be adopted and no balancing account be established for this program.

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20 ORA-07, p. 9, lines 11-15.
21 ORA-07, p. 10, lines 5-9.
22 See Chapter 2 Rebuttal Testimony of Mr. Singh for further discussion regarding balancing accounts.
c. Upgrade Station Controls

Briefly, what is the scope of Upgrade Station Controls Program?

Each compressor station is integrated with a complex process control system that enables operators to control the downstream pressure of incoming natural gas, and eliminate any deviations in normal operation. Upgrade Station Controls Program replaces outdated station Programmable Logic Controllers (PLC) and associated hardware. This includes the PLC controllers, communication devices, and input/output (IO) devices. Upgrade Station Control Program is more fully-discussed in PG&E’s prepared testimony.23

What are parties’ recommendations for Upgrade Station Controls Program?

No party provided recommendations for this program for the 2019-2021 forecast. ORA proposes a $3.3 million reduction for 2018.24 TURN recommends that the Commission limit the amount allowed for the 2018 capital expenditures on the Gerber Station Controls Replacement Project to the Commission’s adopted level of $1.684 million.25 PG&E discusses each of these recommendations in turn.

What is the basis for ORA’s proposed reduction in 2018?

ORA states that PG&E’s forecast for 2018 includes $3.5 million to upgrade its Gerber Station, and almost $2 million to upgrade other stations. ORA further notes that the total of $5.3 million is more than double PG&E’s annual plan for 2018 and higher than the previous years. ORA recommends that the 2018 capital expenditures should be adjusted down to $2.0 million, similar to the forecasted annual expenditures during the 2019 GT&S Rate Case period.

Do you agree with ORA’s recommendations for reducing PG&E’s 2018 capital forecast?

No. ORA’s recommendation does not take in account any incremental scope for this project. As stated in PG&E’s workpapers,26 PG&E plans to

23 PG&E Prepared Testimony, Chapter 7, p. 7-40, line1 to p. 7-41, line 30.
24 ORA-07, p. 11, lines 7-13.
25 TURN, Chapter 7, p. 27, line 1 to p. 28, line 15.
26 PG&E WP 7-58.
upgrade one station control at the cost of $2 million except for Hinkley and Topock stations, for which the pace will be adjusted as the stations have multiple station PLCs.

The Gerber Station controls upgrade project addresses four PLCs: one for compressor station control; one stand-alone PLC that controls the Line 177 transmission regulator station; one compressor unit control replacement; and one generator control. In addition, the project also addresses partial ESD upgrades. The station PLC is also responsible for rapid activation of the ESD system in the event of an emergency. For the station control upgrade to be effective, some of the ancillary electrical equipment may also require upgrading. The Gerber Station project reflects this scope. By bundling projects at the same station, PG&E is able to efficiently address multiple units and projects for different programs (Unit controls, Station Controls and ESD upgrades). For tracking purposes, the costs are kept intact under one program, under Upgrade Station control (Maintenance Activity Type (MAT) 76T), and are not split between different MATs or programs.

Q 28 What is the basis for TURN’s proposed reduction capital for 2018?
A 28 Like ORA, TURN recommends that the Commission limit the amount allowed for the 2018 capital expenditures on the Gerber [S]tation [C]ontrols [R]eplacement [P]roject to the Commission’s [adopted] level of $1.684 million.”

TURN states that “PG&E has provided no testimony justifying its spending 2.4 times the [adopted] level for upgrading the Gerber Station controls.” Additionally, TURN states that “PG&E has provided no information in its testimony and workpapers, apart from a listing of recorded costs for years 2012-2016, and a forecast of costs for years 2017-2021.”

TURN argues that, “[a]bsent a compelling justification for the expenditure level, the Commission should not allow PG&E to place more of the expenditure for the Gerber facility than is adopted by [Decision] D.16-06-056.” TURN “recommend[s] that the Commission authorize the

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27 TURN, Chapter 7, p. 28, lines 10-13.
28 TURN, Chapter 7, p. 27, lines 19 to 20.
29 TURN, Chapter 7, p. 27, lines 20 to 22.
addition of the Gerber [S]tation controls replacement work based on
recorded costs only after the completion of the work” and “[t]he total amount
allowed into rate base should be limited to the Commission’s [adopted] level
of $1.684 million.”

Q 29  How does PG&E respond to TURN’s recommendation?
A 29  PG&E disagrees with TURN’s recommendation. This chapter addresses the
reasonableness of costs incurred for work performed and forecast for this
rate case. Chapter 23, addresses the inappropriateness of the capital
disallowances TURN proposes.

Q 30  Can you justify the forecasts for Gerber Station Control Project above the
2015 GT&S Rate Case adopted level?
A 30  Yes. As stated in A27 above, PG&E addressed multiple projects and
programs in the Gerber project. Traditionally a station control project
includes upgrades for one PLC. But the Gerber Station project addresses
four PLCs and partial ESD upgrades. Gerber station included multiple PLCs
that were being phased-out by the manufacturer, and will no longer be
supported. With obsolete and outdated PLCs, there is a risk of an extended
outage if an equipment failure occurs and replacement parts are not readily
available. For the station control upgrade to be effective, some of the
ancillary electrical equipment also requires upgrading. The Gerber Station
Project reflects this scope.

Q 31  Do you agree with TURN’s recommendations that the total amount allowed
into rate base for Gerber Project should be limited to the Commission’s
adopted level of $1.684 million?
A 31  No. This recommendation is addressed as part of the deferred work rebuttal
testimony Chapter 23, sponsored by Mr. Smith.

Q 32  Do parties dispute PG&E’s forecast for 2019 and beyond for Upgrade
Station Control Program?
A 32  No. Neither ORA nor TURN made any recommendations for PG&E’s
2019-2021 forecast. PG&E plans to complete one station control upgrade
per year at $2 million per year for 2019-2021.

30  TURN, Chapter 7, p. 28, lines 1 to 9.
31  PG&E Prepared Testimony, Chapter 7, p. 7-42, Table 7-14.
Q 33  What is your conclusion based on the parties' recommendations for Upgrade Station Controls Program?
A 33  For the reasons discussed above, both ORA and TURN's forecast recommendations for Gerber Station control upgrade project for 2018 should be rejected and PG&E's Upgrade Station Controls capital forecast of $2 million per year for 2019-2021 be adopted.

2. C&P Compressor Replacements
Q 34  Briefly, what is the scope of Compressor Replacement Program?
A 34  PG&E maintains a fleet of 41 compressor units installed at stations located on its gas transmission pipeline system and Underground (UG) gas storage facilities. The asset management strategy for compressor units focuses on life extension, with the overall objective of ensuring safe and reliable operation of the units. The Compressor Replacement Program mitigates equipment-related threats and risks that can adversely impact gas system operations through the: loss of service; loss of operating flexibility and reliability; and inability to meet evolving industry and environmental regulations. The Compressor Replacement Program is more fully discussed in PG&E's prepared testimony.32

Q 35  What are parties' recommendations for Compressor Replacement Program?
A 35  TURN does not provide any recommendations for 2019-2021 forecasted compressor replacement projects, but recommends that the Commission should allow only the adopted level of Burney K-2 Compressor Replacement Project costs of $54,115 million to be added into rate base in 2019.33 No other parties made recommendations for this program.

Q 36  What is the basis for TURN's proposed reduction?
A 36  TURN claims PG&E appears to have used funds for the Los Medanos compressor-related project to address cost overruns for the Burney K-2 Compressor Replacement Project.34 TURN claims that, "[h]aving access to unspent funds because the Los Medan..."
[P]roject reasonable."³⁵ TURN further claims that “[t]he Commission has an obligation to ensure that costs passed into rates are just and reasonable,” and recommends that the Commission ‘reject PG&E’s proposal to add excessive capital expenditures on the Burney K-2 Compressor Replacement [P]roject to its [TY] 2019 forecast rate base."³⁶

Q 37 How does PG&E respond to TURN’s recommendation?

A 37 PG&E disagrees with TURN’s recommendation and rebuts TURN’s recommendation in two chapters. This chapter addresses the: (1) safety implications of not completing the compressor replacement work forecasted in the last case; (2) reasonableness of costs incurred for work performed; and (3) forecast for this rate case. Chapter 23 rebuttal addresses the inappropriateness of the capital disallowances TURN proposes.

Q 38 Are there any immediate safety implications for not completing the compressor replacement work forecasted in the last rate case?

A 38 No. The cancellation of Los Medanos Compressor Replacement Project does not produce immediate safety or reliability risk because current maintenance activities are sufficient to maintain the Los Medanos K-1 compressor in an operable mode until the facility is sold or decommissioned.³⁷

Q 39 Can you justify the forecasts for Burney Compressor Replacement Project above the 2015 GT&S Rate Case adopted level?

A 39 Yes. The forecasts for Burney Compressor replacement project above the 2015 GT&S Rate Case adopted level is justified below.

The original estimate for the Burney Compressor Replacement Project was provided in the Workpapers Supporting Chapter 6 in the 2015 GT&S Rate Case.³⁸ The original cost estimate used for the 2015 GT&S Rate Case forecast assumed that the Burney compressor replacement would be a like-for-like replacement with no additional footprint to the station. However, the scope of the project was changed during project

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³⁵ TURN, Chapter 7, p. 25, lines 19-21.
³⁶ TURN, Chapter 7, p. 26, lines 2-19.
³⁷ PG&E Prepared Testimony, Chapter 7, p. 7-45, lines 2-6.
³⁸ GT&S 2015, PG&E WP 6-130.
implementation to meet the operational needs at the station, which in turn resulted in costs above the forecast amounts for this project. The key scope changes for Burney Project included the following:

1) The original project was intended to be performed by: taking the existing Burney compressor out of operation for nine months, constructing the new compressor, and building on the same footprint as the original. However, it was determined by the Gas Control team that an outage of this duration would represent a risk to the gas supply and the project approach was changed to maintain the existing Burney compressor in operation while new construction was on-going, and to cut-in the new compressor when complete. This operational change resulted in the following changes to the scope:

- There was a need to extend the existing station footprint and to prepare this existing site to allow for appropriate clearances and fire barriers;
- There was a need to construct a new control building since the existing compressor was going to remain in operation;
- There was a need to construct a new materials storage building, due to location changes required for new control building; and
- There was a need to install three interconnection line taps along L401 to secure compressed natural gas during the winter months in order to maintain system reliability during the station cut-over.

2) The physical security upgrades at Burney Station were originally planned under a separate program, but as part of bundling efforts to address multiple future planned projects at the same location, physical security upgrades were also incorporated into the Burney Compressor Replacement Project scope. This work was bundled with the compressor replacement to achieve efficiencies during the construction phase.

3) The above identified changes in the scope required additional site preparation and heavy construction sequencing. The change in scope also includes additional labor that was required, due to the extension of the schedule.
The costs associated with these changes are provided in Table 7-5 below.

**TABLE 7-5**

**BURNEY COMPRESSOR REPLACEMENT – INCREMENTAL SCOPE (DOLLARS)**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Incremental Scope</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Facility property extension</td>
<td>$330,000</td>
</tr>
<tr>
<td>2</td>
<td>New control building</td>
<td>$4,660,000</td>
</tr>
<tr>
<td>3</td>
<td>New materials storage building</td>
<td>$1,470,000</td>
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<tr>
<td>4</td>
<td>Physical security upgrades</td>
<td>$4,950,000</td>
</tr>
<tr>
<td>5</td>
<td>Line taps</td>
<td>$300,000</td>
</tr>
<tr>
<td>6</td>
<td>Additional Labor</td>
<td>$3,000,000</td>
</tr>
<tr>
<td>7</td>
<td>Total</td>
<td>$14,710,000</td>
</tr>
</tbody>
</table>

Do you agree with TURN’s recommendations that the total amount allowed into rate base for Burney Compressor Replacement Project should be limited to the Commission’s adopted level of $54.115 million?³⁹

No. PG&E disagrees with TURN’s recommendation. This recommendation is addressed as part of the Chapter 23 rebuttal testimony, sponsored by Mr. Smith.

What is your conclusion based on the parties’ proposed recommendations for Compressor Replacement Program?

PG&E disagrees with TURN’s proposed reductions for the following reasons: (1) system reliability and operational needs required a change to the construction approach; (2) the additional costs to change the construction scope are reasonable; and (3) bundling of physical security with the replacement project resulted in construction efficiencies. For the reasons discussed above, TURN’s forecast recommendations for Burney Compressor Replacement Project for the 2015-2018 rate case period should be rejected and PG&E’s Compressor Replacement Program forecasts of $21.5 million, $20.6 million, and $22.1 million for 2019, 2020 and 2021, respectively, should be held reasonable.

³⁹ TURN, Chapter 7, p. 26, lines 19-20.
3. M&C Systems and Components Replacements

a. Routine Expense and Capital M&C

Q 42 Briefly, what is the scope of the Routine Expense and Capital M&C Program?

A 42 The Routine Expense and Capital M&C Program includes projects that arise in the course of normal operation of M&C facilities that must be performed to maintain current levels of service and reliability. Typical projects include: repair or replacement of failed or malfunctioning equipment and instrumentation; inspection and testing of asset components; and needed modifications to address equipment safety or performance issues. The Routine Expense and Capital M&C Program is more fully-discussed in PG&E’s prepared testimony.\(^\text{40}\)

Q 43 What are parties’ recommendations for the Routine Expense and Capital M&C Program?

A 43 As shown in Table 7-6 below, ORA proposes a reduction of $2.691 million for Routine M&C expense. No other parties made recommendations for this program.

<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>Routine M&amp;C Expense</td>
<td>$6,451</td>
<td>$3,760</td>
<td>$6,451</td>
<td>$2,691</td>
<td>–</td>
</tr>
</tbody>
</table>

Q 44 What is ORA’s recommendation for the Routine Expense and Capital M&C Program?

A 44 ORA proposes a 2019 expense funding level of $3.760 million for Routine M&C expense, which is a $2.691 million reduction to PG&E’s forecast.\(^\text{41}\) ORA does not recommend any reductions for Routine M&C capital.

Q 45 What is the basis for ORA’s proposed reduction?

\(^\text{40}\) PG&E Prepared Testimony, Chapter 7, p. 7-45, line 20 to p. 7-47, line 31.

\(^\text{41}\) ORA-07, p. 14, lines 6-11.
ORA uses a 5-year average (2012-2016), based on a claim that it is a better approach than PG&E's use of a 3-year average with adjustments for large one-time projects and projects required for regulation. ORA also claims, "the effects of these additional projects are already captured in the annual recorded data." 

Do you agree with ORA's recommendations for reducing PG&E's cost forecasts?

No. For Routine M&C expense, PG&E used a 3-year average (2014-2017) and added costs for anticipated expense projects related to GHG emissions and CARB Oil and Gas Regulations. These new regulations came into effect in October 2017. Projects to support the new regulations are not reflected in the 5-year (2013-2017) average. Hence, ORA's recommended 5-year average should not be used in place of PG&E's forecast methodology.

Another problem with ORA's forecast is that ORA uses two different forecast methodologies for the same program, one method for expense (5-year average) and one method for capital (adopting PG&E's methodology, a 3-year average) as demonstrated in Table 7-7 below. There is no reason to use two different methodologies for the same program, and ORA does not provide one. Further, ORA's inconsistent approach maximizes the reduction to the program, more so than had ORA used a consistent approach for both the expense and capital components.

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42 ORA recommends a forecast of $3.760 million based on a 5-year average using the years 2013-2017 for routine M&C expense, yet erroneously states it is based on 5-year average using 2012-2016 in the testimony. ORA-07, p. 13, line 16, to p. 14, line 2.

43 ORA-07, p. 13, line 13 to p. 14, line 5.

44 GHG emissions and CARB Oil and Gas Regulations (17 CCR § 95300 et seq.).
<table>
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</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Routine Expense M&amp;C</td>
<td>$2,879</td>
<td>$3,233</td>
<td>$5,132</td>
<td>$4,516</td>
<td>$3,037</td>
<td>$3,760</td>
<td>$6,451</td>
</tr>
<tr>
<td>2</td>
<td>Routine Capital M&amp;C</td>
<td>$16,879</td>
<td>$12,588</td>
<td>$20,348</td>
<td>$21,665</td>
<td>$23,252</td>
<td>$18,946</td>
<td>$18,191</td>
</tr>
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</table>

1 Q 47 What is your conclusion based on the parties’ proposed recommendations for Routine Expense and Capital M&C Program?

2 A 47 For the reasons discussed above, PG&E finds ORA’s forecast recommendations unreasonable and recommends that its $6.451 million expense forecast for Routine Expense M&C Program be adopted.

4. M&C Station Rebuilds

7 Q 48 Briefly, what is the scope of M&C Station Rebuilds Program?

8 A 48 The M&C Station Rebuild Program addresses station equipment aging and obsolescence. The projects under this program: completely rebuild the station (above and below ground) to replace old and obsolete equipment, valves and piping; upgrade configuration to meet current system needs; and address any outstanding issues with station maintenance and operations. There are two types of stations considered in the station rebuild work: simple stations and complex stations. M&C Station Rebuilds Program is more fully-discussed in PG&E’s prepared testimony.45

16 Q 49 What are parties’ recommendations for M&C Station Rebuilds Program?

17 A 49 No parties propose a reduction to the 2019-2021 capital expenditure forecast for this work. However, ORA recommends a one-way balancing account for this program46 and TURN proposes disallowances for the years 2015-2018.47 PG&E discusses each of these recommendations in turn.

21 Q 50 What is the basis for ORA’s recommendation for a one-way balancing account for this program?

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45 PG&E Prepared Testimony, Chapter 7, p. 7-50, line 1 to p. 7-54, line 2.
46 ORA-07, p. 16, lines 9-15.
47 TURN’, Chapter 7, p. 20, line 8 to p.24, line 4.
ORA states that PG&E’s forecasts in the 2015 GT&S Rate Case period were re-prioritized during the 2015-2018 rate case period from emphasis on simple stations to complex stations. Consequently, ORA claims “[t]here will be uncertainty as to what will be the priority after the start of the current rate case period. Therefore, ORA recommends a one-way balancing account treatment for Station Rebuilds. ORA does not recommend any other adjustments to PG&E’s forecast of capital expenditures for Station Rebuilds.”

Do you agree with ORA’s recommendations for one-way balancing account for M&C Station Rebuilds Program?

No. PG&E disagrees with ORA’s recommendation. ORA is basing the need for a one-way balancing account on uncertainties, relative to the identification and prioritization of stations for rebuild from the past rate case period. There is no link between reprioritization and uncertainty as ORA implies. PG&E relied on condition assessment and field verifications before making this strategy change to focus on complex stations due to condition and operational significance. If the information on condition or the operational needs of the asset changes, it is appropriate that PG&E re-prioritize work based on the new information to address reliability or safety issues at the stations. The station specific control assessments and field verifications have greatly reduced the uncertainties. PG&E has prioritized the stations for rebuilding and have planned work for the current rate case period. The priority and pace of work is clearly defined for the current rate case period and hence no reason for balancing account for this program.

See Chapter 2 rebuttal testimony of Mr. Singh for further discussion regarding balancing accounts.
Q  52  Can PG&E justify the strategy change to focus on the Complex Stations for the 2015-2018 rate case period?
A  52  Yes.  PG&E has provided several supporting documents to TURN as part of data requests to explain this strategy change and re-prioritization of Complex station rebuilds.  

At the time of submittal of the 2015 GT&S Rate Case in 2013, PG&E was beginning to develop an overall asset management strategy for its station assets, including the need for station rebuilds.  A pilot study was performed and utilized age to determine a pace of the station rebuild program for the 2015 GT&S Rate Case.  As indicated in the 2015 GT&S Rate Case filing, a station turnover of 60 years was used to set the pace.  However, as indicated in the “M&C Asset Family, Station Rebuilds” White Paper, the actual decision to rebuild a station is made based on a specific review of the actual station and component conditions.  After the filing of the 2015 GT&S Rate Case, PG&E performed a condition assessment of its complex and simple stations, and control assessments of its complex stations, to improve the data used to make asset management decisions and prioritize stations.  The information collected included the following:  

Controls assessments performed for complex stations identified stations as high-, medium-, and low-priority for rebuilds.  Typical conditions identified leading to a high priority of rebuilds were:

• Obsolete regulator and monitor actuators and controllers;
• Regulator and monitor equipment exhibiting poor functional performance;
• Relief valve functional performance and sizing issues;
• Maintenance that requires manual regulation of bypass valves;
• Equipment sizing not aligned with current operational needs; and

50  See PG&E’s response to Data Request TURN_21-Q12, dated 06/28/2018 in Attachment A at the end of this chapter.  The data request attachments are not included since some attachments are marked confidential and since the attachments are over 300 pages in volume.
51  GT&S 2015, PG&E WP 6-186.
52  PG&E WP 7-77 to WP 7-83.
• Structural issues, such as degraded supports.

Typical conditions identified leading to a potential for station rebuild for simple stations were:

• Obsolete regulator and monitor equipment;
• Regulator and valve equipment exhibiting poor functional performance;
• Material issues (e.g., corrosion) prevalent in the station; and
• Equipment sizing not aligned with current operational needs

Based on the information gathered during this time period, PG&E determined that complex station rebuilds were prioritized above the simple station rebuilds that were originally proposed.

Q 53 Are there any uncertainties associated with PG&E’s proposed Station Rebuilds for the 2019-2021 rate case period?

A 53 Yes, but uncertainties have been greatly reduced since the 2015 GT&S Rate Case. PG&E now utilizes the station specific control assessments and field verification data to prioritize stations for rebuild which was limited when PG&E filed the 2015 GT&S Rate Case. These control assessments and field verifications have greatly reduced the uncertainties. The identified stations through these assessments are the basis for selecting the station mix of two simple stations and three complex station rebuilds proposed during 2019-2021 period. The prioritization is continually reviewed against current data and system needs; and all information is utilized prior to initiating a rebuild.

However, it is important to note that since these programs are required to ensure the safe operation of the gas transmission system, it is possible that new information from on-going inspection and maintenance tasks will require some degree of reprioritization to address immediate material and operational issues, consistent with the general need for management flexibility to reprioritize under certain circumstances referenced in Chapter 2 rebuttal. For example, during the 2015-2018 rate case period, the data collection for the Hollister Station indicated that this station had aging control valve equipment used for pressure regulation that increased the potential for over pressure events. This station was, therefore, moved up in priority for a station rebuild. Additionally, as indicated in the 2019 GT&S Rate Case
Chapter 7 Workpapers,\textsuperscript{53} the costs for complex station rebuild was based on a typical station. Station facilities that are very large and with complicated operational schemes are more expensive than the typical complex station rebuilds. The pace, when upgrading such facilities, will be adjusted to match the forecasted spend per year.

Based on the current state of data on stations and the current prioritization list, uncertainty in this program has been greatly reduced for the 2019 rate case period.

Q \textsuperscript{54} What is TURN's recommendation for M&C Station Rebuilds Program?

A \textsuperscript{54} TURN does not dispute PG&E's 2019-2021 forecast for both Simple and Complex Station rebuilds. TURN also agrees that "[b]ased on the enhanced amount of information that PG&E developed about the conditions of the complex stations as well as the simple stations," it was reasonable to reprioritize the use of funds.\textsuperscript{54} However, TURN recommends "that the Commission authorize the addition of the 2018 [S]imple and [C]omplex [S]tation [R]ebuild [P]rogram to rate base only after the completion of the work, and the recording of actual costs", and states that "[t]he total amount allowed into rate base should be limited to no more than the expenditure rate [adopted] by the Commission times the actual number of simple and complex stations, respectively, completed during 2018." TURN also states that "if the Commission wishes instead to adopt PG&E's forecasted 2018 numbers of simple and complex station rebuilds to be completed in 2018, the amount allowed in rate base should be limited to $24.783 million, which is the total of the Commission's [adopted] 2018 level of cost per station for simple stations times the projected number of simple station rebuilds and for the Commission's adopted 2018 level of cost per station for complex stations times the projected number of complex station rebuilds."\textsuperscript{55}

Q \textsuperscript{55} How does PG&E respond to TURN's recommendation?

A \textsuperscript{55} PG&E disagrees with TURN's recommendation and rebuts TURN's recommendation in two chapters. This chapter addresses the: (1) safety

\textsuperscript{53} PG&E WP 7-67, Workpaper Table 7-35.
\textsuperscript{54} TURN, Chapter 7, p. 20, lines 5-7.
\textsuperscript{55} TURN, Chapter 7, p. 23, line 13 to p. 24, line 4 (fns omitted).
implications of not completing the station rebuild work forecasted in the last case; (2) reasonableness of costs incurred for work performed; and (3) forecast for this rate case. Chapter 23 addresses the inappropriateness of the capital disallowances TURN proposes.

Q 56 Did PG&E perform the necessary station rebuild work to eliminate any immediate safety hazards?
A 56 Yes. The reprioritization of simple station work does not produce immediate safety or reliability risk for the following reasons:56

• The condition assessment reviewed physical condition of stations, and the results indicated that simple stations were in better condition than expected and only a few required rebuild during the 2015-2018 rate case period. These stations were included in the rebuild program; and

• Annual maintenance is performed on these stations to test appropriate functionality and reliability of the regulators and valves.

Q 57 What is the basis of TURN’s recommendations?
A 57 TURN claims that “PG&E has provided no explanation regarding the level of investment that was required to restore the stations”, and has provided no analysis of why the costs to rebuilds for each of the stations were higher than anticipated.57 TURN also claims “PG&E requests to recover capital expenditures that are grossly in excess of the levels [adopted] by the Commission in D.16-06-056”, and the Commission should therefore deny PG&E’s request. TURN recommends that “PG&E should be entitled to recover costs that reflect the [adopted] levels for capital expenditure reflecting the number of stations that were completed each year as well as the type of station.”58

Q 58 Do you agree with TURN’s claim that PG&E has provided no support regarding the level of investment and requests to recover capital expenditures that are grossly in excess of adopted amounts?

57 TURN, Chapter 7, p. 22, lines 1-4.
58 TURN, Chapter 7, p. 22, lines 17-22.
A 58 No. As part of filed testimony for Station Rebuilds, PG&E provided an explanation for the increase in complex station rebuilds costs. PG&E has also provided project level details for all the rebuild projects expected to be complete for 2015-2018 period. In addition, even though there are some increases at the individual program level, the overall Chapter 7 – Facilities Asset Family capital expenditures portfolio was lower than the adopted amount, by 2.9 percent for 2015-2018, as indicated in Figure 7-1 below.

FIGURE 7-1
CHAPTER 7 – ASSET FAMILY FACILITIES
2015-2018 CAPITAL EXPENDITURES
(MILLIONS OF DOLLARS)

TURN views the programs in isolation and proposes reductions for 2018. TURN’s claim that PG&E is attempting to recover capital expenditures that are grossly in excess of the levels adopted by the Commission is not true when viewed in the context of the entire portfolio.

Q 59 Do you agree with TURN’s recommendation that the amount allowed in rate base should be limited to $24.783 million for 2018?

60 TURN-21, Question 11.
No. PG&E disagrees with TURN's recommendation. This recommendation is addressed as part of the deferred work rebuttal testimony Chapter 23, sponsored by Mr. Smith.

Q 60 How does PG&E respond to TURN's criticism of overspend in Simple and Complex Station compared to the 2015 GT&S adopted amounts?

A 60 As described in response to Question 52, PG&E has previously described the change in priority for station rebuilds between the simple (Category B) and complex (Category A) stations during the 2015-2018 rate case period. TURN agrees with the re-prioritization strategy, based on the condition and operational information obtained since submittal of the 2015 GT&S Rate Case.61 At TURN’s request, PG&E provided a list of projects to be completed between 2015-2018 for both simple and complex station rebuilds.62 TURN didn’t specifically ask for a comparison of the rebuild project costs against the 2015 GT&S adopted level yet makes the assertion that PG&E has provided no analysis of why the costs to rebuilds for each of the stations were higher than anticipated. The cost of simple and complex station projects in comparison to the 2015 GT&S adopted costs is explained below and in responses to Questions 61-62 below.

At the time of 2015 GT&S filing, the Station Rebuild Program was relatively new. Without a historical basis to rely on, PG&E based its rebuild costs per station, based on an average station, with a scope that consisted of one regulation run for both simple and complex stations. However, specific station rebuild costs are based on a variety of factors including: size, complexity, location, ease of construction, station access, and station operational constraints. Therefore, the cost estimate for a station rebuild is very dependent on the specific station. During the 2015-2018 rate case period, PG&E used its most current condition and operational data to prioritize stations for rebuild. The stations that required priority rebuilds were much more complex in scope compared the base station assumed. The issue of specific simple and complex station costs is addressed in the responses below.

61 TURN, Chapter 7, p. 20, lines 5-7.
62 TURN-21, Question 11.
Can PG&E justify the forecasts for Simple Station rebuild projects cost above the 2015 GT&S forecasted level?

Yes. The station and cost basis for simple stations for 2015 GT&S was provided in the 2015 GT&S Workpapers Supporting Chapter 6, page 6-90. The base station was identified as Pressure Limiting Station (PLS) 6A with an average station cost of $3.37 million. This station contains one regulation run and 11 individual mechanical components. However, the simple stations vary in size and number of equipment, such that rebuild costs will vary from the average station, depending on the size and scope of the rebuild.

Table 7-8 below shows a comparison of the costs of the base station assumed for the rate case and the estimated costs and incremental scope for the three simple stations that were rebuilt. The cost estimates for the rebuilt stations were compared to the base station through the number of regulator runs. The number of regulator runs represents a good basis for comparison of station rebuild complexity and cost. Other key issues that affect the cost of simple station rebuilds from the base estimate are:

- Number of regulation runs;
- Site environmental, remediation and demolition activities on new land;
- Decommissioning and removal of stations that are re-located; and
- Other non-standard equipment installations (such as separators), which are not required at all stations.

All of the above items contribute to driving the cost of a station rebuild above the base estimate.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Simple Stations</th>
<th>Estimate at Completion</th>
<th>No. of Mechanical Components</th>
<th>No. of Regulators (Total)</th>
<th>No. of Lines (In/Out)</th>
<th>No. of Regulator Runs</th>
<th>Incremental Scope Compared to 2015 GT&amp;S Base Station</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Base: PLS-6A</td>
<td>$3,400</td>
<td>11</td>
<td>2</td>
<td>1/1</td>
<td>1</td>
<td>Base Station assumed for 2015 GT&amp;S.</td>
</tr>
</tbody>
</table>
| 2       | Viera Regulator Station                   | $6,065                 | 13                           | 4                         | 1/1                    | 2                      | 1. Twice the number of regulators runs compared to base station.  
2. Scope included rebuild of this station and decommissioning of Wilbur Station. |
| 3       | Oregon and Benson Station                 | $7,510                 | 12                           | 4                         | 1/1                    | 2                      | 1. Twice the number of regulators runs compared to base station.  
2. Station was re-located from an UG location to a new AG location to address potential safety issues with the location, as well as condition issues with piping and valves.  
3. Scope included rebuild of this station and removal of UG station. |
| 4       | Shell Refinery Meter and Regulator Station | $7,257                 | 29                           | 8                         | 1/2                    | 4                      | 1. Four times the number of regulators runs compared to base station.  
2. Station was rebuilt to address obsolete equipment and performance issues related to maintenance. |
Q 62 Can PG&E justify the forecasts for Complex Station rebuild projects cost above the 2015 GT&S forecasted level?

