Company: Southern California Gas Company (U 904 G)
Proceeding: 2024 General Rate Case
Application: A.22-05-015 /-016 (consolidated)
Exhibit: SCG-209-E

**REBUTTAL TESTIMONY OF**

**TRAVIS SERA AND AVIDEH RAZAVI**

**(GAS INTEGRITY MANAGEMENT PROGRAMS)**

**ERRATA**

**BEFORE THE PUBLIC UTILITIES COMMISSION**

**OF THE STATE OF CALIFORNIA**

SoCalGas

**~~May~~ June 2023**

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**REBUTTAL TESTIMONY OF**
**TRAVIS SERA AND AVIDEH RAZAVI**
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## I. SUMMARY OF DIFFERENCES

| **TOTAL O&M** - Constant 2021 ($000) | | | |
|---|---|---|---|
| | **Base Year 2021** | **Test Year 2024** | **Change** |
| SOCALGAS | 167,898 | 224,376 | 56,478 |
| CAL ADVOCATES | 167,898 | 163,396[1] | 4,502 |
| TURN | 167,898 | 200,924 | 33,026[2] |
| TURN-SCGC | 167,898 | 128,586 | 56,478 |
| ~~EDF~~ | ~~167,898~~ | ~~224,376~~ | ~~56,478~~ |

| **TOTAL CAPITAL** - Constant 2021 ($000) | | | | | |
|---|---|---|---|---|---|
| | **2022** | **2023** | **2024** | **Total** | **Difference** |
| SOCALGAS | 426,534 | 461,854 | 537,893 | 1,426,281 | - |
| CAL ADVOCATES | 426,534 | 461,854 | 537,893 | 1,426,281 | 0 |
| TURN | 297,066 | 308,155 | 398,113 | 1,003,334 | 422,947[3] |
| TURN-SCGC | 424,241 | 447,423 | 511,652 | 1,383,315 | 42,966 |

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1 Cal Advocates used SoCalGas's 2021 recorded Distribution Riser Inspection Plan (DRIP) expenses as presented in PAO-SCG-053-DAO_5760 Response 3a (*see* Appendix B) for the basis of calculation and then applied the proposed TY 2024 O&M DRIP adjustment on page 23 of Ex. SCG-09-WP to determine the DRIP recommendation, which was $17.334 million. However, by using the DRIP recorded 2021 expenses from PAO-SCG-053-DAO_5760 Response 3a, Cal Advocates excludes a portion of the Other PAARs line item (which is primarily Program Management) that are attributed to the DRIP. The correct TY 2024 O&M forecast for DRIP is $24.024 million, and based on Cal Advocates' recommendation of no increase for DRIP expenses, Cal Advocates' corrected TY 2024 forecast should be $20.478 million. (*See* Ex. SCG-09-WP (Workpapers to Prepared Direct Testimony of Amy Kitson and Travis Sera) May 2022 at 29.) Nevertheless, the reduction continues to be $3.547 million, so this does not affect the overall recommendation from Cal Advocates which is $163.396 million.

2 TURN recommended a reduction of $6.0 million for VIPP non-shared services, which is greater than SCG's proposed $5.133 million for VIPP. While the table reflects TURN's reduction, the correct amount of reduction should be $5.133 million.

3 TURN excluded IT costs, resulting in costs that are different than what was presented in workpaper Ex. SCG-09-CWP for BSRP and VIPP for 2022-2024. It is assumed that TURN does not take issue with the IT capital costs for the DIMP capital forecasts which are $2.500 million in 2022, $2.501 million in 2023, and $2.504 million in 2024 for VIPP and $1.795 million in 2022, $1.795 million in 2023, and $1.797 million in 2024 for BSRP. This assumption is reflected in the forecasts above. TURN recommends disallowing recovery for all investment into the accelerated replacement of Aldyl-A under VIPP resulting in a difference of $121.095 million in 2022, $142.751 million in 2023, and $190.358 million in 2024. TURN recommends a reduction of $8.373 million in 2022, $10.947 million in 2023, and an adjustment of $53.125 million in 2024 for BSRP.

| TOTAL CAPITAL - Constant 2021 ($000) | | | | | |
|---|---|---|---|---|---|
| EDF[4] | ~~-426,534~~ | ~~-461,854~~ | ~~-537,893~~ | ~~-1,426,281~~ | ~~-0~~[5] |

## II. INTRODUCTION

This rebuttal testimony of Travis Sera and Avideh Razavi, which supports the request of Southern California Gas Company (SoCalGas) for Gas Integrity Management Program costs, adopts the direct testimony of Amy Kitson and Travis Sera (Exhibit SCG-09)[6] and addresses the following testimony from other parties:

- The Public Advocates Office of the California Public Utilities Commission (Cal Advocates), as submitted by Ms. Dao Phan (Exhibit CA-03), dated March 27, 2023.
- The Utility Reform Network (TURN) and Southern California Generation Coalition (SCGC), as submitted by Ms. Catherine Yap (Exhibit TURN-SCGC-04-Revised), dated April 10, 2023.
- The Utility Reform Network (TURN), as submitted by Mr. Rod Walker (Exhibit TURN-05), dated March 27, 2023.
- Environmental Defense Fund (EDF), as submitted by Mr. Michael Colvin, Dr. Richard McCann, and Mr. Joon Hun Seong (Exhibit EDF-01), dated March 27, 2023.

As a preliminary matter, the absence of a response to any particular issue in this rebuttal testimony does not imply or constitute agreement by SoCalGas with the proposal or contention made by these or other parties. The forecasts contained in SoCalGas's direct testimony, performed at the project level, are based on sound estimates of its revenue requirements at the time of testimony preparation.

SoCalGas's Gas Integrity Management Programs testimony (Exhibit SCG-09) consists of the Operations and Maintenance (O&M) and capital expenses to manage federally mandated programs that were designed to continually identify and assess risks, remediate conditions that present potential threats to asset integrity, and provide safe, clean, and reliable service. These

[4] EDF's testimony makes broader recommendations that would impact SoCalGas and SDG&E requests more globally and as a result are not reflected as specific reductions.

~~[5] EDF did not develop quantitative forecasts.~~

[6] Ex. SCG-09 (Prepared Direct Testimony of Amy Kitson and Travis Sera (Gas Integrity Management Programs) May 13, 2022.

programs are the Transmission Integrity Management Program (TIMP), the Distribution Integrity Management Program (DIMP), the Storage Integrity Management Program (SIMP), and the Gas Safety Enhancement Programs (GSEP). Additionally, the testimony discusses the O&M and capital expenses to manage a newly proposed Facility Integrity Management Program (FIMP). The forecasts were developed based on both historical costs and consideration of best practices and changes to business processes.

SoCalGas remains committed to mitigating risks associated with safety, infrastructure integrity, and system reliability, including the implementation of regulatory requirements and best practices across various activities such as program management, data management, and project execution. The forecasts presented in direct testimony support SoCalGas's focus on providing safe and reliable service to customers at a reasonable cost. SoCalGas requests the California Public Utilities Commission (CPUC or Commission) adopt its Test Year 2024 (TY 2024) General Rate Case (GRC) forecast of $224.376 million for O&M, which is comprised of $221.877 million for non-shared services and $2.499 million for shared services. SoCalGas further requests the Commission adopt its forecast for capital expenditures of $426.534 million in 2022, $461.854 million in 2023, and $537.893 million in 2024.

**A. Cal Advocates**

The following is a summary of Cal Advocates' position as it pertains to the Gas Integrity Management Programs:[7]

- Cal Advocates recommends a decrease of $60.980 million in non-shared O&M expenses,[8] reducing SoCalGas's TY 2024 forecast from $221.876 million to $160.896 million, based on Cal Advocates' calculations of lower costs for TIMP, DIMP, and FIMP.
  - While Cal Advocates does not take issue with the scope of the TIMP as proposed for 2024, Cal Advocates claims SoCalGas's TIMP request is excessive and inadequately supported.
  - Cal Advocates takes issue with SoCalGas's Distribution Riser Inspection Plan (DRIP) request.

[7] Ex. CA-03 (Testimony of Dao A. Phan on behalf of Cal Advocates) March 27, 2023.

[8] *See* footnote 1, above, for corrections to Cal Advocates' O&M reduction.

- Cal Advocates opposes SoCalGas's request for the FIMP, claiming that the program activities are included in routine operations and maintenance activities and that the costs are not supported. However, should the Commission authorize the FIMP and a two-way FIMP balancing account (FIMPBA), Cal Advocates recommends Tier 3 advice letter filing for recovery of account balances above authorized levels).

- Cal Advocates does not oppose the $2.499 million shared O&M expenses for 2024.
- Cal Advocates does not oppose SoCalGas's request for Capital expenditures of $426.534 million in 2022, $461.854 million in 2023, and $537.893 million in 2024.
- Cal Advocates does not oppose SoCalGas's request for a two-way balancing account (*i.e.*, GSEPBA), but recommends that the recovery mechanism for the GSEPBA mirror that of the TIMPBA (*i.e.*, Tier 3 advice letter filing for recovery of account balances above authorized levels).

**B. TURN-SCGC**

The following is a summary of TURN-SCGC's position as it pertains to the Gas Integrity Management Programs:[9]

- TIMP
  - TURN-SCGC recommend a decrease of $39.311 million in non-shared O&M TIMP expenses, lowering SoCalGas's proposed $135.433 million for non-shared O&M TIMP expenses to $96.122 million.
  - TURN-SCGC contend that the TIMPBA should be converted to a one-way balancing account combined with a memorandum account that is subject to reasonableness review.

[9] TURN-SCGC-04-Revised (Prepared Testimony of Catherine E. Yap on behalf of TUN and SCGC) April 10, 2023.

- GSEP
  - TURN-SCGC recommend a decrease of $2.294 million in 2022, $14.432 million in 2023, and $26.241 million in 2024, which totals $42.966 million in GSEP capital expenditures, lowering SoCalGas's proposed $137.699 million for GSEP capital expenditures to $94.703 million. TURN-SCGC claim that the GSEP Balancing Account (GSEPBA) should be denied.

**C. TURN**

The following is a summary of TURN's position as it pertains to the Gas Integrity Management Programs:[10]

- TURN claims that the Commission should disallow recovery of all investment into accelerated replacements of Aldyl-A under the Vintage Integrity Plastic Plan (VIPP) or other similar programs; this would decrease capital expenditures by $118.595 million in 2022, $140.250 million in 2023, and $188.034 million in 2024, and would decrease O&M expenses by approximately $6 million in 2024.
- TURN asserts that the Commission should adopt a 3-year historical average for the Bare Steel Replacement Plan (BSRP) activities and reduce the BSRP capital recovery by $6.5784 million in 2022, $9.1516 million in 2023,[11] and $0.2806 million in 2024. TURN also states that, based on TURN's risk analyses and judgment.
- TURN argues that the Commission should disallow the inception of the FIMP and any activities that are reasonable should be reallocated to another appropriate program (*e.g.*, TIMP, SIMP); this would reduce the overall capital expenditures by $2.366 million in 2024 and $15.053 million in 2024 O&M expenses.

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[10] Ex. TURN-5 (Prepared Testimony of Rod Walker on behalf of TURN) March 27, 2023.

[11] *Id*. at 17 (the reduction of $9,151,600 is described as 2023 VIPP capital; however, based on context, SoCalGas assumes TURN meant 2023 BSRP capital and summarizes the recommendation accordingly.)

- TURN provides that SoCalGas has a reasonable basis for determining the scope and proper testing method for transmission pipelines needing reconfirmation of Maximum Allowable Operating Pressure (MAOP) under the ISEP.

### D. EDF

The following is a summary of EDF's position as it pertains to the Gas Integrity Management Programs:[12]

- EDF claims it is concerned the capital expenditure under the Gas Integrity Management Programs will amount to *de facto* stealth expansion of the gas system if based on faulty, exaggerated demand and account growth assumptions.
- EDF contends that, in cases where gas system upgrades are necessary for safety and reliability concerns, SoCalGas should be required to demonstrate the need and justification on a project-by-project basis.

## III. REBUTTAL TO PARTIES' O&M PROPOSALS

### A. Non-Shared Services O&M

| **NON-SHARED O&M** - Constant 2021 ($000) | | | |
|---|---|---|---|
| | **Base Year 2021** | **Test Year 2024** | **Change** |
| SOCALGAS | 165,778 | 221,877 | 56,099 |
| CAL ADVOCATES | 165,778 | 160,896[13] | (7,002) |
| TURN | 165,778 | 200,294 | 32,396 |
| TURN-SCGC | 165,778 | 182,565 | 14,667 |
| ~~EDF~~ | ~~165,778~~ | ~~221,877~~ | ~~53,979~~ |

The following sections respond to parties' positions on the non-shared O&M forecasts for the Gas Integrity Management Programs and confirm SoCalGas's projections are supported, reasonable, and should be adopted by the Commission in their entirety.

[12] Ex. EDF-01 (Testimony of EDF, Michael Colvin, Richard McCann, Ph.D., and Joon Hun Seong), March 27, 2023.

[13] *See* footnote 1, above, for correction to Cal Advocates' recommendation.

