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ALJ	:	R. Lirag
Witnesses	:	N. Stannik, P. Li

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

San Diego Gas & Electric Company
Southern California Gas Company
Test Year 2019
General Rate Case

Risk Management Policy; Enterprise Risk Management Organization; RAMP/GRC Integration; Pipeline Integrity; SoCalGas PSEP

San Francisco, California
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TABLE OF CONTENTS

RISK MANAGEMENT POLICY; ENTERPRISE RISK MANAGEMENT ORGANIZATION; RAMP/GRC INTEGRATION; PIPELINE INTEGRITY; SOCALGAS PSEP

I. INTRODUCTION

This exhibit presents the analyses and recommendations of the Office of Ratepayer Advocates (ORA) regarding the Risk Management Policy, Enterprise Risk Management (ERM) Organization, Risk Assessment Mitigation Phase (RAMP) to General Rate Case (GRC), Transmission Integrity Management (TIMP), Distribution Integrity Management (DIMP), and Pipeline Safety Enhancement Plan (PSEP) proposals of San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas or SCG) in their Test Year (TY) 2019 General Rate Cases. Specifically, ORA addresses forecasts of operation and maintenance (O&M) expenses for 2019 and capital expenditures for 2017 through 2019. ORA also addresses SoCalGas' PSEP forecasts for post-test years 2020, 2021, and 2022.

II. SUMMARY OF RECOMMENDATIONS

A. Risk Management Policy

The following summarizes ORA's recommendations regarding SDG&E/SoCalGas' Risk Management Policy:

- The 7x7 matrix should be phased out as discussed in the SMAP proceeding; and
- ORA generally supports SCG/SDG&E's transition to a more quantitative risk assessment methodology.

B. SDG&E/SoCalGas Enterprise Risk Management Organization

The following summarizes ORA's recommendations regarding the SDG&E/SoCalGas Enterprise Risk Management Organization costs:

- ORA does not oppose SCG/SDG&E's request for an additional Full-Time Equivalent (FTE) for the ERM Organization; and

- ORA does not oppose SCG/SDG&E's request for additional funding for outside expert support, but expects that future requests will be more specific.

C. RAMP / GRC Integration

The following summarizes ORA's recommendations regarding the SDG&E/SoCalGas RAMP / GRC integration:

- The data produced by the RAMP and integrated into this GRC should be used to inform funding decisions, but not to dictate these decisions or bypass the traditional review process in the GRC.

D. Pipeline Integrity Management (TIMP/DIMP)

The following summarizes ORA's recommendations regarding the SDG&E/SoCalGas TIMP/DIMP costs:

- ORA recommends 2017 actual recorded TIMP capital costs ($106.129 million) be adopted;
- ORA recommends 2017 actual recorded DIMP capital costs ($124.104 million) be adopted;
- ORA does not oppose SCG/SDG&E's TIMP forecast ($54.798 million in 2018 and $59.000 million in 2019 for capital; $49.351 million in 2019 for expense); and
- ORA does not oppose SCG/SDG&E's DIMP forecast ($94.602 million in 2018 and $205 million in 2019 for capital; $44.359 million in 2019 for expense).

E. PSEP

The following summarizes ORA's recommendations regarding the SDG&E/SoCalGas PSEP costs:

- ORA's PSEP forecast through 2022 is $584.211 million, which is $100.189 million less than SCG/SDG&E's request for $684.4 million;
- SCG/SDG&E's request for balancing account treatment should be denied;
- SCG/SDG&E's request for contingency funding should be granted, unless balancing account treatment is granted;
- SCG/SDG&E's project substitution proposal should be modified; and

- SCG/SDG&E’s Interpretation of the Code of Federal Regulation Subpart J is Incorrect.

PART I: RISK MANAGEMENT POLICY

I. SUMMARY

Chapter 1 of Ex. SCG-02-R/SDGE-02-R summarizes SCG/SDG&E's Risk Management Policy. Specifically, the chapter discusses how SCG/SDG&E has "incorporated risk management into their… showing" and focuses on "the advancement of risk management principles and practices." The chapter also describes SCG/SDG&E's "safety culture from a risk management perspective."[1]

For the purposes of this testimony, ORA defines the following terms as used below:

- *Subject Matter Expertise (SME):* describes information formed largely or primarily from expert judgement, experience, or estimation. SME information may be informed by or integrate metrics, but is not a metric itself. For example: an engineer's prediction of how many poles will fail in a given month.
- *Quantitative:* describes information that is entirely or fundamentally numeric in nature. For example: the number of poles that failed in a given month or the average lifespan of wooden poles.
- *Qualitative:* describes information that is relative or based on comparison, but is generally not numeric. For example: pole replacement is more effective than pole inspection.

II. ORA'S ANALYSIS

ORA supports SCG/SDG&E's efforts to better assess, manage, and mitigate risk through its risk management policies. A "risk-informed" GRC is an important part of these efforts.

As discussed in the Safety Model Assessment Proceeding (SMAP)[2] and SCG/SDG&E's Risk Assessment Mitigation Phase (RAMP) proceedings, ORA supports a movement towards quantitative and statistically-based risk analysis

[1] SCG-02/SDGE-02, page DD-ii.

[2] The SMAP may also be abbreviated to S-MAP. Both acronyms refer to the same proceeding.

wherever reasonably possible.[3] SCG/SDG&E's continued heavy reliance on subject matter expertise, while in many places understandable, makes quantitative risk assessment difficult and should be reduced in future filings. While subject matter expertise will likely always have *some* role to play in risk assessment and risk-related funding decisions, the Commission's expressed desire to move to a more quantitative framework[4] has not yet been fulfilled.

As the SMAP advances and the Commission implements new safety model requirements or systems,[5] SCG/SDG&E's risk assessment and management policies will likely need to change to accommodate more quantitative methodologies, evidence, or explanations of judgments. These changes should be reflected in future RAMPs and GRCs as determined in the SMAP.

Relatedly, ORA is concerned about SCG/SDG&E's continued use of the "7-by-7" risk matrix.[6] As discussed in the SMAP,[7] the 7x7 matrix is largely based on subjective judgement and does not provide a quantifiable, clear, and appropriate way of measuring and comparing risks. As such, the 7x7 matrix should be phased out by the next SDG&E/SoCalGas RAMP filing.

ORA recognizes that the transition to more quantitative risk and mitigation analysis is an ongoing process that will likely span many years into the future. While specific frameworks or regulatory requirements are still under development, SCG/SDG&E should continue to move towards more quantitative risk assessment and demonstrate this in its future RAMPs and GRCs.

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[3] See, for example, Comments of the Office of Ratepayer Advocates on the Safety and Enforcement Division's Staff Report on the February 15, 2017 Workshop 2. April 25, 2017. See: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M189/K819/189819043.PDF

[4] D.16-08-018 (SMAP), page 179. See: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M165/K862/165862364.PDF

[5] The "Joint Intervenor Approach," also referred to as the "EPRI model" in D.16-08-018, was adopted on an interim basis to be "test-driven" and evaluated by parties and the Commission. See D.16-08-018; http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M165/K862/165862364.PDF

[6] See SCG/SDGE-02, page DD-10 through DD-11.

[7] See D.16-08-018, page 43. See: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M165/K862/165862364.PDF

PART II: ENTERPRISE RISK MANAGEMENT ORGANIZATION

I. SUMMARY

SCG/SDG&E's Enterprise Risk Management Organization request and ORA's recommended amounts are outlined in Table 3-1 below:

Table 3-1
SCG/SDG&E Enterprise Risk Management Organization Expenses
2012-2016 Recorded and 2019 Forecast
(in Millions of 2016 Dollars)

Description	2012	2013	2014	2015	2016	Sempra 2019	ORA 2019
SDG&E ERM & Compliance	$0.663	$0.663	$1.030	$3.706	$4.281	$6.743	$6.743
SoCalGas ERM	$0	$0	$0	$0.113	$0.292	$0.292	$0.292
Total	$0.663	$0.663	$1.030	$3.819	$4.573	$7.035	$7.035

Source: 2012-2016 data from Ex. SCG-02-WP, p. 5 and SDG&E-02-WP, pp. 5, 12, and 18. SCG/SDG&E 2019 forecast from Ex. SCG-02-R/SDG&E-02-R, p. GSF-3, Table GF-3.