A 62 Yes. The station and cost basis for complex stations is provided in the 2015 GT&S Workpapers Supporting Chapter 6, page 6-94. The base station identified was the San Pablo Station, with an average station cost of $4.2 million. This base station contains one regulation run and 23 components. However, the complex stations vary in size and number of equipment, such that rebuild costs will vary from the average station, depending on the size and scope of the rebuild. Key issues that affect the cost of complex station rebuilds from the base estimate are:

- Number of regulation runs;
- Installation of additional control or automated valves;
- Modification of the station for the installation of pig launchers and receivers for In-Line Inspection (ILI);
- Physical security upgrades to comply with current PG&E standards;
- Site environmental, remediation and demolition activities on new land;
- Grounding system upgrades; and
- Other non-standard equipment installations (such as separators), which are not required at all stations.

Each item above contributed to driving the cost of a station rebuild above the base estimate. Table 7-9 below shows a comparison of the costs of the base station assumed for the rate case and the estimated costs and incremental scope for the nine complex stations that were rebuilt during the 2015-2018 period.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Complex Stations</th>
<th>Estimate at Completion</th>
<th>No. of Mechanical Components</th>
<th>No. of Regulators</th>
<th>No. of Control Valves</th>
<th>No. of Lines (In/Out)</th>
<th>No. of Reg. Runs</th>
<th>Incremental Scope Compared to 2015 GT&amp;S Base Station</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Base: San Pablo</td>
<td>$4,200</td>
<td>23</td>
<td>2</td>
<td>4</td>
<td>2/2</td>
<td>1</td>
<td>Base Station assumed for 2015 GT&amp;S</td>
</tr>
<tr>
<td>2</td>
<td>Sheridan Rd</td>
<td>$12,909</td>
<td>12</td>
<td>6</td>
<td>6</td>
<td>1/1</td>
<td>2</td>
<td>1. Twice the number of regulator runs. 2. Two additional automated valves. 3. Installation of two blowdown stacks. 4. Station must be capable of reverse flow. 5. Environmental permit required.</td>
</tr>
<tr>
<td>3</td>
<td>Herrmann Station</td>
<td>$18,468</td>
<td>32</td>
<td>8</td>
<td>6</td>
<td>1/2</td>
<td>4</td>
<td>1. Four times the number of regulator runs. 2. Two additional automated valves. 3. Replace existing stand-by generator.</td>
</tr>
<tr>
<td>4</td>
<td>Cummings Creek</td>
<td>$6,849</td>
<td>25</td>
<td>4</td>
<td>5</td>
<td>1/1</td>
<td>2</td>
<td>1. Twice the number of regulator runs. 2. One additional automated valve. 3. Installation of bypass loop. 4. Installation of pig launcher.</td>
</tr>
<tr>
<td>5</td>
<td>Las Vinas</td>
<td>$4,667</td>
<td>8</td>
<td>4</td>
<td>4</td>
<td>2/1</td>
<td>2</td>
<td>1. Twice the number of regulator runs. 2. Partial rebuild to regulators, monitors, and maintenance valves feeding Sac. Gas Load Center.</td>
</tr>
<tr>
<td>6</td>
<td>Lomita Park</td>
<td>$8,844</td>
<td>15</td>
<td>4</td>
<td>5</td>
<td>1/1</td>
<td>2</td>
<td>1. Twice the number of regulator runs. 2. One additional automated valves. 3. Temporary operating configuration during rebuild included relocation of some facilities. 4. Installation of a pig receiver for ILI. 5. Environmental permit required.</td>
</tr>
<tr>
<td>7</td>
<td>Oakland PLS</td>
<td>$19,093</td>
<td>20</td>
<td>4</td>
<td>4</td>
<td>2/1</td>
<td>2</td>
<td>1. Twice the number of regulator runs. 2. Two additional automated valves. 3. New location requiring environmental permit, site remediation, and building demolition. 4. Installation of a pig receiver for ILI.</td>
</tr>
<tr>
<td>Line No.</td>
<td>Complex Stations</td>
<td>Estimate at Completion</td>
<td>No. of Mechanical Components</td>
<td>No. of Regulators</td>
<td>No. of Control Valves</td>
<td>No. of Lines (In/Out)</td>
<td>No. of Reg. Runs</td>
<td>Incremental Scope Compared to 2015 GT&amp;S Base Station</td>
</tr>
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<tr>
<td>8</td>
<td>Hollister</td>
<td>$44,768</td>
<td>67</td>
<td>8</td>
<td>13</td>
<td>2/4</td>
<td>4</td>
<td>1. Four times the number of regulator runs.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2. Five additional automated valves.</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>3. Construction of control building.</td>
</tr>
<tr>
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<td></td>
<td></td>
<td></td>
<td>4. Installation two pig launchers for ILI.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>5. New physical security system.</td>
</tr>
<tr>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>6. Acquire new land, perform demolition and</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>environmental permitting.</td>
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<td></td>
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<td></td>
<td></td>
<td></td>
<td>7. Similar to terminal and unit cost comparison is not applicable.</td>
</tr>
<tr>
<td>9</td>
<td>Swingle Junction</td>
<td>$25,355</td>
<td>56</td>
<td>12</td>
<td>13</td>
<td>2/3</td>
<td>6</td>
<td>1. Six times the number of regulator runs.</td>
</tr>
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<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td>2. Four additional automated valves.</td>
</tr>
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<td></td>
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<td></td>
<td>3. Installation two pig launchers and a receiver for ILI.</td>
</tr>
<tr>
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<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>4. Upgrade physical security system.</td>
</tr>
<tr>
<td>10</td>
<td>PLS 4A/4B</td>
<td>$15,983</td>
<td>43</td>
<td>6</td>
<td>6</td>
<td>2/2</td>
<td>2</td>
<td>1. Twice the number of regulator runs.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2. Four additional automated valves.</td>
</tr>
<tr>
<td></td>
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<td></td>
<td></td>
<td></td>
<td>3. Upgrade grounding system.</td>
</tr>
<tr>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>4. Installation of two pig launchers and receivers for ILI.</td>
</tr>
</tbody>
</table>
What is your conclusion based on the parties’ proposed recommendations for Station Rebuilds?

PG&E disagrees with the parties’ recommendations for the following reasons: (1) system reliability and operational needs required prioritization of some stations that are large and are complicated in scope for rebuild during 2015-2018 rate case period; (2) the incremental costs to rebuild these stations are reasonable and justified; (3) PG&E maintains a prioritized list of candidates for station rebuilds that provides confidence in work for 2019-2021; and (4) the uncertainty of the program work has been reduced, as PG&E continually updates data and makes decisions on rebuilds.

For the reasons discussed above, PG&E finds the parties’ forecast recommendations unreasonable and recommends that PG&E’s forecast for 2019-2021 be adopted and no balancing account be required for M&C Station Rebuilds Program.

5. M&C Terminal Upgrades

Briefly, what is the scope of M&C Terminal Upgrades Program?

The M&C Terminal Upgrade and Rebuild Program addresses equipment aging and obsolescence for the three gas terminals at Milpitas, Antioch, and Brentwood. All three terminal stations require regular upgrades and maintenance to maintain reliability of the gas transmission system.

PG&E plans to perform selected equipment upgrades at all three existing transmission terminals. Additionally, PG&E will begin rebuilding the Brentwood terminal during the rate case period. M&C Terminal Upgrades Program is more fully-discussed in PG&E’s prepared testimony.

What are parties’ recommendations for Terminal Upgrades program?

As shown in Table 7-10 below, ORA proposes “adjusting the annual expenditures downward by [50] percent to $3.750 million per year during [the 2019] rate case period”, and recommends one-way balancing account treatment for this program. TURN proposes adjusting PG&E forecasts to $2.43 million per year during the 2019 rate case period and

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63 PG&E Prepared Testimony, Chapter 7, p. 7-54, line 4 to p. 7-56, line 10.
64 ORA-07, p. 18, lines 9-13.
deferring Brentwood Rebuild project. PG&E will discuss each of these recommendations in turn.\footnote{TURN, Chapter 7, p. 9, lines 11-12 and p. 10, lines 6-9.}

\begin{table}[h]
\centering
\caption{M&C TERMINAL UPGRADES}
\begin{tabular}{lccccccc}
\hline
\hline
1 & PG&E & $7,436 & $7,544 & $7,622 & – & – & – \\
3 & TURN & $2,430 & $2,430 & $2,430 & $5,010 & $5,110 & $5,190 \\
\hline
\end{tabular}
\end{table}

\begin{questions}
\item What is the basis for ORA’s proposed reduction of $11.352 million? \footnote{ORA-07, p. 18, lines 12-13.}
\item ORA states that the historical capital expenditure trend shows many fluctuations over the years. This trend indicates uncertainty in PG&E’s planning process and/or ability to provide the resources needed to handle the work load. ORA recommends extending the Terminal Upgrades into the next GT&S rate case period by adjusting the annual expenditures, downward by 50 percent to $3.750 million per year, during the 2019 rate case period, but ORA does not oppose the overall concept of the rebuild. In addition, “ORA recommends one-way balancing account treatment to track the expenditures for Terminal Upgrades during” the 2019 rate case period.\footnote{ORA-07, p. 18, lines 7-8.}
\item Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts? \footnote{ORA-07, p. 18, lines 12-13.}
\item No. ORA does not provide any justification for reducing the terminal upgrades forecast by 50 percent. In addition, ORA speculates that there is uncertainty in the planning process and resource limitation without any basis. That is not the case. ORA’s analysis was focused on the level of spending for terminal upgrades in the past, and ignores the proposed scope for this program.
\end{questions}

\footnote{TURN, Chapter 7, p. 9, lines 11-12 and p. 10, lines 6-9.}
\footnote{ORA-07, p. 18, lines 12-13.}
\footnote{ORA-07, p. 18, lines 7-8.}
1) Terminal upgrades, which includes general component upgrades; and
2) Major rebuild of the Brentwood Terminal.

The first effort is related to on-going capital improvements at the terminals including valve and actuator replacements, controls equipment upgrades, etc. The general terminal upgrades are forecast based on the historical costs for upgrade of equipment that requires replacement or rebuild based on obsolescence or need for repair. Typical work includes valve and actuator replacements, meter replacements, control upgrades, monitoring enhancements, etc. These items are identified during inspection and maintenance activities. In addition, there may be unplanned emergency repair or replacement work that occurs during the year. PG&E has requested $2.8 million per year for terminal upgrade work during the 2019-2021 rate case period.68

The second effort is the beginning of a long-term rebuild of the Brentwood Terminal to address aging and operational needs of the terminal. PG&E has identified Brentwood Terminal as one of the most critical pressure control facilities in need of a major rebuild.69 Brentwood was originally constructed in 1949 and portions of the original facility remain in service. The terminal has been modified many times over decades creating a complex network of piping that requires complicated operation of the facility. The complexity, equipment problems and age provide the opportunity for an equipment or operations problems to create an Over Pressure (OP) event. The overall objective is to rebuild Brentwood Terminal in a way that improves operational flexibility and reliability, reduces the potential for operating error and over pressure event.70 Given the critical nature of this facility, completion of engineering is considered a critical task during the next several years. The Brentwood Terminal rebuild will be performed in phases and the current forecast is to perform engineering and to remove equipment that is no longer in use. It is very important to

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68 PG&E WP 7-69 to WP 7-70.
69 Energy Experts International, Inc., Summary of Completed Performance Assessments and Repair Work (Updated March 21, 2018), provided in TURN-21, Question 12, Attachment 11CONF.
70 TURN-11, Question 04.
complete the detailed engineering work during the 2019-2021 to understand
the extent of work and costs required for other phases which will extend in to
next GT&S rate case period.

Q 68 Do you agree with ORA’s recommendations for a one-way balancing
account for the Terminal Upgrades Program?

A 68 No. PG&E disagrees with ORA’s recommendation for one-way balancing
account related to the Terminal Upgrades Program.

PG&E has clearly defined scope of work for 2019-2021. PG&E
forecasts ongoing component upgrades at all the three terminals, based on
a historical 3-year average (2014-2016), and costs for Phase 1 of the
Brentwood terminal rebuild for detailed engineering and equipment removal.
The scope of this program is clearly defined with minimal uncertainties and a
balancing account is not required. See Chapter 2 rebuttal testimony for
more discussion regarding balancing accounts.

Q 69 What is the basis of TURN’s proposed reductions for the Terminal Upgrade
Program and deferring the Brentwood rebuild project?

A 69 TURN states that the expensive Brentwood Rebuild Project should be
defered until PG&E has demonstrated its cost-effectiveness, compared to
alternatives. TURN argues that “PG&E has failed to demonstrate that it has
sufficiently considered all alternatives to a project that could cost over
$100 million and has likewise failed to show that its proposed approach,
a rebuild of the station, is the most cost-effective. Rather than devoting a
large amount of money, $14 million, to begin a project that PG&E has failed
to justify, the Commission should decline to earmark any funds for rebuilding
at this point.”71

TURN also recommends that the terminal upgrade work should be
reduced to reflect more complete cost data. TURN states that “given the
volatility in the recorded costs for this category, TURN recommends that the
forecast be based on the longer six-year average, resulting in an
approximately $0.5 million reduction to PG&E’s annual forecasts.”72

71 TURN, Chapter 7, p. 9, lines 1-5.
72 TURN, Chapter 7, p. 10, lines 2-5.
Q 70 Do you agree with TURN’s recommendation that the potentially very expensive Brentwood Rebuild Project should be deferred?

A 70 No. PG&E does not agree with TURN’s recommendation. As stated previously, PG&E has identified the Brentwood Terminal as one of the most critical pressure control facilities in need of a major rebuild. The terminal is in highly populated area. Brentwood was originally constructed in 1949 and portions of the original facility remain in service. The potential for equipment failure is high due to equipment age and obsolescence. The risk of equipment failure is exacerbated by monitor valves that have set points close to Maximum Allowable Operating Pressure and that may operate too slowly to catch a regulator failure, resulting in an over pressure event.73 Also, recent investigation following the discovery of a leak indicated the presence of external corrosion which illustrates the need for a rebuild of the Brentwood facility.

Q 71 Are there alternatives to this Brentwood terminal phased rebuild?

A 71 No. The Terminal has been modified many times over decades, creating a complex network of piping that is difficult to operate. The complexity, equipment problems, and age, provide too much opportunity for an operating error, and potentially, an OP event. As PG&E stated in the data request response to TURN, the alternatives considered for terminal rebuild are equipment upgrade and routine component replacement.74 This approach has been used often at the Brentwood Terminal to replace control valves and other equipment items. However, this approach has limitations over time. PG&E has performed component replacement over the life of this facility but this approach cannot address the needed operational improvements at the facility. As stated in the previous response, major rebuild is required to address the obsolescence issues and to simplify the terminal. The selected alternative is a station rebuild that is proposed to be performed in a phased approach.

73 TURN-11, Question 04.
74 TURN-11, Question 05.
Why is a phased rebuild appropriate for Brentwood terminal?

The Brentwood Terminal is one of the most complex operating facilities in PG&E’s system. The Brentwood Terminal receives natural gas from four major backbone pipelines, and delivers gas by three major pipelines. The facility also allows for delivery from two of the receiving lines from McDonald Island, which requires the station to allow for reverse flow to the storage facilities. This facility is required to operate on a continuous basis and cannot be taken out of service. Hence the rebuild of this facility requires a phased, integrated approach to allow for rebuild of parts of the facility.

A phased approach requires the consideration of how to modify the station, while maintaining the operation of the station. Therefore, this approach requires detailed engineering studies to define the most efficient and cost-effective approach.

Do you agree with TURN’s argument that PG&E has failed to demonstrate that it has sufficiently considered all alternatives to a project that could cost over $100 million?

No. It is important to note that PG&E is not requesting $100 million for the Brentwood Terminal in this rate case. PG&E has forecast $13.5 million for two specific tasks related to the Brentwood Terminal rebuild during the 2019-2021 rate case period: (1) removal of assets no longer in use; and (2) engineering to define the scope of the rebuild effort for further phases.

**Removal of Assets:** The task to remove assets that are no longer needed for operation is required to alleviate congestion in the site and to free up land for use in the Brentwood Terminal rebuild effort. This asset removal task is required for any rebuild or upgrade scheme that will be selected.

**Engineering and Design:** The phased facility rebuild is not “like-for-like” replacement of the current facility, but requires a reconfiguration of the facility to allow for more flexible operations, and to improve reliability and maintenance. Therefore, the engineering effort will include a detailed review of the phased approach to allow for continued facility operations, as well as the engineering and design associated with the facility.
Do you agree with TURN’s recommendation that the terminal upgrade work should be reduced to reflect more complete cost data?

No. PG&E does not agree with TURN’s recommendation. TURN recommends a 6-year average, as opposed to PG&E’s 3-year average. As shown in the Table 7-11 below, PG&E’s forecasted 3-year average is also consistent with the 5-year average for the work. TURN applies inconsistent methodology, by introducing a sixth year in to the average to maximize reductions for this work. Irrespective of whether we use 3-year or 5-year average, there are enough routine upgrade projects identified at all three terminals that will consume PG&E’s forecasted spend level for 2019-2021.

### TABLE 7-11
**TERMINAL UPGRADES**
**SUMMARY OF TERMINAL UPGRADE 5-YEAR AVERAGE 2013-2017 (MILLIONS OF DOLLARS)**

<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Terminal Upgrade</td>
<td>$0.62</td>
<td>$4.02</td>
<td>$4.19</td>
<td>$3.21</td>
<td>$0.87</td>
<td>$1.25</td>
<td>$2.36</td>
<td>$2.76</td>
<td>$2.71</td>
</tr>
</tbody>
</table>

What is your conclusion based on the parties’ proposed recommendations for Terminal Upgrade Program?

PG&E disagrees with the parties’ proposed reductions for the following reasons: (1) there is an established need for rebuild of the Brentwood Terminal for aging and operational issues to ensure safe operation of the gas transmission system; (2) there is limited uncertainty in the overall scope of work for the Brentwood Terminal rebuild scope as the majority of the scope is associated with detailed engineering, and (3) the terminals are critical facilities in the PG&E system, and work must be performed to address obsolescence issues. For the reasons discussed above, PG&E finds the parties’ forecast recommendations unreasonable, and recommends that its 2019, 2020 and 2021 forecasts of $7 million,
$7.5 million, and $7.6 million for M&C terminal upgrades be adopted, and that no balancing account be required for this program.

6. M&C Gas Quality Assessment

Q 76 Briefly, what is the scope of M&C Gas Quality Assessment Program?
A 76 The Gas Quality Assessment Program addresses gas quality issues, such as: particulate and liquids so that equipment operates correctly; materials do not degrade due to corrosion; and gas entering the PG&E system meets CPUC gas quality regulatory requirements. The M&C gas quality assessment is more fully-discussed in PG&E’s prepared testimony.76

Q 77 What are parties’ recommendations for M&C Gas Quality Assessment Program?
A 77 As shown in Table 7-12 below, ORA proposes a reduction of $0.59 million for Gas Quality Assessment Program.77 No other party submitted testimony regarding this program.

<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>M&amp;C Gas Quality Assessment Expense</td>
<td>$1,040</td>
<td>$450</td>
<td>$1,040</td>
<td>$590</td>
<td>–</td>
</tr>
</tbody>
</table>

Q 78 What is the basis for ORA’s proposed reduction?
A 78 ORA states that “the adjusted-recorded O&M for 2017 for Gas Quality Assessment is $0.430 million, which is less than half of the forecasted $1.028 million, or $0.598 million lower. ORA recommends O&M expenses of $0.450 million for 2019 Gas Quality Assessment, instead of the forecasted $1.040 million, similar to the adjusted-recorded amount of $0.430 million for 2017, an adjustment of $0.590 million downward.”78

76 PG&E Prepared Testimony, Chapter 7, p. 7-56, line 11 to p. 7-57, line 23.
78 ORA-07, p. 19, lines 8-13.
Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts?

No. PG&E disagrees with ORA’s recommendation. PG&E leveraged Gas Quality Program subject matter experts for causal evaluations for large OP events, and for building the OP elimination strategy. This resulted in limited spending in the gas quality area in 2017. This allocation of expertise is not expected on an on-going basis. Also, the Gas Quality Assessment Program now works in lockstep with Station OPP Program to outline an OP elimination strategy by analyzing liquids, sulfur, or debris in the pipelines and impact on pressure regulator performance. The proposed gas quality plan for the rate case period reflects this strategy. Hence ORA’s recommendation to use the 2017 recorded costs as the basis for 2019 expense forecast is not appropriate.

As stated in workpapers, the major causes of over pressure events are related to issues related to gas quality, liquids, and debris in the system due to construction, In Line Inspection (ILI), and third-party gas import. The gas quality assessment program includes studies and evaluation to address these causes, by identifying locations subject to these issues, and by defining specific activities to eliminate these occurrences. This work complements and works hand in hand with the Station OPP Enhancements Program to minimize OP events.

PG&E intends to increase its work associated with gas quality in this rate case period to support this work, and hence, ORA’s recommendation to use the 2017 recorded as the basis for the 2019 forecast should be rejected.

What is your conclusion based on the parties’ proposed recommendations for Gas Quality Assessment Program?

PG&E disagrees with the ORA’s proposed reductions for the following reasons: (1) The 2017 recorded costs do not reflect the work that is required to support new work during 2019-2021; (2) Gas quality is an integral part of the overall OPP solution, and a key program to continue to ensure safe operation of the gas transmission system. For these reasons, PG&E finds the ORA’s forecast recommendations unreasonable.
and recommends that its $1.04 million expense forecast for M&C Gas Quality Assessment expense be adopted.

7. M&C Station OPP Enhancements

Q 81 Briefly, what is the scope of the Station OPP Enhancements Program?

A 81 The station OPP Enhancement Program is a new program to prevent large OP events, due to equipment failure at regulator stations. The expense projects in this program are for system studies to determine the most effective individual regulator station and system solution, as well as new technology pilot studies. The capital projects in this program are for modifying or adding station equipment to provide protection against OP events. The M&C OPP Enhancement Program is more fully-discussed in PG&E’s prepared testimony.80

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Q 82 What are parties’ recommendations for the Station OPP Enhancements Program?

A 82 As shown in Table 7-13 above, ORA proposes no reduction for expense and capital, but recommends a memorandum account for this program. TURN recommends PG&E’s Station OPP Capital Program be deferred until the next rate case period, and proposes no reduction for expense. PG&E discusses each of these recommendations in turn.

Q 83 What is the basis for ORA’s recommendation for a memorandum account for this program?

A 83 ORA notes that as PG&E states in the testimony:

80 PG&E Prepared Testimony, Chapter 7, p. 7-57, line 24 to p. 7-60, line 30.
The project costs vary by technology application and are based on estimates from preliminary study.\footnote{ORA-07, p. 21, line 17 to p. 22, line 1.}

ORA claims that it is more appropriate to track the costs of the program with a memorandum account because of the unknowns. Therefore, ORA recommends the Commission require PG&E to set up a memorandum account to track the costs for the Station OPP Enhancements Program.

\textbf{Q} 84 Do you agree with ORA's recommendations for memorandum account for the Station OPP Enhancements Program?

\textbf{A} 84 No. PG&E disagrees with ORA's recommendation. At the time of the 2019 GT&S Rate Case filing, the OPP Enhancements program was being initialized. During the ensuing months, more detailed plans were developed based on data collection and analysis activities to further define the program. The major advancement in the program is the focus on the pilot-operated (H-14) regulator stations and rebuilding the Large Volume Customer (LVC) primary regulation sets.\footnote{TURN-023, Question 04c.} These are the stations that are subject to a common mode failure of the primary pressure control and the over pressure control devices and have become the focus of the Capital Program. The total population of transmission pilot-operated stations and LVC primary regulation sets are 292 with a goal to address 50 percent of these installations over a 5-year period.\footnote{TURN-023, Question 04c.} These stations will be addressed primarily using the slam-shut installations as the secondary OPP. Other station types and technology options will be studied during this rate case period, but are not forecasted for broad implementation. Therefore, the number and pace of stations for the Station OPP program for 2019-2021 is well defined based on work completed since filing of the 2019 GT&S Rate Case and a new memorandum account is not necessary.

\textbf{Q} 85 What is TURN's recommendation for Station OPP Enhancements Program?

\textbf{A} 85 TURN recommends that PG&E's Station OPP Capital Program "be deferred until the next rate case period, when PG&E will have the benefit of the system planning studies it intends to perform in this rate case period. In the next GT&S [Rate Case], PG&E should be required to explain how its
proposed plan addresses the known risks and limitations for slam-shut devices and any other solutions it proposes.”

Q 86 What is the basis for TURN’s proposed reduction?
A 86 TURN claims that “it makes more sense to obtain the benefits of [PG&E’s] planning studies before committing ratepayer funds to a new capital program that, [as PG&E stated], was still evolving when it prepared this rate case and that relies on a strategy, slam-shut devices, for which PG&E’s own white paper identifies significant risks and limitations that need further study. Therefore, TURN recommends that PG&E’s Capital Program be deferred until the next rate case period, when PG&E will have the benefit of the system planning studies it intends to perform in this rate case period.”

Q 87 Do you agree with TURN’s recommendations to defer the Station OPP Capital Program until the next rate case period?
A 87 No. PG&E disagrees with TURN’s recommendation. PG&E has made significant progress in its OPP Program since the 2019 GT&S filing. After assessing the white paper with secondary OPP options and recommended actions, PG&E enlisted the services of a third-party consultant, SPEC Services, to evaluate those options and to develop an overall OPP Program. As stated in a PG&E response to a TURN data request, the program focus during the 2019-2021 rate case period will be on pilot-operated (H-14) regulator stations through installation of secondary OPP devices, such as slam shuts, and rebuilding the Large Volume Customer (LVC) primary regulation sets with a goal to address 50 percent of the stations over a 5-year period. Based on the evaluation by SPEC Services, and the planning approach developed by PG&E and SPEC, there is a well-defined and justified program for OPP mitigation actions for the 2019-2021 rate case period.

84 TURN, Chapter 7, p. 12, lines 19-23.
85 TURN, Chapter 7, p. 12, lines 14-21.
86 PG&E WP-7-84 to WP 7-109.
87 TURN-023, Question 04c.
88 TURN-011, Question 09.
Q 88 Do you agree with TURN’s criticism that PG&E relies on a strategy, slam-shut devices, for which PG&E’s own white paper identifies significant risks and limitations that need further study?

A 88 No. TURN’s criticism is without basis. PG&E has performed system studies, and executed pilot projects to test the validity of multiple pressure control and OPP devices, including slam-shuts. PG&E has previously produced documents related to evaluation of various technologies and pilot study for OPP Program as part of a data response to a TURN data request.\(^\text{89}\) As stated in the response above, PG&E has enlisted services of a third-party consultant, SPEC Services with OPP Program implementation. The overall OPP plan is provided in the roadmap included in Attachment B, “Overpressure Event Elimination Program (Transmission): Summary of Program Development and Recommendations,” prepared by SPEC Engineering Services, August 2018. The program document sufficiently addresses the following with respect to TURN’s criticism:

1) The OPP team reviewed the results of the white paper from engineering firm Exponent who performed system studies and executed pilot projects to test the validity of proposed mitigations.

2) Based on these studies, a decision was made to pursue a dual strategy of installing secondary OPP (slam shut devices), and increasing system visibility in the control room for LVCs and pilot-operated regulating stations. The installation of slam shut devices is the most cost-effective solution to reduce the risk of large OP events.

3) As noted in the Exponent White paper,\(^\text{90}\) “slam shuts are currently installed at PG&E low-pressure distribution stations and have a good track record for prevention of [OP] events on these systems” without causing unnecessary customer outages.

4) PG&E developed decision trees to determine the stations to receive the slam shut devices. Stations that cannot handle the risk of station shut-in are supplied with an alternative method of OPP.

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\(^{89}\) TURN-023, Question 06c.

\(^{90}\) PG&E WP 7-97.
PG&E has begun the process of prioritizing and planning slam shut installations throughout the system. The LVC Program, and the Pilot-Operated Regulator Station Program, are planned to be executed over a period of 10 years—with the expectation that 50 percent of the stations will have secondary OPP installed by the end of 2022.

If PG&E has already performed the system planning studies to determine a OPP strategy with slam shut devices, then what is the purpose of the future system planning studies proposed for 2019 GT&S Rate Case period?

As defined in the SPEC services program document, the slam-shut installation provided the best alternative since it prevents OP events, has relatively-low-cost, and is easy to install. PG&E has previously provided a draft operating philosophy for selection of OPP alternatives to TURN that showed the criteria of critical customers, less than 5,000 customers, and dual versus single run, to govern the use of slam shuts. System studies and evaluation were performed to develop this operating philosophy. For applications where slam-shut devices cannot be installed, further system studies will determine the appropriate secondary OPP. The system studies during the rate case period will focus on potential asset and customer impacts for such stations.

What is your conclusion based on the parties’ proposed recommendations for Station OPP Enhancements Program?

PG&E disagrees with the parties’ proposed reductions for the following reasons: (1) the OPP program during the 2019-2021 period of time are well-defined based on work completed since filing of the rate case; (2) currently known and tested technology is the only solution that will be applied during this rate case period; (3) specific station type (pilot-operated stations) locations are the only stations that will implement OPP enhancement under this program; and (4) there is limited uncertainty in this program. For these reasons, PG&E finds the parties’ forecast recommendations unreasonable and recommends that its expense forecast of $1.56 million, Capital forecasts for 2019, 2020, and 2021 of $6.13 million,

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91 TURN-023, Question 06a.
$6.16 million, and $6.15 million for the Station OPP Enhancements Program be adopted.

8. Critical Documents Program

Q 91 Briefly, what is the scope of Critical Documents Program?
A 91 The Critical Documents Program consists of revising and/or developing new critical drawings and documents. These drawings and documents assist operation and maintenance personnel in understanding, operating, and troubleshooting systems and equipment. Critical Documents Program is more fully-discussed in PG&E’s prepared testimony.92

Q 92 What are parties’ recommendations for Critical Documents Program?
A 92 As shown in Table 7-14 below, ORA proposes no reduction for expense and capital for these programs, but recommends that PG&E continue to track costs for this program in existing memorandum account.93 TURN recommends that “no rate recovery of Critical Documents costs should be permitted at this time and PG&E should continue to track costs in a memorandum account.”94 PG&E will discuss each of these recommendations in turn.