### 1. TIMP

#### a. Cal Advocates

Cal Advocates takes issue with SoCalGas's TIMP O&M non-shared services forecast and recommends a reduction based on a comparison of the level of activity between Base Year and TY 2024. Cal Advocates asserts that the forecast for assessment activities is excessive when compared to historical spend and that the increase is inadequately supported.[14]

Cal Advocates is mistaken and fails to recognize that integrity management activities vary over time and are not fully predictable based on assessment history alone. Threat and risk analyses, which are subject to change over time, are updated annually based on industry trends, assessment findings, and regulatory requirements. Moreover, the number and type of assessment tools utilized to inspect pipeline segments, and the findings that result from those assessments, are not static and can vary from pipeline to pipeline and from year to year. Since the inception of the TIMP, the tools and procedures used to execute the program's projects have evolved, and advanced tools are being deployed at an increasing rate, resulting in additional assessment and remediation activities and costs that are not reflected in historical spending. Additionally, existing tools and analytics continue to improve and result in increasingly more complex assessments and more remediations. These changes are generally expected to increase the resources (*e.g.*, employees, contractors, vehicles) needed to manage new findings.

Historical spend alone is not the best predictor of future spending needs because: (1) infrastructure continues to change and evolve (*e.g.*, aging, environmental changes such as earth movement or weather related outside forces); and (2) continuous improvement of assessments and results through on-going program modifications (*e.g.*, technological and process improvements, new regulatory requirements such as the recent Gas Transmission Safety Rule (GTSR), and resulting changes to threat identification and repair requirements). For example, new threat identification requirements and process improvements regarding the management of Stress Corrosion Cracking (SCC) have added over 1,000 miles of HCAs with a high or moderate susceptibility to SCC that now require cracking assessment.

It is not reasonable to assume that assessment activities, inspection tools, and remediations are static and fully reflected in past assessments. While SoCalGas's forecast is

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[14] Ex. CA-03 (Doa Phan) at 13.

informed by historical projects, unit costs were developed with SME input to account for future changes to the program. Using Line 293 as an example, the addition of a crack detection tool on a 2019 assessment increased costs by 1000% compared to the assessment that was conducted in 2012. Due to the additional cost of the tool and evaluations resulting from the increased number of anomalies detected and reported by this tool, the 2012 costs were not reflective of the 2019 costs. Acknowledging the variable nature of TIMP assessments, SoCalGas requests the continuation of the TIMPBA, which would allow for returns to ratepayers if actual costs are less than forecasted.

Cal Advocates also asserts that SoCalGas has already conducted non-HCA assessments, suggesting new federal requirements do not introduce new scope and costs. Cal Advocates seems to have misconstrued SoCalGas's forecast and discussion of non-HCA segments in Gas Integrity Management Programs direct testimony (Exhibit SCG-09). New federal requirements increase the number of miles and segments currently included within the TIMP scope.[15] Nonetheless, the increase in O&M expenses is primarily driven by the changes in processes and tools described above. However, new requirements for non-HCA segments (notably the changes to threat identification which are incremental to the assessment methods previously applied), as well as the extension of HCA remediation timelines to non-HCA segments, will increase SoCalGas's capital activities and expenditures to which Cal Advocates did not object.

**b. TURN-SCGC**

TURN-SCGC object to SoCalGas's TY 2024 O&M non-shared forecast for the TIMP, focusing reduction recommendations on assessment and remediation activities and program management. The Commission should reject TURN-SCGC's recommended reduction for the following reasons described below.

**i. Cost Forecasting By Number Of Projects Rather Than Miles Is Appropriate**

SoCalGas uses both the External Corrosion Direct Assessment (ECDA) and In-Line Inspection (ILI) assessment methods to assess over 95% of pipeline segments in the TIMP program. For pipelines assessed using ECDA, the cost to perform an inspection survey on a

[15] At the time of the TY 2024 GRC filing, SoCalGas had identified 69 segments on 15 distinct pipelines within scope for 49 CFR § 192.710. Seven pipelines with 13 segments had not previously been included in the TIMP and represent new Non-HCA pipelines and segments to be added to the TIMP.

pipeline is dependent on the length of the pipeline since the process requires measurements at fixed intervals along the length of the pipeline. However, the number of direct examinations that are required[16] is mainly independent of project length. Since excavation requirements are a function of pipe characteristics and inspection findings, a longer pipeline may have fewer required examinations, and a shorter pipeline may have more required examinations. As such, even in the case of ECDA projects, cost per mile metrics are not necessarily the most accurate means of forecasting for any particular project. High-cost projects tend to require more examinations and/or more complex examinations.

For pipelines assessed using ILI, the relationship between cost and miles assessed is even less of an accurate forecasting metric. The cost to deploy the inspection tool, retrieve it at the end of the inspection, verify the completeness of the inspection, and clean and return the tool to the inspection vendor's facility is typically fixed regardless of the length of the inspection. ILI inspection tools can inspect even the relatively longer pipeline projects in one full workday, so physical length of the inspection does not significantly affect the inspection cost. For example, the estimated cost to inspect 10 miles of a 26-inch diameter pipeline can be half the estimated cost to inspect over 75 miles of a 30-inch diameter pipeline, despite being only one-seventh of the length.[17]

Typically, as with ECDA projects, the most significant cost driver in estimating the total cost of an ILI assessment project is the number of direct examinations required, and longer pipeline assessments do not always result in more direct examinations. The primary drivers of cost for an ILI assessment are the number of tools run, pipeline retrofitting to accommodate tools, and the number of excavations required. Using a straight-line cost per mile evaluation to determine the funding necessary to perform TIMP assessments is not a suitable method to evaluate the appropriateness of SoCalGas's TY 2024 GRC request. SoCalGas appropriately utilized estimated cost per inspection, estimated costs per excavation, and expected number of excavations per assessment.

[16] 49 CFR § 192.925(b)(3)

[17] Data analysis by the vendor does tend to be proportional to inspection length, which is one of the reasons why the longer inspection in the example costs more; however, this is only one component of the cost to perform an ILI.

### ii. Historical Costs Are Not Necessarily Reflective Of Future Costs

The primary driver increasing costs to comply with the requirements of TIMP is the additional inspection tools necessary to detect and characterize cracking defects. The extensive use of crack detection tools was not part of the cost calculation for the 2019 GRC and is a primary driver of the increased funding request for the 2024 GRC. The cost of pipeline inspection with the addition of crack detection tools is significantly higher than inspecting the same pipe with only magnetic flux leakage (MFL) tools. The approximate cost to run various inspection tools in a 30 mile long, 36-inch diameter pipeline are shown in the table below.

| Inspection Tool | Approximate Cost[18] |
|---|---|
| High Resolution MFL-Axial | $100,000 |
| Ultra High Resolution MFL-Axial | $300,000 |
| MFL-Circumferential | $150,000 |
| EMAT (crack detection tool) | $1,150,000 |

Pipelines identified with a cracking threat require inspection utilizing a crack detection tool. Each inspection tool requires its own deployment through the pipeline, trained analysts to review the inspection data, response criteria to manage the results of the inspection, and validation examinations. These additional activities also require project management and engineering resources to select excavation locations, site the locations, and document the results. Additionally, for assessments involving crack detection tools, the use of specialized Non-Destructive Examination (NDE) tools is necessary to measure the dimensions of the cracks and validate tool results.

TURN-SCGC attempt to challenge SoCalGas's TY 2024 forecast by pointlessly referencing Pacific Gas and Electric Company's (PG&E) direct examination unit cost forecast. It is impracticable to compare the excavation costs of SoCalGas and PG&E since the manner in which the companies estimate excavation costs likely differs (*i.e.*, an apples to oranges comparison). For example, in addition to the cost to remove the soil surrounding the pipeline, SoCalGas's costs include associated with traffic control, post-excavation site restoration, coating removal, shoring, and NDE activities performed on the exposed pipe.

[18] Approximate cost is based on sample vendor quote.

The primary factors that drive excavation costs are compliance with the regulatory requirements for site selection and the safety and integrity of the overall pipeline system, which determine site specific requirements. Compliance driven site selection can result in excavations at locations which can be difficult to access and excavate. For example, large portions of the SoCalGas pipeline system are located in desert environments with protected endangered species that result in restrictions on the volume and speed of vehicles, which can add significant cost to each excavation. In other environments, inhospitable mountainous terrain, access issues due to waterways, above-ground features, and third-party property owners, as well as a myriad of infrastructure issues in highly urbanized environments, can also increase excavation costs.

TURN-SCGC further claim that project management, data management, preventative and mitigative measures, and risk and threat costs should not increase since the number of miles that SoCalGas will manage under the TIMP remains largely unchanged.[19] TURN-SCGC mistakenly assume that these activities are driven solely by the number of miles assessed. As described in Section III.A.1.b.i of this testimony, assessments consist of components that are independent of distance such as tool deployment and data analysis. As additional activities are implemented to manage threats to the pipeline, and with an expected increase in the number of detected anomalies associated with the introduction of new tools and changes to risk and threat analyses, SoCalGas anticipates more data to evaluate and, correspondingly, more prevention and mitigation activities. The funding required to manage projects, integrate data, analyze risks and threats, and determine risk mitigation actions increases regardless of whether the number of in-scope miles increase. For example, the new requirements regarding the use of Stress Corrosion Cracking Direct Assessment (SCCDA) prescribe the development of a threat identification and risk assessment process for evaluating segments in the SoCalGas pipeline system. This work will involve the use of crack detection inspection tools that will require additional project management, data evaluation, development of inspection processes and response criteria for addressing findings from the inspections, and validation of crack detection tools. Similarly, program improvements related to geohazards, weather-related outside force (WROF), and the verification of material properties and attributes will drive the need for additional data analysis

[19] Ex. TURN-SCGC-04-Revised (Catherine Yap) at 16-18.

and integration, as well as pipeline examination activities in the case of material verification.[20] These activities in turn increase the need for FTEs and other resources (*e.g.*, tools, vehicles) related to project management, data management, risk and threat evaluation, and preventive and mitigative measures.

SoCalGas's forecasts take into consideration these evolving aspects of the TIMP and federal regulations, which are new and are not included in historical activities and costs. TURN-SCGC's recommendation to use the five-year average of assessment costs would result in insufficient funding to manage safety-focused compliance work necessary under the TIMP.

**iii. TURN-SCGC Misconstrue The Impact of Non-HCA Assessments on SoCalGas's Forecast**

As explained in Section III.A.1.a. of this testimony, the federal requirements for outside-of-HCA assessments did not drive increases to the TY 2024 TIMP O&M activities and forecast; the increases are driven by changes to risk and threat identification and assessment processes. Although 49 CFR § 192.710 does introduce new scope, SoCalGas has incorporated the pipeline segments into the Assessment Plan to be completed by July 3, 2034.[21] As pipeline location classifications change, SoCalGas will continue to incorporate pipeline segments as needed. Since these changes are outside of SoCalGas's control and are additional factors driving the variability of TIMP assessments, SoCalGas requests the continuation of the TIMPBA. The two-way balancing account would allow for returns to ratepayers if actual costs are less than forecasted and would also enable SoCalGas to comply with regulatory requirements and manage its pipeline system safely should changes occur outside of the company's control.

**iv. A Two-Way Balancing Account Is Necessary**

TURN-SCGC mistakenly assert that SoCalGas's TIMPBA should be converted from a two-way balancing account to a one-way balancing account with a memorandum account. TURN-SCGC contend: (1) TIMP costs have increased more substantially since 2017 and particularly since the Commission "authorized a more light-handed approach to reviewing the TIMP balancing account,"[22] and (2) SoCalGas was able to develop detailed cost estimates for

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[20] GTSR Part 1 introduced new requirements related to geohazard and WROF threats (49 CFR § 192.917(a)(3)), as well as verification of material properties and attributes (49 CFR § 192.607).

[21] 49 CFR § 192.710(b).

[22] Ex. TURN-SCGC-04-Revised (Catherine Yap) at 19.

PSEP projects and manage activities efficiently "when properly incentivized."[23] While SoCalGas discusses TURN's recommended cost recovery mechanism in the Regulatory Accounts rebuttal testimony (Ex. SCG-238), the reasons why TURN-SCGC's assertions are unfounded are discussed herein.

In presenting their position for why the TIMPBA should be converted to a one-way balancing account, TURN-SCGC assume facts where there are none. TURN-SCGC imply that the "tremendous run-up in costs" is due to the Commission authorizing a "more light-handed approach to reviewing the TIMP balancing account."[24] This is inaccurate. First, while TIMP costs have increased steadily since 2017, these increases are not due to inefficiencies or a lack of a "proper incentive" as TURN-SCGC alleges. In the last several years, based on existing processes and tools alone, SoCalGas has continued to see increases to costs due to contract increases. Advances in assessment tools and processes have also increased the number of activities associated with TIMP assessments. As discussed in Section 3.A.1.b.ii. of this testimony, the primary factors driving the increase in SoCalGas's requested O&M funding are the use of additional inspection tools focused on the detection and characterization of cracks and the continuous improvements to business processes as well as regulatory changes (*e.g.*, threat and risk analyses). The extensive use of crack detection tools was not considered as a part of the cost calculation for the TY 2019 GRC, and the addition of these inspection tools to the overall assessment program is a primary driver of the increase in the funding request for the 2024 GRC. The use of additional tools increases inspection costs, excavation costs, and project managements costs for each assessment that requires the use of crack-detection tools.