II. OVERVIEW OF SCG/SDG&E'S REQUEST

SCG/SDG&E requests a total of $7.035 million in TY 2019 for its Enterprise Risk Management organization. Of this, $6.743 million is attributable to SDG&E ERM & Compliance[8] and $0.292 million is attributable to SCG ERM.[9]

SCG/SDG&E's recorded costs for SDG&E and SCG, respectively, in 2016 were $4.281M and $0.292M.

Cost drivers are primarily management positions in the ERM organization[10] and a requested increase to "be primarily used to obtain support from experts within the industry."[11]

[8] See page 2 of workpaper SDG&E-02-WP.

[9] See page 2 of workpaper SCG-02-WP.

[10] See SCG/SDG&E-02, pages GSF-4 through GSF-6.

[11] SCG/SDG&E-02, page GSF-6.

III. ORA'S ANALYSIS

In its review process, ORA confirmed that the three management positions have existed since 2015 and the requested incremental funding is for an additional Full-Time Equivalent (FTE) and consultant support as described above.

A. Additional FTE

In response to ORA discovery, SCG/SDG&E stated that the proposed additional FTE will be responsible for the following tasks/duties:[12]

- "Drive risk identification, analysis, and evaluation for both SoCalGas and SDG&E.
- Develop and maintain the risk register(s) and enhance methodologies for evaluating risks.
- Help integrate asset management processes and systems.
- Develop and maintain reporting and monitoring processes related to risk management.
- Interact with leadership team and support executive oversight needs.
- Work collaboratively with all business units to ensure a consistent and systematic approach to risk management throughout the companies.
- Facilitate communications and share best practices among business units.
- Perform other duties as assigned."

As the RAMP and SMAP proceedings continue to evolve and SCG/SDG&E continues to develop its risk analysis and risk assessment processes, ORA does not oppose the addition of one FTE to assist in these efforts.

B. Incremental Funding for Outside Expert Support

In discovery, ORA asked SCG/SDG&E to "[p]lease provide any draft scopes of work, engagement plans, or similar documents to be used by/for the experts in the manner described to 'continue to mature [SCG/SDG&E's] risk management

[12] SCG/SDG&E response to ORA data request ORA-SCG-073-NS4, Question 3.

practices.'"[13] While SCG/SDG&E was unable to provide any specific documents, it stated that "[t]he nature of the work is consistent as presented in the Revised Direct Testimony of Risk Management and Policy witness Diana Day (DD-24 – DD-27)" and that the covered activities include "supporting the development of the accountability reports, increasing the use of quantification in our assessment of risk and mitigation plans, continued involved participation in the S-MAP proceedings, creation of operating risk registries, and the integration of asset life cycle data with risk mitigation action and investment planning."[14]

Given the evolving nature of RAMP and SMAP and the uncertainty of future requirements stemming from the SMAP proceeding, ORA concludes that it is reasonable that specific tasks or scopes or work are not yet precisely defined. Therefore, it is reasonable for SCE/SDG&E to seek expert assistance, with the understanding that the requested funding will be used in the manner described above. As SMAP requirements crystalize and SCG/SDG&E's own risk assessment tools and methodologies mature, ORA would expect future requests to include more specific and/or detailed information on the services sought and deliverables expected.

ORA does not oppose SCG/SDG&E's request for incremental funding to contract with outside experts to continue to develop risk management practices as described above, but recommends that this funding be provided via a 1-way balancing account since Commission requirements may change and exact funding purposes have not been defined.

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[13] ORA data request ORA-SCG-073-NS4, Question 6.

[14] SCG/SDG&E response to ORA data request ORA-SCG-073-NS4, Question 6.

PART III: RAMP / GRC INTEGRATION

I. SUMMARY

In Chapter 2 of Ex. SCG-02-R/SDG&E-02-R, SCG and SDG&E summarize how and through what processes items in its RAMP filing were integrated into the General Rate Case.

II. ORA'S ANALYSIS

A. Risk Analysis Methodology

This GRC is the first GRC immediately following a RAMP proceeding. As discussed in Part II above, the Commission's increased focus on safety in the utilities' General Rate Cases will likely continue to evolve over the years to come, both in the RAMP/GRC processes and through the utilities' SMAP filings.

In the RAMP proceeding, the vast majority of parties' (including ORA's) and the Safety and Enforcement Division's (SED's) comments on SCG/SDG&E's RAMP focused on process improvements to future RAMPs and how SCG/SDG&E views and assesses risk writ large. For example, ORA's comments suggested, among other recommendations, that SCG/SDG&E report Risk-Spend Efficiency Scores for alternative mitigations (not just recommended mitigations) and that future RAMPs describe what timeframe risks were measured or proposed over.[15] The Coalition of California Utility Employees (CUE) noted that "SCG/SDG&E's RSE scores rely on SME inputs rather than objective data and cannot be used to compare risk spend efficiencies across chapters."[16] TURN noted many numerical concerns including

[15] Comments of the Office of Ratepayer Advocates on November 2016 Submission of Southern California Gas Company and San Diego Gas & Electric Company's Risk Assessment and Mitigation Phase. April 24, 2017. See: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M184/K628/184628106.PDF

[16] Opening Comments of the Coalition of California Utility Employees on San Diego Gas and Electric Company's and Southern California Gas Company's Risk Assessment Mitigation Phase Report and the Safety and Enforcement Division's Report, page 2. See: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M184/K628/184628102.PDF

comparability, the type of events assessed, and others.[17] Other parties' comments generally reflected similar concepts or recommendations.

In its GRC request, SCG/SDG&E has presented more detail on specific funding requests[18] and has associated each funding request with one or more risks detailed in the RAMP, as described in Ex. SCG-02-R/SDG&E-02-R.[19] This further definition represents improvement from the more general risks presented in RAMP, making assessment of requests more straightforward. However, parties' recommendations (including but not limited to those described above) are generally guidance for *future* RAMPs or SCG/SDG&E's risk analysis approach in general, which will continue to be developed over the next one to two RAMP/GRC cycles. As such, most of the critiques or recommendations are changes that will need to be made over a longer time period than a single RAMP-to-GRC transition.

Via discovery, ORA asked SCG/SDG&E to provide its best estimate of when certain recommendations will be implemented in its risk-management policy and RAMP/GRC process. While stating that the "requirements and associated timelines … are currently in transition" and that estimates are "based on SoCalGas and SDG&E's best estimate of timing considerations given what is known at this time," SCG/SDG&E responded that many of the recommendations are anticipated to be included in the next RAMP.[20] Multiple other recommendations, for example the ability to compare Risk-Spend Efficiency Scores across risks and reduced "bundling"

[17] Opening Comments of The Utility Reform Network on the SCG/SDG&E Utilities RAMP Report and SED Report. See: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M184/K628/184628667.PDF

[18] For example, SCG/SDG&E's request for its TIMP/DIMP programs including specific dollar amounts, forecasted program "units," and past historical data. In contrast, SCG's RAMP Risk (Chapter SCG-4) includes TIMP and its requirements generally without specific program costs or metrics.

[19] See Ex. SCG-02-R/SDG&E-02-R, pages JKY-3 through JKY-4.

[20] See SCG/SDG&E response to ORA-DR-090, Question 1. The recommendations specifically identified as such are: Development of Risk-Spend Efficiency (RSE) Scores for alternative mitigations (in addition to proposed mitigations); Inclusion of the timeframe over which risks/mitigations are measured; Provision of complete, unlocked RAMP workpapers at the time of RAMP application; Reporting of added, removed, or changed risks since last RAMP filing; and Identification of SME input used and any supporting metrics/data.

of mitigations, are more complex but are also anticipated in the next RAMP or depend on the specific risk and RAMP presentation.

While substantial room for improvement remains and precise future requirements have yet to be determined in the SMAP proceeding, SCG/SDG&E appears to be taking the Commission's recommendations into account and moving in the right direction.

Since a large number of recommendations focus on quantitativeness and comparability, ORA recommends that future RAMPs and GRCs address this issue directly by requiring utilities to describe what specific, tangible steps have been taken to move risk analysis and data to a more quantitative framework and make comparability between risks and mitigations possible. Such a requirement should reflect any Decision in the SMAP proceeding and provide parties information regarding what steps utilities are taking to meet the Commission's goals of increased quantitative data and analysis in risk assessment. ORA continues to support SCG/SDG&E's move toward a more quantitative method and more data gathering in the medium- to long-term[21] to provide a more quantitative risk assessment methodology and greater transparency in funding requests.

B. RAMP-to-GRC Funding Request Changes

At this time, the RAMP and associated risk metrics are insufficiently developed to dictate, or even substantially guide, funding decisions in the GRC. RAMP data and judgments, while potentially informative, are not appropriate to use in determining safety funding at this stage for two reasons.