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Q 93 What is the basis for ORA’s recommendation?
A 93 ORA states that the “[c]omparison of PG&E’s 2017 forecasts and adjusted-recorded actual O&M shows that for Critical Documents, PG&E’s forecast is $1.887 million versus negative $1.698 million actual. . . . The discrepancies in this comparison of 2017 forecasts versus actuals show that this is not the time to eliminate. . . the memorandum accounts.

92 PG&E Prepared Testimony, Chapter7, p. 7-61, line 1 to p. 764, line 2.
93 ORA-07, p. 22, line 18 to p. 23, line 2.
94 TURN, Chapter 7, p. 14, lines 16-18.
Therefore, ORA recommends the Commission requires PG&E continue to track the costs in…memorandum account as [the] program wind[s] down."\textsuperscript{95}

Q 94 Do you agree with ORA’s recommendations for continuing the existing memorandum accounts for Critical Documents Program?

A 94 No. ORA does not accurately convey PG&E’s 2017 recorded information for Critical Documents, although PG&E explained the 2017 recorded costs for these programs through data request responses. As stated in PG&E’s data request response to ORA 65, Question 4:

Consistent with 2015 GT&S decision, PG&E has established accounting process and has been tracking costs in memorandum account for Critical Documents. PG&E has been tracking costs associated with the stations installed before January 1, 1956 and after January 1, 1956 separately. PG&E made retroactive adjustments to remove the shareholder portion of the 2015 and 2016 costs in 2017. These adjustments for 2015 and 2016 were booked in 2017, which resulted in an underspend for Critical Documents in 2017.\textsuperscript{96}

The underspend is simply due to an accounting adjustment, not due to uncertainty in the programs, contrary to ORA’s statement.

Far from uncertainty, the Critical Documents Program is well-established and is now in the production phase. The project currently averages 10 facilities per month, and is on track to finish by 2021. Additionally, eight subsequent procedures are in various stages of refinement and publication, as well as TD-4551S, the cornerstone standard for the program. These procedures are being issued to standardize requirements, and incorporate PG&E and industry best practices for the creation and update of the critical documents going forward.

A separate memorandum account is not necessary to track these costs as PG&E continues to track the shareholder and ratepayer costs separately for this program.\textsuperscript{97}

Q 95 What is the basis of TURN’s recommendations?

A 95 TURN asserts that “[t]he Commission should reject PG&E’s request to discontinue the memorandum account and should continue to defer

\textsuperscript{95} ORA-07, p. 22, line 18 to p. 23, line 2.

\textsuperscript{96} ORA-65, Question 04.

\textsuperscript{97} See PG&E Chapter 2 rebuttal testimony, sponsored by Mr. Singh, for additional discussion regarding balancing and memorandum accounts.
recovery of costs tracked in the memorandum account until the
reasonableness issues for all the tracked costs can be addressed in a future
application.” TURN states that “PG&E’s removal of costs relating to facilities
installed post-1955 does not fully address the Commission’s concern that
some of the incurred costs are to remediate past record-keeping
deficiencies.” TURN claims “PG&E has made no effort in its request to
demonstrate that the costs included in its forecast were prudently incurred
and were not to remediate past deficiencies. Rather than trying to address
that prudence issue in this case, the issue can be comprehensively
addressed for all costs tracked in the memorandum account when PG&E
files its future application pursuant to D.16-06-056.’

Q 96 Do you agree with TURN’s recommendations for reducing PG&E’s 2018
forecasts?
A 96 No. PG&E disagrees with TURN’s recommendation. The need to generate
new and revised station documentation by the Critical Documents Program
is driven by the vintage of the documentation, not by deficient document
management practices. Consequently, PG&E does not consider this
work remedial.

Critical documents created for M&C and C&P gas transmission facilities
followed industry practices at the point in time that the station was
constructed. A small percentage of the documentation within the scope of
Critical Documents is code or regulatory driven and none of those drivers
existed prior to 1956. The Critical Documentation Program is therefore an
opportunity for standardization to ensure the accuracy and efficacy of these
documents.

As directed by D.16-06-056, PG&E continues to track the costs for
stations installed before January 1, 1956, and those installed on or after
January 1, 1956, separately, for the rate case period 2019-2021.

98 TURN, Chapter 7, p.14, lines 6-15.
99 See PG&E Chapter 2 rebuttal testimony, sponsored by Mr. Singh, for additional
discussion regarding balancing and memorandum accounts.
Q 97 What is your conclusion based on the parties’ proposed recommendations for Critical Documents Programs?

A 97 PGE disagrees with the parties’ proposed reductions for the following reasons: (1) the underspend in this program for 2017 is due to an accounting adjustment not due to uncertainty in the program scope; (2) the work is not remedial and PG&E continues to track the costs for stations installed before January 1, 1956 and those installed on or after January 1, 1956 separately for the rate case period 2019-2021 per 2015 GT&S decision. For the reasons discussed above, PG&E finds the parties’ forecast recommendations unreasonable and recommends that the $3.1 million expense forecast for Critical Documents Program be adopted, and allow PG&E to discontinue the memorandum account for this program.

9. Station Assessment Programs

Q 98 Briefly, what is the scope of Station Assessment Programs?

A 98 Station Assessment Programs consists of:

- **ECA Phase 1** – Involves identifying component design anomalies, field investigating components and developing and performing associated remediation activities;

- **ECA Phase 2** – Aims to obtain information on station asset integrity through the evaluation and application of technologies that may be considered as alternatives to strength testing that minimize risk to the station components; and

- **Station Strength Testing** – Performs station component pressure testing, when warranted as a result of ECA Phase 1 and Phase 2 findings. The Station Strength Testing Program is designed to address components that cannot be addressed via the non-destructive alternatives from ECA Phase 2.

Station assessment programs are more fully-discussed in respective sections in PG&E’s prepared testimony.100

Q 99 What are parties’ recommendations for Station Assessment Programs?

A 99 As shown in Table 7-15 below, ORA proposes no reduction for expense and capital for these programs but recommends that PG&E continue to track the

100 PG&E’s Prepared Testimony, Chapter 7, p. 7-66, line 12 to p. 7-75, line 29.
costs for these programs with the existing balancing accounts and memorandum accounts.\textsuperscript{101} TURN does not object to PG&E’s expense forecasts for ECA Phases 1 and 2 provided that the one-way balancing account is retained.\textsuperscript{102} TURN also recommends that the forecast for Station Strength Testing Program should not be approved, and PG&E should be allowed to continue to track costs in a memorandum account.\textsuperscript{103} PG&E will discuss each of these recommendations in turn.

\begin{table}
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\caption{STATION ASSESSMENT PROGRAMS}
\begin{tabular}{lrrrr}
\hline
Line No. & Description & 2019 PG&E & 2019 ORA\textsuperscript{(a)} & 2019 TURN & ORA Proposed Reduction\textsuperscript{(a)} & TURN Proposed Reduction \\
\hline
1 & ECA1 Expense & $4,720 & $4,612 & $4,720 & – & – \\
2 & ECA2 Expense & $1,835 & $1,835 & $1,835 & – & – \\
3 & Station Strength Testing Expense & $1,014 & $1,014 & $1,014 & – & $1,014 \\
4 & ECA2 Capital & $287 & $287 & $287 & – & – \\
5 & Station Strength Testing Capital & $102 & $102 & $102 & – & – \\
\hline
\end{tabular}
\textsuperscript{(a)} Reductions are from ORA’s testimony. In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
\end{table}

Q 100 What is the basis for ORA’s recommendation?
A 100 ORA states that the “\textsuperscript{104}comparison of PG&E’s 2017 forecasts and adjusted-recorded actual O&M shows that for \textsuperscript{104}ECA 1 PG&E’s forecast is $5.570 million forecast versus $7.718 million actual, and for ECA 2, it is $1.930 million forecast versus $0.198 million actual. The discrepancies in this comparison of 2017 forecasts versus actuals show that this is not the time to eliminate the balancing accounts and memorandum accounts. Therefore, ORA recommends the Commission requires PG&E continue to track the costs in these areas with the existing balancing accounts and memorandum accounts.”

\textsuperscript{101} ORA-07, p. 22, line 18 to p. 23, line 2.
\textsuperscript{102} TURN, Chapter 7, p. 16, lines 5-9.
\textsuperscript{103} TURN, Chapter 7, p. 17, lines 10-12.
\textsuperscript{104} ORA-07, p. 22, line 18 to p. 23, line2.
Do you agree with ORA’s recommendations for continuing the existing balancing accounts and memorandum account for Station Assessment Programs?

No. PG&E disagrees with ORA’s recommendation. Consistent with 2015 GT&S decision, PG&E has established accounting process and has been tracking costs for these programs in balancing accounts for ECA 1 and ECA 2 expense.

For ECA 1, more components than forecasted for pre-January 1, 1956 vintage stations needed field investigation or replacement, which caused some variances compared to the 2017 forecast. A thorough and robust tracking mechanism has been established for ECA 1 program to ensure that PG&E excludes from recovering costs to address facility components installed on or after January 1, 1956 that do not, but were required to have traceable, verifiable and complete records.

For ECA2, PG&E made retroactive adjustments to remove the shareholder portion of the 2016 costs in 2017. These adjustments for 2016 booked in 2017, which resulted in an underspend for 2017 for ECA 2 expense. The underspend is simply due to an accounting adjustment, not due to uncertainty in the programs like ORA claims. A separate balancing account mechanism is not necessary to track these costs.

The Station Strength Testing Program is designed to address components that cannot be addressed via ECA 2. The scope of the Station Strength Testing program is clearly defined. A separate memorandum account is not necessary to track these costs for the 2019-2021 period, as PG&E’s current accounting process is consistent with the 2015 GT&S Rate Case decision.

Also, for 2019 GT&S, as part of the ECA 2 and Station Strength Testing Program, PG&E forecasts some capital expenditures. This capital work will enable non-destructive, and destructive, station component evaluation, and will encompass the replacement of equipment or other components that is required because of the ECA 2 or Station Strength Testing work. There are no existing balancing accounts for ECA 2 and Station Strength Testing
Capital programs, however PG&E will continue to track the shareholder and ratepayer costs separately for these programs similar to expense work.\footnote{105}{See PG&E Chapter 2 rebuttal testimony, sponsored by Mr. Singh, for additional discussion regarding balancing and memorandum accounts.}

Q 102 What is the basis of TURN’s recommendations?  
A 102 TURN states “that PG&E’s recorded results for 2015-2017 have been much lower than [adopted], particularly for ECA Phase 2, where, for example, 2017 actual spending was only 2 [percent] of the adopted amount. TURN claims that “[i]n light of PG&E’s proven difficulty in accurately forecasting costs for these programs—and demonstrated bias toward over-forecasting—TURN recommends that the Commission retain the one-way balancing account for the 2019-2021 rate case period. Provided that the one-way balancing account is retained, TURN does not take issue with PG&E’s 2019 expense.”\footnote{106}{TURN, Chapter 7, p.15 line 18 to p. 16, line 9.}

Q 103 Do you agree with TURN’s recommendations for recommendations for continuing the existing balancing accounts and memorandum account for Station Assessment Programs?  
A 103 No, PG&E disagrees with TURN’s recommendation. TURN’s claim regarding PG&E’s difficulty and bias towards forecasting these programs is baseless. The primary reason why these programs had recorded costs lower than the adopted amount is because the entire adopted amount was placed in a balancing account without the split between pre-1/1/1956 and post-1/1/1956 costs. Consistent with 2015 GT&S decision, PG&E has established accounting process, and tracks the difference between adopted and actual cost of work during the 2015-2018 rate case cycle, for stations installed on or before December 31, 1955, and station components installed on or after January 1, 1956, that have traceable, verifiable, and complete records. A separate balancing account mechanism and memorandum accounts are not necessary to track these costs for the 2019-2021 period, as PG&E’s current accounting process is consistent with 2015 GT&S decision for these programs.\footnote{107}{See PG&E Chapter 2 rebuttal testimony, sponsored by Mr. Singh, for additional discussion regarding balancing and memorandum accounts.}
Q 104 What is your conclusion based on the parties’ proposed recommendations for Station Assessment Programs?

A 104 PG&E disagrees with the parties’ proposed reductions for the following reasons: (1) there are no uncertainties associated with forecasting process or in the program scope; (2) PG&E continues to track the shareholder and rate payer portion of the work separately for these programs per 2015 GT&S decision. For these reasons, PG&E finds the parties’ forecast recommendations unreasonable, and recommends that expense and capital forecasts these programs be adopted and allow PG&E’s request to discontinue the existing balancing accounts and memorandum accounts for Station Assessment Programs be approved.

10. Physical Security

Q 105 Briefly, what is the scope of Physical Security program?

A 105 The Physical Security Program implements physical security measures at critical station facilities for both C&P and M&C assets. Physical security upgrades are required based on guidelines from the Transportation Security Administration (TSA) and the level of upgrade required is based on site-specific reviews of the stations. PG&E’s Corporate Security team has defined specific mitigations to close security gaps and establish mitigation measures to better protect critical Gas Transmission facilities/assets. The Physical security program is more fully-discussed in PG&E’s prepared testimony.**108**

Q 106 What are parties’ recommendations for Physical Security Program?

A 106 As shown in Table 7-16 below, TURN proposes a reduction of $5.4 million for 2019-2021 period.*109* No other party submitted testimony regarding this program.

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**108** PG&E’s Testimony, Chapter 7, p. 7-76, line 1 to p. 7-78, line 7.

**109** TURN, Chapter 7, p. 18, lines 17-19.
### TABLE 7-16
**PHYSICAL SECURITY CAPITAL**

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#### Question 107
What is the basis for TURN’s proposed reduction?

#### Answer 107
TURN states that “[t]he average cost of the three 2017 projects, $3.1 million, is significantly lower than the average cost of the two 2016 projects, $4.6 million, that PG&E used for its forecast.” TURN claims “that the 2017 average cost per project should be used, which reflects the most recent costs and may reflect cost savings that PG&E has achieved. However, TURN will use the average of all five projects, $3.70 million, for its forecast. Accordingly, TURN recommends that PG&E’s forecast be reduced.”

#### Question 108
Do you agree with TURN’s recommendations for reducing PG&E’s cost forecasts?

#### Answer 108
No. PG&E disagrees with ORA’s recommendation. It is important to understand that every station is unique. The average physical security upgrade costs for the stations with larger footprint will be higher than the stations with the smaller footprint. 2017 projects included one big station and two stations with small footprint, so TURN’s claim that the 2017 average may reflect cost savings is not true.

### TABLE 7-17
**PHYSICAL SECURITY UPGRADES – AVERAGE COSTS (MILLIONS OF DOLLARS)**

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110 TURN, Chapter 7, p. 18, lines 12-17.
PG&E has completed physical security upgrades at two more stations in 2018 as of July. As shown in the table above, the average costs for the seven projects completed between 2016-2018 is $4.3 million, which is in line with the 2016 average that PG&E proposed at the time of filing.

The physical security risks and mitigation measures are set forth by corporate security in Utility Standard TD-4050S, “Security Standard for Gas Operations,” and varies based on the size and type of the station. PG&E’s strategic objective is to address all the 24 critical facilities identified by 2023.\textsuperscript{111} The size of the facility varies from small to large and the level of upgrade required also varies based on station size.

Based on the data available at the time of the 2019 GT&S Rate Case filing, PG&E used the average for the projects completed in 2016, which is now supported by latest available information for all projects completed between 2016-2018. Therefore, TURN’s recommendation to use the 2017 average as the basis for the 2019 forecast is not appropriate.

Q 109 What is your conclusion based on the parties’ proposed recommendations for Physical Security Program?
A 109 PG&E disagrees with the parties’ proposed reductions for the following reasons: (1) based on the available information for all seven projects completed between 2016-2018, the average costs are in line with the 2016 average that PG&E proposed at the time of filing; (2) TURN’s recommendation to use the 2017 average as the basis for the 2019 forecast is not appropriate as it didn’t reflect cost information of all projects completed. For these reasons, PG&E finds the parties’ forecast recommendations unreasonable and recommends that the capital forecasts for 2019, 2020, and 2021 of $9.39 million, $9.43 million and $9.43 million for the Physical Security Program be adopted.

D. Response to Parties’ Recommendations Concerning Decommissioning of Facilities for the NGSS

Q 110 Briefly, what is the scope of Decommissioning of Facilities for the NGSS?
A 110 PG&E’s 2019 GT&S filing, Chapter 11, “Natural Gas Storage Strategy,” describes several proposed changes to PG&E’s asset holdings, its system

\textsuperscript{111} TURN-23, Question 07.
operations, and its storage services. An element of PG&E’s proposal includes ceasing storage operations at its Los Medanos and Pleasant Creek storage facilities. Ceasing operations at these facilities will involve decommissioning work for AG facilities at the Los Medanos and Pleasant Creek storage fields. The scope of decommissioning of AG facilities is more fully discussed in PG&E’s prepared testimony.  

Q 111 What are parties’ recommendations for decommissioning of AG facilities at Los Medanos and Pleasant Creek?

A 111 CE states that “PG&E should have provided actual itemized estimates of the costs to demolish the [AG] storage plant, as well as offsetting salvage costs. PG&E has failed to do the minimum to support its claims for recovering the cost of decommissioning these storage facilities.” CE recommends that “the Commission should not allow recovery of these costs until and unless an adequate estimate of the costs based on credible bids for the work is prepared.”

Q 112 What is the basis for CE’s recommendations?

A 112 CE states that PG&E “provided no itemized estimates or evidence of the costs for remediation of the surface equipment, and merely supplied a single figure for each field of similar size to its estimate of the [plugging and abandonment] costs.” CE also states that, “it is reasonable to assume that PG&E’s compression and dehydration equipment has some marketable value, if for nothing more than scrap.” CE also argues that “PG&E should have provided actual itemized estimates of the costs to demolish the [AG] storage plant, as well as offsetting salvage costs. PG&E has failed to do the minimum to support its claims for recovering the cost of decommissioning these storage facilities.” CE recommends that “the Commission should not allow recovery of these costs until and unless an adequate estimate of the costs based on credible bids for the work is prepared.”

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112 PG&E Prepared Testimony, Chapter 7, p. 7-78, line 8 to p. 7-79, line 9.
113 CE, p. 23, lines 15-19.
114 CE, p. 23, lines 5-9.
Q 113 Do you agree with CE’s recommendations regarding decommissioning of AG facilities at Los Medanos and Pleasant Creek?

A 113 No. PG&E disagrees with CE’s recommendation. CE’s claim that PG&E has not provided any itemized estimates or evidence of the costs for remediation of the surface equipment or salvage value is not true. PG&E has provided testimony and workpapers with details on decommissioning of AG facilities. The decommissioning cost for each storage facility is based on detailed cost estimate developed by an engineering and construction firm for the specified scope. The details of the cost forecast for the AG Facilities decommissioning are presented in workpapers116 on page WP 7-76, Workpaper Table 7-44. PG&E also provided the detailed cost estimates from the engineering firm as part of the data request response to OSA 002, Question 10.

The cost estimates from the engineering firm assumed salvage value for some above aground equipment at both Los Medanos,117 and Pleasant Creek.118

Q 114 What is your conclusion based on the Commercial Energy’s proposed recommendations regarding decommissioning costs for AG facilities?

A 114 PG&E disagrees with Commercial Energy’s recommendation and claim on the premise on lack of support. PG&E has provided ample documentation through testimony, workpaper and data requests supporting the decommissioning costs for AG facilities at Los Medanos and Pleasant Creek. PG&E finds the parties recommendations unreasonable, and recommends that the Commission allow recovery of these costs until as adequate support for estimate of the costs have already been provided.

Q 115 Does this conclude your rebuttal testimony?

A 115 Yes, it does.

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116 PG&E June 5, 2018 Errata, Vol. 1, WP 7-76, Workpaper Table 7-44.
117 OSA-002, Question 10, Attachment 05 CONF.
118 OSA-002, Question 10, Attachment 07 CONF.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

ATTACHMENT A

DISCOVERY
SUBJECT: 2015 GT&S Rate Case Programs Forecast to Have Deferred Work During 2015-2018 Rate Case Period

QUESTION 12

Simple Station Rebuild Program: Please refer to the statement on pages 7-52 to 7-53: “Condition assessments completed since filing the rate case indicated that there were fewer concerns over the simple stations, and that more work was needed on the complex stations (for both condition and system operational needs).”

a) Please provide all documents (including the date of the document) showing the condition assessments of the simple and complex stations.

b) Please provide the compilation of simple and complex station conditions that was relied upon in the 2015 GT&S case.

c) Please provide the compilation of simple and complex station conditions that supports the quote statement.

ANSWER 12

Several attachments to this response have been marked CONFIDENTIAL pursuant to a Non-Disclosure Agreement as they contain customer-specific data and critical energy infrastructure data.

a. PG&E relied on multiple data sources for review of condition assessment for its simple and complex stations. The data sources are:

1. Station condition assessment:
   The condition assessment initiative was set up and performed by engineering firm Exponent. The condition assessment is intended to identify and prioritize potential work at simple and complex stations. The condition assessment included a desktop review of available data from asset management, project management and maintenance databases and supplemented by visual inspection from field visits. The information and analysis was then compiled in a database to generate individual station reports showing equipment and station health scores. This information was intended to be used as a starting point for further evaluation of potential rebuild or targeted projects. The condition assessment initiative started in second quarter of 2013 as a pilot project and the
remainder of the initiative was performed during 2013-2014. PG&E is providing the following documentation from the condition assessment:

- Station Condition Assessment Phase 0 Report that was used to set up the condition process and to inform the original 2015 GT&S Rate Case submittal. (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch01CONF)
- The station condition approach and scoring algorithms provided in the 2014 M&C Asset Management Plan Appendix E (Station and Component Scoring Criteria), Appendix I (Station Target Scores), and Appendix J (Station Scoring Results). (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch02)
- Example of Station Condition report from assessment program database (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch03CONF)
- Station Condition Summary Results for M&C that provides a summary of station condition issues and opportunities (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch04CONF)
- Complex station assessment of potential stations for rebuild or targeted work (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch05CONF)
- Simple station assessment of potential stations for rebuild or targeted work (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch06CONF)
- “Station Rebuild White Paper” included in Workpapers Supporting Chapter 6 of the 2015 GT&S Rate Case describes the approach for selecting rebuild vs. targeted action. (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch07)

2. Controls Assessments for Complex Stations: PG&E commissioned Energy Experts International (EEI) to perform control assessments at complex stations. Control assessments are performed at selected stations each year to evaluate the operation of the regulation equipment at complex stations. These assessments test the operation of the station to maintain the pressure regulation function and provided specific information to inform station rebuild or targeted actions. The documentation for the controls assessments includes:

- 2014 control assessment summary report (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch08CONF)
- 2015 control assessment summary report (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch09CONF)
- 2016 control assessment summary report (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch10CONF)
- 2017 control assessment summary report (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch11CONF)

In addition to these reports, PG&E will provide the documents related to individual station control assessment reports in a supplementary response
b. The simple and complex station conditions that were relied upon in the 2015 GT&S Rate Case were based on a pilot study performed by Exponent (See attachment GTS-RateCase2019_DR_TURN_021-Q12Atch01CONF) to define the station condition assessment program as well as assess condition based on a sample of M&C stations. The pilot study developed the approach to the condition assessment and identified key issues from the review of the pilot stations. The conditions relied upon for the 2015 GT&S Rate Case were:

- Station age: The station ages were obtained and were used as one element in an overall asset strategy to determine the pace of the station rebuilds. Older stations have a higher propensity for obsolescence, operational, and material issues.
- Site conditions: The physical condition and functional performance of the station was obtained from site visits and personnel interviews. This information was used to identify potential issues at the pilot sites, such as corrosion or equipment functional issues.
- Obsolete or problem equipment: Based on interviews, various equipment models were identified as obsolete (equipment not supported or with difficult to obtain spare parts, such as Bristol controllers) or problem (general performance issue, such as Becker cabinet issue). This information was utilized to identify stations that may need near-term work.
- Corrective maintenance: The ratio of corrective maintenance to total maintenance man-hours was used as a basis for assessing equipment issues at a station. This information is indicative of potential operational and aging issues.

The pace of the station rebuild program was based on an asset management approach (based on age of the station) as defined in the “Station Rebuild White Paper” included in the 2015 GT&S Rate Case Chapter 6 Workpapers (Attachment GTS-RateCase2019_DR_TURN_021-Q12Atch07). However, as indicated in the White Paper and Pilot Study (Attachment GTS-RateCase2019_DR_TURN_021-Q12Atch01CONF), the actual decision to rebuild a station is made based on a specific review of the actual station and component conditions.

c. The condition assessments for stations that were complete in 2014, subsequent to the filing of the 2015 GT&S Rate Case, were summarized to identify potential issues (Attachment GTS-RateCase2019_DR_TURN_021-Q12Atch04CONF). The complex and simple station assessments (Attachments GTS-RateCase2019_DR_TURN_021-Q12Atch05CONF and GTS-RateCase2019_DR_TURN_021-Q12Atch06CONF) were documented to provide a list of potential projects for rebuild (or identify if targeted work was required).

The conditions that support the quoted statement are:

- **Complex Stations:**
  Over the course of the 2015-2018 rate case period, controls assessments performed by EEI for complex stations (see Attachment GTS-RateCase2019_DR_TURN_021-Q12Atch08CONF through GTS-RateCase2019_DR_TURN_021-Q12Atch11CONF) identified stations as high, medium and low priority for rebuilds. Typical conditions, as identified in the controls assessment, identified leading to a high priority of rebuild were:
- Obsolete regulator and monitor actuators and controllers
- Regulator and monitor equipment exhibiting poor functional performance
- Relief valve functional performance and sizing issues
- Maintenance that requires manual regulation of bypass valves
- Equipment sizing not aligned with current operational needs
- Incompatible equipment in regulation run
- Structural issues, such as degraded supports.

**Simple Stations:**
Typical conditions, as identified in the condition assessment, leading to a potential for station rebuild were:
- Obsolete regulator and monitor equipment
- Regulator and valve equipment exhibiting poor functional performance
- Material issues (e.g., corrosion) prevalent in the station
- Equipment sizing not aligned with current operational needs
- Incompatible equipment in regulation run

For simple stations identified as potential for rebuild, field engineering and maintenance personnel performed were consulted to review and confirm if rebuilds were necessary. During the course of the rate case period, the field verifications indicated that there were not many major station-level condition issues at these sites and that targeted actions were prescribed, as required. The condition assessment and the annual maintenance also led to specific program actions including painting stations to address rust or atmospheric corrosion occurrences, specific maintenance activities to address support and structural issues, and other targeted equipment replacement which minimized the need for full simple station rebuilds. Therefore, the number of simple stations for rebuild was reduced.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

ATTACHMENT B

OVERPRESSURE EVENT ELIMINATION PROGRAM

(TRANSmission): SUMMARY OF PROGRAM DEVELOPMENT

AND RECOMMENDATIONS
Overpressure Event Elimination Program (Transmission):

Summary of Program Development and Recommendations

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August 8, 2018

Prepared for: Pacific Gas & Electric
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Background

Beginning in 2011, the PG&E Overpressure Event Elimination Team began collecting large and small overpressure event statistics. PG&E has seen a reduction of overpressure events from 775 in 2011 to 21 in 2017. It is important to note that the majority of the overpressure events in 2011 were the result of high set points to MAOP that resulted in minor, short duration events during maintenance. The reduction was driven by company-wide operating and design recommendations and changes. Reducing normal operating pressure (NOP) set points of regulation station equipment to below maximum allowable operating pressure (MAOP) was a primary driver to reduce overpressure events. PG&E also made design changes, such as raising vent lines on low pressure vaults to reduce the risk of overpressure events due to flooding. And finally, PG&E added pressure and temperature monitoring instruments to enhance visibility in the Gas Control Room, which assists in identifying trends and allows for further operational recommendations. PG&E established an organizational goal to drive the occurrence of large overpressure events to near zero within 10 years. The company put together a team from the Measurement & Control (M&C) group to study this risk and develop a program strategy to meet the goal.

The year by year reduction of overpressure events is shown below in chart 1.

Chart 1: Number of Overpressure Events (Annually)

The team conducted international and North American benchmarking studies to determine overpressure elimination best practices. Three benchmarking studies were performed, one by SWRI1 to

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benchmark North America operators, and one by DNV\textsuperscript{2} for European operators, and a final was a general international benchmark study that included relevant overpressure performance information prepared by Juran Global\textsuperscript{3}. The studies helped influence the development and strategies of the Overpressure Event Elimination Program. The reports indicated that PG&E was a top quartile performer amongst North American operators with respect to the number of overpressure events. The key finding of the European report was that European operators experienced large overpressure events at a significantly reduced rate primarily due to the required installation of secondary overpressure protection devices. After reviewing the conclusions of the benchmarking studies, PG&E began developing a program to utilize industry best practices to reduce the company’s risk of large overpressure events.

PG&E contracted an engineering consulting firm, Exponent, to perform a root cause analysis of the large overpressure events. Exponent prepared and submitted a white paper titled, “Secondary Overpressure Protection Strategies\textsuperscript{4}”. The primary conclusions indicated that the majority of large overpressure events were equipment-related and impacted all measurement and control asset families. Exponent reviewed and analyzed PG&E overpressure event data available through the end of 2016. PG&E has continued to collect and perform root cause analyses of large overpressure events. By 2017, the team had identified 51 large overpressure events within the transmission and distribution systems. 29 of the 51 large overpressure events were due to equipment failure.

The primary causes of equipment failure include common failure modes caused by debris, liquid, or sulfur in the system; and poor equipment condition. Construction activities upstream of the regulation stations can introduce a variety of debris and liquids into the system which can damage station equipment. Fine debris, sulfur, and liquid can block the regulation equipment sense lines for pilot-operated equipment and prevent the station from properly regulating the flow of gas downstream.

The breakdown of overpressure events by station type are shown in Figure 1.

\textsuperscript{2} “Threat Management: Preventing Loss of Containment Due to Overpressure Protection”, DNV Report No. OGNL.126867; April 11, 2017.
After evaluating the overpressure events that have occurred since 2012 and after applying the lessons learned from the North American and European benchmarking activities, PG&E has elected to prioritize two classes of transmission assets: Large Volume Customers and Pilot-Operated Regulating stations.

Overall, PG&E plans to address the overpressure risks for all transmission and distribution assets. Several supporting initiatives are currently in development or have been deployed to help mitigate the risk of large overpressure events. All the initiatives have been created to support PG&E’s goal of near-zero risk of large overpressure events.