TURN-SCGC also express concern that the two-way balancing account has not protected ratepayer interests and argue that "a two-way balancing account gives the utility too much discretion to spend, particularly if it thinks it will not be subject to a robust reasonableness review, as afforded by an application."[25] However, TURN-SCGC appear to misunderstand the TIMPBA recovery mechanism and fail to account for the ratepayer protections currently in place. SoCalGas is currently required to file a Tier 3 advice letter for an undercollection up to

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[23] *Id*. at 26.

[24] *Id*. at 19.

[25] *Id*. at 22.

35% of the total O&M and capital expenditures authorized. The undercollection cannot be recovered without Commission approval and the Commission may audit SoCalGas's costs prior to approval. Furthermore, SoCalGas is required to file an application for an undercollection greater than 35% and this application is subject to reasonableness review.

SoCalGas maintains it would be imprudent and irresponsible to prioritize cost over safety and compliance when making decisions about integrity management. Integrity management activities are driven by safety, either through compliance with regulatory requirements or adoption of best practices. For example, if inspections identify multiple locations where corrosion may be occurring, the operator is required by regulation to excavate and examine these locations in priority order from most to least severe, regardless of efficiency. SoCalGas considers regulatory requirements a floor from which safety-related activities are initiated, not a ceiling to limit additional safety-related activities. For instance, safety considerations may lead SoCalGas to extend an excavation to verify that conditions on an exposed pipe segment are absent on a similar unexcavated pipe segment.

TURN-SCGC similarly ignore the importance of continuous improvement of integrity management procedures and the effect of change on overall TIMP activities and costs. Each project is distinct and driven by the dynamics of risk and threat conditions. The in-line inspection tools required to perform a comprehensive assessment of TIMP pipelines have grown in number and cost, and a better understanding of the conditions that promote cracking has driven the increased use of these tools. In addition to the cost of performing the inspections, the use of each crack detection tool requires its own set of pipeline examination excavations, use of specific NDE tools to measure cracks, and tailored mitigation activity.

TURN-SCGC's argument that SoCalGas should be able to forecast the TIMP projects as it does the PSEP projects has no merit. As further discussed below, TIMP projects are more complex in scope than PSEP hydrostatic pressure tests and pipeline replacements. The TIMP program management team uses many of the same cost estimating tools as those used for the PSEP, however, it is more challenging to accurately estimate the final cost of a TIMP project than a PSEP project. The majority of PSEP projects do not result in pressure test failures and, therefore, result in more predictable project outcomes. By contrast, TIMP outcomes are based on findings that often must be addressed within established timeframes per code requirements. As a result, TIMP projects are subject to variability dependent upon inspection discoveries that can increase costs more regularly than would occur with PSEP projects. This fundamental activity (*i.e.*, threat assessment and remediation) of the TIMP drives the need for a two-way balancing account, which the Commission has continually approved in recognition of the inherent variability in TIMP project work. The Commission first approved a two-way balancing account for the TIMP (*i.e.*, the TIMPBA) in D.13-05-010, in which it stated, "A two-way balancing account is appropriate due the costs of complying with Subpart O and possible changes in pipeline inspection requirements in the future."[26] Most recently, the Commission approved the continuation of the TIMPBA as a two-way balancing account in D.19-09-051.[27]

In general, there are fewer high-cost variables in PSEP projects and PSEP projects have more scheduling flexibility to mitigate the impact of planning or execution challenges to a project, such as difficulty accessing a proposed work area. Additionally, the PSEP allows more latitude in selecting work areas for segments of pipe. TIMP projects, on the other hand, require direct examinations at locations discovered through assessments regardless of access or work site complications. TIMP projects also have regulation-mandated deadlines, so delays must be expeditiously resolved, sometimes regardless of cost, since postponement of the work is often not an option. As a result, when compared to PSEP, TIMP forecasts should be expected to exhibit greater variability since the project activities are inherently much more dynamic.

TURN-SCGC also oversimplify the requirements of 49 CFR Part 192, Subpart O. While seven years is the maximum reassessment interval, there are instances when a pipeline segment must be placed on an accelerated schedule. This determination is typically based on assessment results of the pipeline condition, and the evaluation of the potential growth rate of existing flaws which both affect risk. The discovery of previously undetected threats could prompt additional assessment activities on other pipelines with similar characteristics.[28] This "similar segments" concept also applies industry-wide among operators (*i.e.*, an operator may become aware of a condition that drives others in the industry to evaluate the presence of similar conditions on their systems). The scope of TIMP is greatly determined by federal mandate. Contrary to TURN-SCGC's claims, even non-HCAs were included in 49 CFR Part 192, Subpart O prior to the

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[26] D.13-03-010 at 387.

[27] D.19-09-051 at 694-695.

[28] 49 CFR § 192.917.

GTSR.[29] In its Gas Transmission Integrity Management FAQs, PHMSA has made it clear that operators are required to fix anomalies in non-HCAs, consider findings in non-HCAs when developing Integrity Management Plans, and evaluate and remediate, as necessary, pipeline segments in non-HCAs when corrosion is found on HCA segments of similar material coating and environmental characteristics. Regulatory requirements associated with TIMP continue to evolve. The Commission recognized and accounted for this when it first directed SoCalGas to establish a TIMPBA.[30]

TURN-SCGC are misguided in evaluating a safety-driven program primarily through the narrow lens of cost efficiency. The suggestion that SoCalGas needs to be "properly incentivized" to "bring projects in at costs below estimates"[31] ignores the fact that PSEP projects are not comparable to TIMP projects in scope, complexity, and variability. Integrity projects are fundamentally tied to the specific integrity threats associated with a pipeline system. As a result, integrity projects are driven by the discovery of conditions which are affected by evolving inspection technologies and changing pipeline conditions. This is in stark contrast to the one-time set of largely repeatable actions that are characteristic of most hydrostatic pressure tests.

SoCalGas strongly recommends the Commission find SoCalGas's TIMP forecast reasonable and authorize the continuation of the two-way balancing account.

**c. TURN**

While TURN contends that it "is difficult to conclusively evaluate the reasonableness of the scale and cost of the work proposed"[32] and suggests this might be due to a lack of granular data, TURN acknowledges that "the activities themselves appear based on technical requirements, and there is no data demonstrating inappropriate handling or forecasting of these costs."[33] SoCalGas maintains that the forecasts are appropriate and agrees with TURN that the activities are based on technical requirements. Accordingly, SoCalGas recommends the

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[29] *See e.g.*, 49 CFR § 192.971(e)(1) and 49 CFR § 192.917(b).

[30] D.13-05-010 at 387 ("A two-way balancing account is appropriate due the [*sic*] costs of complying with Subpart O and possible changes in pipeline inspection requirements in the future.").

[31] Ex. TURN-SCGC-04-Revised (Catherine Yap) at 26.

[32] Ex. TURN-05 (Rod Walker) at 101.

[33] *Ibid*.

Commission find SoCalGas's TIMP forecast reasonable and authorize the continuation of the TIMPBA to track and recover actual costs.

### 2. DIMP

#### a. Cal Advocates

Cal Advocates recommends a $3.547 million reduction to SoCalGas's non-shared O&M forecast for the DIMP based on its opposition to the increase in DRIP costs.[34] Cal Advocates' proposed reduction for the DRIP is not appropriate since the increase in expenses is necessary to maintain the level of remediation described in our direct testimony (Exhibit SCG-09). As explained previously, anodeless risers have shown a propensity to fail before the end of their useful lives and the consequence of this component failing can be significant since risers are attached to meter set assemblies, which are typically located next to a residence.[35] The increases in DRIP costs are driven by: (1) economic conditions, and (2) the increasing number of non-standard remediations that will require additional resources.

SoCalGas anticipated changes in the market when preparing the TY 2024 GRC filing. For example, the agreements SoCalGas has with its DRIP vendors have shown to be non-competitive in the current California market. These agreements were established under 2019 rate schedules with previously standard annual increases. In 2022, one vendor declined to continue with their DRIP contract because SoCalGas was not able to accommodate an increase in rates. To retain the remaining DRIP vendors, SoCalGas was required to include amendments to existing service agreements. SoCalGas will solicit bids through a Request for Proposal process in 2024 for new contracts for the DRIP. However, SoCalGas's recent experience with its current agreements indicate there will be significant price increases in the proposals received from vendors.

Additionally, the increasing number of non-standard remediations will require additional resources. For example, SoCalGas encounters situations where anodeless risers are not accessible due to concrete installed around the gas riser, making it infeasible for the technician to employ remediation measures (*i.e.*, installation of a protective wrap). This is not an uncommon scenario due to property owners installing concrete pathways after a gas service is installed. In

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[34] Ex. CA-03 (Dao Phan) at 19-20.

[35] Ex. SCG-09 (Amy Kitson and Travis Sera) at AK-TS-39.

these situations, a cylindrical section of concrete around the riser must be removed or "cored." This task involves the removal of the existing gas meter, exposing and coring around the riser, extending the height of the riser, reinstalling the meter, and finally installing the protective wrap. The inventory of these locations continues to increase, and additional resources are necessary to complete this work by 2029. The cost to perform the more complex mitigation is also approximately ten times greater than the cost to perform the standard mitigation (*i.e.*, only installing the protective wrap). The additional funding requested for the DRIP is driven by both the increases to DRIP vendor costs and the need to hire additional resources dedicated to this work.

The Commission should reject Cal Advocates' proposed forecast because it does not provide the necessary funding to support the DRIP, which mitigates the risk of failure of anodeless risers that are commonly located alongside residences. The Commission should instead adopt SoCalGas's proposed TY 2024 DIMP O&M forecast.

**b. TURN**

TURN objects to SoCalGas's VIPP and BSRP O&M forecasts as a byproduct of their objection to the capital replacement activities. Since TURN's basis for objection relates to capital activities, this is discussed in detail in Section IV.B. of this testimony.

**3. SIMP**

Parties did not take issue with SoCalGas's forecast for the SIMP non-shared O&M expenses. Accordingly, the Commission should find SoCalGas's SIMP forecast reasonable and authorize the continuation of the SIMPBA to record authorized and actual revenue requirement.

**4. FIMP**

**a. Cal Advocates**

Cal Advocates opposes the FIMP and recommends no funding for the program. The Commission should reject Cal Advocates' recommended reduction for the following reasons:

**i. FIMP Activities Would Go Beyond Routine Operations and Maintenance**

Cal Advocates' testimony states, "the activities SoCalGas proposes for FIMP should be a part of the utility's routine operation and maintenance work activities" and that "SoCalGas is presently receiving funding in rates to perform routine vessel inspections as part of the utility's

Gas Engineering group's work activities."[36] The FIMP is not duplicating a request for existing inspections; rather, it is proposing a comprehensive inspection process beyond existing routine maintenance to systematically address the integrity of equipment located at its facilities. For example, the Company's existing operations and maintenance activities do not routinely include American Petroleum Institute (API) 510 inspections performed by certified inspectors in the Gas Engineering group. An API 510 inspection evaluates pressure vessels both internally and externally for operational stability, material quality and safety. Regarding the fixed equipment activities that Cal Advocates points to as already funded, the Gas Engineering group focuses on performing and overseeing NDE inspections upon the request of the Operations groups, if and when an integrity concern is identified.

The FIMP, however, would include the development of new and incremental processes to comprehensively collect and analyze data for risk and threat analysis based on industry recommended practices.[37] The FIMP would also include a systematic inspection of vessels located at its Transmission Compressor Stations, Pressure Limiting Stations, Storage Fields, and Natural Gas Vehicle (NGV) fueling facilities via a new Pressure Vessel Integrity Management Program that would utilize API 510 to identify and manage equipment integrity on a cyclical basis. Moreover, the FIMP would involve the additional collection of data on vessels, as opposed to data collection of vessels that have an identified integrity concern detected via other activities managed by operations. The pressure vessel integrity management program is modeled after mechanical integrity programs that have existed for years for oil and gas production facilities and petrochemical industries.[38] This will enable evaluation of equipment integrity, promoting the identification and management of integrity risks. The benefits of programmatic management of facility equipment are beyond enhancing safety. The benefits also include maintaining the reliability of the SoCalGas system and reducing maintenance costs over time due to the ability to use data analytics to optimize inspection and remediation activities and extend the life of the equipment.

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[36] Ex. CA-03 (Dao Phan) at 22.

[37] Pipelines Research Council International, FIMP Guidelines, December 23, 2013, at 22, Table 4.

[38] 29 CFR 1910.119 (OSHA Process Safety Management of Highly Hazardous Chemicals -- Compliance Guidelines and Enforcement Procedures); California Code of Regulations (CCR), Title 8, Division 1, Chapter 4, Subchapter 15 (Petroleum Safety Orders).

Cal Advocates also argues that SoCalGas's request for FIMP funding to inspect electrical equipment at four aboveground storage facilities are presently funded as part of SoCalGas's Gas Storage in rates.[39] National Fire Protection Association (NFPA) 70B inspections are not performed as part of existing routine maintenance and inspection activities. The NFPA 70B-driven Electrical Equipment Integrity Program would be a new and incremental activity implemented under the FIMP for Storage, Transmission, and NGV facilities.