First, the level of data and comparability in RAMP is not sufficiently mature to compare risks and provide appropriate levels of transparency as to how funding requests for those risks were developed. For example, each risk in SCG/SDG&E's RAMP was based on vastly different background data. Some risks (for example, third-party dig-ins) have a fairly well-developed level of detail with information on

[21] Although the SMAP proceeding is still ongoing and process changes will likely be an ongoing process, ORA would expect substantially more quantitative data and analysis within the next one to two SCG/SDG&E RAMP/GRC cycles (approximately 5-10 years).

specific location, timing, and type of pipeline affected.[22] Risk likelihood and consequence for other risks, such as workplace violence,[23] are based almost entirely on national statistics that may not necessarily be directly relevant to California utilities and have a wide range of possible outcomes based on potential mitigations. While SCG/SDG&E cannot at this time reasonably be expected to have the same type and quality of data for all risks, it is not appropriate to compare risk scores, expected results of mitigations, and funding of those mitigations between risks with such great differences in data quality and relevance to SCG/SDG&E assets.

In addition, the Commission has not yet fully determined how to assess so-called “cross-cutting” risks, which generally refers to risks whose drivers or outcomes are varied and not always easily quantified (for example, wildfire sparked by utility equipment). The same applies for cross-cutting mitigations that address multiple risks (for example, vegetation management, which can address both reliability and wildfire risk). Without better information or methodologies, parties and the Commission cannot be certain that risk scores, Risk-Spend Efficiency scores,[24] or mitigation effectiveness scores provide metrics sufficient for informed and accurate decision-making.

Secondly, the risks and mitigations discussed in the RAMP are not necessarily the same as those proposed in the GRC. As acknowledged by SCG/SDG&E witness Jamie York, “[t]he requested amounts for RAMP activities in the TY 2019 GRC may differ from what was presented in the November 2016 RAMP Report, for several reasons”[25] including that “GRC witnesses revisited the cost estimates developed in the RAMP Report.”[26] Given these changes and the witnesses’ freedom to change risk and mitigation proposals between the two

[22] See, for example, workpaper SCG-1-WP-RSE in I. 16-11-015 (SCG/SDG&E RAMP).

[23] See workpaper SCG-5-WP-RSE in I. 16-11-015 (SCG/SDG&E RAMP).

[24] In describing Risk-Spend Efficiency, Decision 16-08-018 stated that “is defined as risk reduction (difference between pre-mitigation and post-mitigation risk scores) divided by the cost of the risk mitigation program or project.” See D. 16-08-018, page 35. See: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M165/K862/165862364.PDF

[25] See SCG/SDG&E-02, page JKY-4, lines 15-16.

[26] See SCG/SDG&E-02, page JKY-4, lines 19-20.

proceedings, the use of RAMP risk scores, Risk-Spend Efficiency scores, or mitigation effectiveness scores in the GRC to dictate funding decisions is not reasonable at this time. ORA anticipates that over time, as the RAMP and SMAP processes mature, the changes between RAMP and the GRC should decrease.

Based on data provided by SCG/SDG&E,[27] ORA performed a high-level analysis of revisions between the potential funding requests described in RAMP and the actual requests for those programs (or any others added) in the GRC. While changes in programs' funding requests may not always be comparable or may be more complex than is reflected in a single number,[28] ORA's analysis is intended to provide a large-scale, general picture of how effectively SCG/SDG&E's RAMP filing reflects or predicts actually funding requests in the GRC, with the goal of improvement over subsequent RAMP cycles. The metrics discussed below are sufficiently general in that they apply to all programs lumped together or take an average of percentage changes. By their very nature, such metrics do <u>not</u> assess the reasonableness or value of any program, and should not be used in determining funding for any program or set of programs.

For purposes of the following description, the terms "program cost increases" and "program cost decreases" (or similar terms) refer to the difference between the actual GRC-requested cost and the average of the RAMP minimum and maximum range. Please see ORA workpaper 02 for calculations and further details.

For O&M spending, SCG's/SDG&E's total potential RAMP cost (the potential cost of all programs assessed) ranged from $494.88 million to $895.31 million. The total of the differences of each program's average predicted RAMP range and actual GRC request is $140.13 million below the RAMP estimate.[29] ORA observed that 80 of the 322 programs (25%) were in the RAMP-predicted range, while 242 (75%)

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[27] See SCG/SDG&E Response to ORA-DR-090, Questions 2 and 3.

[28] For example, it is conceivable that a program discussed in RAMP was not requested in the GRC because its mitigations were implemented in other programs, or vice versa.

[29] In other words, if the averages of every single SCG/SDG&E GRC-proposed program were subtracted from the averages of the RAMP programs as defined in RAMP, the difference would be $140.13M.

were not. Ignoring zero values (programs not included in RAMP), the median program decreased by $49,000 while the median percentage change from the RAMP average value was an 11.72% decrease. ORA notes a wide range of changes in individual programs and several outliers in the dataset. For example, the largest single program cost decrease[30] more than cancels out all increases to program costs.

ORA's analysis of capital spending assessed the sum of years 2017-2019 (vs. test year 2019 for O&M). For capital spending, SCG/SDG&E's three-year total potential RAMP cost (the potential cost of all programs assessed) ranged from $3.752 billion to $5.086 billion. The total of the differences of each program's average predicted RAMP range and actual GRC request is $1.942 billion. 36 of the 326 programs (11%) were in the RAMP-predicted range, while 290 (89%) were not. Ignoring zero values (programs not included in RAMP), the median program decreased by $3.477 million while the median percentage change from the RAMP average value was a 46.43% decrease. Similarly to O&M, ORA notes a wide range of changes in individual programs and several outliers in the dataset.

Table 3-2: RAMP-GRC Comparison ($ million)

	A	B	C	D
1		**RAMP Minimum**	**RAMP Maximum**	**GRC Request**
2	**2019 O&M**	$494.88	$895.31	$559.70
3	**2017-2019 Capital**	$3,752	$5,086	$2,394

The "decreases" above do not mean that SCG/SDG&E has necessarily reduced costs, cut back on programs, or presented reasonable costs in any or all programs. As described above, the use of the words "increase" or "decrease" simply indicates a change to SCG/SDG&E's request relative to the average of the RAMP range, which in many cases encompassed a wide range with a high upper bound.

[30] The program "Hydrostatic pressure testing of HCA pipelines" was reduced (relative to its RAMP range) by approximately $119 million, while all program cost increases totaled approximately $118 million.

ORA recommends that the data produced by the RAMP and integrated into this GRC be used to inform funding decisions, but not to dictate these decisions or bypass a traditional review of proposals and their alternatives.

PART IV: PIPELINE INTEGRITY MANAGEMENT

I. SUMMARY

In Ex. SCG-14 and Ex. SDG&E-11, SCG/SDG&E describe their Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP).

According to PHMSA, Gas Transmission Integrity Management programs entail improving pipeline safety through "Accelerating the integrity assessment of pipelines in High Consequence Areas (HCAs)," "Improving integrity management systems within companies," "Improving the government's role in reviewing the adequacy of integrity programs and plans," and "providing increased public assurance in pipeline safety."[31] PHMSA's gas distribution integrity management requirements "require operators, such as natural gas distribution companies, to develop, write, and implement an integrity management program" with elements including "understand[ing] system design & material characteristics, operating conditions & environment, and maintenance & operating history," "identify[ing] existing and potential threats," and "identify[ing] and implement[ing] measures to address risks."[32]

SCG/SDG&E's TIMP costs are essentially level relative to six years of recorded costs (2012-2017), while DIMP costs have increased substantially since 2014, with further increases expected through 2019.

SCG/SDG&E's TIMP costs are both labor and non-labor based and cost drivers "are based on the number of assessments…, repairs, and mitigation activities to achieve compliance."[33] Examples of assessments that fall under TIMP

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[31] See PHMSA Gas Transmission Integrity Management: Fact Sheet. https://primis.phmsa.dot.gov/gasimp/fact.htm

[32] See: PHMSA Gas Distribution Integrity Management Program (DIMP). https://primis.phmsa.dot.gov/dimp/

[33] SCG-14, page MTM-19, lines 16-21.

are In-Line Inspection (ILI), pressure testing of a pipeline, and internal corrosion analyses.[34] SCG/SDG&E's TIMP program is on an approximately 7-year cycle.[35]

SCG/SDG&E's DIMP costs are also both labor- and non-labor-based. SCG/SDG&E's DIMP is structured around Programs/Projects and Activities to Address Risk (PAARs), for which the cost drivers include "time required to gather necessary information, integrate and analyze that information, analyze potential mitigation activities, and implement the selected mitigation approach."[36] SCG/SDG&E's proposed DIMP PAARs starting in 2018[37] are:

- the Gas Infrastructure Protection Project (GIPP),
- the Sewer Lateral Inspection Program (SLIP),
- the Vintage Integrity Plastic Plan (VIPP),
- the Bare Steel Replacement Plan (BSRP),
- the Distribution Riser Inspection Project (DRIP), and
- the Damage Prevention Advisor Program (DPAR).