**Overpressure Event Elimination Options & Philosophy**

The Exponent report presented six overpressure elimination options to PG&E for consideration. The options included addition of:

1. Slam shut devices / rupture disks
2. Additional regulation on single run stations
3. Additional working monitor
4. Station relief valves
5. System relief valves
6. SCADA control and visibility (Control valves)
The review identified that pilot-operated regulator stations (using the H-14 Design Standard) were the most susceptible to overpressure from the various threats to the system (debris, liquids, etc.). For the pilot-operated regulators, it was determined that the most cost-effective solution was generally the installation of a slam shut device, filtering equipment, and gas pressure and temperature monitoring instruments. This option creates that potential for shut-in of a station, which would result in customer outages. PG&E reviewed its stations and for those that can sustain a shut-in, the installation of slam shuts was considered the most appropriate mitigation action. This conclusion was affirmed through historical PG&E cost data and costs obtained during the execution of the pilot projects. However, for other station designs, secondary overpressure protection may require other solutions.

To assist in narrowing the scope of the OPE program, the team developed a decision tree to identify stations that would need custom solutions. Stations that require custom solutions are excluded from the current OPE program and will be addressed by other initiatives. In general, a station is excluded if Gas Planning determines that the station is too critical to be shut-in. Critical stations are defined as stations that are needed under all operating conditions. Other considerations include the number of customers potentially impacted and the station configuration.

The decision trees for pilot-operated regulator stations and large volume customers are shown below in Figure 2.

**Figure 2 – Critical Station Decision Trees for Pilot-Operated Regulator Stations and Large Volume Customers**
Execution Strategy & Objectives

PG&E is currently pursuing a dual strategy of installing secondary overpressure protection and increasing system visibility in the control room for large volume customers and pilot-operated regulating stations. The PG&E OPE team is developing a 10-year master program schedule of short- and long-term overpressure mitigations for these assets.

Large Volume Customers (LVCRs) - Transmission

Large volume customers\(^5\), when compared to other measurement & control station types, have a high probability of experiencing an overpressure event. The higher risk is attributed to the fact that these assets supply “dead-end”\(^6\) systems that can be sensitive to overpressure risk due to intermittent service, plus oftentimes the primary regulation device and the primary overpressure device (regulator and monitor) fail because of the same issue (sulfur, liquids, debris) and both also fail in the “open” position. PG&E has conducted studies and pilot projects to target these specific issues and develop solutions to mitigate the risk of large overpressure events.

In 2017, PG&E completed an LVCR pilot project to assess the feasibility and determine the necessary modifications to prevent large overpressure events. The study concluded that the most appropriate and cost-effective configuration for this asset type is the installation of slam shut devices paired with gas pressure recording instruments (ERX). Slam shut devices appear to be a best-fit solution due to a

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\(^5\) The Overpressure Elimination Program includes only Transmission LVCs (LVCRs). Distributions LVCs are not included.

\(^6\) A “dead-end” or “dead-leg” is a length of unused pipe in a system which previously may have been in use.
number of factors, including the fact that Large Volume Customer assets have variety of configurations and designs.

Following the pilot project, PG&E conducted condition assessments for each of the LVCRs. The condition assessments required a field team to conduct a physical review of the assets and assess the age, condition, design configuration, and types of equipment installed at each location. The condition assessments revealed that several LVCRs were inconsistent with current design standards or in sufficiently poor condition to warrant a rebuild. Leveraging PG&E’s past experience with station rebuilds, the current strategy to address the rebuild population is to shop fabricate a dual run regulator station similar in design to a pilot-operated regulator station. The station will be equipped with a slam shut device, gas pressure and temperature recording instrument (ERX or similar), and a by-pass line with pressure regulator valve (PRV).

There is also a population of LVCRs that are more appropriate for retrofitting than for entirely replacing the existing station. These stations are typically of more recent vintage and are designed to more modern design standards. For the purposes of budgeting and scheduling, it is assumed that each location will require a slam shut device and ERX installed. In some cases, stations may require additional modifications or component replacements to conform to current design standards. Completing the station rebuilds and retrofits for this group of assets will significantly reduce the risk of large overpressure events.

**Pilot-operated Regulator Stations - Transmission**

Pilot-operated regulator stations are also subject to a higher likelihood of overpressure events than other station designs. This is due primarily to the fact that the regulator and monitor (the primary overpressure protection device) installed in many of these stations fail in the “open” position and, similar to LVCs, are impacted by debris in the system (sulfur, liquids, misc. debris). Similar to the LVCR effort, PG&E conducted studies to identify root causes of large overpressure events and pilot project to test alternate equipment.

PG&E has conducted a feasibility study to evaluate secondary overpressure protection devices and other approaches to define acceptable methods of mitigating large overpressure events. The study concluded that the root cause of many of the failures are gas quality issues, however, the majority of the failures may be avoided if the regulators and monitors at these stations had different failure modes (open / close as opposed to open / open ) or additional filtering equipment.

The large volume customer and pilot-operated station programs will be executed in parallel to increase the pace of overall risk mitigation. The two programs are anticipated to be executed over a period of 10 years, with the expectation that 50% of the stations will have secondary overpressure protection installed by the end of 2022.
**Conclusion**

Addressing the overpressure events risks associated with transmission Large Volume Customer and Pilot-Operated Regulation stations is one facet of the overall Overpressure Event Elimination program. However, by utilizing best practices and performing system modifications PG&E can significantly reduce the risk of large overpressure events. Reducing the risk of overpressure events is critical to preserving life and property. One large overpressure event could have considerable consequences to the community. Similar programs have been deployed or are in development for distribution asset families. As PG&E moves forward with refining and scope development efforts, this report shall be updated to document any changes in strategy, operating philosophy, or program execution.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

REBUTTAL TESTIMONY OF DAVID McQUILLING

CORROSION CONTROL
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A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.
A 1 My name is David McQuilling. This testimony responds to the direct testimony of the Office of Ratepayer Advocates (ORA)\(^1\) and The Utility Reform Network (TURN).\(^2\) Pacific Gas and Electric Company (PG&E or the Company) summarizes parties’ positions in Section B below.

Q 2 Did any party other than ORA or TURN serve testimony concerning PG&E’s corrosion control forecast?
A 2 No.

Q 3 Did either ORA or TURN question the need to perform any of the work in PG&E’s forecast?
A 3 ORA did not; nor did TURN with one exception. In the case of contacted casings replacements, TURN supports the program, but recommends updating PG&E’s forecast for the number of replacements based on more current data. As discussed below, more current data than TURN relied on suggests that PG&E’s original forecast is reasonable.

Q 4 Did either ORA or TURN challenge PG&E’s unit costs used to forecast corrosion control work?
A 4 No, they did not.

Q 5 What is the basis for ORA’s recommendations?
A 5 In many cases ORA accepts PG&E’s forecast. Where ORA recommends a different forecast, ORA forecasts PG&E’s 2019 expenses as the average of PG&E’s 2015-2017 recorded costs, with no adjustment for escalation/inflation.

Q 6 Does PG&E agree that averaging 2015-2017 recorded costs is a reasonable method of forecasting PG&E’s 2019 corrosion control expenses?

\[^1\] ORA-08.
\[^2\] TURN Chapter 8.
No. The work PG&E performed in 2015, 2016 and 2017 is not representative of the work PG&E plans to perform in 2019. Averaging 2015-2017 recorded costs is thus not a reasonable way to calculate what PG&E will likely spend in 2019.

Please summarize why this is the case.

There are three primary reasons. First, PG&E is planning some new programs in 2019, such as its proactive Direct Current (DC) Interference and Drip Replacement programs. Because these are new programs, PG&E did not incur these costs in 2015, 2016 or 2017. Second, PG&E installed many new corrosion control assets in 2015, 2016 and 2017. In 2019, PG&E will incur additional costs to inspect and maintain these new assets. Third, the use of 2015-2017 recorded costs unfairly penalizes PG&E for risk-based decisions concerning the pace and scope of programs, such as PG&E’s suspension of the Enhanced Cathodic Protection (CP) Criteria Program between February 2016 and June 2017. Recommendations to fund programs solely based on historic expenditures provides a disincentive to shift funding to higher priority work based on risk.

Please summarize PG&E’s response to TURN’s recommendations.

In some cases, TURN recommends slowing the pace of new programs. As I will explain below, PG&E believes that it forecast a reasonable pace of work. TURN supports their recommendation to slow the pace of programs by stating PG&E is not aware that any of the proposed work is needed to mitigate an immediate safety hazard. This argument is unfounded, as an immediate safety hazard requires immediate action and should rarely be the basis for rate forecasts. In other cases, TURN used information not available at the time of PG&E’s forecast to update it. As discussed below, the forecast presented by PG&E is reasonable.

Summary of Parties’ Positions

Please provide parties’ recommendations.

PG&E’s application forecast and the parties’ recommendations are set forth in Table 8-1 (2019 expense) and Table-8-2 (2019-2021 capital expenditures) below.
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<th>PG&amp;E Proposed Reductions</th>
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<td>–</td>
</tr>
<tr>
<td>8</td>
<td>DC Interference</td>
<td>GJ</td>
<td>713</td>
<td>713</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>9</td>
<td>GT Mitigate Corrosion Other</td>
<td>GJ</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>10</td>
<td>Internal Corrosion</td>
<td>GJ</td>
<td>3,561</td>
<td>3,561</td>
<td>(2,131)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<tr>
<td>11</td>
<td>Routine Corrosion Maintenance</td>
<td>JO</td>
<td>2,174</td>
<td>2,174</td>
<td>(680)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>12</td>
<td>StanPac Expense</td>
<td>34</td>
<td>376</td>
<td>376</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<tr>
<td>13</td>
<td>Test Stations</td>
<td>GJ</td>
<td>257</td>
<td>257</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<tr>
<td>14</td>
<td>Total</td>
<td></td>
<td>$35,699</td>
<td>$35,699</td>
<td>$(7,955)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>(9,500)</td>
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(a) PG&E's Errata as of August 17.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Program</th>
<th>MWC</th>
<th>Current Forecast</th>
<th>ORA</th>
<th>TURN</th>
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<tbody>
<tr>
<td>1</td>
<td>AC Interference</td>
<td>3K</td>
<td>$13,012</td>
<td>$3,991</td>
<td>$6,180</td>
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<tr>
<td>2</td>
<td>Atmospheric Corrosion</td>
<td>3K</td>
<td>2,803</td>
<td>2,891</td>
<td>2,976</td>
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<tr>
<td>3</td>
<td>Casings(a)</td>
<td>3K</td>
<td>24,411</td>
<td>22,784</td>
<td>17,485</td>
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<tr>
<td>4</td>
<td>Cathodic Protection</td>
<td>3K, 75</td>
<td>13,646</td>
<td>13,273</td>
<td>10,014</td>
</tr>
<tr>
<td>5</td>
<td>DC Interference</td>
<td>3K</td>
<td>12,242</td>
<td>12,627</td>
<td>12,999</td>
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<td>6</td>
<td>Internal Corrosion</td>
<td>3K</td>
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<td>13,421</td>
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<td>7</td>
<td>StanPac Capital</td>
<td>44</td>
<td>74</td>
<td>42</td>
<td>43</td>
</tr>
<tr>
<td>8</td>
<td>Test Stations</td>
<td>3K</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>9</td>
<td>Total</td>
<td></td>
<td>$79,201</td>
<td>$69,028</td>
<td>$63,513</td>
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</table>

(a) Includes Errata increasing the forecast by $1,187 in 2020 and decreasing the forecast by $1,222 in 2021 (‘000’s).
Are there programs that parties do not dispute?

Yes. As Table 8-1 and 8-2 show, no party disputes PG&E’s forecast for the following programs:

- DC Interference (Expense)
- Casings (Expense)
- CP (Expense and Capital)
- Test Stations (Expense and Capital)
- Corrosion Support (Expense)
- StanPac (Expense and Capital)
- Atmospheric Corrosion (Capital)

Do parties make recommendations regarding programs that PG&E disagrees with?

Yes, PG&E does not agree with recommendations made by ORA or TURN regarding the following Corrosion Control programs:

- Routine Corrosion Maintenance (Expense)
- DC Interference (Capital)
- Alternating Current (AC) Interference (Expense)
- Casings (Capital)
- Atmospheric Corrosion (Expense)
- Close Interval Survey (CIS) (Expense)
- Internal Corrosion (Capital)

Adopting ORA’s Recommendation to Fund Certain 2019 Corrosion Control Programs at the Average Of PG&E’s 2015-2017 Recorded Costs Would Provide Insufficient Funding to Perform Mandatory Work as Well as Discretionary Risk Reduction Programs

ORA recommends using the average recorded spending for 2015-2017 as the basis for forecasting 2019 funding needs for the following programs:

- Routine Corrosion Maintenance (Expense)
- AC Interference (Expense and Capital)
- CIS (Expense)
- Internal Corrosion (Expense)
- Casings (Capital)

Is this a reasonable forecasting approach?
This could be a reasonable approach to forecasting unit costs, if the recorded costs are adjusted to reflect escalation, but it is not a reasonable approach to forecasting the expected units of work that will be completed.

Q 13 Did ORA make specific recommendations concerning forecast unit costs or units of work?
A 13 No. ORA made recommendations only to overall funding.
Q 14 Did ORA apply escalation to recorded costs to arrive at its 2019 recommendation?
A 14 No, it did not.
Q 15 Why is this not a reasonable approach to forecasting the units of work that will be completed in 2019?
A 15 PG&E does not believe the rationale presented by ORA is reasonable for the three reasons stated above, as well as additional reasons specific to each program that are identified below.
Q 16 Has ORA recommended that PG&E perform a different scope or pace of work?
A 16 No, at least not directly. ORA’s testimony does not discuss the scope or pace of work, just overall funding. PG&E served ORA with a data request asking:

Does ORA recommend a different scope or pace of work for any of the corrosion control programs PG&E forecast? If the answer is yes, for each such program:

a. What is ORA’s recommended scope of work and pace?
b. Why does ORA believe its recommended scope of work and pace is more reasonable than the scope and pace PG&E forecast?

ORA responded by repeating its recommendations concerning the level of funding. ORA did not identify any recommended changes to the scope or pace of work, or explain why it believed PG&E should perform less work than PG&E forecast performing.

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3 ORA’s response to PG&E Data Request PG&E-ORA-003-Q03, dated 7/23/2018 in Attachment A.
4 ORA’s response to PG&E Data Request PG&E-ORA-003-Q01, dated 7/23/2018 in Attachment A.
5 Id.
Q 17  Can PG&E perform the work it forecast, at the pace it forecast, with the
funding recommended by ORA?
A 17  No, it cannot. As discussed below, in some cases adopting ORA’s
recommendation would provide insufficient funding to comply with pipeline
safety regulations. In other cases, adopting ORA’s recommendation would
require PG&E to dramatically slow the pace of important work designed to
extend the lives of Gas Transmission and Storage (GT&S) facilities and to
reduce the risk of a corrosion-caused incident.

D. Response to Parties’ Recommendations Concerning Specific Programs or
Projects

1. Routine Corrosion Maintenance (MATs JOA, JOB, JOC, JOQ, JOZ)

Q 18  Briefly, what is the scope of Routine Corrosion Maintenance Program?
A 18  Routine monitoring of PG&E’s corrosion control systems is required to
identify areas where corrosion control systems have failed; investigate and
troubleshoot such problems; and either correct the problem or escalate the
issue in order to mitigate corrosion growth. Left unmitigated, corrosion will,
over time, compromise the integrity of metallic piping systems. PG&E’s
Routine Corrosion Maintenance Program is required to maintain compliance
with Subpart I of 49 Code of Federal Regulations (CFR) §192 and mitigate
the degradation of the pressure containing capacity of the gas piping.
Routine corrosion maintenance is more fully discussed in PG&E’s opening
testimony.6

Q 19  What parties commented on the Routine Corrosion Maintenance Program in
testimony?
A 19  ORA was the only party to address this program.
Q 20  What is ORA’s recommendation?
A 20  ORA proposes a 2019 expense funding level of $1.494 million, which is a
$0.68 million reduction to PG&E’s forecast.7 ORA provided no detail as to
how the proposed reductions should be applied to the various activities
associated with the program.

6  PG&E Prepared Testimony, Chapter 8, p. 8-23, line 7 to p. 8-27, line 11, including
Table 8-6.
7  ORA-08, p. 2, Table 8-1 and p. 4, lines 17-20.
Q 21 What is the basis for ORA’s proposed reduction?
A 21 ORA averaged PG&E’s spending in 2015, 2016 and 2017 at Maintenance Activity Type (MAT) level and assumed that PG&E could complete the 2019 forecast work for that amount of funding.8

Q 22 Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts?
A 22 No. PG&E disagrees with ORA’s recommendation to reduce funding levels for this program. ORA’s recommended level of funding is insufficient to enable PG&E to complete mandatory work in 2019. PG&E forecasts performing 91 Atmospheric Corrosion Inspections (MAT Code JOZ),9 10,000 CP Monitoring reads (MAT Code JOB)10; and 967 CP Rectifiers inspections (MAT Code JOA)11 in 2019. If adopted, the ORA recommendation will eliminate funding for 28 required atmospheric inspections,12 3,100 required CP reads,13 and 299 required rectifier inspections.14 PG&E disagrees with ORA’s recommendation to reduce funding for the Routine Corrosion Monitoring, Investigation and Maintenance Program which will impair PG&E’s ability to perform this function on approximately one third of the GT&S system. ORA provides no detail as to how such reductions could be accomplished without violating pipeline safety regulations and increasing the risk of an external corrosion failure.

a. Rectifiers (MAT JOA)

Q 23 Why will rectifiers require more funding in 2019 than PG&E spent on average from 2015 through 2017?
A 23 PG&E needs to perform more work in 2019 than it performed during the 2015-2017 period. At the beginning of 2014, PG&E had approximately

8 ORA-08, p. 4, lines 18-20.
9 PG&E WP 8-20.
10 PG&E WP 8-21.
11 PG&E WP 8-23.
12 49 CFR § 192.481.
13 49 CFR § 192.465(a), §192.465(c), §192.467(c).
14 49 CFR § 192.465(b).
866 rectifiers.\textsuperscript{15} By the beginning of 2019, PG&E will have approximately 967 rectifiers.\textsuperscript{16} PG&E disagrees with ORA's recommendation and cannot monitor the additional rectifiers at the 2015-2017 average annual cost recommended by ORA. The 101 new rectifiers installed between 2015 and 2018 did not require inspection or maintenance prior to the year they were installed, but will require inspection and maintenance in 2019 and beyond. The second reason is simple inflation. ORA did not apply escalation to adjust 2015, 2016 or 2017 recorded costs to estimate 2019 funding.

\textbf{b. Cathodic Protection Monitoring (MAT JOB)}

\textbf{Q 24} Why will CP monitoring require more funding in 2019 than PG&E spent on average from 2015 through 2017?

\textbf{A 24} First, ORA did not apply escalation to adjust 2015, 2016 or 2017 recorded costs to estimate 2019 funding. Second, PG&E will take CP reads at substantially more monitoring points in 2019 than it did on average over the 2015-2017 time period. At the beginning of 2015, PG&E had approximately 6,447 CP monitoring points.\textsuperscript{17} By the beginning of 2019, PG&E will have approximately 3,550 additional monitoring points.\textsuperscript{18} PG&E disagrees with ORA's recommendation and cannot monitor all of the additional locations at the 2015-2017 average annual cost recommended by ORA. The 3,550 new monitoring points did not require inspection or maintenance prior to the year they were installed, but will require inspection and maintenance in 2019 and beyond.

\textbf{c. Low Read Investigation and Troubleshooting (MAT JOC)}

\textbf{Q 25} Why will low read investigations and troubleshooting require more funding in 2019 than PG&E spent on average from 2015 through 2017?

\textbf{A 25} Again, ORA did not apply escalation to adjust 2015, 2016 or 2017 recorded costs to estimate 2019 funding. Second, ORA provided no granularity as to how the recommended 31 percent reduction in funding for routine corrosion monitoring, investigation, and maintenance should be applied. PG&E based

\textsuperscript{15} 2015 GT&S, PG&E WP 7-10.
\textsuperscript{16} PG&E WP 8-19.
\textsuperscript{17} 2015 GT&S, PG&E WP 7-16.
\textsuperscript{18} PG&E WP 8-19.
its forecast for 2019 Routine Low Read Investigations on the average number of investigations from 2012 to early 2017 (1,058) and the average unit cost over that period, adjusted to reflect escalation to 2019. In this instance, PG&E utilized a similar methodology as ORA; however, the ORA recommendation to reduce routine corrosion monitoring, investigations, and maintenance by 31 percent would eliminate funding for 327 required low-read investigations. PG&E disagrees with ORA’s recommendation and cannot perform required low-read investigations at the 2015-2017 average annual cost recommended by ORA.

d. Corrective Maintenance (MAT JOQ)

Q 26 Why will corrective maintenance require more funding in 2019 than PG&E spent on average from 2015 through 2017?

A 26 Again, ORA did not apply escalation to adjust 2015, 2016 or 2017 recorded costs to estimate 2019 funding. More importantly, ORA ignored the expected increased amount of corrective maintenance work PG&E reasonably expects to perform in 2019 relative to the 2015-2017 time period.

PG&E based its forecast for 2019 Corrective Maintenance on the average number of investigations from 2013-2016 (296) and increased this number by 50 percent due to the number of Enhanced CP Criteria Survey and Close Interval Survey miles the Company will execute. Note that PG&E suspended the Enhanced CP Criteria (850 Off) Program from February 2016 to June 2017—approximately half of the 3-year period average of recorded expense used by ORA. ORA did not account for suspension of the Enhanced CP Criteria, or for increased Close Interval Survey, work streams that identify areas requiring Corrective Maintenance, in their analysis.

PG&E’s 2019 Corrective Maintenance forecast is reasonable.

PG&E disagrees with the funding levels proposed by ORA and believes that the forecast for Corrective Maintenance presented in testimony is

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19 PG&E WP 8-24.
20 PG&E WP 8-22.
appropriate to mitigate risk and maintain corrosion control in accordance with pipeline safety regulations.

e. Atmospheric Corrosion Inspections (MAT JOZ)

Q 27 Why will atmospheric corrosion inspections require more funding in 2019 than PG&E spent on average from 2015 through 2017?

A 27 As with the other work categories, ORA did not apply escalation to adjust 2015, 2016 or 2017 recorded costs to estimate 2019 funding.

Second, ORA provided no granularity as to how the recommended 31 percent reduction in funding for atmospheric corrosion inspections should be applied. PG&E based its forecast on the actual number of atmospheric spans that require inspection in 2019. PG&E cannot perform required atmospheric corrosion monitoring at the 2015-2017 average annual cost recommended by ORA.

Q 28 In summary, what is PG&E’s position in response to ORA’s recommendation?

A 28 PG&E disagrees with the ORA’s proposed reductions for the following reasons: (1) the 3-year average cost methodology utilized by ORA is not a reasonable basis for forecasting 2019 work and funding requirements; (2) funding levels proposed by ORA do not include escalation; (3) funding levels proposed by ORA are not adequate to maintain corrosion control for approximately one third of the GT&S system and, if adopted, would increase the risk associated with operating the GT&S system; and (4) funding levels proposed by ORA are not adequate to maintain compliance with pipeline safety regulations.

Q 29 What is your conclusion based on the parties’ proposed recommendations for Routine Corrosion Maintenance?

A 29 For the reasons discussed above, PG&E recommends that its $2.174 million expense forecast for Routine Corrosion Maintenance be adopted.

2. Direct Current Interference (MATs GJF and 3K9)

Q 30 Briefly, what is the scope of DC Interference Program?

A 30 DC interference occurs when DC currents in the earth utilize buried metallic piping systems as part of their electrical circuit. The point at which the DC current flows back to the earth may be subject to accelerated metal loss
which could compromise the integrity of the metallic piping system.

PG&E’s DC Interference Program investigates areas of potential DC Interference, designs mitigation systems (as required), and mitigates the detrimental effects of DC interference in accordance with Subpart I of 49 CFR §192. DC Interference is more fully discussed in PG&E’s opening testimony.\(^\text{22}\)

Q 31 What are parties’ recommendations for DC Interference?

A 31 No party contests PG&E’s expense forecast for this program. ORA proposes a 2019 capital reduction of $6.121 million (50 percent),\(^\text{23}\) and TURN proposes a total capital reduction of $5.72 million.\(^\text{24}\) PG&E discusses each of these recommendations in turn.

Q 32 What is the basis for ORA’s proposed reduction?

A 32 The only explanation ORA provides is:

PG&E does not describe this new risk, of which PG&E was previously unaware. Based on this, ORA recommends $6.1 million of capital expenditures in 2019.\(^\text{25}\)

Q 33 Is ORA correct that PG&E did not describe a new risk of which PG&E was previous unaware?

A 33 No. The risk of corrosion from DC interference is not a new risk. PG&E has had a DC Interference Program for years, and forecast costs to mitigate DC interference in the 2015 GT&S Rate Case. The evolution of the DC Interference Program from the 2015 GT&S Rate Case forecast to the 2019 GT&S Rate Case forecast was presented in opening testimony\(^\text{26}\) and the DC Interference Program was detailed in opening testimony,\(^\text{27}\) to include an extensive discussion of threats and risks.\(^\text{28}\) What is new to

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\(^{22}\) PG&E Prepared Testimony, Chapter 8, p. 8-27, line 12 to p. 8-35, line 18, including Tables 8-8 and 8-9.

\(^{23}\) ORA-08, p. 6, lines 12-14.

\(^{24}\) TURN, Chapter 8, p. 5, line 10 to p. 6, line 1, including table titled “DC Interference Capital (MAT 3K9).”

\(^{25}\) ORA-08, p. 6, lines 12-14.

\(^{26}\) PG&E Prepared Testimony, Chapter 8, p. 8-15, lines 12-17.

\(^{27}\) PG&E Prepared Testimony, Chapter 8, p. 8-27, line 12 to p. 8-35, line 18, including Tables 8-8 and 8-9.

\(^{28}\) PG&E Prepared Testimony, Chapter 8, p. 8-28, line 11 to p. 8-32, line 17.
the DC Interference Program is the transition from a reactive program to a proactive program.29

Q 34 Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts?

A 34 No. ORA’s justification is flawed and ignores PG&E’s opening testimony. The risk of corrosion from DC interference is not a new risk. PG&E has had a DC Interference Program for years, and forecast costs to mitigate DC Interference in the 2015 GT&S Rate Case. The evolution of the DC Interference Program from the 2015 GT&S Rate Case forecast to the 2019 GT&S Rate Case forecast was presented in opening testimony30 and the DC Interference Program was detailed in opening testimony,31 to include an extensive discussion of threats and risks.32 As PG&E explained in its opening testimony, the forecast increase in required funding for this program is because, based on extensive analysis, PG&E determined that it is prudent to shift from a reactive program to a proactive program.

Q 35 Did ORA offer any evidence suggesting that it would not be prudent for PG&E to implement its proactive program?

A 35 No.

Q 36 Did ORA offer any evidence that PG&E’s proposed pace of its DC Interference Program is unreasonable?

A 36 No.

Q 37 Did ORA offer any evidence that PG&E’s forecast of the cost to implement its DC Interference Program is unreasonable?

A 37 No.

Q 38 What is TURN’s recommendation for DC Interference?

A 38 TURN proposes a total capital funding level of $32.15 million, which is a $5.72 million reduction to PG&E’s forecast.33 TURN’s proposed reduction

29 PG&E Prepared Testimony, Chapter 8, p. 8-15, lines 12-17.
30 Id.
31 PG&E Prepared Testimony, Chapter 8, p. 8-27, line 12 to p. 8-35, line 18, including Tables 8-8 and 8-9.
32 PG&E Prepared Testimony, Chapter 8, p. 8-28, line 11 to p. 8-32, line 17.
33 TURN, Chapter 8, p. 5, Table 2.
is based on its recommendation of a “reduction in the pace of this work by postponing lower priority work to the next rate case period.”

Q 39 What is the basis for TURN’s proposed reduction?

A 39 TURN claims that PG&E “does not explain why it believes it is necessary for ratepayers to pay for Priority 3 or 4 work in this rate case period as opposed to delaying that work until the next rate case period.” “TURN recommends that PG&E’s pace be modestly lengthened by removing Priority 4 work, i.e., 15 projects planned for 2021, from the 2019-2021 rate case period and redistributing the Priority 2 and 3 work evenly across the period.” TURN also asserts that PG&E “has not justified the need for and cost-effectiveness of the work it proposes for this rate case period” and that PG&E “is not aware that any of the proposed work is needed to mitigate an immediate safety hazard.”

Q 40 Do you agree with TURN’s recommendations for reducing PG&E’s cost forecasts?

A 40 No. PG&E disagrees with TURN’s recommendation to defer Priority 4 DC Interference projects to the next rate case period. PG&E outlined in testimony the potential for damage to underground metallic piping systems installed in proximity to DC transit systems; the correlation between historic DC interference investigations and DC transit systems; the correlation between actual metal loss density and severity, as found during in-line inspections (ILI) of gas transmission piping in proximity to DC transit systems; and the need for safety systems to allow leakage current from DC transit systems to be safely discharged to the earth without loss of pipeline metal. In addition, PG&E provided a discussion of industry best practices for DC Interference programs and presented a forecast to implement a risk-based program consistent with industry best practices. TURN provides

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34 TURN, Chapter 8, p. 3, lines 9-10.
35 TURN, Chapter 8, p. 4, lines 14-16.
36 TURN, Chapter 8, p. 5, lines 6-8.
37 TURN, Chapter 8, p. 5, lines 3-4.
38 TURN, Chapter 8, p. 5, lines 4-5.
no testimony to support its assertion that PG&E did not justify the need for
the work and appears to contradict this assertion by supporting PG&E’s
forecast to install proactive DC Interference monitoring and mitigation
systems in Priority 1-3 locations. In addition, TURN does not contest the
need for proactive DC interference monitoring and mitigation systems in
Priority 4 and 5 locations, only the pace at which this work is to be
completed.

Q 41 How do you respond to TURN’s assertion that it is reasonable to defer some
of this work because it is not necessary to mitigate an immediate safety
hazard and not proven to be cost effective? 40

A 41 This is a short-sighted view. Corrosion is a time dependent threat.
One should not expect that corrosion control work would mitigate an
immediate safety hazard. Rather, corrosion control work is designed to
prevent immediate safety hazards from occurring in the first place, and to
extend the useful lives of metallic assets. The longer PG&E waits to
implement corrosion control programs, the more likely it is that metallic
assets, including pipe used to deliver gas at high pressure, will corrode,
and ultimately leak or require replacement.

Q 42 How do you respond to TURN’s recommendation that the execution of
Priority 4 DC Interference work be deferred until the next rate case period?

A 42 PG&E believes that mitigation of Priority 4 DC Interference is prudent and
consistent with industry best practices. The 2019 forecast cost of a
single Dynamic DC Interference mitigation system is $369,66641 while the
2019 forecast cost of a single ILI dig is $235,03642 and the 2019 forecast
cost of a single pipe replacement exceeds $2.2 million. 43 PG&E does not
believe it is prudent or cost effective to defer work to mitigate a known risk
and potentially allow metal loss due to DC interference to grow to an
immediate safety hazard.