SoCalGas's existing integrity management programs were developed and are based on regulatory requirements. For example, DIMP, under 49 CFR Part 192, Subpart P, focuses on gas distribution pipelines, and TIMP, under CFR Part 192, Subpart O, focuses on gas transmission pipelines. These applicable regulations and corresponding programs do not incorporate integrity-related activities for the types of equipment currently being proposed for inclusion in the FIMP (*e.g.*, pressure vessels, aboveground storage tanks and piping,[40] electrical equipment, other high-pressure gas complex facilities such as NGV stations).

The objective of the FIMP is to promote and support the safety and integrity of equipment not currently incorporated into existing integrity management programs or routine O&M activities. The FIMP reaches beyond compliance through systematic implementation of risk mitigation activities which enhance safety, integrity, and reliability, and serves to reduce unplanned maintenance activities and remediation costs and extend the life of facility assets. Mechanical integrity programs, rotating equipment integrity programs, and electrical equipment integrity programs included in the FIMP are based on established standards and requirements in the oil and gas production facilities and petrochemical industries and are intended to further support the company's ability to deliver safe and reliable service.

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39 Ex. CA-03 (Dao Phan) at 22.

40 Integrity testing of aboveground piping within facilities containing multiple commodities and liquids does not generally fall within the scope of existing mandated integrity management programs. Although there are other regulatory requirements requiring integrity testing of certain aboveground piping, these requirements address only a subset of piping within gas storage facilities. (*See* Assembly Bill (AB) 1420 (2015 Cal. Legis. Serv. Ch. 601) available at: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB1420; AB 1960 (2008 Cal. Legis. Serv. Ch. 562, available at: http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_1951-2000/ab_1960_bill_20080929_chaptered.html.)

### ii. A Centralized FIMP Promotes Safety

Cal Advocates contends that "by proposing to use existing departments and resources to perform inspections and collect data, and by using existing procedures to develop FIMP, SoCalGas has not adequately demonstrated that ratepayers should be funding a separate program with additional redundant/duplicate costs such as program management and data management costs."[41] First, Cal Advocates misunderstands the discussion of existing procedures and the use of existing departments and resources to perform inspections and collect data. SoCalGas is currently leveraging existing resources to gather data to develop a comprehensive FIMP. SoCalGas plans to evaluate existing systems and processes associated with facilities equipment and develop new procedures and/or enhance existing procedures to optimize and expand integrity programs such as vessel inspections in a programmatic manner across multiple organizations and facilities. SoCalGas is adding exploratory processes, procedures, and data collection to the scope of existing resources. The scope of these exploratory, pilot activities are limited. Moreover, while existing resources are being leveraged, and current work groups are not significantly impacted by the incremental activities, this does not mean SoCalGas would be able to continue to use those same resources going forward to perform all the additional activities proposed under the FIMP.

A robust, comprehensive, systematic, and integrated FIMP is essential to confirming that equipment integrity is addressed across multiple departments and would enhance the safety of SoCalGas's transmission, storage, and NGV facilities. Applying integrity management principles to facilities would enable effective allocation of resources for prevention, detection, and mitigation activities. However, integrity related and data collection activities included in the FIMP would be less effective if decentralized. Planning and managing integrity assessment and remediation activities, along with data and risk management, necessitate trained individuals with multidisciplinary expertise in risk and threat identification, prevention, and mitigation. Data management and integration is necessary for effective threat identification and risk assessment to prioritize integrity management work. In the absence of a centralized program management approach, there is an increased risk of inconsistency and inefficiency.

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[41] Ex. CA-03 (Dao Phan) at 23.

The FIMP, as proposed, would implement safety programs across various facilities across transmission, storage, and NGV facilities, and dedicated resources would be needed to plan and manage integrity related activities across the different assets effectively and efficiently.

**iii. SoCalGas Has Provided a Detailed Forecast For The FIMP**

Cal Advocates states that "while SoCalGas claims that many of the FIMP costs were developed using third-party estimates and subject matter experts' input, no materials were presented to confirm these costs. SoCalGas also claims that some unit costs were based on historical cost, however, no further information or support was provided to identify the program or timeframe from which these costs were derived."[42] SoCalGas strongly disagrees with Cal Advocates assessment of the supporting information provided in its supplemental workpapers and responses to the Cal Advocates' data requests. SoCalGas provided a detailed cost breakdown of the activities included in the program by work description, unit quantity, and unit cost in its response to PAO-SCG-036-DAO.[43]

**b. TURN**

TURN disagrees with SoCalGas's proposal for a FIMP, asserting that any work needed under the FIMP should be incorporated in existing integrity management programs or other company programs. TURN also claims that SoCalGas has not proven that the FIMP is a best practice, industry standard, or requirement, or that it is necessary. The Commission should reject TURN's recommended reduction for the following reasons.

First, FIMP is modeled after the TIMP, DIMP, and SIMP which are integrity management programs required by regulations to increase safe operation of gas systems. FIMP also incorporates industry recommended practices (*e.g.*, electrical equipment inspections per NFPA 70B). Second, TURN, in its recommendation that the FIMP be included in existing integrity management programs, clearly demonstrates a lack of understanding of the drivers that have shaped these programs and the differences between pipeline and facility threats and risks. As stated in Section III.A.4.a.i. of this testimony, TIMP, DIMP, and SIMP are mandated by federal regulations[44] and these regulations establish the scope of the programs. Each program

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[42] *Id*. at 23.

[43] *See* Appendix B, Response to PAO-SCG-036-DAO.

[44] 49 CFR Part 192, Subparts O and P; 49 CFR § 192.12.

has been developed to address threats and risks specific to the assets for which they are prescribed. Facility assets, such as electrical equipment, are characteristically different from transmission pipe and appurtenances, for example, and integrity management programs for these assets are not included in the federal regulations governing natural gas systems; they also require different approaches to integrity management risk and threat assessment.

TURN also argues that "the Companies' concerns that this decentralization of efforts will somehow make the activities less effective does not appear reasonable. The activities proposed to be performed under a FIMP involve many different divisions and would need to be coordinated with TIMP, DIMP, SIMP, Gas Distribution, and other operating divisions of the Companies.[45] TURN's concerns are similar to those of Cal Advocates' which are addressed in Section III.A.4.a.ii of this testimony. Currently, the TIMP, DIMP, and SIMP are managed under two departments (Integrity Management and Asset Risk and Strategy) and while the departments coordinate with other work groups, the centralized effort enables SoCalGas to analyze risks and determine appropriate risk mitigation measures and remediations more expeditiously and cohesively than if the work were scattered throughout the company. Decentralization carries the risk of inconsistent implementation of integrity-related activities and a lack of a consistent strategy to implement and manage multiple integrity management activities across departments.

As discussed in Section III.A.4.a.i. of this testimony, SoCalGas is proposing a FIMP beyond routine operations and maintenance. The FIMP is a centralized and comprehensive approach to enhance the safety of its facility assets by implementing a systematic program. The scheduled inspections and remediations under the FIMP necessitate additional resources (*e.g.*, FTEs and vehicles) to manage and support this work. A centralized FIMP team will be better able to analyze asset data for interactive threats, determine necessary actions and timelines, and manage these safety activities both comprehensively and consistently across different types of assets and operating divisions.

The FIMP reflects SoCalGas's commitment to safety and the Commission should approve the FIMP to enable SoCalGas to manage the safety of its gas infrastructure more comprehensively. Additionally, the Commission should authorize a two-way balancing account due to the variable nature of inspection and remediation activities like those of the TIMP, and

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[45] Ex. TURN-5 (Rod Walker) at 92.

because the program will be in the early phases of development and implementation. A two-way balancing account will allow flexibility to respond to risks and will also provide ratepayer protection while SoCalGas develops and refines scope, threat identification and risk analysis procedures, and safety mitigations. The balancing account treatment would be consistent with that of the TIMP, DIMP and SIMP, which all address important safety, system integrity, and risk management initiatives.

**5. GSEP**

**a. Cal Advocates**

Cal Advocates did not object to SoCalGas's non-shared O&M forecast for the GSEP. Cal Advocates also did not take issue with SoCalGas's request for a two-way balancing account (*i.e.*, GSEPBA), although Cal Advocates recommends that the recovery mechanism for the GSEPBA mirror that of the TIMPBA (*i.e.*, Tier 3 advice letter filing for recovery of account balances above authorized levels).[46] As discussed in the Regulatory Accounts rebuttal testimony (Exhibit SCG-238), Cal Advocates appears to misunderstand the GSEPBA proposed in the Regulatory Accounts direct testimony (Exhibit SCG-38-R); SoCalGas requested a GSEPBA with the same recovery mechanism as the TIMPBA. Thus, SoCalGas recommends the Commission find SoCalGas's GSEP forecast reasonable and authorize a two-way GSEPBA to record authorized and actual revenue requirement.

**b. TURN-SCGC**

TURN-SCGC object to the number of miles associated with SoCalGas's ISEP portion of the GSEP forecast, as well as SoCalGas's request for the GSEPBA. Since TURN-SCGC focus primarily on the ISEP scope and capital forecast, we discuss TURN-SCGC's position in more detail in Section IV.E. of this testimony. SoCalGas recommends the Commission find SoCalGas's non-shared GSEP O&M forecast reasonable.

[46] Ex. CA-03 (Dao Phan) at 25.

### B. Shared Services O&M

| **SHARED O&M** - Constant 2021 ($000) | | | |
|---|---|---|---|
| | **Base Year 2021** | **Test Year 2024** | **Change** |
| SOCALGAS | 2,120 | 2,499 | 379 |
| CAL ADVOCATES | 2,120 | 2,499 | 379 |
| TURN-SCGC | 2,120 | 2,499 | 379 |
| TURN | 2,120 | 2,399 | 279 |
| ~~EDF~~ | ~~2,120~~ | ~~2,499~~ | ~~379~~ |

Generally, parties did not dispute SoCalGas's Shared Services O&M forecasts. However, TURN recommended the disallowance of FIMP and any associated O&M, which includes $0.1 million in shared services. A more detailed discussion of SoCalGas's response to TURN's position can be found in Section III.A.4 of this testimony.

## IV. REBUTTAL TO PARTIES' CAPITAL PROPOSALS

| **TOTAL CAPITAL** - Constant 2021 ($000) | | | | | |
|---|---|---|---|---|---|
| | **2022** | **2023** | **2024** | **Total** | **Difference** |
| SOCALGAS | 426,534 | 461,854 | 537,893 | 1,426,281 | 0 |
| CAL ADVOCATES | 426,534 | 461,854 | 537,893 | 1,426,281 | 0 |
| TURN-SCGC | 305,439 | 319,102 | 344,988 | 969,529 | 456,752 |
| TURN | 424,241 | 447,423 | 511,652 | 1,383,315 | 42,966 |
| EDF[47] | -~~426,534~~ | -~~461,854~~ | -~~537,893~~ | -~~1,426,281~~ | -~~0~~ |

The following sections respond to parties' positions on the capital forecasts for the Gas Integrity Management Programs and confirm that SoCalGas's projections are supported, reasonable, and should be adopted by the Commission in their entirety.

### A. TIMP

Parties did not take issue with SoCalGas's capital forecast for the TIMP. SoCalGas recommends the Commission find SoCalGas's TIMP forecast reasonable and authorize the continuation of the TIMPBA to record authorized and actual revenue requirement.

[47] EDF's testimony makes broader recommendations that would impact SoCalGas and SDG&E requests more globally and as a result are not reflected as specific reductions.

~~EDF did not develop specific forecasts so the table reflects SoCalGas's forecast~~.

### B. DIMP

#### 1. TURN

TURN generally opposes SoCalGas's forecast for VIPP activities, which SoCalGas has proposed to replace vintage plastics that were manufactured by Dupont under the moniker Aldyl-A and installed from 1969 to 1985. TURN states the "proposed accelerated rate of replacements under the VIPP (and associated accelerated recovery) is unsupported by the data" and "the risks of the targets of the VIPP are negligible in comparison with the relative risk of other types of pipe in the SoCalGas and SDG&E systems."[48] TURN utilized data it erroneously claimed was SoCalGas's data[49] in an attempt to depict the percentage of system leaks that were found on pre-1986 Aldyl-A, leading to incorrect comparisons of leak counts and leak repair rates.

TURN claims that "the relative risk of the targets of the VIPP are negligible in comparison with the other relative risk of other types of pipe in the SoCalGas and SDG&E system" and that "the absolute risk that the targets of the VIPP pose is negligible in and of itself and has not historically represented a significant risk." As made evident by the corrected values provided in the table below,[50] the percentage of leaks on Aldyl-A pipe is not negligible.

| | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **Total Aldyl-A Leaks (SoCalGas)** | 1,598 | 1,887 | 2,048 | 2,184 | 1,809 |
| **Total System Leaks (PHMSA)** | 39,007 | 40,021 | 43,172 | 42,979 | 39,830 |
| **Aldyl-A% (SoCalGas)** | 4.1% | 4.7% | 4.7% | 5.1% | 4.5% |

This is further illustrated by an applicable update to the values provided above. Since VIPP is addressing the threats associated with pre-1986 Aldyl-A, all of which are below ground, the comparison should utilize below ground leaks. This also appears to align with the intent of the analysis as Mr. Walker states, "I attempted to graph the percentages of system leaks that were on Aldyl-A vs. all other pipe…" and most above ground leaks occur on meter set assemblies.

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48 Ex. TURN-5 (Rod Walker) at 67.