ORA recommends 2017 actual recorded TIMP ($106.129 million) and DIMP ($124.104 million) capital costs be adopted. ORA does not oppose SDG&E's and SoCalGas' 2018 and 2019 capital expenditure forecasts, as well as their 2019 expense forecasts.

II. ORA'S ANALYSIS

Based on SCG/SDG&E's testimony and responses to data requests, ORA compiled TIMP and DIMP cost data by cost type (capital vs. expense), utility (SCG vs. SDG&E), and totals for historical (2012-2017) and forecasted (2018-2019) values.

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[34] SCG-14, pages MTM-15 through MTM-16.

[35] SCG-14, page MTM-19, line 8.

[36] SCG-14, page MTM-28, lines 1-3.

[37] Starting in 2018, the Distribution Risk Evaluation and Monitoring System PAAR will be split into two PAARs: the Bare Steel Replacement Plan and the Vintage Integrity Plastic Plan. See SCG Response to ORA data request ORA-SCG-072-NS4, Question 01.

In addition, ORA requested additional information regarding specific DIMP PAARs and their costs in order to calculate scope of work for quantifiable PAARs and high-level unit costs for each PAAR.

Please see ORA workpaper 05 for these data, charts, and data sources.[38]

A. TIMP

Recorded and forecast TIMP costs separated by utility and cost category (capital vs. expense) are reproduced in the tables below. Please see ORA workpapers 05 through 08 for data sources:

Table 3-3: Recorded (2012-2017) and Forecast (2018-2019) TIMP Capital (In 2016 $'000)

	1	2	3	4	5	6	7	8	9
A		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
B	**SCG**	43,428	51,706	35,124	38,939	38,223	103,029	50,801	55,000
C	**SDG&E**	31,071	23,256	7,511	3,569	3,658	3,100	3,997	4,000
D	**Total**	74,499	74,962	42,635	42,508	41,881	106,129	54,798	59,000

Table 3-4: Recorded (2012-2017) and Forecast (2019) TIMP Expense (In 2016 $'000)

	1	2	3	4	5	6	7
A		**2012**	**2013**	**2014**	**2015**	**2016**	**2019**
B	**SCG**	48,066	45,052	43,425	38,995	41,654	44,351
C	**SDG&E**	4,908	4,086	4,998	4,023	4,717	5,000
D	**Total**	52,974	49,138	48,423	43,018	46,371	49,351

As stated in SCG/SDG&E's testimony, TIMP work is performed on a seven-year cycle[39] and is "primarily based on the timing and intervals of prior assessments."[40] ORA's analysis of TIMP costs[41] in constant 2016 dollars indicates that this statement is generally correct. ORA recommends adopting 2017 adjusted

[38] Some components of workpaper 05 are excerpted or reproduced below.

[39] SCG-14, page MTM-19.

[40] SCG-14, page MTM-iv.

[41] See ORA workpaper 02, pages 0035-0036.

recorded capital expenditures for TIMP. ORA does not oppose SCG/SDG&E's 2018-2019 proposed TIMP forecasts.

B. DIMP

Recorded and forecast DIMP costs separated by utility and cost category (capital vs. expense) are reproduced in the tables below. Please see ORA workpapers for data sources:

Table 3-5: Recorded (2012-2017) and Forecast (2018-2019) DIMP Capital (In 2016 $'000)

	1	2	3	4	5	6	7	8	9
A		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
B	**SCG**	2,544	6,784	13,771	30,824	60,854	90,396	74,383	160,000
C	**SDG&E**	1,392	2,184	1,925	4,235	22,346	33,708	20,219	45,000
D	**Total**	3,936	8,968	15,696	35,059	83,200	124,104	94,602	205,000

Table 3-6: Recorded (2012-2016) and Forecast (2019) DIMP Expense (In 2016 $'000)

	1	2	3	4	5	6	7
A		**2012**	**2013**	**2014**	**2015**	**2016**	**2019**
B	**SCG**	20,124	41,492	26,363	24,081	32,739	38,359
C	**SDG&E**	6,059	3,320	2,202	1,649	3,027	6,000
D	**Total**	26,183	44,812	28,565	25,730	35,766	44,359

Via data requests, ORA further investigated the specific PAARs that formed SCG/SDG&E's DIMP. Specifically, ORA requested the unit measurement for each PAAR (for example, "number of lines inspected" or "number of remediated sites"),[42] whether the scope of any PAARs had changed or would substantially change over the 5-year historical and 3-year forecasted period,[43] the total costs of each PAAR,[44] and information on any non-PAAR overhead costs.[45]

[42] SCG's response to data request ORA-SCG-072-NS4, Questions 02 and 03.

[43] SCG's response to data request ORA-SCG-072-NS4, Question 04.

[44] SCG's response to data request ORA-SCG-095-NS4, Question 01.

[45] SCG's response to data request ORA-SCG-095-NS4, Questions 02 and 03.

Based on this information and SCG/SDG&E's testimony, ORA performed an analysis of work levels in each PAAR and the corresponding unit cost (i.e., the dollars it cost SCG/SDG&E, on average, to perform one site inspection, replace one mile, etc.). ORA also calculated an average-normalized unit cost for each program so that the PAARs changes over time could be compared. In its calculation, ORA combined the DREAMS, VIPP, and BSRP PAARs since DREAMS will be separated into VIPP and BSRP starting in 2019.[46]

The unit cost of the SLIP, DRIP, and DREAMS/VIPP/BSRP PAARs are essentially flat over the examined time period.[47] The unit cost of the GIPP PAAR is increasing, likely due to the fact that the units ("Inspections/Mitigations") has dropped dramatically since its peak in 2013, meaning that program fixed costs are spread over fewer units.

ORA did not forecast or quantitatively analyze SCG/SDG&E's proposed DPAR program because of a lack of historical data and difficulty in quantifying the PAAR's output. Instead, ORA requested additional information regarding DPAR from SCG/SDG&E via data request, including overlap with 811 services, similar programs at other utilities, and essential duties of program staff.[48,49] While the program is, at this time, still substantially lacking in specific definition, ORA does not oppose its creation and the requested funding at this time. ORA notes that, given SCG/SDG&E's ranking of "Third-Party Dig-ins" as SCG and SDG&E's first- and second-greatest risks in their RAMP filing[50] and the fact that relatively good data exists for the third-party dig-in risk, the DPAR should be examined for effectiveness in the next GRC and/or RAMP filing.

ORA recommends adopting 2017 adjusted recorded capital expenditures for DIMP. ORA does not oppose SCG/SDG&E's proposed 2018-2019 DIMP forecasts.

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[46] SCG's response to data request ORA-SCG-095-NS4, Question 01.

[47] See ORA workpaper 05, page 0045.

[48] SCG response to data request ORA-SCG-095-NS4, Questions 04, 05, and 06.

[49] SCG response to data request ORA-SCG-155-NS4.

[50] See Chapters SCG-1 and SDGE-2 in I. 16-10-015 (SCG/SDG&E Risk Assessment Mitigation Phase filing).

PART V: PSEP

I. SUMMARY

In its GRC, SoCalGas requests $251.95 million in O&M costs (of which $236.38 million is for pressure test projects) and $649.33 million in capital costs (of which $365.69 million is for replacement and pressure test projects).[51] In pipeline projects, SoCalGas' request covers 16 hydrotest projects (5 in the fourth year) and 13 replacement projects (2 in the fourth year[52]).

In capital projects, SoCalGas requests $246.00 million for 284 "valve enhancement" bundles[53] spanning 2018-2019. SoCalGas requests authorization to record and collect all PSEP costs in a two-way balancing account.[54]

SoCalGas requests $6.17 million as an "allowance for pipeline failure," with this amount extrapolated from past failures and the failure rate used to predict future failures in the GRC period.[55]

ORA recommends that SCG/SDG&E's forecast be reduced by $100.189 million to $584.214 million.