40 TURN, Chapter 8, p. 5, lines 3-8
41 PG&E WP 8-85, line 9.
42 PG&E WP 5-44, line 22.
43 PG&E WP 5-168 (10-foot pipe segment / 24-inch diameter).
In summary, what is PG&E’s position in response to the parties’ recommendations?

PG&E disagrees with ORA’s and TURN’s proposed reductions for the following reasons: (1) the basis for ORA’s recommendation to reduce capital funding for the DC Interference Program ignores the evidence PG&E submitted to justify its forecast; (2) the basis for TURN’s recommendation to lengthen the pace of this program is largely based on the lack of an immediate safety hazard. PG&E does not believe it is prudent or cost effective to defer work to mitigate a known risk and potentially allow metal loss due to DC interference to grow to an immediate safety hazard; and (3) ORA did not apply escalation to adjust 2015, 2016 or 2017 recorded costs to estimate 2019 funding.

What is your conclusion based on the parties’ proposed recommendations for DC Interference?

For the reasons discussed above, PG&E recommends that its $37.868 million total capital expenditure forecast for DC Interference be adopted.

### 3. Alternating Current Interference (MATs GJA and 3K4)

Briefly, what is the scope of the AC Interference Program?

AC Interference can occur when AC power transmission lines are sited in proximity to steel pipelines. AC Interference can manifest as a shock hazards due to levels of AC voltage induced on the piping system; damage to the natural gas piping due to a ground fault of the AC power lines; and/or metal loss of the piping system due to AC corrosion. AC Interference is more fully discussed in PG&E’s opening testimony.44

What are parties’ recommendations for AC Interference?

ORA proposes a 2019 expense reduction of $1.075 million and a 2019 capital reduction of $4.466 million. PG&E discusses each of these recommendations below.

What is the basis for ORA’s proposed reduction?

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44 PG&E Prepared Testimony, Chapter 8, p. 8-36, line 1 to p. 8-40, line 1, including Tables 8-10 and 8-11.
ORA proposes that the forecasts for AC Interference expense and capital expenditures should be the 3-year average (2015 through 2017) of recorded costs, without escalation.

Q Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts?

A No. ORA’s recommendations do not provide sufficient funding levels to maintain compliance with minimum pipeline safety regulations, implement industry best practices, and adequately mitigate health and safety hazards and pipeline integrity threats.

The use of a 3-year average to determine 2019 funding levels is only appropriate if the work stream is stable in terms of scope, pace and cost, and even then would fall short due to normal inflation. That is not the case here. As PG&E explained in its opening testimony, the Arc Fault threat was not identified in collocated electric and gas facilities until 2016 and requested expense funding for four station Arc Fault Investigations in 2019 at a total cost of $0.606 million. In addition, PG&E’s 2019 AC Interference capital forecast includes Arc Fault Mitigation at two Electric Substations at a total cost of $3.976 million. The use of 3-year average expenditures is not appropriate when an additional threat is identified through ongoing threat analysis.

PG&E’s 2019 AC Interference expense forecast also includes Arc Fault Mitigation at 10 pole/tower locations at a total cost of $0.207 million. PG&E states in opening testimony and work papers that the Arc Fault Mitigation systems now being proposed by PG&E were developed in-house and are approximately one-third the cost of systems included in the 2015 GT&S Rate Case. PG&E developed, installed, and verified the effectiveness of the less expensive mitigation systems at five pilot locations between 2015 and 2017. The new mitigation systems are considered expense, not capital as presented in the 2015 GT&S Rate Case. ORA’s use

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45 49 CFR §§192.467(f) and 192.473(a).
46 PG&E Prepared Testimony, Chapter 8, p. 8-36, line 30 to p. 8-37 line 2.
47 PG&E Prepared Testimony, Chapter 8, p.8-39, lines 4-14, and PG&E WP 8-89.
48 PG&E WP 8-28.
of 3-year average expenditures does not recognize that 2015-2017 actual costs only included five pilot locations and does not reflect the cost of fully implementing such mitigation systems.

PG&E’s 2019 AC Interference capital forecast also includes $12.058 million for installation of Induced AC Mitigation (ground rods or zinc ribbon). ORA correctly notes that PG&E did not spend all capital funding authorized in the 2015 GT&S Rate Case for this workstream; however, the methodology that PG&E used to determine whether mitigation is required changed after the 2015 GT&S Rate Case was filed.

PG&E provided Electrical Interference Best Practices that details PG&E’s use of Pipeline Research Council International (PRCI) research to better manage this threat and avoid costly mitigation where it is not required. Through the application of this research, PG&E was able to avoid installation of unnecessary capital AC Mitigation systems on L-107, L-109, L-132, and portions of L-401 that were proposed in the 2015 GT&S Rate Case.

AC Interference is a complex issue that can manifest as an electrical safety threat when hazardous levels of AC are induced on the pipeline; an integrity threat when electrical faults can result in an immediate loss of containment; and/or a time dependent threat when AC discharging from the pipeline negates the effectiveness of corrosion control systems. PG&E does not believe that the funding levels proposed by ORA are adequate to mitigate this threat.

Q 49 In summary, what is PG&E’s position in response to ORA’s recommendations?

A 49 PG&E disagrees with the parties’ proposed reductions for the following reasons: (1) the 3-year average cost methodology utilized by ORA is not appropriate for AC Interference; (2) ORA did not apply escalation to adjust 2015, 2016 or 2017 recorded costs to estimate 2019 funding; and (3) funding levels proposed by ORA are not adequate to implement industry Best Practices.

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49 PG&E Prepared Testimony, Chapter 8, p. 8 Attachment A.
For these reasons, PG&E recommends that its $2.625 million 2019 expense forecast and $23.813 million total capital expenditure forecast for AC Interference be adopted.

4. **Casings (MATs GJL, GJM and 3K5)**

Q 50 Briefly, what is the scope of the Casings Program?

A 50 Loss of electrical isolation between a casing and a gas pipeline can divert CP current from the gas pipeline and increase the risk of external corrosion. PG&E monitors each cased pipeline crossing annually, and investigates all anomalous conditions to determine whether remedial action is required to mitigate the increased risk of external corrosion presented by the contact between the casing and gas piping. PG&E’s Casing Program is more fully discussed in PG&E’s opening testimony.\(^{50}\)

Q 51 What are parties’ recommendations for Casings?

A 51 No party contests PG&E’s expense forecast for this program.

ORA proposes a 2019 capital reduction of $8.70 million.\(^{51}\) TURN proposes a total capital reduction of $26.11 million.\(^{52}\) PG&E discusses each of these recommendations in turn.

Q 52 What is ORA’s recommendation for capital expenditures for the Casings Program?

A 52 ORA recommends a $8.70 million reduction in 2019 casing capital spending.\(^{53}\) ORA provides no detail as to how the proposed reduction should be applied to the various activities associated with this program.

Q 53 What is the basis for ORA’s proposed reduction?

A 53 The basis for ORA’s recommendation to reduce capital forecasts is the unescalated 3-year average (2015 through 2017) of recorded capital casing expenditures.

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\(^{50}\) PG&E Opening Testimony, Chapter 8, p. 8-40, line 2 to p. 8-48, line 1, including Tables 8-14 and 8-15.

\(^{51}\) ORA-08, p. 3, Table 8-2.

\(^{52}\) TURN, Chapter 8, p. 7, lines 3-8, including Table 4 titled “Casings – Capital (MAT 3K5).”

\(^{53}\) ORA-08, p. 2, Table 8-1 and p. 3, Table 8-2.
Q 54 Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts?

A 54 No. WP 8-92 shows that 94 percent of the 2019 Casing capital forecast is related to pipeline replacements. As stated in opening testimony, PG&E did not propose replacement of pipe as an alternative to casing remediation in the 2015 GT&S Rate Case. PG&E did not anticipate, forecast, or receive funding for pipe replacement associated with contacted casings and did not perform such work in 2015, 2016 or 2017. The use of a 3-year average to determine funding levels is only appropriate if the work stream is stable in terms of scope, pace and cost. As the 3-year period ORA uses did not include any pipe replacement projects, ORA’s analysis is faulty and should be rejected.

ORA does not contest the pace specified by PG&E for pipe replacement or risk mitigation achieved by completing this work. PG&E’s opening testimony discussed the 4-year program to remediate contacted casings (2014-2017) and its risk-based decision to extend this program into the 2019 GT&S Rate Case. Nor did ORA put on any evidence to suggest that PG&E’s forecast unit cost is not reasonable. Adopting ORA’s recommendation would extend PG&E’s Contacted Casing Remediation Program beyond 2021 with no consideration of risk, a position considered and rejected by PG&E.

Q 55 What is TURN’s recommendation for casings?

A 55 TURN recommends a total capital spend reduction of $26.11 million.

Q 56 What is the basis for TURN’s proposed reduction?

A 56 TURN recommends a 56 percent reduction to PG&E’s capital forecast based on PG&E’s response to a TURN data request detailing that 12 of the forecast 25 casing projects will either be addressed through other

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55 PG&E Prepared Testimony, Chapter 8, p. 8-44, lines 7-11.
56 TURN, Chapter 8, p. 7, lines 3-8, including Table 4 titled “Casings – Capital (MAT 3K5).”
57 TURN, Chapter 8, p. 5, line 10 to p. 7 including Table titled “DC Interference Capital (MAT 3K9).”
58 See PG&E’s response to TURN Data Request TURN_016-Q01, dated 06/08/2018 in Attachment A.
work streams or are no longer required. Accordingly, TURN recommends PG&E’s forecast be revised to reflect that the Company, at the time PG&E responded to that data request, planned to complete 14 casing replacements, 13 of which are included in its original forecast, and one additional casing identified requiring replacement as described in PG&E’s response to the TURN data request.

Q 57 Do you agree with TURN’s recommendations for reducing PG&E’s cost forecasts?

A 57 No. PG&E disagrees with TURN’s recommendation to reduce funding levels for Casings based on information provided in a data request response for a particular point in time. As stated in the data response, “PG&E also anticipates that additional sites will be discovered during the execution of 2018 casing mitigation projects.”

TURN has not demonstrated that PG&E’s forecast was unreasonable at the time it was made. Moreover, since PG&E’s provided its data request response to TURN, an additional six locations where pipe replacement is required have been identified, bringing the total current number of Contacted Casing Pipeline Replacement (MAT 3K5) projects to 20. PG&E anticipates that additional sites will be discovered during execution of 2018 casing mitigation projects and continues to believe that the forecast for 25 pipe replacements is reasonable and should be adopted by the Commission.

Q 58 In summary, what is PG&E’s position in response to the parties’ recommendations?

A 58 PG&E disagrees with the parties’ proposed reductions for the following reasons: (1) the 3-year average cost methodology utilized by ORA only considers capital casing mitigation, not pipe replacement, and is not appropriate; (2) funding levels proposed by ORA are not adequate to replace pipe and mitigate contacted casings at the pace outlined; (3) funding levels proposed by ORA were provided with no discussion or consideration of the risk of extending remediation; (4) TURN does not account for the

59 TURN, Chapter 8, p. 6, lines 14-16.
60 TURN, Chapter 8, p. 6, line 16 to p. 7, line 1.
61 See PG&E’s response to TURN Data Request TURN_016-Q1, dated 06/08/2018 in Attachment A.
ongoing identification of contacted casings that require mitigation through replacement; and (5) ORA did not apply escalation to adjust 2015, 2016 or 2017 recorded costs to estimate 2019 funding.

For these reasons, PG&E recommends that its $2.057 million 2019 expense forecast and $64.715 million total capital expenditure forecast for Casings be adopted.

5. Atmospheric Corrosion (MATs GJB and 3KA)

Q 59 Briefly, what is the scope of the Atmospheric Corrosion Program?
A 59 Atmospheric Corrosion monitoring and mitigation is required in accordance with Subpart I of 49 CFR §192 to protect PG&E’s metallic gas piping systems that are exposed to the atmosphere from corrosion. Atmospheric Corrosion is more fully discussed in PG&E’s opening testimony.\(^6^2\)

Q 60 What are parties’ recommendations for Atmospheric Corrosion?
A 60 TURN proposes a 2019 expense funding level of $2.0 million which is a $9.5 million reduction to PG&E’s forecast.\(^6^3\) No party challenged PG&E’s capital expenditure forecast for Atmospheric Corrosion.

Q 61 What is the basis for TURN’s proposed reduction?
A 61 TURN states in testimony that PG&E’s 2019 forecast of $11.5 million is not credible due to historic underspending, and recommends a forecast of $2.0 million based on recorded expenses from 2015-2017.

Q 62 Do you agree with TURN’s recommendations for reducing PG&E’s cost forecasts?
A 62 No. PG&E disagrees with TURN’s recommendations to adjust the expense forecast for Atmospheric Corrosion. First, PG&E’s expense forecast for atmospheric corrosion includes a new dedicated work stream, Span Recoat & Upgrade, to replace span coating systems in conjunction with upgrades of supports and/or foundations. This program was described in

\(^6^2\) PG&E Prepared Testimony, Chapter 8, p. 8-55, line 4 to p. 8-58, line 9, including Tables 8-20 and 8-21.

\(^6^3\) TURN, Chapter 8, p. 2, lines 7-9.
testimony\textsuperscript{64} and work papers\textsuperscript{65} and such costs are not fully represented in
historic costs. Second, PG&E has discovered an error in our response to
TURN\_016-Q13\textsuperscript{66} that may further explain PG&E’s forecast. In response to
TURN\_016-Q13.b.iii, PG&E provided 2015-2017 recorded expense
spending for MAT GJB; however, the units provided in response to
TURN\_016-Q13.b.iv are not correct and do not reflect expense work
completed\textsuperscript{67} in 2015-2017. PG&E records indicate that, excluding
shareholder funded work, four expense spans were completed in 2015,
seventeen expense spans were completed in 2016, and fourteen expense
spans were completed in 2017. In addition, eleven expense stations were
completed in 2017. During the period 2015-2017, PG&E shareholder
funded approximately $29.6 million dollars of atmospheric corrosion
expense in addition to the approximately $6 million of atmospheric corrosion
expense that was included in rates.

In response to ORA\_Oral002-Q02,\textsuperscript{68} PG&E provided details on all
atmospheric corrosion orders that were used to calculate the unit prices
provided in WP 8-43 and 8-44, and indicate that the total project duration for
atmospheric corrosion expense can span 3 to 5 years. The units provided in
TURN\_016-Q13.b.iv only reflect the year that the coating rehabilitation was
completed. As such, unit price calculations based on the annual spend and
units provided in TURN-016-Q13 are not accurate.

\begin{itemize}
\item\textsuperscript{64} PG&E Prepared Testimony, Chapter 8, p. 8-15, lines 18-23 and p. 8-57, line 26 to
   p. 8-58, line 4.
\item\textsuperscript{65} PG&E WP 8-47.
\item\textsuperscript{66} See PG&E’s response to TURN Data Request TURN\_016-Q13, dated 06/08/18 in
   Attachment A.
\item\textsuperscript{67} PG&E interprets TURN-016, Question 13.b.iv to request the number of expense units
   by year during the period 2015-2017 where construction records have been received
   and indicate completion of coating repairs and/or application. The units provided above
   (and in PG&E’s pending supplemental response) exclude shareholder funded work.
   Note that the units reported only reflect projects where construction records have been
   received and verified, and are subject to change.
\item\textsuperscript{68} See PG&E’s response to ORA Data Request ORA\_Oral 002-Q02, dated 03/30/18 in
   Attachment A.
\end{itemize}
PG&E apologizes for the mistake and will re-submit our response to TURN_016-Q13 to reflect only expense units completed that were funded with revenue recovered in rates, as discussed above.

The unit costs for Atmospheric Corrosion expense provided in WP 8-43 are reasonable and reflect realized cost reductions in this work stream. In addition, the forecast units are also reasonable when shareholder funded work is included in this analysis. The fact that PG&E funded approximately 83 percent of the total historical atmospheric corrosion expense does not change the forward-looking annual workload due to coating degradation.

TURN’s recommendation to use 2015-2017 average actual costs is not appropriate as: (1) it does not consider a new dedicated work stream, Span Reccoat & Upgrade; and (2) it does not reflect that the majority of work performed during this period was shareholder funded. PG&E provided forecast methodology in testimony and work papers that detail how units and unit costs were derived for each of the individual work streams in MAT GJB. For example, PG&E forecast that 3.4 percent of atmospheric inspections (spans and exposed assets) require repair. PG&E believes the forecast methodology presented in testimony and work papers is valid and reflects the pace and cost of work required for 2019.

Q 63 In summary, what is PG&E’s position in response to TURN’s recommendations?

A 63 PG&E disagrees with TURN’s proposed reductions for the following reasons: (1) 2015-2017 average unit costs do not reflect that the majority atmospheric corrosion expense during this period was funded by shareholders; (2) the forecast and forecast methodology presented by PG&E are credible; and (3) the funding levels proposed by TURN are not adequate to address historic work levels and maintain compliance with pipeline safety regulations.

Q 64 What is your conclusion based on the parties’ proposed recommendations for Atmospheric Corrosion?

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69 PG&E WP 8-44.
For the reasons listed above, PG&E recommends that its $11.501 million 2019 expense forecast and its $8.673 million total capital expenditure forecast for Atmospheric Corrosion be adopted.

6. Close Interval Survey (MAT GJE)

Q 65 Briefly, what is the scope of the Close Interval Survey (CIS) Program?
A 65 CIS is a walking survey to verify levels of CP between Test Stations, verify electrical isolation, and identify potential indications of interference. CIS is recognized as a Best Practice for Gas Transmission Pipelines. CIS is more fully discussed in PG&E’s opening testimony.

Q 66 What are parties’ recommendations for CIS?
A 66 ORA proposes a reduction of $4.069 million in expense from PG&E’s forecast for CIS.

Q 67 What is the basis for ORA’s proposed reduction?
A 67 The basis for ORA’s recommendation to reduce CIS expense forecasts is the unescalated 3-year average (2015 through 2017) of recorded CIS expenditures.

Q 68 Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts?
A 68 No. ORA based its recommendation on a 3-year (2015 through 2017) annual average of actual CIS expenses. ORA does not account for: (1) the non-uniform pace of CIS performed by PG&E; (2) PG&E’s proposed increase of pace to 450 miles per year; or (3) the transition of the program from backbone to local transmission piping. With respect to pace, PG&E completed approximately 700 miles of CIS from 2015–2017 and is scheduled to complete approximately 1,300 miles of CIS in 2018. ORA’s use of a 3-year average cost does not account for the pace of the program. In addition, PG&E proposed to increase the pace of CIS, relative to the 2015-2017 forecast pace, to 450 miles per year.

70 PG&E Prepared Testimony, Chapter 8, p. 8-58, line 10 to p. 8-60, line 19, including Table 8-22.
71 ORA-08, p. 2, Table 8-1.
72 ORA-08, p. 15, line 13 to p. 16, line 6.
73 PG&E Prepared Testimony, Chapter 8, p. 8-59, lines 18-21.

8-25
increased pace should allow for completion of the baseline survey in 2028 and also provides flexibility to resurvey areas where problems were found during the original CIS. ORA did not consider acceleration of CIS pace in their analysis. Finally, PG&E detailed in WP 8-48 that the CIS Program is transitioning to local transmission piping where a much higher percentage of the piping will be located under concrete or asphalt cover in urban areas. Costs to perform CIS in such areas are forecast to be significantly higher. The use of a 3-year average to determine funding levels is only appropriate if the work stream is stable in terms of scope, pace and cost. The pace of the CIS Program from 2015-2017 was not uniform, and on average was significantly lower than the pace PG&E plans to perform over the 2019-2021 period, and the work is transitioning from mostly rural backbone piping to local transmission piping where costs are known to be higher due to a greater percentage of the piping sited in urban areas / under pavement. As such, ORA’s use of a 3-year average is not appropriate and does not represent the cost of performing CIS in 2019. Adoption of ORA’s recommendation would reduce the pace of CIS performed in 2019 from 450 miles to approximately 120 miles. This pace would extend completion of the baseline CIS to 2057.

Q 69 In summary, what is PG&E’s position in response to ORA’s recommendations?

A 69 PG&E disagrees with ORA’s proposed reductions for the following reasons: (1) the pace of the program was not uniform and is not reflected in the 3-year average cost methodology utilized by ORA; (2) PG&E proposed to increase the pace of CIS by 12.5 percent; and (3) the cost of performing work on local transmission piping is significantly higher and is not captured in the 3-year historic spend average; (4) funding levels proposed by ORA are not adequate to perform 450 miles of CIS per year and will extend completion of the baseline survey to 2057; (5) funding levels proposed by ORA do not consider the risk associated with extending the pace of this program; and (6) ORA did not apply escalation to adjust 2015, 2016 or 2017 recorded costs to estimate 2019 funding.

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74 PG&E WP 8-48.
Q 70 What is your conclusion based on the ORA’s proposed recommendations for CIS?

A 70 For the reasons listed above, PG&E recommends that its $5.476 million 2019 expense forecast for CIS be adopted.

7. Internal Corrosion (MATs GJH and 3K1)

Q 71 Briefly, what is the scope of Internal Corrosion Program?

A 71 PG&E’s Internal Corrosion Program is required to monitor for potentially corrosive constituents in the gas stream and mitigate internal corrosion issues when identified. PG&E’s Internal Corrosion Program is required to maintain compliance with Subpart I of 49 CFR §192. Internal Corrosion is more fully discussed in PG&E’s prepared testimony. 75

Q 72 What are parties’ recommendations for Internal Corrosion?

A 72 ORA proposes a reduction of $2.131 million from PG&E’s 2019 expense forecast for Internal Corrosion. TURN proposes a reduction of $13.4 million from PG&E’s 2019-2021 capital expenditure forecast. PG&E discusses each of these recommendations in turn.

Q 73 What is the basis for ORA’s proposed reduction?

A 73 The basis for ORA’s recommendation to reduce Internal Corrosion expense forecasts is the unescalated 3-year average (2015 through 2017) of recorded Internal Corrosion expenditures.

Q 74 Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts?

A 74 No. ORA based its recommendation on a 3-year (2015-2017) average of actual internal corrosion expenses. ORA ignores that new and pending regulations governing underground storage facilities have additional internal corrosion requirements. As stated in prepared testimony, 76 PG&E utilized the methodologies outlined in American Petroleum Institute (API) 1171 to enhance the Internal Corrosion Monitoring Program for storage assets and these enhancements were included in this application. As the 3-year average cost utilized by ORA does not capture costs associated with

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75 PG&E Prepared Testimony, Chapter 8, p. 8-60, line 20 to p. 8-66, line 1, including Tables 8-23 and 8-24.

76 PG&E Prepared Testimony, Chapter 8, p. 8-14, lines 3-34.
implementation of API 1171, ORA’s analysis is faulty and should be rejected.

Q 75 What is TURN’s recommendation for Internal Corrosion?
A 75 TURN recommended a $13.4 million reduction to PG&E’s 2019-2021 capital forecast for Internal Corrosion and did not contest PG&E’s expense spend forecast.77

Q 76 What is the basis for TURN’s proposed reduction?
A 76 TURN argues that PG&E has not sufficiently justified the forecast of 15 drips replacements, stating that PG&E has not demonstrated that there is a critical safety need to perform 15 drips replacements.78 TURN recommends that PG&E be funded to perform 10 replacements during the rate case period and be directed to prioritize those replacements where risk is the highest.79

Q 77 Do you agree with TURN’s recommendations for reducing PG&E’s cost forecasts?
A 77 No. PG&E disagrees with TURN’s recommendation to slow the pace of drip replacements and reduce PG&E’s 2019-2021 capital forecast by $13.4 million.80 PG&E outlined in opening testimony the potential for damage to metallic pipelines by internal corrosion, which is more likely to occur at areas along the pipeline, such as drips, where liquids accumulate. In addition, PG&E provided a discussion on the risks of Selection Seam Weld Corrosion (SSWC) on line pipe that has often been used in drip construction and noted that ruptures have occurred in the pipeline industry due to internal corrosion and SSWC in drips. TURN does not contest the need for drip removal or replacements, only the pace at which this work is to be completed. PG&E records indicate 136 drips are installed on backbone transmission piping. The PG&E forecast to remove 15 drips will provide data on approximately 11 percent of the current backbone drip inventory and

77 TURN, Chapter 8, p. 10, line 15 to p. 11, line 3.
78 TURN, Chapter 8, p. 10, lines 6-8.
79 TURN, Chapter 8, p. 10, lines 15-16.
80 TURN, Chapter 8, p. 11, lines 1-3.
allow PG&E to better evaluate this threat across the gas transmission system.

TURN also alleges that PG&E has not justified the cost effectiveness and risk reduction of performing drip replacements on lower priority projects, and infers that a portion of this work can be deferred to the next rate case period. TURN asserts that PG&E is not aware that any of the proposed work is needed to mitigate an immediate safety hazard. As discussed earlier, this suggestion mischaracterizes the purpose of corrosion control work. Corrosion control work is generally not designed to mitigate immediate safety hazards, but rather to extend the lives of metallic assets and to prevent immediate safety hazards from occurring in the first place.

For the reasons stated above, PG&E believes that its pace of the Drip Removal Program is appropriate to better evaluate this risk and should not be extended.

Q 78 In summary, what is PG&E’s position in response to the parties’ recommendations?

A 78 PG&E disagrees with the parties’ proposed reductions for the following reasons: (1) the 3-year average cost methodology utilized by ORA is not appropriate for Internal Corrosion due to changes in scope caused by new/pending regulations; (2) funding levels proposed by ORA are not adequate to maintain compliance with recent pipeline safety regulations, and (3) PG&E does not believe that TURN’s proposal to extend the pace of the Drip Removal / Replacement program is appropriate.

PG&E recommends that its $3.561 million 2019 Internal Corrosion expense forecast and $40.25 million total capital expenditure forecast be adopted.

Q 79 Does this conclude your rebuttal testimony?

A 79 Yes, it does.

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81 TURN, Chapter 8, p. 10, lines 12-20.
82 TURN, Chapter 8, p. 10, lines 10-12.
QUESTION 2

Please detail how PG&E used the various escalation rates to derive the 2019 forecast for Corrosion Control programs.

ANSWER 2

PG&E notes that attachment “GTS-RateCase2019_DR_ORA_Oral002Atch015” contains one or more of the following: critical infrastructure information that is not normally provided to the general public, the dissemination of which poses public safety risks (pursuant to the Critical Infrastructures Information Act of 2002, 6 U.S.C. §§131-134); sensitive personal information pertaining to PG&E employees; customer information; or commercially sensitive/proprietary information. This information has been redacted in the referenced attachment(s).

Where possible, PG&E forecast its Corrosion Control programs by determining an average unit cost and applying that cost to the units in its program forecast. We examined costs generally from 2012-2017 and applied escalation factors to historical costs to account for inflation. The table below shows the escalation factors PG&E used for most of the Corrosion Control capital and expense work. 1

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<tr>
<th>Year</th>
<th>Capital</th>
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<tr>
<td>2011</td>
<td>5.217%</td>
<td>3.888%</td>
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<tr>
<td>2012</td>
<td>5.383%</td>
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<tr>
<td>2021</td>
<td>2.943%</td>
<td>2.420%</td>
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1 Where a different date range or a different forecasting methodology is used, it is noted in Chapter 8 Testimony.
Attachments GTS-RateCase2019_DR_ORA_Oral002_Q02Atch02 through GTS-RateCase2019_DR_ORA_Oral002_Q02Atch17 show how PG&E identified historical orders associated with Corrosion Control programs, converted costs recorded on those orders to the New Cost Model (NCM), and escalated NCM costs to 2017 dollars. The Workpapers Supporting Chapter 8 Corrosion Control show how PG&E escalated costs from 2017 to the Rate Case Period.²

In gathering these materials, PG&E noted an error in Workpapers related to AC Interference. The error, which appears on WP p. 8-90 and 8-91, double-counted the cost of one project and, therefore, doubled the unit cost of Zinc Ribbon installations. PG&E will correct this in a future errata filing.

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<td>Historical order conversion concerning AC Interference – Expense (GJA)</td>
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<td>Historical order conversion concerning Atmospheric Corrosion – Capital (3KA)</td>
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<td>Historical order conversion concerning Atmospheric Corrosion – Expense (GJB)</td>
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<td>Historical order conversion concerning Casings – Capital (3K5)</td>
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<td>Historical order conversion concerning DC Interference – Capital (3K9)</td>
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² Note that the Workpapers Supporting Chapter 8 present escalation rates as numeric multipliers rather than percentages. For example, the Workpapers show a 2% escalation as 1.02.
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<td>Historical order conversion concerning Test Stations – Expense (GJD)</td>
</tr>
<tr>
<td>-------</td>
<td>---------------</td>
</tr>
<tr>
<td>40001</td>
<td></td>
</tr>
<tr>
<td>40002</td>
<td></td>
</tr>
<tr>
<td>40003</td>
<td></td>
</tr>
</tbody>
</table>

**Note:** All descriptions redacted where customer-specific data or critical energy infrastructure information is an external source.
QUESTION 1

Regarding the 25 Cased Crossing Replacements discussed on pp. 8-16 and 8-43 to 8-44:

a. For each of the 25 casings, please provide a separate description and rationale for the need for replacement.

b. For each of the 25 casings, please indicate whether PG&E affirms that it has exhausted all lower cost alternatives for mitigating the contacted casing and identify each such alternative that was considered and rejected.

ANSWER 1

a-b. GTS-RateCase2019_DR_TURN_016-Q01Atch01 provides the requested rationale for replacement of the 25 Cased Crossing Replacements included in WP 8-96.

PG&E submitted the 2019 Gas Transmission and Storage Rate Case, to include the request for 25 Cased Crossing Replacements, based on data that was available at the time the application was prepared. PG&E continued to evaluate possible alternatives to pipe replacement at each of the locations and has since determined that twelve proposed pipe replacements projects will either be addressed through other work streams or are no longer required, as provided in the “Current Status” column of GTS-RateCase2019_DR_TURN_016-Q01Atch01. Note that an additional location where pipe replacement is required was discovered during this process, bringing the total current number of Contacted Casing Pipeline Replacement (3K5) projects to 14. PG&E also anticipates that additional sites will be discovered during execution of 2018 casing mitigation projects. The ongoing evaluation of cost effective alternatives is inherent to the engineering process and is indicative of the dynamic nature of this industry. Though PG&E now has additional information, based on the information available at the time of PG&E’s filing, PG&E’s forecast of 25 Cased Crossing Replacements was reasonable.