49 The data presented in Table 14 of TURN-5 (*see* Ex. TURN-05 at 73) did not belong to SoCalGas and TURN corrected this in their response to SCG-SDGE-TURN-009 to reflect the data provided by SoCalGas for TURN-SEU-023 Q2. (*See* Appendix B.)

50 The table utilizes data SoCalGas provided to TURN in response to TURN-SEU-023 Q2, and removes leaks related to excavation damage.

Since the total system counts utilized by TURN included both above ground and below ground assets, SoCalGas eliminated the above ground data from the table below and the percentage of leaks on Aldyl-A noticeably increases.

| | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **Total Aldyl-A leaks (SoCalGas)** | 1,598 | 1,887 | 2,048 | 2,184 | 1,809 |
| **Total System Below Ground Leaks** | 8,877 | 8,789 | 8,676 | 10,449 | 9,935 |
| **Aldyl-A % (SoCalGas)** | 18.0% | 21.5% | 23.6% | 20.9% | 18.2% |

Although utilizing leak repair information is an important input for assessing risk, leak counts and leak rates alone are insufficient for properly assessing risk. 49 CFR Part 192 Subpart P requires operators to consider both the likelihood of a failure and the potential consequence of such a failure when assessing risk.[51] In TURN's evaluation of "risk," the potential consequence of a failure was not considered. To determine potential consequence, SoCalGas considers historical incidents that have occurred in the service territory as well as across the industry. SoCalGas considers the leak information TURN relies upon but also considers numerous additional inputs that assist in the assessment of risk, as further described herein. These analytics target higher risk pipelines using quantitative results that enable strategic replacement in lieu of wholesale replacement. SoCalGas provided the results of these risk analytics to TURN in response to a data request in SoCalGas's 2021 RAMP proceeding.[52]

SoCalGas developed, as part of the DIMP, a segment-specific quantitative risk assessment (QRA) model for medium pressure mains that uses a combination of internal datasets and external publicly available data sources. SoCalGas uses this QRA model to estimate safety risk of vintage plastic and bare steel medium pressure mains, where risk is defined as the product of probability of failure and its associated consequence (*i.e.*, probability of a hazardous leak and resulting life-safety consequence[53]). PHMSA's white paper titled "*Pipeline Risk Modeling*

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[51] 49 CFR § 192.1007(c).

[52] *See* Appendix B, TURN-SEU-037, Q16.

[53] The probability of failure is expressed as the probability of a leak per year, which is derived from a model that uses data including, but not limited to, asset attributes and historical leaks. The consequence of failure is expressed as the expected frequency of serious incident given a leak, which is derived from statistical modeling of the probability of a hazardous leak and resulting life-safety consequences. Internal and external data considered in the consequence model includes, but is not

*Overview of Methods and Tools for Improved Implementation,*" published on February 1, 2020, describes the merits and limitations of various risk models.[54] PHMSA describes quantitative risk models as robust and able to measure risk in standard units; they provide greater risk insight than relative risk models to support risk-related decision making. SoCalGas has leveraged the insights gained from the QRA to evaluate risk of the medium pressure distribution mains and identify necessary vintage plastic and bare steel pipeline replacements. This approach supports the overall reduction of risk in the pipeline system and increases safety.

It is important to note that, in the absence of a safety risk threshold from PHMSA and other regulatory bodies, SoCalGas has established that locations along the medium pressure distribution mains system with an annual probability greater than 6 x $10^{-6}$ of a serious incident should be targeted for replacement. Vintage plastic and bare steel medium pressure mains with QRA results that exceed this threshold are targeted for replacement under the VIPP and BSRP. SoCalGas is continuously improving its risk evaluations to consider not just the current state of risk in the system, but also the projected long-term risk since the threats affecting these vintage materials are time-dependent (*e.g.*, corrosion) and the associated risk can escalate at different rates (*e.g.*, corrosion vs. material degradation rates). For example, if risk projections were to indicate that a high mileage of bare steel pipe would exceed the risk threshold in a future year, SoCalGas may increase the replacement rate of bare steel pipe to effectively target segments for replacement before the risk threshold is exceeded. However, SoCalGas also considers it prudent to first address the segments with the current highest risk (*i.e.*, those exceeding SoCalGas's safety threshold) which is driving the current replacement strategies of the VIPP and BSRP.

TURN's proposed disallowance of the VIPP should be dismissed because it eliminates a necessary safety-driven integrity management activity and the recommended moderate increase to BSRP would not adequately address those segments that exceed the SoCalGas established risk thresholds. SoCalGas's proposal of VIPP and BSRP levels of activity is based on those pipe segments that exceed the established safety risk threshold, as well as the need to address the projected long-term risks of aging assets.

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limited to, historical leak data, internal asset data, location, and PHMSA gas distribution incident data.

[54] PHMSA, *Pipeline Risk Modeling Overview of Methods and Tools for Improved Implementation*, February 1, 2020, available at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-03/Pipeline-Risk-Modeling-Technical-Information-Document-02-01-2020-Final.pdf.

### C. SIMP

Parties either did not take issue with SoCalGas's forecast for the SIMP non-shared O&M expenses or did not address the SIMP directly. SoCalGas recommends the Commission find SoCalGas's forecast reasonable and authorize the continuation of the SIMPBA to record authorized and actual revenue requirement.

### D. FIMP

#### 1. Cal Advocates

Cal Advocates disagrees with SoCalGas's proposal for the FIMP which is discussed in detail in Section III.A.4 of this testimony.

#### 2. TURN

TURN disagrees with SoCalGas's proposal for the FIMP which is discussed in detail in Section III.A.4 of this testimony.

### E. GSEP

#### 1. Cal Advocates

Cal Advocates did not object to SoCalGas's capital forecast for the GSEP. SoCalGas recommends the Commission find SoCalGas's GSEP forecast reasonable and authorize a two-way GSEPBA, with the same mechanisms as the TIMPBA (*e.g.*, Tier 3 advice letter filing for recovery of account balances above authorized levels), to record authorized and actual revenue requirement.

#### 2. TURN-SCGC

TURN-SCGC dispute SoCalGas's TY 2022-2024 capital forecasts for the GSEP, contending that SoCalGas's scope is incorrect. TURN-SCGC also dispute the need for a GSEPBA. The Commission should reject TURN's recommendations for the reasons described below.

##### a. TURN-SCGC's Recommended Adjustment is Based on a Fundamental Misunderstanding of SoCalGas's ISEP Proposal

TURN-SCGC first object to the number of miles included in the ISEP, stating that "SoCalGas conflates its obligations under PHMSA regulations with its obligations under Commission directive in making this recommendation."[55] TURN-SCGC also state that "SoCalGas does not provide any explanation for its recommendation [of 1,108 miles] despite the

55 Ex. TURN-SCGC-04-Revised (Catherine Yap) at 28.

recommendation set forth in the independent engineers report…that only 188 miles be retested. SoCalGas claims its technical evaluation of the pipeline mileage pressure tested under ASA Code 'integrates federal requirements.'"[56] TURN-SCGC misunderstand the relationship between the ISEP scoping process,[57] which SoCalGas clearly describes as integrating federal requirements, and the technical decision tree,[58] which SoCalGas has made no claims of integrating federal requirements into since its purpose is to refine PSEP Phase 2B scope as was ordered by the Commission in D.19-09-051.[59]

SoCalGas's ISEP scoping process drives an evaluation of each transmission (*i.e.*, DOT-T) pipeline segment in its High-Pressure Pipeline Database (HPPD) and excludes segments that are addressed through the existing PSEP. The segments that remain are then reviewed for traceable, verifiable, and complete (TVC) test records and any segments lacking elements that would render them non-TVC are further evaluated to determine an appropriate action. The technical decision tree, on the other hand, is used to evaluate DOT-T pipeline segments without sufficient details related to the performance of pressure testing through an analysis of available test data and pipe characteristics. This evaluation is entirely unrelated to the federal requirement, which is based on record-keeping. SoCalGas utilized both processes to scope the proposed ISEP and at the time of filing, 1,108 miles were identified as possible ISEP scope. Since the GRC filing, SoCalGas has continued to review records and update its database to refine the scope,[60] and approximately 750 miles of DOT-T pipeline segments remain in scope for the ISEP. SoCalGas anticipates that this number may decrease further as the company continues to review records and refine the scope.

TURN-SCGC also dispute SoCalGas's capital forecast, claiming that the forecast is based on SoCalGas's plan to complete 1,108 miles by 2035. This assumption is incorrect. To account for the expected decrease of in-scope pipeline segments that was referenced in direct testimony, SoCalGas's forecast assumes an ISEP scope of approximately 750 miles of DOT-T pipeline segments and focuses on the 550 of those miles subject to 49 CFR § 192.624(b). Based

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56 *Ibid.*

57 *See* Ex. SCG-09 (Amy Kitson and Travis Sera), Appendix B (ISEP Scoping Process).

58 *Id.*, Appendix D (Independent Engineer Evaluation).

59 D.19-09-051 at 779-780, OP 15.

60 *See* Ex. SCG-09 (Amy Kitson and Travis Sera) at AK-TS-61.

on preliminary scope evaluations, SoCalGas determined that approximately 518.5 miles would need to undergo initial planning during the TY 2024 GRC cycle at a minimum, to meet the 50% and 100% compliance deadlines for those 550 miles of scope. A hydrotest or replacement project can take years to complete due to external and internal factors such as permitting, environmental studies, or operational limitations and starting the planning process allows SoCalGas the flexibility of quickly responding to execution changes while avoiding inconsistency in productivity.

**b. TURN-SCGC Incorrectly Liken the ISEP to Previously Authorized PSEP Projects**

TURN-SCGC contend that a GSEPBA is not necessary and argue that the ISEP activities, the largest portion of the GSEP forecast, are "essentially PSEP activities" with which SoCalGas has nearly a decade of experience. Though SoCalGas has had almost 10 years of experience with the PSEP, the pipeline segments in scope for the ISEP have only been recently identified. In fact, the ISEP forecasts detailed in supplemental workpapers (Ex. SCG-09-CWP) are preliminary estimates informed by PSEP historical costs and, because there was no project definition at the time of forecasting beyond the number of miles and AACE's prescribed level of project definition for Class 5 estimates is 0-2%, these estimates could only be considered Class 5 estimates at best.[61,62] Due to the timing of TY 2024 GRC filing, it would be unreasonable to expect SoCalGas to provide Class 3 estimates for new scope that is still being evaluated when the projects under the PSEP are simply more mature. Even with the higher amount of project definition that accompanies a Class 3 estimate (10-40%),[63] such as those utilized to forecast PSEP activities, there is still the potential for cost variances associated with uncertainties that are beyond the ability of an estimator and project teams to account for at the time the estimate is produced. The Commission's granting of a memorandum account to track potential PSEP cost overruns in D.19-09-051, even with the higher level of confidence in the project scope typical of

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61 *See* Appendix C (AACE International, Recommended Practice No. 97R-18, "Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Pipeline Transportation Infrastructure Industries" (Bredehoeft et al.)).

62 PSEP data used to forecast the ISEP was considered Class 5 at the time; however, ISEP projects were not defined – miles were preliminary assumptions and other project details were not known and could not be taken into consideration (*e.g.*, pipe diameter, location).

63 *Ibid.*

a Class 3 estimate, suggests that the use of a two-way balancing account as proposed for the GSEPBA is reasonable and consistent with previous, similar Commission findings.

Furthermore, while TURN-SCGC appropriately observe that the ISEP scope subject to PUC 958 must be completed "as soon as practicable," 49 CFR § 192.624 specifies a maximum deadline of July 2, 2035 for in-scope pipeline segments or "as soon as practicable, but not to exceed 4 years after the pipeline segment first meets the condition of § 192.624(a) … whichever is later" and also establishes a midterm July 3, 2028 deadline that must also be met. As stated in Section IV.E.2.a. of this testimony, SoCalGas considered regulatory requirements and estimated that approximately 750 miles of the 1,108 total miles must be completed by the federal deadlines. This is the basis used for SoCalGas's TY 2024 forecast. To comply with the deadlines, SoCalGas anticipates an increase to both internal and external resources (e.g., labor, vehicles, materials) to support the expedited level of activity of the ISEP as it is executed in parallel with the previously authorized phases (Phase 1A, 2A, and 1B) of the PSEP to meet compliance deadlines. Additionally, in the initial years of the ISEP, the imposition of the aforementioned deadlines associated with 49 CFR § 192.624 effectively limits SoCalGas's ability to shift projects if issues arise during the planning and/or execution stages. As projects are planned and released, SoCalGas will need to execute them as planned and should issues arise (e.g., a replacement becomes necessary due to operational needs), there is no option to defer and avoid the added costs without impacting SoCalGas's ability to comply with 49 CFR § 192.624.

At the same time, 49 CFR § 192.624 also establishes six different methods that can be used to reconfirm in-scope pipeline segments. While SoCalGas's forecast is primarily based on hydrotesting pipeline segments for the ISEP, SoCalGas plans to further evaluate each project during detailed planning to determine the most appropriate reconfirmation method. Should the decision be made to use pressure reduction, Engineering Critical Assessment (49 CFR § 192.632), or replacement rather than hydrotesting, the cost of a project could change substantially. A two-way balancing account would provide protection to ratepayers while also providing SoCalGas with the ability to recover costs that are necessarily incurred to comply with federal regulations.