II. ORA'S ANALYSIS

A. ORA's Pipeline Replacement and Hydrotest Cost Analysis Methodology

In order to set an appropriate upper threshold for forecasted PSEP costs, ORA developed statistical models for PSEP replacement and hydrotest projects, based on historical project costs from across California. ORA's analysis is based

[51] Ex. SCG-15, page RDP-iv.

[52] Project Line 44-1008 is allocated 50% to the current GRC period and 50% to the fourth test year. For purposes of the summary above, project Line 44-1008 was not considered in the fourth test year.

[53] Ex. SCG-15-WP-S, page 311.

[54] Ex. SCG-15, page RDP-A-22.

[55] Ex. SCG-15, page RDP-A-34.

upon five years of cost data associated with natural gas pipeline replacement and pressure testing data by Pacific Gas & Electric Company (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Company.

ORA's statistical models use linear regression analysis to assess natural gas pipeline replacement and hydrotest costs. Linear regression produces an equation that describes how cost relates to certain project factors, allowing one to predict how much a project should cost, on average, based on its characteristics. ORA uses the model's prediction with an additional margin to account for factors that may additionally raise costs to set an upper bound for a reasonable cost forecast. The additional margin is calculated using prediction intervals, which represent how likely the cost of a given future project is to fall within certain identified ranges. ORA's upper threshold represents a 90% cumulative interval.[56] Thus, ORA's threshold represents the maximum a project should be expected to reasonably cost, not a prediction of what the actual cost will be, and is expected to exceed the actual cost in many cases.

For a full technical description of ORA's cost modeling, please see ORA supporting attachment 16, the testimony of Mrs. Nusrat Molla in A. 17-03-021 (SCG/SDG&E PSEP Forecast Proceeding),[57] which describes ORA's Statistical Model and Data.[58]

1. Use of Conservative Assumptions

No model, predictor, or analysis is perfect or will provide accurate predictions all of the time. ORA is aware of the limitations of numerical models as applied to the real world, and as such took all reasonable opportunities to build conservative assumptions into its analyses.

[56] In other words, based on ORA's model, there is a 90% probability that a future project will fall at or below the cost threshold established.

[57] In A. 17-03-021, Mrs. Molla's testimony is Exhibit ORA-02.

[58] See ORA workpapers 09 through 28 for full project-by-project calculation and the data and source documents underlying ORA's replacement and hydrotest models.

In the context of this testimony and its underlying data and analysis, “conservative assumptions” generally means the inclusion of more data rather than less, the inclusion or use of higher cost values rather than lower, and methodological approaches and techniques that provide a higher level of confidence in the maximum threshold even when a lower threshold or more narrow range may be acceptable or reasonable.

Many of these assumptions are discussed in supporting attachment 16, the testimony of Mrs. Molla in A. 17-03-021. ORA outlines them in greater detail here:

- **Use of 90% interval**: for each project, ORA’s models produced a single, numerical cost value that is the expected cost for that project given the parameters included in the model. However, as discussed above, ORA recommends using the 90% cumulative interval to increase confidence that the cost accurately reflects real-world conditions and sufficiently takes variability into account. In the dataset ORA used, the use of a 90% cumulative interval represents, on average, a 76% increase in nominal dollar terms over the expected-value cost.[59]

- **Use of Phase 1A data:** ORA notes that the vast majority[60] of the projects in the database are early-phase PSEP projects. Generally, Phase 1 (PG&E) and 1A (SCG/SDG&E) projects are in more urban areas and are shorter lengths,[61,62] making them, on average, comparatively more expensive on a per-mile basis[63] than Phase 1B or Phase 2 PSEP projects. However, ORA conservatively assumed that SCG/SDG&E’s forecasted Phase 1B projects would be comparable to Phase 1A projects.

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[59] See ORA workpaper 09, page 0067.

[60] Of the 673 projects in the database, 43 are from the SCG/SDG&E Utilities PSEP program (which has only completed Phase 1A projects) and 381 are PG&E projects with a start date before January 1, 2015, indicating a Phase 1 project. Together, these represent approximately 63% of all projects.

[61] See Prepared Testimony of PG&E in A. 13-10-017 (PG&E PSEP Update), page 2-2.

[62] See SCG/SDG&E PSEP Decision Tree, Attachment 1 to D. 14-06-007. See: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M096/K599/96599589.pdf.

[63] See Figure 1 above.

- **Cost Improvement Over Time:** In requesting Commission approval of its Performance Partner Program in 2014,[64] SCG/SDG&E stated that by "engaging in longer-term agreements for numerous projects with the partners, SoCalGas and SDG&E expect to achieve lower costs by promoting a sustained workforce with less downtime"[65] and that the program is designed to achieve "lower cost to contract" and "lower cost to construct."[66] While ORA agrees that it is reasonable to expect a utility to decrease costs over time with increased efficiencies and increased experience, as a conservative assumption and because of the uncertainties involved, this expectation was not incorporated into the model. In other words, the model assumes that costs will not decline over time due to the Performance Partner Program or increased efficiencies.

The items listed above are not a comprehensive list of all conservative assumptions[67] ORA used in its model, but rather examples of how a conservative approach was used to provide a high level of confidence that ORA's models encompass the maximum costs that could be reasonably anticipated for the projects in question.

2. Model Update

For its use in this GRC, ORA has updated and further developed its models[68] to include additional and more-recent replacement and hydrotest cost data. ORA's methodology is generally the same as described in workpaper 16, but has been

[64] The Performance Partner Program has been described as "a specialized contractor selection program" that uses a "hybrid approach" incorporating fixed bids from contractors for batches or sets of work, instead of individually bidding every project or project component. See Chapter 1 Testimony of Rick Phillips in A. 14-12-016 (PSRMA), page 20, December 17, 2014.

[65] Prepared Supplemental Testimony of Rick Phillips in A. 14-12-016 (PSRMA), page 17, lines 13-15. April 17, 2015.

[66] Prepared Supplemental Testimony of Rick Phillips in A. 14-12-016 (PSRMA), page 17, lines 8-9. April 17, 2015.

[67] For example, ORA also made conservative assumptions about projects that included multiple diameters.

[68] ORA's model was first created in 2016-2017 for use in SCG/SDG&E's PSEP Forecast proceeding (A. 17-03-021).

reapplied to the new, more inclusive, and updated dataset, yielding a different cost model and corresponding forecast thresholds (relative to A. 17-03-021).[69]

In addition to the numerous data sources previously contained in the database, the following data sources have been added to ORA's database of replacement and hydrotest projects (workpaper 15):

- TIMP (Transmission Integrity Management Plan) data from PG&E.
- TIMP data from Southwest Gas.
- TIMP data from SCG/SDG&E.
- The most recent available information from SCG/SDG&E's monthly PSEP Status Reports.[70]

In addition to the inclusion of more data in its database, ORA also updated its database to include cost escalation. All costs (and thereby, predicted values) are presented in 2016 dollars. Please see workpaper 10 for cost escalation rates and data sources.

Since its initial model development, ORA has also gathered additional information on project duration (i.e., the time between project construction start and when the project is placed back in service), which was found to be a quantifiable and statistically-significant factor in predicting cost.[71] The addition of project duration as a variable improved ORA's replacement cost model[72] and made modeling of hydrotesting costs possible[73] (compared to the non-model statistical analysis

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[69] The additional data (described below) includes approximately 240 projects spanning years 2006-2018.

[70] Due to an approximately 2-month lag in SCG/SDG&E's Monthly PSEP Reports and the timing of ORA's testimony preparation, ORA's database contains information from the December 2017 Monthly PSEP Report.

[71]As used above, "statistically-significant" means an extremely low calculated probability (substantially less than 5%) that a variable has no influence on cost and therefore an extremely high calculated probability that a variable has an influence on cost.

[72] ORA's initial model had a "predictive R-squared" of 0.61, while the new model has a predictive R-squared of 0.64. Predictive R-squared is a measure of how well the model will predict new values and ranges from 0 to 1.

[73] In A.17-03-021, ORA's hydrotest model was not significantly better than a simple average, whereas the new model has a predictive R-squared of 0.24. See Supporting Attachment Testimony of Nusrat Molla in A.17-03-021.

performed previously). The inclusion of project duration also helps account for project cost variances due to a variety of circumstances (since factors that raise costs, such as a hard-to-access location or delays due to specific environmental requirements, often lead to delays or longer construction times).