PG&E’s Corrosion Engineering, ILI and Pipeline Services groups evaluated each proposed crossing and the following alternatives were considered to determine whether more cost-effective options were available. Options evaluated included to:

- Retest the casing to verify historic data
• Make the line piggable and use traditional ILI to manage this threat
• Utilize non-traditional ILI to manage this threat
• Retire the cased crossing
• Verify that the cased crossing was not converted to a distribution asset
• Determine whether the cased crossing can be remediated as part of another scheduled project

PG&E is not aware of any lower cost alternative to replacement at the remaining 14 locations, at this time.
<table>
<thead>
<tr>
<th>Line</th>
<th>Project</th>
<th>Rationale for Replacement</th>
<th>Current Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>142S MP 11.24</td>
<td>Casing contact in a HCA on an un-piggable line segment. Unable to excavate/access to perform required remediation due to close proximity of casing ends to active railroad.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>2</td>
<td>0613-01 MP 2.58</td>
<td>Casing contact in a HCA on an un-piggable line segment. Unable to excavate/access due to close proximity of casing end to active railroad.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>3</td>
<td>172A MP 60.76</td>
<td>Casing contact in a HCA on a piggable line segment. Previous attempt to clear casing was unsuccessful.</td>
<td>Removed from replacement list as line is piggable.</td>
</tr>
<tr>
<td>4</td>
<td>1608-01 MP 1.17</td>
<td>Casing contact in a HCA on an un-piggable line segment. Existing casing does not allow for filling the casing interstice with non-corrodible fillers.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>5</td>
<td>105A MP 39.65</td>
<td>Casing contact in a HCA on an un-piggable line segment. Previous remediation attempt was unsuccessful and casing interstice could not be filled with non-corrodible fillers.</td>
<td>NTILI was determined to be more cost effective than replacement as line will be taken out of service in 2019 for a hydrostatic test.</td>
</tr>
<tr>
<td>6</td>
<td>105B MP 6.3</td>
<td>Casing contact in a HCA on a piggable line segment. Previous attempt to clear casing was unsuccessful.</td>
<td>Removed from replacement list as line is piggable. During casing mitigation digs a girth weld issue was noted that will require future mitigation by another workstream.</td>
</tr>
<tr>
<td>7</td>
<td>300A MP 496.3724</td>
<td>Casing contact in a HCA on a piggable line segment. Casing depth estimated between 10 and 20 feet below grade. Remediation was determined to be infeasible due to depth.</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>105A MP 45.68</td>
<td>Casing contact on an un-piggable line segment. Unable to excavate/access due to close proximity of storm drain.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>9</td>
<td>DREG3872 MP 0.01</td>
<td>Casing contact in a HCA on an un-piggable line segment. Caltrans rejected permit for steel plates within the confines of access control.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>10</td>
<td>177A MP 175.12</td>
<td>Casing contact on an un-piggable line segment. Caltrans rejected permit request.</td>
<td>Removed from replacement list as line is scheduled to be piggable in 2018.</td>
</tr>
<tr>
<td>11</td>
<td>186 MP 8.154</td>
<td>Contacted casing on an un-piggable line segment. Remediation was attempted but unsuccessful due to vintage construction techniques (1930).</td>
<td>Removed from replacement list as casing was removed.</td>
</tr>
<tr>
<td>12</td>
<td>7217-01 MP 0.13</td>
<td>Contacted casing on an un-piggable line segment. Remediation was determined to be infeasible as casing ends are encased in a bridge.</td>
<td>Removed from replacement list as line is scheduled to be piggable in 2021.</td>
</tr>
<tr>
<td>13</td>
<td>1310-01 MP 1.14</td>
<td>Casing contact on an un-piggable line segment. Casing remediation was attempted but unsuccessful.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>14</td>
<td>DREG4323 MP 0</td>
<td>Casing contact on an un-piggable line segment. Engineering evaluation determined that casing remediation was infeasible due to diameter of pipe and casing.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>15</td>
<td>7218-01 MP 0.03</td>
<td>Casing contact on an un-piggable line segment. Casing remediation was attempted but unsuccessful due to one end of the cased crossing terminating under a canal.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>16</td>
<td>1310-01 MP 1.25</td>
<td>Casing contact in a HCA on an un-piggable line segment. Casing remediation was attempted but unsuccessful due to degradation of casing that would not allow for filling the casing interstice with non-corrodible fillers</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>17</td>
<td>1202-04 MP 2.37</td>
<td>Casing contact on an un-piggable line segment. Casing remediation was attempted but unsuccessful due to adjacent storm drain.</td>
<td>Removed from replacement list as crossing was retired.</td>
</tr>
<tr>
<td>18</td>
<td>0141-01 MP 0.28</td>
<td>Casing contact in a HCA on an un-piggable line segment. Unable to excavate/access due to close proximity of casing ends to active railroad.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>19</td>
<td>0621-01 MP 19 0.694769</td>
<td>Casing contact on an un-piggable line segment. Unable to excavate/access due to close proximity of casing ends to active railroad.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>20</td>
<td>1405-01 MP 0.037</td>
<td>Casing contact in a HCA on an un-piggable line segment. Unable to excavate/access east end of casing due to soundwall.</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>21</td>
<td>134A MP 11.819</td>
<td>Contacted casing on an un-piggable line segment. Remediation was attempted but unsuccessful due to vintage construction techniques (1953).</td>
<td>Recommend replacement.</td>
</tr>
<tr>
<td>22</td>
<td>DREG18525 MP 22 0.009</td>
<td>Contacted casing on an un-piggable pipe segment. Remediation was determined to be infeasible due to 3 inch carrier in a 20 inch casing under I-880.</td>
<td>Removed from replacement list as casing is scheduled to be removed in 2019.</td>
</tr>
<tr>
<td>23</td>
<td>1039-01 MP 0.84</td>
<td>Contacted casing on an un-piggable pipe segment.</td>
<td>Removed from replacement list as additional testing verified short was cleared.</td>
</tr>
<tr>
<td>24</td>
<td>DREG3866 MP 24 0.027</td>
<td>Contacted casing on an un-piggable pipe segment.</td>
<td>Removed from replacement list as additional testing verified short was cleared.</td>
</tr>
<tr>
<td>25</td>
<td>7223-01 MP 6.01</td>
<td>Casing contact in a HCA on an un-piggable line segment. Casing remediation was attempted but unsuccessful due to vintage construction techniques (1954) that do not allow for filling the casing interstice with non-corrodible fillers.</td>
<td>Recommend replacement.</td>
</tr>
</tbody>
</table>
QUESTION 13

With respect to Atmospheric Corrosion:

a. Please explain the disparity between the 2017 expense forecast of $19.4 million (p. 8-58) and the recorded results of $1.1 million (ORA_35-Q01Atch01Rev01).

b. Using comparable figures under the new cost model, please provide:
   i. Authorized expense spending for the 2015-2018 period (please also provide the old cost model numbers);
   ii. Authorized units of expense work for the 2015-2018 period;
   iii. Year-by-year recorded expense spending for 2015-2017 and forecast expense spending; and
   iv. Year-by-year units of expense work performed in 2015-2017 and forecast to be performed in 2018.

ANSWER 13

a. PG&E previously calculated the 2017 expense forecast by averaging the cost per span repair completed between 2015 and 2017, and by averaging the cost per exposed asset repair from 2012 – 2014. In 2017, PG&E revised the repair procedure for these assets and reduced scope from full recoats to spot repairs, significantly reducing the cost of span and exposed asset repairs.


<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$19,868,666</td>
<td>$16,147,134</td>
<td>$20,372,890</td>
<td>$16,556,914</td>
<td>$21,458,123</td>
<td>$17,438,77</td>
<td>$22,001,732</td>
<td>$17,880,663</td>
</tr>
</tbody>
</table>

GTS-RateCase2019_DR_TURN_016-Q13 8-AtchA-8
bii. D. 16-06-056 did not expressly authorize units for this program. The estimated total number of Atmospheric Corrosion units for the 2015 – 2018 period, based on PG&E’s 2015 GT&S rate case prepared testimony and WP is as follows: 298 Spans, 63 Reg Stations, 118 Vaults.

biii. PG&E interprets this question to request the year-by-year recorded expense spending for the 2015 – 2017 and 2018 forecast expense spending (MAT GJB). This information can be found in the table below.

<table>
<thead>
<tr>
<th></th>
<th>2015 Actual (NCM)</th>
<th>2016 Actual (NCM)</th>
<th>2017 Actual (NCM)</th>
<th>2018* Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$1,163,245</td>
<td>$3,722,280</td>
<td>$1,148,025</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td></td>
<td></td>
<td></td>
<td>$6,225,047</td>
</tr>
</tbody>
</table>

*Estimated 2018 forecast as of April 30th, 2018.

biv. Year-by-year units of expense work performed in 2015 – 2017 are as follows:

<table>
<thead>
<tr>
<th>Work Type</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Span Repair</td>
<td>50</td>
<td>33</td>
<td>74</td>
</tr>
<tr>
<td>Exposed Asset Repair</td>
<td>1</td>
<td>2</td>
<td>176</td>
</tr>
</tbody>
</table>

PG&E forecasts 56 span repairs and 133 exposed asset repairs in 2018.
ORA Response To PGE-ORA-DR-003
Pacific Gas and Electric Company
2019 Gas Transmission and Storage Application A.17-11-009

Origination Date: July 5, 2018
Due Date: July 19, 2018
Responses Date: July 23, 2018
Revised Date: N/A

To: John Carruthers
   JBC4@pge.com

   Tom Varghese
   TRV2@pge.com

   Steve Koenig
   SJKB@pge.com

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Phone: 415-703-5881
Email: gze@cpuc.ca.gov

ORA Counsel
Noel Obiora
Phone: 415-703-5987
Email: noel.obiora@cpuc.ca.gov

Data Request No: ORA Response To PGE-ORA-DR-003
Exhibit Reference: ORA-08
Subject: Corrosion

Ratepayer Advocates in the Gas, Electric, Telecommunications and Water Industries
The following is ORA’s response to PG&E’s data request. If you have any questions, please contact the responder at the phone number and/or email address shown above.

**QUESTION NO. 1**

Does ORA recommend a different scope or pace of work for any of the corrosion control programs PG&E forecast? If the answer is yes, for each such program:

a. What is ORA’s recommended scope of work and pace?
   b. Why does ORA believe its recommended scope of work and pace is more reasonable than the scope and pace PG&E forecast?

**ORA RESPONSE:**

a. ORA recommends a different scope of work for some corrosion programs based on the reduction of PG&E’s 2019 forecasts. The reductions in Corrosion expenses are as follows:

   - $1.49 million in expense for 2019 Routine Corrosion Maintenance which is 68.7 percent of 2019 PG&E’s proposed forecast of $2.17 million.
   - $1.55 million in 2019 expense for Alternating Current (AC) which is 58.9 percent of 2019 PG&E’s proposed forecast of $2.63 million.
   - $1.41 million in 2019 expense for Close Interval Survey (CIS) which is 25.8 percent of 2019 PG&E’s proposed forecast of $5.48 million.
   - $1.43 million in expense for 2019 Internal Corrosion, which is 59.8 percent reduction from 2019 PG&E’s forecast of $3.56 million.

The reductions in Capital Expenditures are as follows:

   - $6.12 million in capital expenditures for 2019 Direct Current (DC) which is 50 percent of 2019 PG&E’s proposed forecast of $12.12 million.
   - $8.55 million in 2019 capital expenditures for Alternating Current (AC) which is 65.8 percent of 2019 PG&E’s proposed forecast of $13.01 million.
   - $15.71 million in capital expenditures for 2019 Casings; this translates to a 35.7 percent reduction from 2019 PG&E’s forecast of $24.41 million.

b. PG&E’s scope of work and pace is more aggressive based on the 2019 PG&E’s increased forecast. The ORA’s recommended 2019 forecast is based on the historical trend.
QUESTION NO. 2

Please provide documents, including active Excel files if they exist, showing the calculations behind ORA’s recommendations for the programs for which ORA has recommended reductions relative to PG&E’s forecast.

ORA RESPONSE:

Excel files do not exist because ORA recommendations were based on calculations such as averaging the historical costs. Most of these calculations are explained in ORA testimony.
QUESTION NO. 3

Where ORA’s recommendation is based on an average of historical spending, did ORA apply escalation to arrive at its 2019 recommendation? If yes, please provide the supporting calculations. If not, please explain why ORA does not believe escalation should be applied to arrive at a reasonable 2019 forecast.

ORA RESPONSE:

ORA did not apply escalation when deriving the average of historical spending. This has been a normal practice for the past several years and PG&E never objected to that.

END OF RESPONSE
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

REBUTTAL TESTIMONY OF KEVIN ARMATO

OPERATIONS AND MAINTENANCE
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A. Introduction

Q 1 Please state your name and business address.
A 1 My name is Kevin Armato, and my business address is Pacific Gas and Electric Company, 1421 Vineyards Parkway, Brentwood, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).
A 2 I am currently the Corrosion Manager within the Transmission Integrity Management Program (TIMP) Department, where I am responsible for the Corrosion Engineering and support organizations, and I have replaced William Mojica as the Witness for Chapter 9. Since joining PG&E in 2002, I have held various technical and leadership roles. I started as an entry-level Engineer in Distribution Planning, and then joined Corrosion Engineering in Gas Transmission. I became a Senior Engineer in the Corrosion discipline before becoming a Supervising Engineer of Corrosion Engineering, supervising the External Corrosion Direct Assessment group. I then joined the Distribution Integrity Management Program (DIMP) Department as the new DIMP rule was being implemented. After working as a Manager in the DIMP Department, I joined the Gas Transmission and Distribution Operations organization as a Leak Survey Superintendent, where my responsibilities later expanded to include Construction and Corrosion. In that role I oversaw various aspects of work discussed in Chapter 9 for a specific geographic area within PG&E’s service territory.

Q 3 Please summarize your educational background and professional certifications.
A 3 I have a Bachelor of Science degree in Mechanical Engineering from California Polytechnic State University, San Luis Obispo, and hold the internationally recognized National Association of Corrosion Engineers (NACE) Cathodic Protection Specialist (Level 4) certification.

Q 4 Does this conclude your statement of qualifications?
A 4 Yes, it does.
Q 5 Please state the purpose of this rebuttal testimony.
A 5 This testimony responds to the direct testimony of the Office of Ratepayer Advocates (ORA)\(^1\) and The Utility Reform Network (TURN).\(^2\)

PG&E summarizes parties’ positions in Section B below. No other party provided testimony concerning this chapter.

Q 6 Do parties generally criticize PG&E’s showing regarding Operations and Maintenance (O&M)?
A 6 No.

Q 7 Do ORA and TURN make recommendations concerning specific projects and programs?
A 7 Yes, ORA and TURN make recommendations concerning a number of PG&E’s forecast projects and programs.

Q 8 Does PG&E dispute these recommendations?
A 8 Yes, PG&E disputes ORA’s and TURN’s recommendations. PG&E addresses them in Section C of this chapter.

B. Summary of Parties’ Positions

Q 9 Please provide parties’ recommendations.
A 9 PG&E’s application forecast and the parties’ recommendations are set forth in Table 9-1 (Summary of 2019 Expense Forecast) below. Table 9-1 includes PG&E’s expense forecasts, as well as parties’ recommendations for the 2019 test year.

\(^1\) ORA-09.
\(^2\) TURN, Chapter 9.
<table>
<thead>
<tr>
<th>Program</th>
<th>Filed Forecast</th>
<th>Current Forecast</th>
<th>Proposed Reductions</th>
</tr>
</thead>
<tbody>
<tr>
<td>LOCATE AND MARK</td>
<td>$13,234</td>
<td>$13,234</td>
<td></td>
</tr>
<tr>
<td>LEAK MANAGEMENT</td>
<td>$6,072</td>
<td>$6,072</td>
<td></td>
</tr>
<tr>
<td>PIPELINE PATROL</td>
<td>$6,535</td>
<td>$6,535</td>
<td></td>
</tr>
<tr>
<td>PIPELINE MAINTENANCE</td>
<td>$9,664</td>
<td>$9,664</td>
<td></td>
</tr>
<tr>
<td>STATION MAINTENANCE</td>
<td>$19,106</td>
<td>$19,106</td>
<td></td>
</tr>
<tr>
<td>ROW MAINTENANCE</td>
<td>$11,335</td>
<td>$11,335</td>
<td></td>
</tr>
<tr>
<td>VARIOUS PROGRAMS - STANDARD PACIFIC GAS LINE, INC. (STANPAC)</td>
<td>$236</td>
<td>$236</td>
<td></td>
</tr>
<tr>
<td>TOTAL EXPENSE</td>
<td>$65,182</td>
<td>$65,182</td>
<td>($222)</td>
</tr>
</tbody>
</table>

(a) From PG&E's errata as of August 17.
(b) Table 3-1 of direct testimony and the RO model contain the current forecast of $139 (thousands).
(c) Reductions are from ORA’s testimony. In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
Q 10 Are there programs that parties do not oppose?
A 10 Yes. As Table 9-1 shows, ORA “does not oppose” PG&E’s forecast for the following programs:

- Leak Management;
- Pipeline Patrol;
- Pipeline Maintenance; and

As Table 9-1 shows, TURN provides no testimony on the following programs:

- StanPac Expense;
- Locate and Mark;
- Leak Management;
- Pipeline Patrol; and
- Pipeline Maintenance.

Q 11 Does PG&E agree with parties’ proposed recommendations for the Locate and Mark, Station Maintenance, and ROW programs?
A 11 No. For the reasons explained in Section C, PG&E does not believe any reduction is justified for the Locate and Mark, Station Maintenance and ROW Maintenance programs.

C. Response to Parties’ Recommendations Concerning Specific Programs or Projects

1. Locate and Mark

Q 12 Briefly, what is the purpose and scope of the Locate and Mark Program?
A 12 PG&E’s Locate and Mark Program encompasses the following two sub-programs:

3 ORA-09, p. 1, lines 17-18 and ORA-09, p. 2, Table 9-1, ORA also recommends PG&E’s proposed amount for StanPac.
4 Reductions are from ORA’s testimony. In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
5 Ibid.
6 Ibid.
7 ORA-09, p. 1, lines 19-20, p. 2, Table 9-1 p. 3, lines 7-18 and p. 6, line 8 to p. 8, line 1 and TURN, Chapter 9, p. 1, line 21 to p. 2, line 3, p. 2, line 9 to p. 4, line 2, and p. 6, lines 4-14.
1) Locate and Mark; and
2) Standby.

The Locate and Mark Program prevents excavations from causing damage to PG&E’s transmission pipeline assets. Locate and mark activities are required to comply with federal regulations under Title 49 of the Code of Federal Regulations – Transportation (49 CFR), Part 192.614. In addition, California Government Code, Section 4216, Article 2, “Regional Notification Center System,” requires PG&E to belong to and share the costs of operating the regional “one-call” notification system. The one-call system is commonly referred to as Underground Service Alert (USA). Locate and Mark addresses the time-independent threat within the Integrity Asset Risk Classification. The Locate and Mark program is more fully discussed in PG&E’s prepared testimony.8

Q 13 What are parties’ recommendations for the Locate and Mark Program?
A 13 As shown in Table 9-1 above, ORA proposes a 2019 expense funding level of $10.6 million, which is a $2.7 million reduction to PG&E’s forecast.9

Q 14 What is the basis for ORA’s proposed reduction?
A 14 ORA uses 2017 as opposed to 2016 recorded costs as the basis for the 2019 forecast, on the grounds that 2017 is a more recent recorded year and therefore more accurate. ORA states that, “PG&E’s projections regarding the future volumes appear reasonable.”10

Additionally, “ORA assumed the same year over year increases in the volume of Locate and Mark tickets and Standby Requests as PG&E.”11

Q 15 Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts?
A 15 No. PG&E disagrees with the ORA’s proposed reductions.

PG&E appropriately included the 2016 base year in its development of the 2019 forecast. PG&E’s financial accounting system had greater visibility into unit/unit cost information within its financial accounting system for the

8 PG&E Prepared Testimony, Chapter 9, p. 9-12, line 2 to p. 9-13, line 9.
9 ORA-09, p. 2, Table 9-1.
10 ORA-09, p. 3, lines 8-9.
11 ORA-09, p. 3, lines 13-14.
Locate and Mark Program beginning in 2016. Therefore, 2016 was used as a basis for the forecast. Please also see PG&E’s rebuttal testimony in Chapter 23, sponsored by Mr. Smith.

Q 16 What is your conclusion based on ORA’s proposed recommendations for the Locate and Mark Program?

A 16 For the reasons discussed above, PG&E finds ORA’s forecast recommendation unreasonable and recommends that its $13.2 million expense forecast for the Locate and Mark Program be adopted.

2. Station Maintenance

Q 17 Briefly, what is the scope of the Station Maintenance Program?

A 17 PG&E’s Station Maintenance Program encompasses the following seven sub-programs:

1) Preventative and Corrective Maintenance for Station Piping;

2) Preventative and Corrective Maintenance for Gas Processing Equipment;

3) Preventative and Corrective Maintenance Inside the Compressor Building;

4) Preventative and Corrective Maintenance for Storage/Compressor Station Support;

5) Preventative and Corrective Maintenance for Power Units;

6) Preventative and Corrective Maintenance for Storage Wells; and

7) Station Operations.

Station Maintenance is performed to meet requirements outlined in 49 CFR, Part 192.605. PG&E’s Station Maintenance Program addresses the stable/resident, time-independent, time-dependent, capacity and/or reliability, and emergency response threats within the Integrity Asset Risk Classification. The Station Maintenance Program is more fully discussed in PG&E’s prepared testimony.12

Q 18 What are parties’ recommendations for the Station Maintenance Program?

A 18 As shown in Table 9-1 above, ORA proposes a reduction of $1.1 million.13 TURN proposes a reduction of $2.9 million, as well as an alternative

12 PG&E Prepared Testimony, Chapter 9, p. 9-25, line 18 to p. 9-27, line 19.
13 ORA-09, p. 2, Table 9-1.
proposed reduction of $3.3 million.\textsuperscript{14} PG&E discusses each of these recommendations in turn.

Q 19 What is ORA’s recommendation for the Station Maintenance Program?
A 19 ORA proposes a 2019 expense funding level of $18 million, which is a $1.1 million reduction to PG&E’s forecast.\textsuperscript{15}

Q 20 What is the basis for ORA’s proposed reduction?
A 20 ORA recommends a 3-year average (2015-2017), for all but two of the sub-programs,\textsuperscript{16} based on ORA’s claim that a 3-year average is more representative of program costs than PG&E’s use of the 2016 base year, due to year-to-year variance.

Q 21 Do you agree with ORA’s recommendations for reducing PG&E’s cost forecasts?
A 21 No. PG&E disagrees with ORA’s recommendation to use a 3-year average as the basis for the 2019 forecast for the following reasons:

- PG&E appropriately based its 2019 forecast on data available for PG&E’s Gas Transmission and Storage (GT&S) application, the base year 2016.
- As stated in the PG&E’s prepared testimony, California Division of Oil, Gas and Geothermal Resources (DOGGR) issued emergency regulations (1724.9(c) and 1724.9(e)) which affected the Station Maintenance Program.\textsuperscript{17} Because 2016 is the year this became effective, this is the first year which included maintenance work at PG&E storage fields to comply with these emergency regulations put in place by DOGGR. Therefore, using a 3-year average would understate the impacts from DOGGR.
- An average baseline value including 2015 per sub-program would not be the best representation of the alignment of Maintenance Activity Type

\textsuperscript{14} TURN, Chapter 9, p. 3, line 15 to p. 4, line 2 and Table 9-2.
\textsuperscript{15} ORA-09, pp. 7-8, Table 9.4.
\textsuperscript{16} As stated in ORA-09, p. 6, lines 12-16:

“…with the exception of the Preventative and Corrective Maintenance Storage Wells Sub-Program, for which 2016 costs may be more representative due to the introduction of new DOGGR requirements requiring more frequent pressure monitoring, wellhead inspections, and leak surveys in 2016.”

\textsuperscript{17} PG&E Prepared Testimony, Chapter 9, p. 9-8, lines 1-10.
(MAT) Codes and their respective costs as they exist today. In 2015
PG&E introduced two new MAT Codes within the Station Maintenance
Program (i.e., MAT Codes JPO/JPP). As such, 2016 represents the
first year where the aforementioned new MAT Codes were in use for an
entire year. Additionally, 2015 was a transition year of adding greater
granular detail through the use of specific orders.

- As stated in PG&E’s prepared testimony:

  No forecast costs to comply with the GHG (Greenhouse Gas) Rule
  are included in Chapter 9, because PG&E was developing its
  implementation plan for compliance with the California Air
  Resources Board’s (CARB) O&G (oil and gas) GHG rule at the time
  of filing.18

  Consistent with that testimony, as of July 31, 2018, PG&E has observed
  an increase of approximately $1.6 million in the Preventative Maintenance
  Storage/Compressor Station Support (MAT Code JPE) sub-program in 2018
due to CARB. Utilizing 2017 recorded data—which is lower than 2016
  recorded data—as a basis for the forecast will, therefore, underfund
  increases that have been observed through CARB.

Q 22 What is TURN’s recommendation for the Station Maintenance Program?
A 22 TURN proposes a 2019 funding level of $16.2 million, which is a $2.9 million
  reduction to PG&E’s forecast.19

Q 23 What is the basis for TURN’s proposed reduction?
A 23 TURN recommends using a 5-year average (2013-2017), as the basis for
  the 2019 forecast, based on TURN’s claim that a 5-year average:

  …takes into account the up and down nature of the costs and evens out
  unusually high or low years.20

  Additionally, TURN states that:
  
  …since the costs have fluctuated between 2012 and 2017, it cannot be
  assumed that future costs will increase.21

Q 24 Do you agree with TURN’s recommendations for reducing PG&E’s cost
  forecasts?

18 PG&E Prepared Testimony, Chapter 9, p. 9-9, lines 3-5.
19 TURN, Chapter 9, p. 3, line 15-16.
20 TURN, Chapter 9, p. 3, lines 6-7.
21 TURN, Chapter 9, p. 3, lines 1-2.
A 24 No. PG&E disagrees with TURN's recommendations for reducing PG&E's cost forecasts.

Q 25 Do you agree with TURN's statement that, "since the costs have fluctuated between 2012 and 2017, it cannot be assumed that future costs will increase"?22

A 25 No. PG&E does not agree with TURN's statement. TURN's statement that, "since the costs have fluctuated between 2012 and 2017, it cannot be assumed that future costs will increase,"23 is not necessarily accurate as a program can have fluctuation in historic costs while also experiencing an increase in future cost.

Q 26 Do you agree with TURN's recommendation to use a 5-year average (between 2013-2017) as the basis for the 2019 forecast.

A 26 No. PG&E disagrees with TURN's recommendation to use a 5-year average (between 2013-2017) as the basis for the 2019 forecast for the following reasons.

• As stated in the PG&E’s prepared testimony, DOGGR issued emergency regulations (1724.9(c) and 1724.9(e)), which affected the Station Maintenance Program.24 As 2016 is the year this became effective, this is the first year which included maintenance work at PG&E storage fields to comply with these emergency regulations put in place by DOGGR.25 Therefore, using a 5-year average would understate the impacts from DOGGR.

• Additional reasons for not using a 5-year historical average are discussed in more detail in the subsequent discussions within this section.

Q 27 Do you agree with TURN's recommendation to use 2013 recorded costs as part of the basis for the forecast?

A 27 No. PG&E disagrees with TURN’s recommendation to use 2013 recorded costs as part of the basis for the forecast. As PG&E stated in a discovery

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22 TURN, Chapter 9, p. 3, lines 1-2.
23 TURN, Chapter 9, p. 3, lines 1-2.
24 PG&E Prepared Testimony, Chapter 9, p. 9-8, lines 1-10.
25 TURN-020, Question 17.
response: the historical costs in Station Operations (MAT Code JPN) for 2013 included Gas Transmission operating and maintenance expenses charged to standing orders that were mapped to Station Operations (MAT Code JPN). In 2013, the costs for the various MAT Codes in Major Work Categories JO and JP for Pipeline and Station Maintenance work started being charged to different MAT Codes. Examples include costs from Station Operations moving to Pipeline Patrol and Corrosion MAT Codes.\textsuperscript{26} As such, including 2013 within an average to calculate a baseline value for forecasting would result in a less accurate forecast given the current MAT structure for this program.

Q 28 Do you agree with TURN’s recommendation to use 2017 recorded costs as part of the basis for the forecast?

A 28 No. PG&E disagrees with TURN’s recommendation to use 2017 recorded costs as part of the basis for the forecast for the following reasons:

\begin{itemize}
  \item PG&E appropriately based its 2019 forecast on data available from the base year for PG&E’s GT&S application, which is 2016.
  \item As stated in PG&E’s prepared testimony:
    \begin{quote}
    No forecast costs to comply with the GHG Rule are included in Chapter 9, because PG&E was developing its implementation plan for compliance with the CARB’s O&G GHG rule at the time of filing.\textsuperscript{27}
    \end{quote}
\end{itemize}

As stated above, PG&E has already observed an increase of approximately $1.6 million in the Preventative Maintenance Storage/Compressor Station Support (MAT Code JPE) sub-program as of July 31, 2018, due to CARB. Utilizing 2017 recorded—which is lower than 2016 recorded—as a basis for the forecast will, therefore, underfund increases that have been observed through CARB.

Q 29 What is TURN’s alternative recommendation for the Station Maintenance Program?

A 29 TURN alternatively proposes a $3.3 million reduction to PG&E’s 2019 forecast,\textsuperscript{28} which reduces the 2019 funding level to $15.8 million.

\textsuperscript{26} TURN-020, Question 17(a).
\textsuperscript{27} PG&E Prepared Testimony, Chapter 9, p. 9-9, lines 3-5.
\textsuperscript{28} TURN, Chapter 9, p. 3, line 19 to p. 4, line 2.
Q 30 What is the basis for TURN’s alternative reduction?

A 30 TURN alternatively recommends 2017 as the basis for the 2019 forecast, as it is more recent.

Q 31 Do you agree with TURN’s alternative recommendations for reducing PG&E’s cost forecasts?

A 31 No. PG&E disagrees with TURN’s alternative recommendation for the reasons stated above.

Q 32 What is your conclusion based on the parties’ proposed recommendations for Station Maintenance?

A 32 For the reasons discussed above, PG&E finds the parties’ forecast recommendations unreasonable and recommends that its $19.1 million expense forecast for Station Maintenance be adopted.

3. **ROW Maintenance – Vegetation Management**

Q 33 Briefly, what is the scope of the ROW Maintenance – Vegetation Management (VM) sub-program?

A 33 The VM sub-program supports the safety and integrity of gas pipelines by keeping exposed and buried pipelines clear of vegetation, such as: trees, brush, and tall grass. VM activities include: removal of trees, brush, and grasses by contractors utilizing specialized equipment; and consulting with scientists, where necessary, to protect native flora and fauna. The VM sub-program is more fully discussed in PG&E’s prepared testimony.29

Q 34 What are parties’ recommendations for the ROW Maintenance – VM sub-program?

A 34 As shown in Table 9-1 above, TURN proposes a reduction of $1.2 million.

Q 35 What is TURN’s recommendation for the ROW Maintenance – VM sub-program?

A 35 TURN proposes a $1.2 million reduction to PG&E’s 2019 forecast for this subprogram30, which reduces the funding level to $7.9 million as shown in Table 9-1 above.