TURN-SCGC purport that the "tremendous cost over runs" of the TIMPBA is a basis for denying the two-way balancing mechanism for the GSEP, explaining that it would "provide very poor incentive for SoCalGas regarding cost control."[64] However, as discussed in Section III.A. of this testimony, TURN-SCGC attempts to compare two very different programs and scopes and the Commission should evaluate these programs under separate criteria.

**c. TURN-SCGC's Assertion That Non-HCA Repairs Should Be Included In Rate Base Is Irrelevant to the GSEPBA**

TURN-SCGC claim that "enhanced repair requirements for non-HCA mileage under the GTSR Part 2…should not be a particularly challenging aspect of the PHMSA regulations given that SoCalGas has been exceeding the PHMSA requirements for transmission line assessments for nearly two decades."[65] While SoCalGas does not agree with TURN-SCGC's statement, it is irrelevant for the discussion of the GSEP and GSEPBA.

SoCalGas did not request funding for non-HCA repairs under the GSEP and does not seek approval of a GSEPBA to recover costs associated with non-HCA repairs. GTSR Part 2 costs that were included in the GSEP forecast are driven by corrosion control activities, as detailed in supplemental workpapers.[66] The new requirements associated with these sections of the federal code drive additional survey and remediation activities that will require additional resources (*e.g.*, employees, vehicles). However, since the GTSR Part 2 was published August 2022, the added scope of work was not known with certainty at the time of the GRC filing and SoCalGas is currently refining forecasts to determine cost impacts. A balancing account would allow SoCalGas to recover incurred compliance costs while safeguarding ratepayers should GTSR Part 2 changes result in lower actual costs than forecasted.

**d. TURN-SCGC Unjustly and Falsely Claim That SoCalGas Is Seeking a "Blank Check"**

TURN-SCGC allege SoCalGas is "asking for rate treatment of costs that they have no knowledge of because they have not been established by those future gas rules and regulations"[67] and that "under SoCalGas's proposal, the Commission would truly be providing the company with a blank check."[68] However, TURN-SCGC conveniently exclude the details of the request

[64] Ex. TURN-SCGC-04-Revised (Catherine Yap) at 31.

[65] *Id.* at 32.

[66] Ex. SCG-09-CWP (Capital Workpapers to Direct Testimony of Amy Kitson and Travis Sera) at 113-115.

[67] Ex. TURN-SCGC-04-Revised (Catherine Yap) at 32.

[68] *Id*. at 33.

summarized in the Regulatory Accounts direct testimony (Exhibit SCG-38-R), which explain that SoCalGas would seek Commission approval to create new subaccounts in order to record costs incurred associated with future gas rules and regulations as they are published through a Tier 2 Advice Letter. Upon approval of the creation of a new subaccount, SoCalGas would still be subject to the same cost recovery mechanisms as the other integrity management balancing accounts (*e.g.*, 135% trigger for an Application process).

Ultimately, the impending publication of new rules and regulations is not uncertain and, based on currently available information from PHMSA, there will be new requirements with which SoCalGas must comply during the TY 2024 GRC cycle.

| Regulation | 2022 | | | 2023 | | | | 2024 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| Gas Pipeline Leak Detection‡ | | | | | X | | | | | | |
| Safety of Gas Distribution Pipelines‡ | | | | | | X | | | | | |
| Liquefied Natural Gas Facilities | | | | | | | U | | | | |
| Class Location Changes* | | | | | | | X | | | | |
| Pipeline Operational Status‡ | | | | | | | X | | | | |
| Carbon Dioxide and Hazardous Liquid Pipelines‡ | | | | | | | | U | | | |

X: Applicable; U: Applicability Unknown

*Final rule is published or expected to be published in the quarter shown.

‡Draft rule language is expected to be published in the quarter shown.

For the reasons described above with regards to the GSEP capital forecast and GPSEBA, SoCalGas recommends the Commission find SoCalGas's GSEP forecast reasonable and authorize a two-way GSEPBA to record authorized and actual revenue requirement.

### 3. TURN

TURN did not object to SoCalGas's capital forecast for the GSEP and, having evaluated the flowcharts included in Attachment B and Attachment D of direct testimony (Exhibit SCG-

09), concluded that SoCalGas has "a reasonable basis for determining the proper testing regime for transmission pipelines needing reconfirmation of MAOP."[69]

**F. EDF Testimony**

EDF did not directly recommend reductions to SoCalGas's Gas Integrity Management Programs forecasts, but instead raised general concerns about the "huge amount" of capital requested[70] and recommended the Commission reject the company's overall request and set an alternative, lower level revenue requirement.[71] This testimony will address EDF's position as it relates to the Gas Integrity Management Programs. EDF expresses their concern that "'safety' and 'reliability' capital expenditure – if based on faulty, exaggerated demand and account growth assumptions – will amount to *'de facto* stealth expansion of the gas system."[72] This statement purports to suggest that SoCalGas's integrity management programs might be driven, in part, by assumptions of account growth, which is baseless and undermines the objective of integrity management. SoCalGas's integrity programs are driven by infrastructure risks as mandated by regulations and informed by industry best practices. As stated in ASME B31.8S - Managing System Integrity of Gas Pipelines, "Managing the integrity of a gas pipeline system is the primary goal of every pipeline system operator. Operators want to continue providing safe and reliable delivery of natural gas to their customers without adverse effects on employees, the public, customers, or the environment. Incident-free operation has been and continues to be the gas pipeline industry's goal."

Additionally, EDF makes the unsubstantiated claims that ratepayers "now have access to a range of non-pipeline alternatives that will address safety and reliability concerns without having to rely on the gas system" and that "these options are in many cases more cost-effective…[and] are readily available."[73] Without a more detailed overview of these non-pipeline alternatives and how they will address safety and reliability concerns or how their cost-effectiveness was evaluated against the gas system's cost-effectiveness, SoCalGas cannot cogently address this assertion or evaluate whether these claims have merit. However, EDF's

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[69] Ex. TURN-5 (Rod Walker) at 99.

[70] Ex. EDF-01 (Colvin, McCann, and Seong) at 48.

[71] *Id*. at 45.

[72] *Id*. at 48.

[73] *Ibid*.

concern overlooks the complexities of SoCalGas's pipeline system and its service territory as well as the importance of maintaining a safe and reliable system, which is further discussed in the Gas Policy rebuttal testimony (Exhibit SCG-201). Balancing compliance and SoCalGas's commitment to safety and reliability, the Gas Integrity Management Programs activities are forecasted based on the risk profile of the current infrastructure and are not intended to expand the system. Furthermore, EDF's recommendation that SoCalGas be required to demonstrate need and justification on a by-project basis minimizes the variability of assessment findings and resulting remediation activities and ignores the time-sensitive nature and compliance-driven structure of integrity management.

Under the TIMP, SoCalGas regularly assesses its transmission pipelines with a maximum reassessment cycle of seven years.[74] However, per 49 CFR § 192.939(a)(1), operators are required to consider threats when establishing a reassessment cycle. Additionally, operators are required to evaluate and remediate, as necessary, similar pipeline segments depending on the types of findings during TIMP assessments.[75] Recommending the Commission require SoCalGas to demonstrate need and justification on a project-by-project basis, when new threats are discovered and additional scope needs to be evaluated, is essentially recommending that SoCalGas wait until approval has been granted before it can comply with regulations and address safety concerns.

Adopting a project-by-project approval process would also not be prudent or cost effective for the DIMP. Under the DIMP, the VIPP and BSRP are replacement plans informed by the DREAMS quantitative risk assessment (QRA) model and operational considerations. The QRA model prioritizes individual pipe segments based on risk analytics, such as historical performance (leakage), pipe attributes, construction practices, and relative location to populated areas. The net effect of these combined factors is expected to change over time, which in turn will change the prioritization of pipeline segments to be replaced. Considering the span of the GRC period, the development and subsequent use of a static replacement project list that spans this timeframe would result in the use of outdated risk results. This would be contrary to the

[74] 49 CFR § 192.939.

[75] 49 CFR § 192.917.

DIMP requirement of continuous improvement through evaluating performance and effectiveness.[76]

The initiation of projects for the replacement of pipelines under the VIPP and BSRP involve the evaluation of characteristics of pipeline location, such as the area/neighborhood, the governing municipality, the pipe alignment, and proximity of targeted pipeline segments to one another. The pipelines targeted by VIPP and BSRP are typically located in densely populated areas and diligence is necessary when planning in these locations. The evaluations are crucial to the development of scopes to support successful replacement projects and are not insignificant. In general, for every one mile of VIPP/BSRP pipeline to be replaced, two projects are created to support the replacement. For example, the combined 146 miles of VIPP/BSRP replacements forecasted for 2024 would require the creation of over 1,100 projects ahead of filing the GRC application, and this would not even include PTY projects that would need to be executed during the GRC cycle. Since project durations may span over two years depending on the requirements of the area (*e.g.*, permitting, moratorium, environmental mitigation), project-by-project approvals would also require that the Commission review and provide approvals or disapprovals of projects in a timely manner for SoCalGas to successfully execute them within the GRC cycle.

Furthermore, the costs for pipeline replacement fluctuate significantly between projects due to the unique characteristics of each scope. This variation may be attributed to the characteristics of the pipeline location and the specific construction-related requirements of the governing municipality. The level of targeted replacement mileage and its distribution across the service territory allows SoCalGas to develop a budgetary estimate that incorporates such cost variation. The combined uncertainty of both project approval and additional/unforeseen changes requested by the Commission could negatively affect overall project spend and the accuracy of cost projections, essentially impacting the cost effectiveness of SoCalGas's safety and reliability activities and increasing the burden on ratepayers.

SoCalGas considers delivering safe and reliable service at reasonable rates to be of paramount importance and recommends the Commission consider a balanced approach when evaluating the Gas Integrity Management Programs.

[76] 49 CFR § 192.1007.

## V. LINE 235 REPAIR

In accordance with Administrative Law Judge Manisha Lakhanpal's ruling,[77] SoCalGas is no longer seeking review and approval of longer-term remediation options of repairing or replacing Line 235 in this general rate case. Rather, SoCalGas will plan for the repair of Line 235 West to comply with PHMSA regulations. As stated in direct testimony (Exhibit SCG-09), actions beyond the interim repairs planned for 2023-2024 will be necessary to comprehensively address safety and compliance since conditions discovered on the pipeline demonstrate the need for longer-term cathodic protection system improvements.[78] SoCalGas intends to record future safety and compliance costs that are required under 49 CFR Part 192, Subpart O to the TIMPBA, including the costs associated with Line 235 West repairs that are anticipated during the post-test years. SoCalGas will reassess Line 235 West during this GRC cycle in accordance with regulations and also plans to perform a corrosion reliability assessment consistent with Canadian Standards Association (CSA) Section Z662, Annex O[79] to determine repair requirements to comply with regulations. Both the timing of costs and actual costs incurred are likely to vary based on assessment findings, actual pipeline conditions, the physical repair locations, and operational constraints (*i.e.*, system capacity planning). SoCalGas strongly recommends that the Commission authorize the continuation of the two-way TIMPBA due to the variability of Line 235 and other TIMP safety and compliance activities.

## VI. CONCLUSION

The activities and projects described herein and in our direct testimony and workpapers are necessary for SoCalGas to achieve its goal of providing safe and reliable service at reasonable rates. SoCalGas remains committed to mitigating risks associated with safety, infrastructure integrity, and system reliability, and as described in this rebuttal testimony, the proposals of the parties are either based on inaccurate assumptions, misunderstandings of SoCalGas's proposals, or a lack of appreciation for the vital nature of integrity management. Additionally, parties' recommendations for reductions and disallowance of activities and

[77] A.22-05-015, Administrative Law Judge's Ruling Granting The Joint Motion Filed By The Utility Reform Network And The Southern California Generation Coalition, May 1, 2023, available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M507/K388/507388191.PDF.

[78] Ex. SCG-09 (Amy Kitson and Travis Sera) at AK-TS-79.

[79] *Id*. at AK-TS-78.

balancing accounts generally demonstrate a failure to consider the challenges that SoCalGas faces while managing safety, reliability, and compliance activities; these challenges include continuously changing asset conditions (*e.g.*, age, environment) and evolving regulatory requirements and industry best practices.

SoCalGas recommends the Commission find SoCalGas's O&M and Capital forecasts reasonable and authorize the continuation of the TIMPBA, DIMPBA, and SIMPBA, as well as the creation of the FIMPBA and GSEPBA.

This concludes our prepared rebuttal testimony.

## VII. WITNESS QUALIFICATIONS

### AVIDEH RAZAVI

My name is Avideh Razavi. I assumed sponsorship of this area from Amy Kitson. I am employed by SoCalGas as the Director of Asset Risk and Strategy Management for SoCalGas and SDG&E. My business address is 555 West Fifth Street, Los Angeles, CA 90013-1011.

I joined SoCalGas in 2012 as an Engineer in Pipeline Integrity. Since that time, I have held numerous technical and management positions with increasing levels of responsibility in Storage Technical Services, Underground Storage Operations, and Integrity Management and Strategic Planning. I have been in the position of Director of Asset Risk and Strategy Management since 2023. In this position, my responsibilities include overseeing the Storage Integrity Management Program, Facilities Integrity Management Program, Regulatory and Financial Controls, and Risk Strategy for the Gas Integrity Management Programs.