B. SoCalGas' PSEP Forecast Costs Should be Adjusted

ORA applied its cost model to 19 of the 29 PSEP projects in SCG/SDG&E's application. Of the remaining ten projects, eight[74] were out of the models' range (making statistical analysis using ORA's models inadvisable from a statistical standpoint) and two[75] contained substantial valve work (making ORA's model inapplicable, since it does not directly account for the inclusion of substantial valve work).

Of the 19 test and replacement projects assessed, eleven fall above ORA's recommended 90% prediction interval threshold (see below). ORA recommends that SCG/SDG&E's forecast be adjusted to the 90% prediction interval upper limit for these projects, leading to a total forecast (including non-assessed projects) of $584.214 million,[76] a reduction of $100.189 million compared to the SoCalGas forecast.

[74] These projects are: 235 West Section 1, 235 West Section 2, 235 West Section 3, 2000 Blythe to Cactus City Hydrotest, 85 Elk Hills to Lake Station, 44-1008, 1030, and 2001 East.

[75] These projects are: 36-1032 Section 11 and 36-1032 Section 12.

[76] This total includes projects not assessed by ORA. See Table 03-08 below.

Table 3-7 below shows Applicant's forecast and ORA's recommended forecast for assessed replacement and hydrotest projects.

Table 3-7: ORA Assessed Projects and Forecast Adjustments

	A	B	C
1	**Project**	**Applicant Forecast**	**ORA Recommended Forecast**
2	407	$5,150,003	$5,150,003
3	1011	$5,166,590	$4,285,683
4	2000 Chino Hills	$45,335,233	$8,349,113
5	2000 Section E	$15,519,987	$7,852,455
6	2001 W Section C	$26,228,994	$9,679,517
7	2001 W Section D	$29,276,933	$11,022,926
8	2001 W Section E	$14,181,668	$7,755,309
9	36-9-09 North Section 12	$9,812,585	$8,407,696
10	36-9-09 North Section 14	$19,980,133	$17,635,298
11	36-9-09 North Section 15	$14,193,433	$14,119,335
12	36-9-09 North Section 16	$18,035,570	$18,035,570
13	36-1032 Section 13	$17,811,294	$17,811,294
14	36-1032 Section 14	$13,937,352	$13,937,352
15	2000-E Cactus City Compressor Station	$6,697,990	$6,697,990
16	225 North	$15,463,919	$7,673,951
17	2001 West	$8,417,661	$6,606,734
18	2005	$3,359,158	$3,359,158
19	2001 East Replacement	$3,798,756	$3,798,756
20	5000	$4,486,491	$4,486,491
21	***Total of Assessed Projects***	***$276,853,750***	***$176,664,631***

As described above, ORA's statistical models rely on a database of projects of historical pipeline replacement and hydrotest projects. One aspect of ORA's models is the use of project length to determine a forecasted cost. However, eight of the projects in SCG/SDG&E's application had lengths greater than any projects in

ORA's database, making prediction for those eight projects using the model statistically questionable.

Table 3-8: Non-Assessed Projects

Project Name	Applicant Forecast	Reason for ORA Non-Assessment
235 West Section 1	$53,767,963	Out of Model Range
235 West Section 2	$36,860,059	Out of Model Range
235 West Section 3	$17,489,297	Out of Model Range
2000 Blythe to Cactus City Hydrotest	$51,845,055	Out of Model Range
85 Elk Hills to Lake Station	$88,905,860	Out of Model Range
44-1008	$76,581,831	Out of Model Range
1030	$25,355,229	Out of Model Range
2001 East	$21,450,100	Out of Model Range
36-1032 Section 11	$8,692,307	Contains Valve Work
36-1032 Section 12	$26,601,263	Contains Valve Work
Total of Non-Assessed Projects	***$407,548,964***	

Given the range of length over which the model accurately predicts costs, it is possible that some or all of these projects could have reasonably been assessed using ORA's model, and ORA is not aware of any non-length factors that prevent them from being compared. However, in the interest of applying the model conservatively and attempting to avoid subjective judgments regarding how far out of its range the model can reasonably be extrapolated, ORA chose not to evaluate the eight projects using its model. Similarly, two projects included substantial valve work, making them markedly different than projects in ORA's database; it is not clear that their costs are appropriate for statistical analysis using ORA's model. For these reasons, ORA takes no position on SoCalGas' forecast for these projects.

ORA notes, however, that most of the ten projects would have been above ORA's recommended threshold if so evaluated, but for the reasons described above, ORA does not recommend using the model for those specific projects.

C. Balancing Account Treatment Should be Denied

ORA opposes SoCalGas' request for 2-way balancing account treatment of its PSEP forecasts. The fact that time will lapse between cost estimates and construction does not alone warrant balancing account treatment, and SoCalGas has not demonstrated that the forecasted PSEP projects are inherently unpredictable in their nature such that a balancing account is necessary.

SoCalGas' per-project estimates are fairly well-developed and the majority contain contingencies of up to 20% in certain categories to account for some level of cost uncertainty.[77] Cost changes over time or changes from when an estimate is developed are not unusual or specific to the PSEP program, and should reasonably be integrated into the estimating process and covered by the contingency forecasts. This is especially true for large construction and maintenance projects like PSEP, with which SoCalGas has substantial experience.

As of the time of filing their current GRC, SoCalGas had completed fifty PSEP and TIMP projects[78] and had prepared cost estimates for dozens more.[79] This experience in estimating indicates that SoCalGas has had ample time to refine its PSEP estimating methodologies and details therein, obviating the need for a balancing account.

As discussed by TURN/SCGC in A.17-03-021 (SCG/SDG&E PSEP Forecast Application),[80] PG&E completed its entire PSEP program without any balancing account treatment under a single, forecasted cost. SoCalGas has provided no evidence showing that it is incapable of managing its projects to a fixed budget or that its own projects' costs are inherently more unpredictable than PG&E's.

The Commission should deny SoCalGas' request for a 2-way balancing account for PSEP costs regardless of the forecast dollar amount adopted.

[77] See, for example, Attachment "ORA-SCG-047-NS4 Q01 CONFIDENTIAL 2001WD Ph2 Stage 3 Est 01-19-17_redacted.xlsx" to ORA data request ORA-SCG-047-NS4, Question 01. Tab "CM", column Q.

[78] See ORA workpaper 10 (ORA database of projects).

[79] SCG/SDG&E presented 29 cost estimates in this GRC and 12 in A. 17-03-021.

[80] See Direct Testimony of Catherine E. Yap on Behalf of The Utility Reform Network and The Southern California Generation Coalition in A.17-03-021, pages 4-5.

D. SoCalGas' Failure Contingency Allowance Should be Granted, Unless Balancing Account Treatment is Granted

SoCalGas' failure rate extrapolation on a per-mile basis is reasonable and the contingency allowance should be granted, provided that balancing account treatment is denied (see Section II-C above). ORA recommends that future GRCs and stand-alone PSEP applications provide updated failure-rate information so that contingency amounts accurately reflect current and actual conditions.

If the Commission grants balancing account treatment to SCG/SDG&E's PSEP, the contingency allowance should be denied, as the costs associated with any hydrotest failures will be reflected in and collected via the balancing account, obviating the need for a specific, pre-funded allowance.

E. SoCalGas' Proposal for Project Substitution Should be Modified to Allow for Greater Analysis and Oversight

SoCalGas' request for authority to substitute PSEP projects[81] should be modified to allow for more in-depth analysis of any proposed project substitutions. ORA recommends a working group that could expedite the approval of project substitutions, as is used for approval of certain interstate gas capacity contracts.

ORA understands that projects specifics can vary and that factors not within SoCalGas' control can cause delays or increase cost. In such situations, project substitutions may be the most appropriate avenue to continue important safety work and/or save ratepayer dollars. However, SoCalGas' substitution process as proposed is too vaguely defined and abdicates substantial Commission authority to review forecasts and their associated costs.

SoCalGas' proposed condition that "costs of completing the substituted project(s) would not cause SoCalGas to exceed the aggregate amount authorized by the Commission in this Application"[82] is alone insufficient for substitution. At the very least, the scope of the substitute project should be well-defined and similar to the original project. This will help reduce the possibility of substantial changes to a

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[81] SCG-15, page DRP-A-56.