Q 36 What is the basis for TURN’s proposed reduction?

29 PG&E Prepared Testimony, Chapter 9, p. 9-28, lines 1-20 and p. 9-30, lines 5-11.

30 TURN, Chapter 9, p. 5, line 1 to p. 6 line 14.
A 36 TURN recommends the removal of contingency within the VM sub-program, as TURN believes it is inappropriate to ask ratepayers for these unforeseen costs that are not known and measurable.

Q 37 Do you agree with TURN’s recommendations for reducing PG&E’s cost forecasts?

A 37 No. PG&E disagrees with TURN’s recommendation to remove contingency for the following reasons:

• PG&E believes contingency may be needed in the future for unforeseen events, including costs associated with addressing communities where tree removals are opposed and to address environmental policy changes; and

• Population growth and residences that are built near pipelines may also contribute to increased frequency of encroachments and monitoring costs.

There is also a difficult to quantify variable related to climate change that may impact the health of vegetation of trees in the easement. Although climate change is difficult to quantify, climate change is real and presents evolving challenges. As such, PG&E does not agree with TURN’s criticism of contingency within this subprogram including that it is “unsupported ‘just in case’ funds”.

Q 38 What is your conclusion based on the TURN’s proposed recommendations for the ROW Maintenance – VM sub-program?

A 38 For the reasons discussed above, PG&E finds TURN’s forecast recommendation unreasonable and recommends that its $9.2 million expense forecast for the ROW Maintenance – VM sub-program be adopted.

Q 39 Does this conclude your rebuttal testimony?

A 39 Yes, it does.

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31 TURN, Chapter 9, p. 6, lines 9-10.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

REBUTTAL TESTIMONY OF CHRISTINE COWSERT

GAS SYSTEM OPERATIONS
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
REBUTTAL TESTIMONY OF CHRISTINE COWSERT
GAS SYSTEM OPERATIONS

A. Introduction

Q 1  Please state your name and the purpose of this rebuttal testimony.
A 1  My name is Christine Cowsert. This testimony responds to the direct
testimony of the Office of Ratepayer Advocates (ORA), The Utility Reform
Network (TURN), Indicated Shippers and Northern California Generation
Coalition (IS/NCGC), Calpine Corporation (Calpine) and Commercial
Energy (CE). Pacific Gas and Electric Company (PG&E or the Company)
summarizes parties’ positions in Section B.

Q 2  Do parties generally criticize PG&E’s showing regarding Gas
System Operations?
A 2  Parties do not offer any general criticism regarding Gas System Operations.

Q 3  Do parties make recommendations concerning specific projects
and programs?
A 3  Yes, parties make recommendations concerning a number of PG&E’s Gas
System Operations forecast projects and programs.

Q 4  Do parties have any issues with non-program related items?
A 4  Yes, Calpine and IS/NCGC claim there are issues with PG&E’s Local
Transmission (LT) Cost Allocation Study (LT Study). CE recommends that
PG&E begin a Gas Demand Response Program. ORA recommends
PG&E provide additional information regarding the Line 407
Reasonableness Report.

Q 5  Does PG&E dispute any of parties’ recommendations?

1 ORA-10.
2 TURN, Chapter 10.
3 IS/NCGC-1.
4 Calpine, p. 14, line 1 to p. 17, line 16 and IS/NCGC-1, Chapter 10, p. 10-1, line 2 to
p. 10-8, line 10.
5 CE, p. 24, line 18 to p. 35, line 2.
6 ORA-10, p. 27, lines 2-8.
A 5 Yes. PG&E addresses parties’ forecast recommendations in Section C.

PG&E addresses parties’ LT Study recommendations in Section D, responds to CE’s recommendation to begin a Gas Demand Response Program in Section E, and responds to ORA’s comments regarding the Line 407 Reasonableness Report in Section F.

B. Summary of Parties’ Positions

Q 6 Please provide parties’ recommendations regarding PG&E’s forecast.

A 6 Tables 10-1 (2019 expense) and 10-2 (2019-2021 capital expenditures) below set forth PG&E’s expense and capital expenditure forecasts, as well as parties’ recommendations for the years 2019 through 2021.

TABLE 10-1
SUMMARY OF 2019 EXPENSE FORECAST – PG&E (THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Program</th>
<th>MAT</th>
<th>Filed Forecast</th>
<th>Errata(b)</th>
<th>Current Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Gill Ranch Storage Operations and Maintenance</td>
<td>AH4</td>
<td>$2,846</td>
<td>$(140)</td>
<td>$2,706</td>
</tr>
<tr>
<td>2</td>
<td>Gas System Operations</td>
<td>CMA</td>
<td>15,877</td>
<td>–</td>
<td>15,877</td>
</tr>
<tr>
<td>3</td>
<td>Unclaimed Meters</td>
<td>CMA</td>
<td>796</td>
<td>31</td>
<td>827</td>
</tr>
<tr>
<td>4</td>
<td>Compressor Fuel and Power</td>
<td>CMB</td>
<td>21,199</td>
<td>(43)</td>
<td>21,156</td>
</tr>
<tr>
<td>5</td>
<td>Marketing/Business Development</td>
<td>CXA</td>
<td>5,488</td>
<td>–</td>
<td>5,488</td>
</tr>
<tr>
<td>6</td>
<td>Capacity Uprates</td>
<td>JTM</td>
<td>6,196</td>
<td>–</td>
<td>6,196</td>
</tr>
<tr>
<td>7</td>
<td>Total Expense</td>
<td></td>
<td>$52,402</td>
<td>$(152)</td>
<td>$52,250</td>
</tr>
</tbody>
</table>

(a) No party proposed reductions to PG&E’s Chapter 10 expense forecasts.

(b) PG&E’s errata as of August 17.
TABLE 10-2A
SUMMARY OF 2019-2021 CAPITAL EXPENDITURES FORECAST — PG&E AND ORA
(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Program</th>
<th>MWC</th>
<th>PG&amp;E (a)</th>
<th>ORA</th>
<th>PG&amp;E (a)</th>
<th>ORA</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Gill Ranch Storage Capital</td>
<td>76</td>
<td>$2,755</td>
<td>$261</td>
<td>$1,580</td>
<td>$(2,494)</td>
</tr>
<tr>
<td>2</td>
<td>New Business</td>
<td>26</td>
<td>4,749</td>
<td>4,828</td>
<td>4,467</td>
<td>(1,744)</td>
</tr>
<tr>
<td>3</td>
<td>Meter Sets — Power Plants</td>
<td>26</td>
<td>1,052</td>
<td>1,085</td>
<td>1,117</td>
<td>(1,052)</td>
</tr>
<tr>
<td>4</td>
<td>Capacity for Load Growth</td>
<td>73</td>
<td>54,696</td>
<td>55,486</td>
<td>59,016</td>
<td>(37,516)</td>
</tr>
<tr>
<td>5</td>
<td>Capacity Betterment</td>
<td>73</td>
<td>1,052</td>
<td>2,170</td>
<td>2,234</td>
<td>(167)</td>
</tr>
<tr>
<td>6</td>
<td>Capacity for Normal Operating</td>
<td>73</td>
<td>12,701</td>
<td>9,232</td>
<td>8,046</td>
<td>(12,701)</td>
</tr>
<tr>
<td></td>
<td>Pressure (NOP) Reductions</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Line 407</td>
<td>73</td>
<td>522</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>8</td>
<td>GT Supervisory Control and Data</td>
<td>76</td>
<td>2,740</td>
<td>4,285</td>
<td>3,127</td>
<td>(2,390)</td>
</tr>
<tr>
<td></td>
<td>Acquisition (SCADA) Visibility</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Total Capital Expenditures</td>
<td></td>
<td>$80,268</td>
<td>$77,347</td>
<td>$79,587</td>
<td>$(58,065)</td>
</tr>
</tbody>
</table>

(a) There are no errata for Chapter 10 capital expenditures.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Program</th>
<th>Sub-Program</th>
<th>MWC</th>
<th>PG&amp;E&lt;sup&gt;(a)&lt;/sup&gt;</th>
<th>TURN</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Capacity</td>
<td>Capacity for Load Growth</td>
<td>73</td>
<td>$54,696</td>
<td>$55,486</td>
<td>$59,016</td>
<td>$(46,684)</td>
<td>$(47,358)</td>
</tr>
<tr>
<td>2</td>
<td>Capacity</td>
<td>Capacity for NOP Reductions</td>
<td>73</td>
<td>12,701</td>
<td>9,232</td>
<td>8,046</td>
<td>(10,840)</td>
<td>(7,880)</td>
</tr>
<tr>
<td>3</td>
<td>Total Capital</td>
<td></td>
<td></td>
<td>$67,397</td>
<td>$64,718</td>
<td>$67,062</td>
<td>$(57,524)</td>
<td>$(55,238)</td>
</tr>
</tbody>
</table>

<sup>(a)</sup> There are no errata for Chapter 10 capital expenditures.
Q 7 Please describe the two capital expenditure tables.

A 7 Table 10-2A reflects all the capital expenditure reductions recommended by ORA. Table 10-2B reflects the capital expenditure recommendations by TURN witness Yap.

Q 8 Are there programs that parties do not dispute?

A 8 Yes. As Table 10-1 shows, no party disputes PG&E’s expense forecast for the programs listed below. ORA explicitly recommends that the California Public Utilities Commission (CPUC or Commission) adopt and approve PG&E’s expense forecast.\(^7\)

- Maintenance Activity Type (MAT) Code CMA – Gas Transmission and Storage (GT&S) System Operations;\(^8\)
- MAT Code CMB – Electric Power for Gas Compressors;\(^9\)
- MAT Code CXA – GT&S Marketing, Sales, and Strategy;
- MAT Code JTM – GT Capacity Uprates; and
- MAT Code AH4 – Gill Ranch Storage Expense.\(^10\)

Q 9 Are there forecasts that parties dispute for this rate case period?

A 9 Yes. ORA\(^11\) disputes PG&E’s capital expenditure forecast for the following programs for this rate case period:

- Gill Ranch Storage – Capital;
- New Business;
- Meter Sets-Power Plants;
- GT Supervisory Control and Data Acquisition (SCADA) Visibility;
- Capacity for Load Growth;
- Capacity Betterment; and
- Capacity for Normal Operating Pressure (NOP) Reductions.

TURN recommends reductions to PG&E’s forecast for Capacity for Load Growth and Capacity for NOP Reductions.\(^12\)

---

\(^7\) ORA-10, p. 3, lines 4-5.
\(^8\) In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
\(^9\) In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
\(^10\) In ORA’s testimony, ORA’s recommended amounts do not reflect PG&E’s errata.
\(^11\) ORA-10, p. 3, line 10 to p. 4, line 18.
\(^12\) TURN, Chapter 10, p. 3, lines 5-13 and lines 18-21.
Q 10 Do parties recommend non-financial proposals that PG&E disagrees with?
A 10 Yes. PG&E disagrees with the following non-financial proposals:

- ORA recommends the establishment of memorandum accounts for the Meter Sets-Power Plants and Capacity for NOP Reductions. ORA also recommends PG&E provide additional information regarding the Line 407 Reasonableness Report.
- CE recommends that PG&E offer a gas demand response program.
- IS/NCGC and Calpine both claim that PG&E’s LT Study is flawed.

C. Response to Parties’ Recommendations Concerning Specific Programs or Projects

1. Customer-Connected Equipment

Q 11 Briefly, what is the scope of the Customer-Connected Equipment Program?
A 11 The Customer-Connected Equipment Program consists of activities and equipment required to connect new customer facilities to the transmission system. Such customers have large loads that are more practical to connect to the transmission system, rather than to the distribution system. These activities are covered by the following MAT Codes:

- 26A – New Business; and
- 26B – Large Power Plant Meter Sets.

The foregoing is more fully discussed in PG&E’s prepared testimony.\(^\text{13}\)

Q 12 What are parties’ recommendations for the Customer-Connected Equipment Program?
A 12 As shown in Table 10-2 above, ORA proposes a reduction of $7.391 million across the 3-year period of 2019-2021 for the Customer-Connected Equipment Program, which includes MAT Code 26A – New Business, and MAT Code 26B – Large Power Plant Meter Sets.\(^\text{14}\) This is composed of:

(1) a $4.1 million reduction under MAT Code 26A; and (2) a $3.3 million reduction, which provides zero funding, under MAT Code 26B, with an associated memorandum account proposal.

\(^\text{13}\) PG&E Prepared Testimony, Chapter 10, p. 10-20, line 1 to p. 10-22, line 13, including Table 10-6.

\(^\text{14}\) PG&E calculation derived from amounts shown in ORA-10 at p. 5, Table 10-2, lines 1-2; p. 5, Table 10-3, lines 1-2; and p. 6, Table 10-4, lines 1-22.
PG&E addresses ORA’s forecast recommendations first, then addresses ORA’s memorandum account proposal.

Q 13 Do you agree with ORA’s recommendation that PG&E’s proposed funding levels for the New Business Program be reduced by $4.14 million across the 3-year period of 2019-2021?

A 13 No. The need to perform customer connections is not within PG&E’s control; it is driven by customer requests. Because of this, expenditures for New Business will fluctuate. This is demonstrated by the history of actual expenditures from 2012-2017. ORA acknowledges that the average annual expenditure for New Business (MAT Code 26A) for the period 2012-2016 was $5.1 million.\footnote{ORA-10, p. 16, lines 1-3.} Shifting this 5-year average one year later, to 2013-2017, results in an average recorded annual expenditure of $2.4 million. However, actual costs for 2017 were atypically low. The 6-year average from 2012-2017 is $4.4 million, close to PG&E’s 2019 forecast of $4.8 million. Given that during the 2012-2017 period there was one year with an actual expenditure of $14.2 million and another with an actual expenditure of $5.5 million, PG&E’s request of $14.0 million over the 3-year period of 2019-2021, or an average of approximately $4.7 million per year, is reasonable.

Q 14 Do you agree with ORA’s recommendation that the funding for MAT Code 26B – Large Power Plant Meter Sets, be reduced from $1.1 million for each of the years 2019, 2020 and 2021, to zero for each year, with any expenditures related to MAT Code 26B during the 2019-2021 period recorded in a memorandum account, with potential recovery subject to reasonableness review in the next GT&S Rate Case?

A 14 No, we do not agree, for the same reasons we disagree with ORA’s recommended reductions for MAT Code 26A. PG&E’s forecast of $1.1 million per year of the rate case period for MAT Code 26B, Large Power Plant Meter Sets, reflects the 5-year average recorded cost for the program. Most of the recorded costs occurred in a single year. This illustrates the impact that customer activity can have on costs. While no specific project was envisioned at the time of our filing, the sporadic nature
of the cost history indicates that these needs can arise at any time, driven by
customer requests. Our 5-year-average-based request for $1.0 million per
year (nominal) is reasonable because it reflects the possibility that this work
will not materialize, while providing some funding in the event it does.

Q 15 What is ORA’s recommendation regarding a memorandum account?
A 15 ORA recommends a memorandum account as it, “sees little potential
expenditures” for this program. ORA further notes that:

Like all expenditures recorded into a memorandum account, any
potential actual recorded expenditure amounts … should be subject to
reasonableness review.16

Q 16 Does PG&E agree with ORA’s recommendation regarding a memorandum
account for this program?
A 16 No. First, PG&E's forecast is reasonable as described above. Second,
PG&E believes this value is too small to warrant the creation of a
memorandum account – and further, subject it to a time-consuming
reasonableness review – when the forecast for this program is $1.0 million
(nominal) per year. See Chapter 17B rebuttal testimony for a more detailed
discussion of the administrative costs associated with memorandum
accounts.

Q 17 What is your conclusion based on the parties’ proposed recommendations
for the Customer-Connected Equipment Program?
A 17 For the reasons discussed above, PG&E recommends that its capital
forecast of $14.0 million over the 3-year period of 2019-2021 be adopted,
and that its capital forecast for Large Power Plant Meter Sets (MAT
Code 26B) of $3.3 million over the three-year period of 2019-2021
be adopted.

2. Capacity

Q 18 Briefly, what is the scope of the Capacity Program?
A 18 The Capacity Program consists of installing pipe and regulation equipment
to provide sufficient capacity in the transmission system to enable
uninterrupted service on the applicable design day—Abnormal Peak Day
(APD) or Cold Winter Day (CWD). In certain circumstances, it is less

16 ORA-10, p. 16, lines 19-21.
expensive to uprate existing pipeline to a higher Maximum Allowable Operating Pressure to increase capacity. Unlike the direct installation of pipe, uprating, which involves pressure-testing, is an expense rather than capital activity.

These activities are covered by the following MAT Codes:

- 73A – Capacity for Load Growth (capital);
- 73B – Capacity Betterment (capital);
- 73C – Capacity to Support NOP Reductions (capital); and
- JTM – GT Capacity Uprates (expense).

The foregoing is more fully discussed in PG&E’s prepared testimony.¹⁷

Q 19 What are parties’ recommendations for the Capacity Program?

A 19 As shown in Table 10-2 above, ORA proposes a reduction in the capital portion of the Capacity Program of $145.1 million across the 3-year period of 2019-2021. This is a reduction of 71 percent compared to PG&E’s capital forecast of $204.6 million. ORA does not oppose PG&E’s forecast for the expense portion of the program, MAT Code JTM, Capacity Uprates.

a. ORA’s Recommendation to Reduce PG&E’s Capital Expenditure Forecast for the Capacity Program Is Not Based on the Reasonableness of PG&E’s Forecast at the Time It Was Made and Should Be Rejected

Q 20 What does ORA recommend for Capacity for Load Growth, MAT Code 73A?

A 20 ORA recommends a reduction in the proposed funding level for MAT Code 73A of $112.6 million across three years, 2019-2021.¹⁸

Q 21 Do you agree with ORA’s recommendation that the proposed funding levels for MAT Code 73A be reduced from $169.2 million over the period 2019-2021 by $112.6 million?

A 21 No. It is expected that amounts spent will vary from what is forecast for a given program, whether higher or lower, and the forecast should be

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¹⁷ PG&E Prepared Testimony, Chapter 10, p. 10-22, line 14 to p. 10-27, including Tables 10-7 and 10-8.

¹⁸ Calculated from amounts shown in ORA-10 at p. 5, Table 10-2, line 3; p. 5, Table 10-3, line 3; and p. 6, Table 10-4, line 3.
evaluated for reasonableness as of the time it was made. The projects we identified in our filing were expected to go forward as of that time. See also PG&E’s response to TURN’s recommendation regarding the capacity forecast below.

Q 22 What does ORA recommend for Capacity Betterment, MAT Code 73B?

A 22 ORA recommends a reduction in the proposed funding level for MAT Code 73B of $2.5 million across the three years, 2019-2021.

Q 23 Do you agree with ORA that the proposed funding levels for MAT Code 73B should be reduced from $5.5 million over the period 2019-2021 by $2.5 million?

A 23 No. ORA has programmatically applied a 3-year-average test to identify its recommended funding levels. PG&E does not agree that this reflects the proposed scope of work for 2019-2021.

Q 24 What explanation does ORA provide for its reduction in the proposed funding level for MAT Code 73B?

A 24 ORA provides no explanation for its recommended reductions to the Capacity Betterment Program except to say that PG&E:

[D]oes not show much capacity betterment capital expenditure amounts in MAT 73B for the period 2019-2021 compared to those shown in MAT 73A.

Q 25 What is the basis of PG&E’s forecast for the Capacity Betterment Program?

A 25 PG&E started with a 3-year average of 2014-2016 recorded expenditures. This average was approximately $2.0 million. For the test year, PG&E used a value of $1.0 million, rather than the 3-year average, because PG&E made a qualitative judgment that the amount of work necessary in 2019 would be less than the calculated average.

Q 26 What does ORA recommend for Capacity to Support NOP Reductions, MAT Code 73C?


19 See Chapter 2 rebuttal testimony of Mr. Singh and Chapter 23 rebuttal testimony of Mr. Smith.

20 Calculated from amounts shown in ORA-10 at p. 5, Table 10-2, line 4; p. 5, Table 10-3, line 4; and p. 6, Table 10-4, line 4.

21 ORA-10, p. 22, lines 1-3.

22 PG&E WP 10-22, lines 1-12.
ORA recommends a reduction in the proposed funding level for MAT Code 73C of $30.0 million across the three years, 2019-2021. ORA further proposes that any expenditures related to MAT Code 73C during the 2019-2021 period be recorded in a memorandum account subject to reasonableness review in the next GT&S Rate Case.

Q Do you accept ORA’s recommendation that the proposed funding levels for MAT Code 73C be reduced from $30.0 million over the period 2019-2021 by $30.0 million, so that the funding is zero, and that any expenditures related to MAT Code 73C during the 2019-2021 period be recorded in a memorandum account subject to reasonableness review in the next GT&S rate case?

A No. It is expected that amounts spent will vary to some degree from what is forecast for a given program, whether higher or lower, and the forecast should be evaluated for reasonableness as of the time it was made. The projects identified in our filing were expected to go forward as of that time.

b. TURN’s Recommendation to Reduce PG&E’s Capital Expenditure Forecast for the Capacity Program Should Be Rejected

Q What is TURN’s recommendations regarding PG&E’s forecast for the Capacity Program?

A TURN recommends reducing PG&E’s forecast for Capacity for Load Growth (MAT Code 73A) by $144.4 million across the three years, 2019-2021 and the forecast for Capacity for NOP Reductions (MAT Code 73C) by $25.6 million for the same time period. TURN also includes an alternative recommendation that the three large projects that make up about 70 percent of the total spending on Capacity for Load Growth be treated as rate adders during the current GT&S rate case cycle, and only be included in rates when they become operational. PG&E addresses TURN’s recommendations

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23 Calculated from amounts shown in ORA-10 at p. 5, Table 10-2, line 5; p. 5, Table 10-3, line 5; and Table p. 6, 10-4, line 5.
24 ORA-10, p. 25, lines 22-25.
25 See Chapter 23 rebuttal testimony of Mr. Smith.
26 Calculated from amounts shown in TURN-10 at p. 7, Table 10-2.
27 TURN, Chapter 10, p. 9, lines 22-24.
regarding forecast reductions first, then addresses their recommendation regarding treating three large projects as rate adders.

Q 29 What is the basis of TURN’s recommendation to reduce the forecast for Capacity for Load Growth and Capacity for NOP Reductions?

A 29 TURN notes that PG&E spending (recorded and forecasted) for both load growth and NOP reductions was considerably less than the adopted forecast in the final decision from the 2015 GT&S Rate Case.\textsuperscript{28}

Q 30 Does PG&E agree with TURN’s recommendation?

A 30 No. As discussed in PG&E rebuttal Chapter 23, the Commission has recognized that the work utilities perform will likely not perfectly match adopted forecasts, and that utilities can and should reprioritize work when appropriate.

Q 31 Why did PG&E not complete as much capacity work as originally forecast?

A 31 As discussed in prepared testimony,\textsuperscript{29} PG&E continually evaluates its transmission system for capacity related to both load growth and NOP reductions. Gas Operations strives to implement the least-cost alternatives to meet anticipated capacity shortfalls that are expected to occur. PG&E did not need to complete as much capacity work in these years as it thought it would in 2013, when it prepared its 2015 GT&S Rate Case forecast, in large part because it found other, lower-cost ways to satisfy capacity requirements. In some cases, its ongoing reanalysis of peak-day temperatures relative to gas usage using SmartMeter™ data and of its basic weather data revealed that: (1) some projected peak-day temperatures are now warmer than previously calculated, (2) hourly peak usage as a percentage of total-day usage is generally higher than previously estimated, but (3) heating degree-day (HDD) base temperatures are generally lower, the net effect being lower peak-hour projections for the design day.\textsuperscript{30}

Q 32 Did PG&E defer any necessary capacity work?

A 32 No.

Q 33 Is PG&E meeting its APD and CWD capacity design standards?

\textsuperscript{28} TURN, Chapter 10, p. 5, line 15 to p. 6, line 1.

\textsuperscript{29} PG&E Prepared Testimony, Chapter 10, p. 10-10, line 21 to p. 10-14, line 2; p. 10-22, line 14 to p. 10-27, including Tables 10-7 and 10-8.

\textsuperscript{30} PG&E Prepared Testimony, Chapter 10, p. 10-27, line 2 to p. 10-28, line 11.
A 33 Yes, PG&E continues to meet its APD and CWD capacity design standards.
Q 34 Are there safety implications associated with not performing the forecasted amount of capacity work for both load growth and NOP reductions?
A 34 No. As explained in PG&E’s prepared testimony, we described capacity work that was associated with load growth (MAT Code 73A) that also allowed NOP to be reduced on five Local Transmission (LT) systems. Additionally, revisions to the Company’s standard for establishing set-points on over-protection devices also resulted in reducing the amount of capacity work related to NOP reductions during the 2015-2018.
Q 35 Does PG&E believe its 2019-2021 forecast for capacity work should be reduced for work that was not needed or for money the Company saved customers by finding other ways to achieve the same operating results during 2015-2018?
A 35 No. PG&E’s forecast should not be reduced. Rather, the Company should be permitted to allocate financial resources to perform other work that benefits customers.
Q 36 What is TURN’s recommendation regarding rate adders?
A 36 TURN-Florio recommends that three large projects in PG&E’s forecast for Capacity for Load Growth be treated as rate adders during the current GT&S rate case cycle that PG&E will be authorized to implement by advice letter only as each project enters into service.
Q 37 What is the basis of TURN’s recommendation?
A 37 TURN identifies three projects that make up approximately 70 percent of PG&E’s forecast for the Capacity for Load Growth Program. These projects include:
- Fresno Main Belt Extension;
- Crosstie Lawrence to Tully; and
- Bakersfield Distribution Feeder Main Extension.
  TURN states that:

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31 PG&E Prepared Testimony, Chapter 10, p. 10-30, lines 12-5.
33 See Chapter 23 rebuttal for further discussion.
34 TURN, Chapter 10, p. 8, line 7 to p. 10, line 2.
In some past GT&S cases, the costs of relatively large projects of this nature have been treated as “rate adders” that are only charged to customers when the projects become operational. In essence, the revenue requirements associated with the projects are removed from the rate case forecast and converted into pre-determined rate components, or adders, that the utility will be authorized to implement by advice letter once a project enters into service. This approach reduces the risk for both the utility and ratepayers, because the projects are entered into revenue requirements and rates exactly when they should be, no sooner and no later.  

Q 38  Is the TURN-Florio recommendation an alternative approach to the TURN-Yap recommendations described above?  
A 38  That is how PG&E interprets the TURN-Florio recommendation.  

TURN-Florio notes that:  

[S]ome or all of this chapter of my testimony may be rendered moot if TURN witness Yap’s recommendations in her separate portion of this chapter are adopted and these costs are disallowed from rates.  

Q 39  What is PG&E’s response to the TURN-Florio recommendation?  
A 39  Please see Chapter 23 rebuttal testimony of Bruce Smith.  

3. Gas Transmission SCADA Visibility  

Q 40  Briefly, what is the scope of the Gas Transmission SCADA Visibility Program?  
A 40  The Gas Transmission SCADA Visibility Program consists of connecting electronic data collection devices to compressors, regulators, valves, critical pipeline locations, and other equipment that currently lack them. These devices transmit operational data to the Gas Transmission Control Center (GTCC). The Gas Transmission SCADA Visibility Program also encompasses specialty software that supports this data collection and its display and analysis.  

These activities are covered by the following MAT Code:  

• 76M – Gas Transmission SCADA Visibility.  

The foregoing is discussed in detail in PG&E’s prepared testimony.  

Q 41  What does ORA recommend for the Gas Transmission SCADA Visibility, MAT Code 76M?  

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35 TURN, Chapter 10, p. 9, lines 15-21.  

36 TURN, Chapter 10, p. 2, lines 17-19.  

37 PG&E Prepared Testimony, Chapter 10, p. 10-31, line 3 to p. 10-33, line 23, including Table 10-9.
ORA recommends a reduction in the proposed funding level for MAT Code 76M of $9.0 million across the three years, 2019-2021. This is a reduction of 89 percent from PG&E’s requested $10.2 million over 2019-2021.

Q 42 Do you agree with ORA’s recommendation that the proposed funding levels for MAT Code 76M be reduced from $10.2 million over the period 2019-2021 by $9.0 million?

A 42 No, PG&E disagrees with the proposed reduction for several reasons. First, additional SCADA installations are needed for safety and reliability. As PG&E explained in its prepared testimony:

The goal of the Transmission SCADA Visibility Program is to install SCADA at all transmission regulating stations, compressor stations, and at points of low elevation to enable a high degree of monitoring and control for the GTCC. An additional goal is to enhance the Online Pipeline Simulator (OPS) with additional telemetry.

The pursuit of both these goals will enhance the ability of system operators to monitor and control the system. The new SCADA installations will provide real-time data that will help operators reduce the risk of overpressure events and detect ruptures and large leaks, and to take earlier actions to prevent these events from escalating into safety emergencies.

Second, the low recorded expenditures of prior years 2015-2016 largely reflects program start-up issues related to standardizing technical designs within the context of finalizing our overall project objectives, and a highly heterogeneous installed base. Transmission Station layouts vary greatly throughout the system since each was designed for a specific purpose at its location. This complexity made it difficult to standardize the design of SCADA installations across the system. We resolved this issue largely by standardizing as much as possible at the component level. We also leveraged work that has been completed within the distribution SCADA program where possible. Having worked through these issues, we now expect execution to ramp up. We have a working definition of visibility goals for the gas transmission system. The objective is to have SCADA on both

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38 Calculated from amounts shown in ORA-10 at p. 5, Table 10-2, line 7; p. 5, Table 10-3, line 7; and p. 6, Table 10-4, line 7.

the upstream and downstream side of all transmission regulating stations by 2025. We also plan to add SCADA devices and computerized logic routines to support the OPS to improve its ability to detect losses of pressure earlier than it does now.\(^{40}\)

Third, ORA did nothing more that substitute a 3-year average of actual costs for the forecast. ORA did not provide any testimony or analysis suggesting that a 3-year average is sufficient to cover the level of expenditures expected during the rate case period.

Q 43 What is your conclusion based on the parties’ proposed recommendations for the Gas Transmission SCADA Visibility Program?

A 43 For the reasons discussed above, PG&E finds the parties’ forecast recommendations for the Gas Transmission SCADA Visibility Program (MAT Code 76M) unreasonable and recommends that its capital forecast of $10.2 million over the 3-year period of 2019-2021 be adopted.

4. Gill Ranch Storage

Q 44 Briefly, what is the scope of the Gill Ranch Storage program?

A 44 The Gill Ranch Storage Program covers capital and expense activities associated with PG&E’s 25 percent ownership share of Gill Ranch Storage, an Independent Storage Provider (ISP) near Fresno, California. In the instant case, PG&E is proposing to incorporate the 100 million cubic feet per day of withdrawal capacity that PG&E owns at Gill Ranch, and the related injection and inventory capacity, into its storage holdings that are subject to rates. Gill Ranch Storage capacity is an integral part of our Natural Gas Storage Strategy (NGSS) proposal, in which we propose to exit the commercial storage market and operate the GT&S system on a reliability-only basis. This proposal includes the decommissioning of our Pleasant Creek and Los Medanos storage facilities.