Prior to joining SoCalGas, I worked at the Inland Empire Utilities Agencies and Schlumberger. I graduated from California Polytechnic State University of Pomona in 2011 with a Bachelor of Science Degree in Chemical Engineering.

I have not previously testified in a formal proceeding before the Commission.

**APPENDIX A**

**GLOSSARY OF TERMS**

| ACRONYM | DEFINITION |
|---|---|
| A | Application |
| API | American Petroleum Institute |
| ASA | American Standards Association |
| ASME | American Society of Mechanical Engineers |
| BSRP | Bare Steel Replacement Program |
| CFR | Code of Federal Regulations |
| Commission | California Public Utilities Commission |
| CPI | Consumer Price Index |
| CPUC | California Public Utilities Commission |
| D. | Decision |
| DIMP | Distribution Integrity Management Program |
| DIMPBA | Distribution Integrity Management Program Balancing Account |
| DREAMS | Distribution Risk Evaluation and Monitoring System |
| DRIP | Distribution Riser Inspection Program |
| ECDA | External Corrosion Direct Assessments |
| EDF | Environmental Defense Fund |
| EMAT | Electro Magnetic Acoustic Transducer |
| FIMP | Facilities Integrity Management Program |
| FIMPBA | Facilities Integrity Management Program Balancing Account |
| FTE | Full Time Equivalent |
| GIS | Geographic Information System |
| GRC | General Rate Case |
| GSEP | Gas Safety Enhancement Program |
| GSEPBA | Gas Safety Enhancement Program Balancing Account |
| GTSR | Gas Transmission Safety Rule |
| HCA | High Consequence Area |
| HPPD | High Pressure Pipeline Database |
| ILI | Inline Inspection |
| ISEP | Integrated Safety Enhancement Plan |
| MAOP | Maximum Allowable Operating Pressure |
| MFL | Magnetic Flux Leakage |
| NACE | National Association of Corrosion Engineers |
| NDE | Non-Destructive Examinations |
| NFPA | National Fire Protection Association |
| NGV | Natural Gas Vehicle |
| OSHA | Occupational Safety and Health Administration |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PSEP | Pipeline Safety Enhancement Program |
| PUC | Public Utilities Code |

| ACRONYM | DEFINITION |
|---|---|
| QRA | Quantitative Risk Assessment |
| RAMP | Risk Assessment Mitigation Phase |
| SCCDA | Stress Corrosion Cracking Direct Assessment |
| SCGC | Southern California Generation Coalition |
| SDG&E | San Diego Gas & Electric Company |
| SIMBA | Storage Integrity Management Program Balancing Account |
| SIMP | Storage Integrity Management Program |
| SME | Subject Matter Expert |
| SoCalGas | Southern California Gas Company |
| SPD | Safety Policy Division |
| TIMP | Transmission Integrity Management Program |
| TIMPBA | Transmission Integrity Management Program Balancing Account |
| TURN | The Utility Reform Network |
| TVC | Traceable, Verifiable, Complete |
| TY | Test Year |
| TY | Test Year |
| VIPP | Vintage Integrity Plastic Program |

**APPENDIX B**

**DATA REQUEST RESPONSES**

1. Response to PAO-SCG-053-DAO, Question 3a, submitted on 10/17/2022.
2. Response to PAO-SCG-036-DAO, submitted on 09/14/22.
3. Response from TURN to SCG-SDGE-TURN-009, received on 04/21/23.
4. Supplemental response to TURN-SEU-023, Question 2, submitted on 03/06/23.
5. Supplemental Attachment to TURN-SEU-023, Question 2, submitted on 03/06/2023.
6. Response to TURN-SEU-037, Question 16, submitted on 03/02/2023.
7. Response to TURN-SEU-011, Question 1, submitted on 12/05/2022.

**Data Request Number:** PAO-SCG-053-DAO
**Proceeding Name:** A2205015_016 - SoCalGas and SDGE 2024 GRC
**Publish To:** Public Advocates Office
**Date Received:** 10/3/2022
**Date Responded:** 10/17/2022

3. Referring to the Workpapers for Chapter 9, pages 22-24, please provide the following information for each of the following programs: DREAMs, DRIP, SLIP, and GIPP.

a. Annual expenses incurred, completed unit of work, and number of FTEs recorded each year from 2017-2021.

b. A copy of the calculations and supporting documents for the 2023 forecasts for (i) expenses, (ii) units of work to be completed, and (iii) number of FTEs

**SoCalGas Response 3a:**

Annual O&M costs incurred, and the number of FTEs recorded each year from 2017-2021 by DREAMS, DRIP, SLIP, GIPP, and various DIMP projects are presented below. Completed units of work for DRIP, SLIP, and DIMP are also presented below, however DREAMS (VIPP & BSRP) GIPP and other PAARS units of work are associated with Capital costs rather than O&M; however, the units of work associated with the Capital costs impact the O&M costs.

| **Recorded Distribution Integrity Management (DIMP) Programs Recorded Costs In 2021 $ (000's)** | | | | | | |
|---|---|---|---|---|---|---|
| | | **2017** | **2018** | **2019** | **2020** | **2021** |
| **DREAMS** | Labor | $1,883 | $1,282 | $1,268 | $1,892 | $1,381 |
| | Non-Labor | $2,151 | $1,822 | $1,922 | $3,261 | $2,387 |
| | **Total** | **$4,033** | **$3,105** | **$3,190** | **$5,153** | **$3,767** |
| | FTE | 21.9 | 42.7 | 47.1 | 18.7 | 13.4 |
| | Units/Miles | N/A | N/A | N/A | N/A | N/A |
| **DRIP** | Labor | $3,819 | $3,757 | $3,094 | $3,059 | $3,530 |
| | Non-Labor | $12,698 | $12,602 | $11,814 | $11,438 | $10,256 |
| | **Total** | **$16,517** | **$16,359** | **$14,908** | **$14,497** | **$13,787** |
| | FTE | 38.8 | 38.7 | 31.7 | 30.7 | 35.8 |
| | No. of Inspections | 207,682 | 215,328 | 193,008 | 181.393 | 192,758 |
| **GIPP** | Labor | $1,356 | $2,028 | $2,389 | $424 | $270 |
| | Non-Labor | $745 | $421 | $348 | $1,115 | $443 |
| | **Total** | **$2,101** | **$2,449** | **$2,738** | **$1,540** | **$713** |
| | FTE | 12.3 | 19.5 | 22.4 | 3.9 | 2.4 |
| | No. of Mitigations | N/A | N/A | N/A | N/A | N/A |
| **SLIP** | Labor | $2,127 | $2,017 | $2,031 | $1,775 | $1,454 |
| | Non-Labor | $8,920 | $8,446 | $8,830 | $9,951 | $11,274 |
| | **Total** | **$11,047** | **$10,463** | **$10,861** | **$11,726** | **$12,728** |
| | FTE | 22.4 | 20.5 | 19.7 | 17.4 | 14.3 |
| | No. of inspections | 64,184 | 66,246 | 64,593 | 63,070 | 66,737 |
| **Other** | Labor | $3,637 | $6,710 | $5,530 | $6,266 | $5,861 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **PAARS** | | | | | | |
| | Non-Labor | $4,840 | $7,887 | $7,707 | $9,189 | $8,464 |
| | **Total** | **$8,477** | **$14,597** | **$13,238** | **$15,455** | **$14,325** |
| | FTE | 42.4 | 70.9 | 59.3 | 64.9 | 61.9 |
| | Units | N/A | N/A | N/A | N/A | N/A |
| **Total DIMP** | Labor | $12,821 | $15,794 | $14,313 | $13,416 | $12,496 |
| | Non-Labor | $29,354 | $31,179 | $30,621 | $34,954 | $32,824 |
| | **Total** | **$42,175** | **$46,973** | **$44,934** | **$48,370** | **$45,321** |
| | FTE | 137.8 | 192.3 | 180.2 | 135.6 | 127.8 |

**SoCalGas Response 3b:**

The table below represents forecasted 2023 O&M units, FTEs, and expenses for SLIP, DRIP, and Other PAARS, all of which are primarily O&M programs. DREAMS & GIPP are primarily capital programs, so the program units associated are not reflected as O&M.

The calculations for each O&M program are based on cost per unit. Program management costs are allocated across all program areas.

| **2023 DIMP Forecast** | | | | |
|---|---|---|---|---|
| **Programs Name** | **Units** | | **O&M In 2021 $(000s)** | |
| **DRIP** | | | Labor | $7,802 |
| | | | Non-Labor | $15,987 |
| | | | Total | $23,788 |
| | FTEs | 79.79 | | |
| | Miles | 200,000 | | |
| | Unit Cost | $~~0~~119 | | |
| **SLIP** | | | Labor | $2,986 |
| | | | Non-Labor | $16,519 |
| | | | Total | $19,505 |
| | FTEs | 30.54 | | |
| | Miles | 60,000 | | |
| | Unit Cost | $325 | | |

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FIMP SCG O&M Supplemental Workpaper

Table 1: 2024 SCG O&M Non-Shared Services Forecast

| Organization | Workpaper # | Category | Labor | Non-labor | Total | Units | Unit Measure | $/Unit | Narrative |
|---|---|---|---|---|---|---|---|---|---|
| Distribution | 2TD004.000 | Data Management | $ 7,800 | $ 992,280 | $ 1,000,080 | 0 | | $ - | Data management costs include data collection, record research, data entry and data integration. In addition, this cost includes process improvement by implementing an inspection workflow lifecycle solution to track fixed equipment inspections throughout the lifecycle of the equipment. |
| | | Electrical Equipment | $ - | $ 287,025 | $ 287,025 | 15 | Facilities | $ 19,135 | Electrical equipment costs include planning and scheduling support for inspections, NFPA 70B inspections, repairs and remediations resulting from inspections at SoCalGas' 15 Natural Gas Vehicle stations. |
| | | Program Management | $ 17,100 | $ 3,637 | $ 20,737 | 0 | | $ - | Program management costs include program development and governance, program performance monitoring and tracking. |
| | | Fixed Equipment | $ - | $ 89,200 | $ 89,200 | 28 | Equipment | $ 3,186 | Fixed equipment costs include pressure vessels preassessment, assessment and post assessment activities for approximately 28 vessels at 15 Natural Gas Vehicle stations. These activities include planning, scheduling, equipment preparation for inspection, inspection and data analysis, post inspection data QA/QC, repairs and alterations as a result of inspections. |
| **Distribution Totals** | | | **$ 24,900** | **$ 1,372,142** | **$ 1,397,042** | | | | |
| Storage | 2TD004.000 | Data Management | $ 1,248,000 | $ 364,800 | $ 1,612,800 | 0 | | $ - | Data management costs include data collection, record research, data entry and data integration. In addition, this cost includes process improvement by implementing an inspection workflow lifecycle solution to track fixed equipment inspections throughout the lifecycle of the equipment. |
| | | Electrical Equipment | $ 360,000 | $ 685,688 | $ 1,045,688 | 4 | Facilities | $ 261,422 | Electrical equipment costs include planning and scheduling support for inspections, NFPA 70B inspections, repairs and remediations resulting from inspections at SoCalGas' 4 Storage facilities. |
| | | Rotating Equipment | $ 120,000 | $ 240,000 | $ 360,000 | 6 | Compressor | $ 60,000 | Rotating equipment costs include inspections on rotating equipment, repairs resulting from inspections at 6 compressor stations located within storage facilities. |
| | | Program Management | $ 2,736,000 | $ 581,963 | $ 3,317,963 | 0 | | $ - | Program management costs include scoping, identification of threats and risk assessment, program development, program performance monitoring, governance and tracking. |
| | | Fixed Equipment | $ 240,000 | $ 4,497,796 | $ 4,737,796 | 520 | Equipment | $ 9,111 | Fixed equipment costs include pressure vessels, tanks, and piping pre-assessment, assessment and post assessment activities for approximately 520 equipment at 4 storage facilities. These activities include equipment preparation for inspection, data analysis, post inspection data QA/QC, repairs and alterations as a result of inspections. |
| **Storage Totals** | | | **$ 4,704,000** | **$ 6,370,247** | **$ 11,074,247** | | | | |
| Transmission | 2TD004.000 | Data Management | $ 273,000 | $ 88,920 | $ 361,920 | 0 | | $ - | Data management costs include data collection, record research, data entry and data integration. In addition, this cost includes process improvement by implementing an inspection workflow lifecycle solution to track fixed equipment inspections throughout the lifecycle of the equipment. |
| | | Electrical Equipment | $ 240,000 | $ 447,200 | $ 687,200 | 9 | Compressor | $ 76,356 | Electrical equipment costs include planning and scheduling support for inspections, NFPA 70B inspections, repairs and remediations resulting from inspections at SoCalGas' 5 compressor stations and 4 renewable natural gas facilities. |
| | | Rotating Equipment | $ 120,000 | $ 110,000 | $ 230,000 | 5 | Compressor | $ 46,000 | Rotating equipment costs include inspections on rotating equipment, repairs resulting from inspections at 5 compressor stations. |
| | | Program Management | $ 598,500 | $ 141,854 | $ 740,354 | 0 | | $ - | Program management costs include scoping, identification of threats and risk assessment, program development, program performance monitoring, governance and tracking. |
| | | Fixed Equipment | $ 120,000 | $ 341,800 | $ 461,800 | 75 | Equipment | $ 6,157 | Fixed equipment costs include pressure vessels, tanks, and piping pre-assessment, assessment and post assessment activities for approximately 75 equipment at 5 compressor stations. These activities include equipment preparation for inspection, data analysis, post inspection data QA/QC, repairs and alterations as a result of inspections. |
| **Transmission Totals** | | | **$ 1,351,500** | **$ 1,129,774** | **$ 2,481,274** | | | | |
| **Total Combined** | | | **$ 6,080,400** | **$ 8,872,163** | **$ 14,952,563** | | | | |

Notes:
1-19.5%, 80%, and 0.5% of the total Gas Engineering and IM&SP non-labor costs ( Shown in Table 3) were distributed between Transmission, Storage, and Distribution, respectively.