[82] SCG-15, page RDP-A-56.

project or substitution of large, complex projects with potentially smaller, simpler projects that costs the same dollar amount. For example, the replacement of a hypothetical $30 million, 20-mile hydrotest project with a $30 million, 1-mile hydrotest project would clearly warrant further examination. However, in the scenario proposed by SCG/SDG&E, such a substitution would require nothing more than a Tier 1 Advice Letter noticing the substitution. The potential issues raised by such a process are not purely hypothetical; ORA has previously filed testimony documenting a PSEP hydrotest project that more than doubled in cost while its defined length increased by less than 2%.[83]

ORA recommends that project substitutions be handled through an expedited “pre-approval” process similar to what the Commission uses in evaluating some interstate gas capacity contracts, as discussed in D.04-09-022.[84] Through this process, the utility consults with ORA, TURN, and the Commission’s Energy Division regarding interstate gas capacity contracts to expedite the approval of such contracts before the Commission. Generally, contracts are approved quickly, but where no agreement is reached, the utility can file its request via Advice Letter.[85] The Commission retains its standard authority to approve or deny the contract. This expedited pre-approval process has worked well for interstate gas capacity contracts and allows parties to work collaboratively and avoid the administrative and legal work necessary for a full filing, request for modification of a Decision, or Tier 3 Advice Letter. ORA would recommend a similar working group for PSEP project substitution be formed of SCG/SDG&E, Energy Division, ORA, TURN, OSA, and SED.

Alternatively, project substitution could be allowed in a narrow, well-defined set of circumstances or if the projects are of similar cost and of similar scope. For example, substitute projects should be of the same type (hydrotest, replacement,

[83] See ORA Prepared Testimony in A. 14-12-016 (PSRMA), page 27.

[84] D. 04-09-022, page 29. See: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/39721.PDF

[85] D. 04-09-022, page 28. See: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/39721.PDF

abandonment, etc.), approximately the same length, have approximately the same cost, and not contain major factors that would unusually raise or depress project cost.

If the Commission does not utilize the working group approach recommended above nor better defines substitution criteria, the authority to substitute projects should be denied, as it is not sufficiently well-defined and removes parties' and the Commission's ability to review forecasted PSEP projects.

F. SCG/SDG&E's Interpretation of the Code of Federal Regulation Subpart J is Incorrect and Should be Clarified by the Commission (Li)

1. SoCalGas/SDG&E's Request for Commission's Clarification on Pipelines Installed before 1970

In Ex. SCG-15 on the Pipeline Safety and Enhancement Plan (PSEP), SoCalGas and SDG&E requested the Commission clarify State policy regarding pipelines with documentation of pressure tests pre-dating the 1970's adoption of the federal pressure testing requirements.[86] Both Commission decisions and Federal Regulations have clearly identified the State's policy and have acknowledged the appropriateness and validity of pre-1970 pressure testing.

2. Historical Background of Pressure Test Standards

Transmission pipelines generally undergo pressure tests at the time of installation.[87] Depending on when the installation took place, the test standards vary. Title 49 of the Code of Federal Regulations (CFR) Section 192 came into effect on November 12, 1970 (49 CFR 192).[88] Prior to that the applicable industry standard

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[86] See Exhibit SCG-15, Direct Testimony of Rick Phillips (Pipeline Safety and Enhancement Plan (PSEP)), at pp. RDP-A-56 to RDP-A-57.

[87] Since 1935, the American Standards Association (ASA) has required pressure testing either before or after installation. Since 1955, the ASA has been more prescriptive in pressure testing, and General Order 112 (in 1961) required pressure testing for pipeline operating at or above 20% of its specified minimum yield strength with a minimum 1 hour hold at the test pressure. Prior to 1961, there were some exemptions from testing including freezing conditions and poor water quality.

[88] 49 CFR, Section 192.619 (49 CFR 192.619), excluding subsection 192.619(c), requires pipelines to be tested to standards as set in 49 CFR 192 Subpart J (Subpart J). See supporting attachment 29 for 49 CFR 192.619 and supporting attachment 30 for Subpart J.

was the American Standards Association (ASA) standards for Gas Transmission and Distribution Piping Systems B31, in the American Standard Code for Pressure Piping, which was restructured and reorganized in ASA B31.8 in 1955 (1955 Code). For the comparison between 49 CFR 192.619, Subpart J, and the 1955 Code, please refer to supporting attachment 35 to this testimony. The 1958 edition of ASA B31.8, which had little change for pressure testing compared to the 1955 Code, were the industry standards that served as the basis for General Order (GO) 112, which became effective on July 1, 1961.[89] Pressure testing standards, however, date back to 1935.[90]

3. Application (A.) 11-11-002, the Three Subsequent Rehearings, and Order Denying a Fourth Rehearing

On November 1, 2011, SoCalGas and SDG&E filed A.11-11-002 for a safety enhancement plan. In response, in Decision (D.) 14-06-007 (PSEP Decision), the Commission approved SoCalGas' and SDG&E's Decision Tree analytical approach in identifying and prioritizing pipelines to be replaced or pressure tested.[91] After the first application for rehearing was denied in D.14-11-021 (First Rehearing), the Commission stated its intent in D.15-03-049 (Second Rehearing Decision), "[t]o conclusively determine whether ratepayers or shareholders should cover the cost to pressure test pipeline installed between 1956-1961…."[92]

4. D.15-12-020, the Third Rehearing Decision to A.11-11-002

In D.15-12-020, The Commission interpreted the previous Second Rehearing Decision as a recognition "*that it would not be appropriate for ratepayers to pay twice to pressure test pipeline – first in the 1950s prior to service, and then again*

[89] See Attachment to ORA-1-RH2 of A.11-11-002

[90] Although the 1958 edition of the ASA B31.8 Code was used when GO 112 was created, the 1955 Code is substantively similar in regards to pressure testing.   See Attachment to ORA-1-RH2 of A.11-11-002.

[91] See supporting attachment 34 for Attachment 1 to D.14-06-007, or: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M096/K599/96599589.pdf

[92] See supporting attachment 33 for D.15-03-049 at Ordering Paragraph 3, or: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M144/K835/144835483.PDF

now due to lack of records of the first test – and reopened the record granting rehearing for the purpose of these determinations."[93] In response to an ORA's data request, "the Utilities [SoCalGas and SDG&E] have located pressure test records for 678 miles and are missing records for 62 miles or less than 8% of the total mileage."[94]

Ordering Paragraph No. 1 of D.15-12-020 directed (emphasis added):

> *SoCalGas and SDG&E must exclude from regulated revenue requirement all costs associated with pressure testing pipeline segments installed between January 1, 1956 and July 1, 1961, where pressure test records are not available that provide the minimum information to demonstrate compliance with the industry or regulatory strength testing and record keeping requirements then applicable*; further, where such pipeline segment is replaced rather than pressure tested, the utility must absorb an amount equal to the average cost of pressure testing a similar segment, or where such pipeline segment is abandoned, the utility must absorb the undepreciated plant in service balance.[95]

In the above, the Commission stated that, if test records are not retained for pipelines installed between 1956 and 1961, the utilities' shareholders – instead of the ratepayers – shall cover the cost of testing those pipelines for the second time. The Commission has already found that from 1956 onwards, SoCalGas/SDG&E (in addition to PG&E) pressure tested their pipelines and that if the utilities did not retain these records then shareholders are to pay for the costs of retesting the pipelines.[96] By adopting D.15-12-020, the Commission also recognized the validity of past pressure tests which are compliant with the 1955 Code, even though such tests

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[93] See supporting attachment 32 for D.15-12-020, at pp. 3-4, or: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K980/156980952.PDF

[94] See ORA Exh. 8, at p. 9, (relying on the SoCalGas and SDG&E's response to DRA-DAO-16). See also D.15-12-020, at p. 14 at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K980/156980952.PDF

[95] D.15-12-020, at p. 24. See: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K980/156980952.PDF

[96] The original PSEP decision made a similar finding, but covering from July 1, 1961 onwards.

were carried out prior to the adoption of the federal pressure testing requirements in 1970.