These activities are covered by the following MAT Codes:

- AH4 – Gill Ranch Storage Expense; and
- 762 – Gill Ranch Storage Capital.

The foregoing is more fully-discussed in PG&E’s prepared testimony.\(^{41}\)

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\(^{40}\) PG&E Prepared Testimony, Chapter 10, p. 10-31, line 14 to p. 10-33, line 2.

\(^{41}\) PG&E Prepared Testimony, Chapter 10, p. 10-34, line 23 to p. 10-35, line 24.
Q 45 What does ORA recommend for this program
A 45 ORA recommends no reductions to the expense forecast (MAT Code AH4) but does recommend reducing the capital forecast (MAT Code 762) by $3.8 million across the three years, 2019-2021. This is a reduction of 82 percent from PG&E’s requested $4.6 million over 2019-2021.

Q 46 Do you agree with ORA’s recommendation?
A 46 No. ORA provides no reason for its recommended reduction. As we stated in our prepared testimony, the forecast amounts are largely needed to support PG&E’s share of capital work driven by the new California Division of Oil, Gas, and Geothermal Resources (DOGGR) safety requirements.

Q 47 What was the basis of PG&E’s forecast?
A 47 PG&E’s testimony explains that the Company has a 25 percent interest in the Gill Ranch Storage facility and that under NGSS, we propose to integrate our share of the Gill Ranch Storage costs into our new reliability-only transmission system services. Capital expenditures for the Gill Ranch Storage facility are for repairs and for work to comply with the final draft of the DOGGR regulations. The forecasted work for the rate case period includes retrofitting 10 wells with tubing and packer, as well as the cost to perform routine work.

Q 48 What does PG&E recommend for Gill Ranch Storage capital expenditures?
A 48 PG&E recommends that the Commission adopt PG&E’s forecast for Gill Ranch Storage capital expenditures.

D. Response to Parties’ Issues Regarding the LT Study
Q 49 Please provide a brief summary of the LT Study.
A 49 The 2015 GT&S decision ordered PG&E to “provide an analysis . . . demonstrating whether local transmission costs should be allocated more equitably by accounting for the actual relationships between pipeline capacity, throughput and costs.” PG&E performed the analysis and

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42 Calculated from amounts shown in ORA-10 at p. 5, Table 10-2, line 6; p. 5, Table 10-3, line 6; and p. 6, Table 10-4, line 6.
43 PG&E Prepared Testimony, Chapter 10, p. 10-36, lines 4-6.
44 PG&E Prepared Testimony, Chapter 10, p. 10-36, lines 7-8.
included a copy of the report in the workpapers. The analysis compared the
costs of building an LT system from scratch for core customers only, and
noncore customers only. The analysis showed that the ratio of relative cost
was 62 percent core and 38 percent non-core.46
Q 50 Do parties comment on the study?
A 50 Yes. Both IS and Calpine comment on the study. PG&E addresses their
comments in the following sections.

1. IS/NCGC Testimony Regarding the LT Cost Allocation Study
Q 51 Please summarize IS/NCGC’s comments.
A 51 IS/NCGC claim that PG&E’s LT Study was non-responsive to the specific
direction provided in Decision (D.) 16-06-05647 and is contrary to Ordering
Paragraph (OP) 38 in that decision.48 IS/NCGC incorrectly states that
PG&E itself has concluded that no changes are needed or warranted to its
LT cost allocation methodology.49 IS/NCGC makes various claims,
enumerated below, to the effect that PG&E’s study is not based on cost
causation or cost of service principles. IS/NCGC asserts that the study has
various other specific defects, discussed below.
Q 52 What is PG&E’s response to IS/NCGC’s assertion that the LT Study is non-
responsive and contrary to the Commission’s directions in D.16-06-056?
A 52 PG&E performed a thorough, reasonable and good-faith study in response
to OP 38 of D.16-06-056. PG&E summarized the study in Chapter 10 of its
Prepared Testimony and provided the full study in its Chapter 10
Workpapers. PG&E’s study is based on detailed hydraulic modeling of
two representative areas of its LT system, and detailed analysis of the costs
of building local transmission systems to serve core and noncore customers
in each area. Although IS/NCGC does not like the conclusions of the study,
and claims the study has certain defects (which are addressed below),
IS/NCGC have no basis for claiming the study is non-responsive to the
Commission’s directions.

46 PG&E Prepared Testimony, Chapter 10, p. 10-47, lines 6-10.
47 IS/NCGC-1, Chapter 10, p. 10-8, lines 6-7.
48 IS/NCGC-1, Chapter 10, p. 10-7, lines 10-11.
49 IS/NCGC-1, Chapter 10, p. 10-3, lines 12-15.
Q 53 IS/NCGC asserts that PG&E itself has concluded that no changes are needed or warranted to its LT cost allocation methodology. Is this a correct characterization of PG&E’s position?

A 53 No. PG&E did not say that. PG&E stated that the cost allocators derived from the LT Study (62% core, 38% noncore) are similar to the currently adopted LT cost allocators derived from Cold Year Peak Month demands (approximately 68% core, 32% noncore). PG&E also stated in response to a data request that it has not identified any deficiencies in the currently adopted cost allocation method. This statement merely recognizes that there is more than one reasonable way to do cost allocation.

Q 54 IS/NCGC also claims that PG&E’s proposed LT cost allocation methodology lacks cost causative justification, is not based on cost of service principles, “is purely results-driven”, and is coincidentally convenient. Is IS/NCGC correct in these assertions?

A 54 No. PG&E’s proposed LT cost allocation is based on cost causation principles. As explained in the LT Study, PG&E determined the capacity necessary to serve core customers on an APD and the costs of building this capacity. PG&E also determined the capacity necessary to serve noncore customers on a CWD and the cost of building that capacity. The ratio of the costs so determined to serve the core and noncore classes is the basis for the cost allocation proposed in the Chapter 10 LT Study. IS/NCGC does not dispute or take issue with these facts.

It is only the next step in PG&E’s proposal that IS/NCGC appears to take issue with. In Chapter 16A, PG&E identified a proxy cost allocator that produced the same cost allocation results as the LT Study. The proxy allocator was the average of Cold Year Winter Season throughput and Average Year Winter Season throughput. PG&E developed the proxy

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50 IS/NCGC-1, Chapter 10, p. 10-3, lines 2-15.
52 IS/NCGC-1, Chapter 10, p. 10-4, lines 5-8.
53 IS/NCGC-1, Chapter 10, p. 10-7, lines 15-18.
54 IS/NCGC-1, Chapter 10, p. 10-4, line 2.
allocator merely as a convenience so that the cost allocation methodology could potentially be extended in the future without performing another labor-intensive LT Study.

Importantly, the second step did not change the cost allocation results. PG&E could have just as well directly used the results from the Chapter 10 LT Study. Nevertheless, IS/NCGC spends a great deal of time attacking the proxy allocator used in Chapter 16A without acknowledging that it is just a proxy. IS/NCGC has relatively few criticisms of the Chapter 10 LT Study itself.

Q 55 Please describe IS/NCGC’s specific criticisms of the LT Study.

A 55 IS/NCGC notes the following:

- The LT study includes land and land rights costs on a system average basis and does not recognize that these costs may be higher for the core than for the noncore;\(^\text{56}\)
- PG&E provides no showing that the two systems it evaluated are representative of the total PG&E system;\(^\text{57}\) and
- PG&E compares hypothetical data rather than actual data, contrary to the Commission’s direction.\(^\text{58}\)

Q 56 How does PG&E respond to IS/NCGC’s claim that the costs of land and land rights are accounted for on a system average basis, but may be higher for core customers than noncore customers?

A 56 PG&E is not exposed to the high costs of land purchases in urban areas. Instead PG&E’s franchise fees provide for the right to install pipelines in under publicly-owned streets. Determination of the costs attributable to core versus noncore service would be a difficult exercise, requiring numerous assumptions and analysis of the type and amount of land costs associated with each pipeline over decades of records and the relative use of each pipeline by core and noncore customers. PG&E has not performed this analysis. Nor has IS/NCGC. However, PG&E did account for land costs in the model of average pipeline costs we used for our cost estimates, the

\(^{56}\) IS/NCGC-1, Chapter 10, p. 10-7, lines 1-7.  
^{57}\) IS/NCGC-1, Chapter 10, p. 10-7, lines 8-9 and lines 12-14.  
^{58}\) IS/NCGC-1, Chapter 10, p. 10-7, lines 10-11.
Pipeline Unit Cost Tool, which is shown on page WP 10-40 of our workpapers. They are a component part of each job cost history PG&E used to develop that model.

Q 57 How does PG&E respond to IS/NCGC’s claim that PG&E provides no showing that the two LT systems it evaluated are representative of the total PG&E system?

A 57 As PG&E stated in the LT Study, evaluation of its entire in-place LT system would be an enormous and impractical undertaking. Accordingly, PG&E analyzed two LT systems that, taken together, serve about one-third of its customer base, and approximates the overall LT system’s mix of core and noncore load. The two systems are the East Bay system in Alameda and Contra Costa counties which serves 832,000 customers and serves predominately noncore load, and the North Bay system in Solano, Napa, Marin, Lake, and Mendocino counties which serves 455,000 customers and serves predominately core load. Taken together, these two systems fairly represent PG&E’s overall LT system.

Q 58 How does PG&E respond to IS/NCGC’s claim that PG&E compares hypothetical data rather than actual data, contrary to the Commission’s directions?

A 58 OP 38 of D.16-06-056 directs PG&E to perform a study that takes into account “actual relationships between pipeline capacity, throughput and costs.” PG&E has performed such a study. IS/NCGC does not indicate how they believe the LT Study should be modified, except to make the unrealistic complaint that we should have used actual land costs for every segment of pipe implicated in the study. We believe the word “actual” in OP 38 modifies the word “relationships,” and was not a direction from the Commission to engage in such a burdensome undertaking. Nor does IS/NCGC acknowledge that the existing LT cost allocation methodology relies on forecasted (that is, non-actual) data rather than actual data, or that

59 PG&E WP 10-36 to WP 10-37.
60 PG&E WP 10-37 to WP 10-38.
61 D.16-06-056, mimeo, p. 484, OP 38.
a different methodology, such as the one IS/NCGC espouses based on APD and/or CWD demands, would also rely on non-actual data.

Q 59 What is PG&E’s overall conclusion regarding IS/NCGC’s comments on the LT Study?

A 59 IS/NCGC’ assertion that PG&E’s LT Study is non-responsive to the Commission’s directions in D.16-06-056 is unsupported. IS/NCGC incorrectly claims that PG&E itself has concluded that no changes are necessary to its LT cost allocation methodology. IS/NCGC’s various claims that PG&E’s proposed LT cost allocation is not based on cost causation or cost of service principles are unsupported in that they attack the proxy cost allocators that PG&E employed for convenience sake, not the LT Study itself. Finally, none of IS/NCGC’s specific criticisms of the LT Study stand up to scrutiny.

2. Calpine’s Comments Regarding the LT Study

Q 60 Please summarize Calpine’s comments.

A 60 Calpine states that PG&E’s LT Study fails to reflect the reality of how PG&E’s LT system is designed in that it does not account for PG&E’s joint service to core and noncore customers or the fact that core customers have a higher priority of service than noncore customers.62 Calpine also presents the results of its own “more realistic study,” which analyzes the hypothetical costs of a combined LT system and attributes costs to the core and noncore classes based primarily on the assumption that the combined system was built first to serve the core class, with service to the noncore class being secondary or incremental.63

Q 61 How does PG&E respond to Calpine’s comments?

A 61 PG&E’s LT Study developed costs for two hypothetical stand-alone LT systems: one to serve only the core class under APD conditions; and another to serve only the noncore class under CWD conditions, to isolate the cost of service to each customer class as if it were the only class to be served. The ratio of the costs of these two stand-alone systems is PG&E’s recommended LT cost allocation (62% core, 38% noncore). PG&E

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63 Calpine, p. 14, line 23 to p. 16, line 3.
employed this approach because its actual LT system cannot be attributed primarily to either the core class or the noncore class—meaning the system cannot be viewed as being built first to serve core customers, with service to noncore customers being incremental, nor can it be viewed as being built first to serve noncore customers, with service to core customers being incremental. In reality, different parts of PG&E’s system were built for different original purposes and over time came to serve dual purposes. It would be very difficult to untangle the system history and determine the instances when core load was incremental or noncore load was incremental. For these reasons, PG&E believes that the best way to attribute LT costs to the core and noncore classes is the methodology PG&E used in its LT Study. Calpine’s study is deeply flawed in two ways. First, Calpine’s study makes the false assumption that the LT system was built first to serve core customers, with service to noncore customers being incremental. Second, Calpine’s study uses equations for flow and flow capacity that do not follow the laws of physics.

Q 62 Please explain why Calpine’s study assumes the LT system was built primarily for service to the core class, with service to the noncore class being incremental.

A 62 Calpine started with the capacity and costs from PG&E’s LT Study necessary to serve only the core class on an APD; Calpine attributed these costs to the core class. Calpine then added the LT capacity and costs necessary to expand that system such that it could serve both the core and noncore classes on a CWD; Calpine attributed these incremental costs to the noncore class. The result is the LT cost allocation shown on line 5 of Table 1 of Calpine’s testimony (“Revised Study: Core-APD / Incremental Noncore”) which attributes 79 percent of LT costs to core customers and 21 percent to noncore customers.64

Q 63 Why is Calpine’s assumption that the LT system was built primarily to serve the core customer class mistaken?

A 63 Calpine’s assumption that yielded its line 5 results is biased. Calpine’s analysis assumes all costs belong to the class that originally drove the need

64 Calpine, p. 13, Table 1, line 5.
for the capacity (as if that could be determined). It also ignores the value each customer receives from having the system available to connect to at all. It is unfair to require all customers of the class that may have predominated at the time of construction to pay the lion’s share of costs in perpetuity. Calpine assumed this class was the core; therefore, the self-fulfilling result of their analysis is that costs are high for the core and low for the noncore. Calpine’s method in its Line 5 analysis also assumed that on a CWD, when the core is not using all the capacity for an APD, the noncore is entitled to use the idle core capacity for free.

If we were to make the arbitrary assumption that the system was built primarily for the noncore, and ascribe all costs of that CWD system to them, and that the core was the class that was incremental, adding cost only for the tranche of capacity needed to reach the APD peak, we would get the inverse of Calpine’s results: Core costs would be low, noncore costs would be high, and the core could use the (ample) noncore portion for free. To assume that either customer class has prior claim on the value of the pipeline, or prior responsibility for its cost, is unfair. Avoiding this bias is a major reason our study used the even-handed approach of creating two separate hypothetical systems.

Q 64 Did Calpine create any additional cost allocation scenarios?
A 64 Yes. Calpine created two additional cost allocation scenarios. In its second scenario, Calpine started with the same total LT capacity and costs as in its first scenario, summarized above, but allocated the costs in accordance with core and noncore usage on a CWD. The result is shown on Line 4 of Table 1 of Calpine’s testimony (“Revised Study: Noncore Contribution to Core-APD”) which attributes 66 percent of LT costs to core customers and 34 percent to noncore customers.65 In its third scenario, Calpine calculated the simple average of the results from its first and second scenarios, then adjusted the results to account for the fact that the modeled LT systems did not have the same core/noncore usage split as PG&E’s entire LT system. The result of this scenario is shown on Line 6 of Table 1 of Calpine’s testimony (“Calpine: 50% #4 / 50% #5, with adjustment”). This scenario,

65 Calpine, p. 13, Table 1, line 4.
which is Calpine’s recommended LT cost allocation, attributes 76 percent of LT costs to core customers and 24 percent to noncore customers.  

Importantly, because this scenario is derived by averaging Calpine’s first and second scenarios, it suffers the same defect as the first scenario. It is tainted by the incorrect assumption that PG&E’s LT system was built to serve core customers, with service to noncore customers being incremental.

Q 65 Please explain how Calpine’s study uses equations for flow capacity that violate the laws of physics.

A 65 Calpine calculated the internal volume of each pipeline segment using the simple geometric formula, \( V = \pi r^2 h \). This equation treats pipelines as simple vessels or tanks. However, gas flows through the pipeline under pressure. It does not sit idly, like water in a jug. The equation Calpine used ignores not only pressure, which is a major determinant of pipeline capacity, but numerous other factors that affect the flow of gas in a pipeline, including friction, elevation, and gas Btu value. The rate of gas flow is an integral part of capacity, and the proper pipeline flow equations must be used to determine it. Calpine’s entire cost allocation is built on volume ratios that ignore the physics of flow capacity, and are therefore invalid and should be disregarded.

Q 66 What is PG&E’s response to Calpine’s assertion that PG&E’s LT Study does not account for the higher priority of LT service afforded to core customers?

A 66 The core’s higher priority of service is accounted for in the design criteria used in PG&E’s LT Study—APD for the core versus CWD for the noncore—and in the higher core LT rates that result from PG&E’s proposed LT cost allocation. Therefore, to the extent that the higher capacity needed to serve APD conditions versus CWD conditions drives cost of service, that impact is included in this study and the resulting core and noncore cost allocation shares. Furthermore, Calpine ignores that curtailments are extremely rare, and fails to account for the extremely high level of service the noncore

66 Calpine, p. 13, Table 1, line 6.
68 See Calpine’s response to PG&E Data Request PG&E-Calpine_001-Q01, dated 08/15/2018 in Attachment A.
receives despite its lower priority. The noncore gets this very high level of service because APD design provides significant capacity headroom in weather that is warmer than APD. Essentially, noncore customers get near-APD-level service but pay only CWD-level rates. Total gas sendout over the period January 2008 through December 2017 was 4,999,430 million cubic feet (MMcf). Curtained noncore volumes in that time were 21 MMcf, or 0.0004 percent. Put another way, noncore service over that time was 99.9996 percent reliable.

Q 67 What is PG&E’s overall conclusion regarding Calpine’s comments on the LT Study?
A 67 Calpine attempted to devise an alternative LT cost allocation methodology using the data in PG&E’s LT Study as a starting point. However, Calpine relied on the flawed and tendentious assumption that PG&E’s LT system was built primarily to serve the core, with service to the noncore being merely incremental. Further, they used an equation for gas pipeline capacity that has no bearing on the relevant physics. For these reasons, Calpine’s recommended LT cost allocation should be disregarded.

E. Response to Commercial Energy’s Recommendation Regarding Gas Demand Response Program

Q 68 Please describe Commercial Energy’s recommendation regarding the establishment of a gas demand response program.
A 68 Commercial Energy recommends that PG&E offer a gas demand response program to customers with a minimum load of 100,000 therms per year as a means of reducing peak demands and, ultimately, the need to build additional capacity in locations that face constraints during periods of peak demand. They estimate about 800 customers could participate in the program within the first 18 months of inception.69

Q 69 Does PG&E agree with Commercial Energy’s recommendation to establish a gas demand response program?
A 69 No. PG&E disagrees with this recommendation for several reasons.

69 CE, p. 24, line 18 to p. 35, line 2.
First, a mechanism already exists to curtail load. It is the noncore rate structure, in which customers are curtailable upon demand in exchange for a lower rate than non-curtailable core customers are subject to.

Second, ensuring curtailment compliance would be very difficult and expensive, relative to the return on investment. Our installed metering and regulation equipment generally does not allow for the real-time monitoring and control of the gas supply at the burnertip of customers who may choose to become part of a gas demand response program. Such devices would have to be installed. PG&E has not estimated the cost of such an installation program, but believes it would be significant.

Last, depending on the number, types, and location of customers that may choose to participate in a gas demand response program, the reduction in capacity investment that CE puts forward as a benefit is very likely to be small relative to the high cost of the program. This is because a high number of participating customers in a concentrated area would be required to avoid incremental capacity investments under MAT 73A. A gas demand response program would not obviate capacity investment in areas of low participation, nor would it reduce the investments required for non-capacity related work (Integrity Management work, pipeline replacement, strength testing, etc.).

F. Response to ORA’s Testimony Regarding the Line 407

Reasonableness Report

Q 70 Which parties submitted testimony regarding PG&E’s Line 407 Reasonableness Report dated April 30, 2018?

A 70 ORA was the only party to submit testimony concerning Line 407.70

Q 71 What is ORA’s overall recommendation?

A 71 ORA states:

Overall, ORA recommends the Commission find PG&E’s showing on the Line 407 project costs reasonable subject to PG&E providing a direct showing of the composition of the amounts in excess of the authorized cap.71

70 See ORA-10.

71 ORA-10, p. 27, lines 11-13.
Q 72 Are there elements of PG&E’s report that ORA supports?

A 72 Yes, ORA “finds support for” the following items of PG&E’s report:

- Table 1, which is the Line 407 forecast from the 2015 GT&S Rate Case; 72
- Table 2, which is the Line 407 forecast from the 2015 GT&S Rate Case adjusted for project scope amounts removed from Table 1; 73
- ORA, “does not take issue with” the cost categories PG&E uses in the Line 407 report; 74
- ORA, “does not oppose” the identified expenditure items on remaining work; and 75
- ORA: …finds that although Line 406 76 has basic project features more similar to Line 407 than [Pipeline Safety Enhancement Plan] or 2015 GT&S projects, there is sufficient basis provided by PG&E to explain and account for the significantly lower cost per mile of Line 406 compared to Line 407. 77

Q 73 What does ORA recommend?

A 73 ORA recommends that PG&E make a direct showing of the composition of cost amounts in excess of the authorized/adopted cap of $157 million. 78 ORA’s report specifies the items in excess of the $157 million value, as shown below: 79

- Construction Work-in-Progress (CWIP), as of December 2012 $10.646 million;
- Allowance for Funds Used During Construction (AFUDC) Actual Recorded Excess over Forecast $6.0 million;
- Station Actual Recorded Excess over Forecast $3.5 million;

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72 ORA-10, Appendix 1, p. 43, lines 17-20.
73 ORA-10, Appendix 1, p. 43, line 23 to p. 44, line 2.
74 ORA-10, Appendix 1, p. 44, lines 20-21.
75 ORA-10, Appendix 1, p. 49, lines 13-14.
76 The Line 406 pipeline is the most recently completed project (operational in 2010) that is comparable to the Line 407 project.
77 ORA-10, Appendix 1, p. 55, lines 10-13.
78 D.16-06-056, mimeo, pp. 489-490, OPs 57 and 58, authorized cost recovery of up to $157 million beginning when Line 407 is placed in service.
79 ORA-10, Appendix 1, p. 51, lines 6-7.
• Land Acquisition Actual Recorded Excess over Forecast $0.4 million;
• Forecast Cost to Project Completion $11.0 million; and
• CWIP Recorded in 2014 & 2014 not included in Forecast $3.3 million.
  These items total $34.8 million.

Q 74 How does PG&E respond?
A 74 The 2015 GT&S Rate Case decision ordered PG&E to perform a reasonableness review of the entire project, not the amounts over the $157 million value authorized/adopted for cost recovery. PG&E’s reasonableness report does that; the costs ORA specifies above are simply part of the reasonableness review for the entire project. This rebuttal testimony addresses each of the six items.

Q 75 Please address the $10.646 million item related to CWIP.
A 75 CWIP is an account in which all costs associated with the construction of new facilities are recorded until the facilities are placed in-service (i.e., become operational). The CWIP value of $10.646 million that ORA notes (and is shown in Table 1 of the Line 407 report) represent expenditures PG&E made prior to December 2012. The activities these expenditures represent are shown in the workpapers supporting the report. Specifically, “Table 3: Summary Table” shows actual expenditures for the years 2006 through 2017. The table includes expenditures for the entire project and therefore includes expenditures from 2006 to December 2012. The table is organized in the categories ORA found support for as noted above. Next, Tables 4 through 9 of the workpapers provide the expenditure details by cost categories for the entire project that Table 3 summarizes. These tables segregate costs into additional categories (which are summarized at the top of each table) and provides information related to cost element and vendor description.

With respect to expenditures from 2006 to 2012, Table 3 shows those expenditures were for land acquisition activities (further details are provided in Table 5), pipeline work (engineering, permits, project management, etc., further details are provided in Table 6) and AFUDC (Table 9 provides additional details).
Please address the $6.0 million item related to AFUDC.

AFUDC is an accounting procedure used by utilities to capitalize the costs of financing the construction of facilities. PG&E has explained all the AFUDC costs for the project in Section C.3.d., “Allowances for Funds Used During Construction.” As explained in that section, AFUDC is calculated automatically by PG&E’s accounting system and the calculation is in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts Plant Instruction No. 3 (17) – AFUDC. Additionally, PG&E reviewed the AFUDC costs associated with the project and found that:

- Land Acquisition orders were appropriately created so as not to accrue AFUDC;
- AFUDC did not accrue during the postponement period of the project from February 2012 until January 2013, which is appropriate; and
- AFUDC stopped accruing when the project became operational.

The report also explains that PG&E did a manual calculation check of monthly AFUDC values using combined order costs showed that the recorded AFUDC amounts were reasonable. Based on all the above, PG&E believes cost recovery for all AFUDC costs for the Line 407 project is appropriate. Basically, PG&E under-forecast AFUDC in the context of the 2015 GT&S Rate Case.

Please address the $3.5 million item related to Station actual costs.

PG&E has explained all the Station costs for the project in Section C.3.c., “Station Work.” In the report PG&E attributes the variance to:

- The need to re-engineer Station 1 to satisfy the requirements of the City of Roseville, which ultimately led to changing the location of Station 1 requiring additional engineering;
- Additional costs associated with PG&E revising SCADA equipment requirements due to PG&E updating standards as the project was being constructed; and

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81 Line 407 Report, p. 27, line 17 to p. 30, line 17.
• Underestimating the forecast for Station 2 in the 2014 Major Business Case.

Q 78 Please address the $0.4 million item related to land acquisition actual costs.

A 78 PG&E has explained all the land acquisition costs for the project in Section C.3.b., “Land Acquisition.” Total land acquisition costs as of December 31, 2017 were $16.1 million which could increase by project-end depending on the outcome of eminent domain litigation. ORA has not objected to the overall costs for land acquisition. Yet, ORA believes a review of $400,000 worth of land expenses—a small fraction of total land acquisition expenditures—is appropriate. Additionally, ORA does not specify what portion of the $400,000 should be subject to the review. Is it land acquisition payments? Support Activities? PG&E Labor? This is a good example of why a review of amounts greater than the arbitrary value $157 million is unnecessary when all the project costs have already been presented by PG&E.

Q 79 Please address the $11 million item related to forecast cost to project completion.

A 79 A detailed view of the forecast cost to project completion is provided in Table 10 of the Line 407 workpapers. There are costs forecasted for completing the station work and the ongoing environmental remediation work associated with the transmission pipeline (both of which ORA acknowledges at page 49 of their report). These costs are further sub-categorized for each item (e.g., costs by PG&E labor, contract, materials, invoices, credits, etc.). However, most of the remaining forecast cost is associated with eminent domain cases that are still pending. To see all the elements associated with the forecast to complete the project please see Table 10 of the Line 407 workpapers.

Q 80 Please address the $3.3 million item related to CWIP recorded in 2014 and 2014 not included in the forecast.

A 80 As explained previously, CWIP is an account in which costs associated with the construction of new facilities are recorded until the facilities are placed

82 Line 407 Report, p. 22, line 13 to p. 27, line 16.
in-service. CWIP itself is not a work activity. The Line 407 report and supporting workpapers include all recorded costs for the project through December 2017. CWIP is not a relevant factor when reviewing costs for a completed project that is now operational. The relevant factor is the recorded costs which PG&E has provided. OP 57 from D.16-06-056 ordered a review of the reasonableness of all project costs in the Company’s next GT&S application. PG&E has done that by providing recorded cost data for the entire project in Tables 3 through 10 of the workpapers supporting the Line 407 report.

Q 81 Please summarize PG&E’s position.
A 81 PG&E has complied with the OPs 57 and 58 of D.16-06-056. The Company’s reasonableness report has explained all the costs associated with the Line 407 project. Additionally, ORA finds support for key elements from PG&E’s report and this rebuttal testimony addresses all the items ORA raises regarding the composition of cost amounts in excess of the authorized cap of $157 million. Lastly, no other party submitted testimony regarding the Line 407 project in this rate case. Therefore, there is no need for a further “direct showing.”

Q 82 What is PG&E’s recommendation?
A 82 As stated in the report, PG&E recommends the Commission authorize full cost recovery for the Line 407 project as described in the reasonableness report. Specifically, PG&E proposes that the 2019 GT&S Rate Case decision rule on the reasonableness of all the costs recorded and forecast (i.e., the $191.8 million) and incorporate the result in the overall adopted revenue requirement. Subsequently, once all costs for the Line 407 project have been recorded, PG&E will file a Tier 2 advice letter for reasonableness review of any additional forecast costs beyond the $191 million to be reviewed in this proceeding. If PG&E records costs less than forecast in Table 5, PG&E will file an advice letter proposing that any such over-collections be returned to customers through the Annual Gas True-Up. Once these remaining costs/over-collections are addressed through the
advice letter process, PG&E will close the memorandum account referenced in OP 57.84

Q  83 Does this conclude your rebuttal testimony?

A  83 Yes, it does.

Q1: In Calpine’s GT&S testimony on p. 14, line 24, to p. 16, line 3, Calpine’s witness indicates that he performed a revised local transmission cost allocation study. Please provide all workpapers for Calpine’s revised study, with all formulas and calculations intact.

Response to Q1: Please find, attached, Calpine’s revised local transmission cost allocation study: “Revised LT Split Between Core and Noncore.xlsx.” Please note that the workpaper does not rely on any confidential data.
### LT cost allocation between core and noncore, assuming incremental rather than stand-alone noncore system ($MM)

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Source of CWD volumes: WP-10-44
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**Formulas:**

- **Formula #1:** \( y = 406x + 2197.5 \)
- **Formula #2:** \( y = 60.743x + 24938 \)

**Cost Analysis:**

- **Cost (formula 1):** 63,360
- **Cost (formula 2):** 63,360

**Percentage Breakdown:**

- 75%: 3,623,607
- 90%: 7,982,795
- 100%: 8,832,392

**Total:** 8,832,392

**Notes:**

- Source: WP 10-36 to WP 10-47
- Units: cubic inches
- Categories: Noncore System, Incremental Noncore System, Approximate Cost (\$)

**Columns:**

- Number of Items
- Description
- Cubic Inches
- Noncore System
- Incremental Cost
- Noncore System
- Approximate Cost (\$)

**Additional Notes:**

- Cost Breakdown:
  - 0% - 100%
  - 25% - 75%
  - 75% - 100%

**Additional Information:**

- Formulas used for cost calculations
- Data breakdown for specific items and locations

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10-AtchA-3