5. D.16-06-024, the Fourth Rehearing

SoCalGas and SDG&E contested and filed an application for Rehearing of D.15-12-020, which was denied by the Commission in D.16-05-020. There, the Commission stated that it has (emphasis added):

> … repeatedly acknowledged the time periods during which voluntary versus mandatory testing and record retention requirements were in place. Our decision did not change that, nor did it find the Utilities [SoCalGas and SDG&E] were required to follow GO 112 or the ASA Code between 1956-1961.
>
> But that does not mean the cost to retest pipeline installed during that time period automatically warranted approval….
>
> Public Utilities Code section 451 provides that only just and reasonable costs will be allowed. And the Commission has authority to disallow any cost request, or portion thereof, if we find the costs to be unreasonable. For example it is well established that it is unreasonable for a utility to recover costs for expenses that it has not incurred. By the same token, it would be unjust and unreasonable for a utility to recover twice for the same product or service.
>
> *Here [in D.16-06-024], it could be determined with reasonable certainty that allowing ratepayer recovery for the utilities cost requested would allow them to recover twice for the same activity.* The Utilities [SoCalGas and SDG&E] should and do know such recovery would run counter to established ratemaking principles, as well as other utility PSEP decisions. The Utilities may not like the outcome but it does not mean they had no way of knowing such costs could be disallowed.[97]

6. Determination of Pipeline Risks: PSEP vs. the Transmission Integrity Management Program (TIMP)

The Commission already determined, in A.11-11-002 (and R.11-02-019), that the standards to which PSEP is held is based on the age of the pressure test. For

[97] D16-05-024, at pp. 12-13. See: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M159/K708/159708536.PDF

example, a pressure test conducted in 1957 that meets the 1955 Code, as long as the test was held for at least one hour, satisfies PSEP requirement.[98]

Furthermore, both ASA and 49 CFR 192 provide the minimum standards. If an operator exceeded the 1955 Code, and doing so met the later 49 CFR 192 requirements, it is illogical for an operator to insist that the test is invalid. Federal regulations clearly indicate the validity of pre-1970 pressure tests in meeting 49 CFR 192.619(a)(2)(ii).[99]

For those tests that meet the test standards of the 1955 Code, if the utility determines a pipeline has sufficient risks involved with integrity (e.g. during regular inspections), then federal code allows pressure testing as one of the Transmission Integrity Management Program (TIMP) reassessment options. If the utility does not determine sufficient risks or that the risks to the pipeline are better assessed through other mechanisms (as listed in Table 3-9), these pipelines are then not required to be retested.

A section of pipe that meets the 1955 Code, with the one hour minimum duration which meets California's additional requirements for PSEP projects, is compliant with Public Utilities Code section 958 whether the test itself was performed before or after the said standards first became effective in 1970. According to D.15-12-020, when the utility did not retain the proper records for a section of a pipe, retesting the same section of the pipe, is subject to shareholder funding, not ratepayer funding.

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[98] Refer to the Decision Tree analytical approach (in identifying and prioritizing pipelines to be replaced or pressure tested) as in Attachment 1 to D.14-06-007. See: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M096/K599/96599589.pdf

[99] "For steel pipe operated at 100 p.s.i. (689 kPa) gauge or more, the test pressure is divided by a factor determined in accordance with the following table:" The table then includes a column that states "Installed before (Nov. 12, 1970)" and a separate column for "Installed after (Nov. 11, 1970)".

Table 3-9 MAXIMUM REASSESSMENT INTERVALS FROM 49 CFR 192.939[100]

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years(**)
Confirmatory Direct Assessment	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in §192.941.

(*)A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**)A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

7. Conclusion

While ORA supports SoCalGas' and SDG&E's efforts to increase pipeline integrity, SoCalGas and SDG&E's attempt to universally retest pipelines passing pressure tests that are already compliant with pre-1970 standards, is an attempt to shift costs already assigned to shareholders onto ratepayers.

[100] See Attachment 36 for 49 CFR 192 § 939.

WITNESS QUALIFICATIONS – N. STANNIK

My name is Nils Stannik. My business address is 505 Van Ness Avenue, San Francisco, California. I am employed by the Office of Ratepayer Advocates (ORA) as a Utilities Engineer in the Energy Safety and Infrastructure Branch.

I received a Bachelor of Science in Engineering (BSE) degree in Electrical Engineering from the University of Michigan. I am a California-registered Engineer in Training (EIT).

Prior to joining ORA, I worked as an engineer designing and permitting residential photovoltaic systems throughout California. Prior to that, I worked as an electrical engineer on power and instrumentation technologies for large power generation plants.

Since joining the ORA in 2014, I have worked on various proceedings and projects related to pipeline safety, gas and gas safety, General Rate Cases, cost allocation, safety modeling, risk mitigation, wildfires, disadvantaged communities, utility asset transfers, electrical transmission, and electrical transmission and distribution security, among others. These include the Safety Model Assessment Proceeding (A.15-05-002), SCG/SDG&E's Risk Assessment Mitigation Phase (I.16-11-015), PG&E's Risk Assessment Mitigation Phase (I.17-11-003), multiple Pipeline Safety Enhancement Plan (PSEP) proceedings (A.14-12-016, A.16-09-005, A.17-03-021), and fire safety-related proceedings (A.15-05-006, A.15-09-010, A.17-07-011). I also regularly perform work on non-proceeding safety issues including gas pipeline events and safety recordkeeping/record management.

I am sponsoring this entire exhibit except for Part V Section F and the Witness Qualifications of Pui-Wa Li.

This completes my prepared testimony.

WITNESS QUALIFICATIONS – P. LI

My name is Pui-Wa Li. My business address is 505 Van Ness Avenue, San Francisco, California. I am employed by the Office of Ratepayer Advocates (ORA) as a Public Utilities Regulatory Analyst in the Energy Safety and Infrastructure Branch.

I have a Master's degree and a Bachelor's degree in Civil and Environmental Engineering, respectively, from Massachusetts Institute of Technology and University of California, Berkeley. I am a California-registered Engineer in Training (EIT).

Prior to joining the Commission, I worked as a research petroleum engineer and was a member of the European Association of Geoscientists and Engineers. My focus was on subsurface fluid flow modeling in porous medium (for hydrocarbon) and I have a US and overseas patents pending.

Prior to joining ORA, I worked on various proceedings and projects related to General Rate Cases filed by investors' owned water utilities.

Since joining ORA in 2018, I have been working on proceedings related to the safety of natural gas transmission pipelines, including the Gas Transmission and Storage General Rate Case (A.17-11-009).

I am sponsoring this Part V, Section F of this exhibit.

This completes my prepared testimony.

APPENDIX A - ORA PSEP PROJECT CALCULATIONS

Table 3-10: ORA Assessed Projects and Forecast Adjustments

	A	B	C	D	E	F
1	**Project**	**Applicant Forecast**	**ORA Model Prediction**	**ORA Model 90% Prediction Interval Upper Limit**	**ORA Recommended Adjustment (Lesser of B or D)**	**ORA Recommended Forecast (B - E)**
2	407	$5,150,003	$3,654,724	$6,001,236	$0	$5,150,003
3	1011	$5,166,590	$1,942,497	$4,285,683	$880,907	$4,285,683
4	2000 Chino Hills	$45,335,233	$5,977,189	$8,349,113	$36,986,120	$8,349,113
5	2000 Section E	$15,519,987	$5,487,675	$7,852,455	$7,667,532	$7,852,455
6	2001 W Section C	$26,228,994	$7,274,807	$9,679,517	$16,549,477	$9,679,517
7	2001 W Section D	$29,276,933	$8,571,435	$11,022,926	$18,254,007	$11,022,926
8	2001 W Section E	$14,181,668	$5,390,368	$7,755,309	$6,426,359	$7,755,309
9	36-9-09 North Section 12	$9,812,585	$3,725,314	$8,407,696	$1,404,889	$8,407,696
10	36-9-09 North Section 14	$19,980,133	$9,940,653	$17,635,298	$2,344,835	$17,635,298
11	36-9-09 North Section 15	$14,193,433	$7,484,302	$14,119,335	$74,098	$14,119,335
12	36-9-09 North Section 16	$18,035,570	$10,644,715	$18,622,620	$0	$18,035,570
13	36-1032 Section 13	$17,811,294	$18,056,096	$28,707,529	$0	$17,811,294
14	36-1032 Section 14	$13,937,352	$7,964,499	$14,837,256	$0	$13,937,352
15	2000-E Cactus City Compressor Station	$6,697,990	$4,894,427	$10,337,425	$0	$6,697,990
16	225 North	$15,463,919	$5,309,660	$7,673,951	$7,789,968	$7,673,951
17	2001 West	$8,417,661	$4,256,293	$6,606,734	$1,810,927	$6,606,734
18	2005	$3,359,158	$2,402,685	$4,749,125	$0	$3,359,158
19	2001 East Replacement	$3,798,756	$4,408,120	$9,584,995	$0	$3,798,756
20	5000	$4,486,491	$4,014,338	$8,967,782	$0	$4,486,491
21	***Total***	***$276,853,750***			***$100,189,119***	***$276,853,750***