1. Referring to the Distribution portion of the spreadsheet above, please provide the following information:

a. the total number of Facilities as part of "Electrical Equipment" in SCG's system each year from 2017-2022 YTD;

**SoCalGas Response 1a:**

SoCalGas is proposing FIMP, a new program, in the TY2024 GRC. The table below lists the Natural Gas Vehicle (NGV) facilities currently included under FIMP.

**SoCalGas notes that, in responding to this data request, it has identified an overstatement of NGV facilities (34 rather than 27) that will impact the RSE calculations. SoCalGas will make this correction at the soonest opportunity.*

| Year | # of NGV Facilities |
|---|---|
| 2017 | 21 |
| 2018 | 25 |
| 2019 | 26 |
| 2020 | 26 |
| 2021 | 27 |
| 2022 | 27 |

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b. a copy of the calculations and supporting documentation used in determining the number of units (15 Natural Gas Vehicle (NGV) Facilities units) and unit cost for the expense forecast;

**SoCalGas Response 1b:**

SoCalGas plans on adopting the National Fire Protection Association (NFPA) 70B – Recommended Practice for Electrical Equipment Maintenance as a best practice. SoCalGas developed a three year plan as outlined below to distribute the workload:

- 2023 (first year) taking inventory and developing an inspection/testing plan;
- 2024 inspections and testing at 15 NGV facilities; and
- 2025 inspections and testing at 12 NGV facilities.

The unit cost for electrical equipment is estimated based on third party and subject matter expert input. The table below shows the unit cost breakdown.

**Table 1b-1: Cost Breakdown for Distribution Electrical Equipment ( SCG O&M)**

| Category | Work description | Units | Unit Cost | Non-Labor ( Unit cost x Units) | Labor | Total |
|---|---|---|---|---|---|---|
| Distribution Electrical Equipment | EE IMP - NFPA 70B Inspections and testing (Note 1) | 15 Facilities | $12,000 | $180,000 | $0 | $180,000 |
| | EE IMP - Electrical Equipment O&M Repairs (Note 2) | 15 Facilities | $7,095 | $106,425 | $0 | $106,425 |
| | 0.5% of total Gas Engineering Cost (Table 1b-2) (0.005x$120,000) | | | $600 | $0 | $600 |
| | **Total Distribution Electrical Equipment cost** | | | **$287,025** | **$0** | **$287,025** |

*Note1: Third party cost estimate for equipment verification was used to estimate testing and inspection costs.*
*Note2: Based on third party cost estimate and subject matter expert input, the unit cost for repairs is 33% of $21,500. (0.33x$21,500).*

**Table 1b-2: SCG O&M Gas Engineering Electrical Equipment**

| Category | Work description | Labor | Non-labor | Total |
|---|---|---|---|---|
| Gas Engineering Electrical Equipment Support | Design, drawing QA/QC, and support oversight | $0 | $120,000 | $120,000 |

c. the annual recorded cost and CPUC authorized funding SCG receives each year from 2017-2022 YTD, to provide (i) planning and scheduling support for inspections, (ii) inspections, (iii) repairs/remediations of SCG's NGV stations, (iv) Data Management, and (v) assessments and inspections related to the 28 "vessels" identified under Fixed Equipment;

**SoCalGas Response 1c:**

Annual recorded cost and CPUC authorized funding for maintenance activities on the pressure vessels can be found in the Gas Engineering testimony Exhibit SCG-07-R. SoCalGas is proposing as an element of the FIMP an incremental safety program on these pressure vessels in accordance with the American Petroleum Institute (API) 510 Pressure Vessel Inspection Code and API Recommended Best Practices 572 Inspection Practices for Pressure Vessels, for (i) planning and scheduling support for inspections, (ii) inspections, (iii) repairs/remediations of SCG's NGV stations, (iv) Data Management, and (v) assessments and inspections for vessels under fixed equipment at NGV stations. The FIMP inspections will focus on identifying, remediating, and preventing equipment integrity issues and promoting safer operations.

The FIMP activities are separate from routine maintenance activities and separate from inspections driven by routine maintenance activities referenced in Exhibit SCG-07-R. For example, if a pressure vessel inspection was warranted during routine maintenance activities, it would be performed by the Gas Engineering group and separate from the FIMP planned inspections; FIMP intends to perform inspections and assessments on the pressure vessels programmatically on a more regular basis. The fixed equipment integrity program (which includes pressure vessels at NGV facilities) is new and incremental and is being developed under FIMP based on API standards and industry best practices. Refer to Exhibit SCG-09, AK-TS-53 to AK-TS-55.

d. the definition of "vessels";

**SoCalGas Response 1d:**

SoCalGas interprets this question to seek the definition of a pressure vessel. The definition of a pressure vessel depends on whether the pressure vessel is code or non-code stamped. SoCalGas's definitions are as follows:

Pressure Vessel (Code Stamped): An unfired container, including cylinders, used for the storage or accumulation of any gas or liquid under pressure that is designed in compliance with ASME Section VIII Boiler and Pressure Vessel Code and is subjected to an internal or external design pressure greater than 15 PSIG.

Pressure Vessel (Non-Code Stamped): An unfired container, including cylinders, used for the storage or accumulation of any gas or liquid under pressure that is designed and constructed in accordance with the ASME Section VIII Code or in accordance with good engineering practice for the pressure and service in which they are to be used but is not code stamped.

e. the Budget Code SCG uses to track the expenses for inspections and repairs of NGV stations from 2017-2022 YTD;

**SoCalGas Response 1e:**

SoCalGas created Budget Code 240 for FIMP capital expenses/repairs resulting from FIMP inspections at NGV stations in 2021.

f. the total number of Fixed Equipment units in SCG's system each year from 2017- 2022 YTD;

**SoCalGas Response 1f:**

SoCalGas interprets this request to seek the total number of pressure vessels with respect to the NGV facilities listed above. Approximately 200 pressure vessels have been identified at the NGV facilities at this time.

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g. a copy of the calculations and supporting documentation used in determining the number of units (28 pieces of equipment) categorized as "Fixed Equipment" and unit cost in SCG's 2024 forecast; and

**SoCalGas Response 1g:**

SoCalGas interprets this request to seek information related to pressure vessels. SoCalGas estimates the number of pressure vessels to be on average two per facility. SoCalGas is currently planning inspections at 15 facilities. To determine cost per pressure vessel inspection, SoCalGas relied on historical inspection costs at storage facilities, third party cost estimate and subject matter expert input as shown in Tables 1g-1 and 1g-2.

**Table 1g-1: Cost Breakdown for Distribution Fixed Equipment (SCG O&M)**

| Category | Work description | Units | Unit Cost | Total Non-Labor (Units x Unit Cost) | Labor | Total |
|---|---|---|---|---|---|---|
| Distribution Fixed equipment | Pressure vessel inspections and data entry, QA/QC (Note1) | 28 | $3,143 | $88,004 | $0 | $88,004 |
| | Repairs (Note 2) | 28 | $0 | | | |
| | 0.5% of total Gas Engineering fixed equipment cost (Table 1g-2) (0.005x$240,000) | | | $1,200 | $0 | $1,200 |
| **Total Distribution Fixed Equipment cost** | | | | **$89,204** | **$0** | **$89,204** |

*Note1:* SoCalGas assumed 2 vessels for 13 sites and 1 vessel at 2 sites to total 28 sites at the time of this forecast. The unit cost is based on historical cost for inspections conducted at the Storage Facilities. Inspection costs can vary significantly depending on vessel size and inspection type.
*Note2: SoCalGas assumed no repairs are needed at the time of this forecast, however, the need for repair will be confirmed at the time of inspection.*

**Table 1g-2: Gas Engineering Fixed Equipment (O&M)**

| Category | Work description | Non-Labor | Labor | Total |
|---|---|---|---|---|
| Gas Engineering Fixed Equipment Cost | In-service inspections and NDE oversight | $240,000 | 0 | $240,000 |

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h. a copy of the calculations and supporting documentation used in determining the cost forecasts for (i) Data Management and (ii) Program Management.

**SoCalGas Response 1h:** Data management and program management cost forecasts are based on third party cost estimates and subject matter expert input. SoCalGas recommends a two-way balancing account to be adopted as costs presented in Tables 1h-1 and 1h-2 below are variable and depend on program development.

| **Table 1h-1: Estimated Cost Breakdown for Distribution Data Management and Program Management (SCG O&M)** | | | | |
|---|---|---|---|---|
| **Category** | **Work Description** | **Non-Labor** | **Labor** | **Total** |
| Distribution Data Management | Data collection and management for NGV facilities.<br>Facility P&ID and back modeling | $990,000 | $0 | $990,000 |
| | 0.5% of total IM&SP data management cost (Table 1h-2) | $2,280.0 | $7,800.0 | $10,080.0 |
| **Total Distribution Data Management** | | **$992,280** | **$7,800** | **$1,000,080** |
| Distribution Program Management | 0.5% of total IM&SP program management cost. (Table 1h-2) | $3,637 | $17,100 | $20,737 |
| **Total Distribution Program Management** | | **$3,637** | **$17,100** | **$20,737** |

| **Table 1h-2: Estimated Cost Breakdown of IM&SP Data management and Program Management (O&M)** | | | | |
|---|---|---|---|---|
| **Category** | **Work Description** | **Non-Labor** | **Labor** | **Total** |
| IM&SP Data Management | Data integration and records management | $250,000 | $480,000 | $730,000 |
| | Inspection workflow management tool | $130,000 | $0 | $130,000 |
| | Fixed equipment data management and resource planning | $0 | $1,080,000 | $1,080,000 |
| | Development of dashboards for data analysis | $76,000 | $0 | $76,000 |
| **Total IM&SP Data Management** | | **$456,000** | **$1,560,000** | **$2,016,000** |
| IM&SP Program Management | FIMP program management (including training) | $100,000 | $240,000 | $340,000 |
| | Program development, governance, and engineering | $150,000 | $780,000 | $930,000 |
| | Program analytics and performance monitoring | $100,000 | $720,000 | $820,000 |
| | Risk framework and risk model development | $100,000 | $480,000 | $580,000 |
| | Quality assurance | $250,000 | $0 | $250,000 |
| | Assessment analysis | $0 | $600,000 | $600,000 |
| | Assessment planning and scheduling | $27,454 | $600,000 | $627,454 |
| | | **$727,454** | **$3,420,000** | **$4,147,454** |

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2. Referring to the Storage portion of the spreadsheet above, please provide the following information:

a. a copy of the calculations and supporting documentation used in determining the cost forecasts for (i) Data Management and (ii) Program Management.

**SoCalGas Response 2a:** Data management and program management cost forecasts are based on third party cost estimates and subject matter expert input. SoCalGas recommends a two-way balancing account to be adopted as costs presented in tables 2a-1 and 2a-2 below are variable and depend on program development.

**Table 2a-1: Estimated Cost Breakdown for Storage Data Management and Program Management (SCG O&M)**

| Category | Work Description | Non-Labor | Labor | Total |
|---|---|---|---|---|
| Storage Data Management | 80% of total IM&SP data management cost (Table 2a-2) | $364,800 | $1,248,000 | $1,612,800 |
| Storage Program Management | 80% of total IM&SP program management cost (Table2a-2) | $581,963 | $2,736,000 | $3,317,963 |

**Table 2a-2: Estimated Cost Breakdown of IM&SP Data management and Program Management (O&M)**

| Category | Work Description | Non-Labor | Labor | Total |
|---|---|---|---|---|
| IM&SP Data Management | Data integration and records management | $250,000 | $480,000 | $730,000 |
| | Inspection workflow management tool | $130,000 | $0 | $130,000 |
| | Fixed equipment data management and resource planning | $0 | $1,080,000 | $1,080,000 |
| | Development of dashboards | $76,000 | $0 | $76,000 |
| **Total IM&SP Data Management** | | **$456,000** | **$1,560,000** | **$2,016,000** |
| IM&SP Program Management | FIMP program management (including training) | $100,000 | $240,000 | $340,000 |
| | Program development, governance, and engineering | $150,000 | $780,000 | $930,000 |

**SoCalGas Response 2a:-Continued**

| | | | | |
|---|---|---|---|---|
| | Program analytics and performance monitoring | $100,000 | $720,000 | $820,000 |
| | Risk framework and risk model development | $100,000 | $480,000 | $580,000 |
| | Quality assurance | $250,000 | $0 | $250,000 |
| | Assessment analysis | $0 | $600,000 | $600,000 |
| | Assessment planning and scheduling | $27,454 | $600,000 | $627,454 |
| **Total IM&SP Program Management** | | **$727,454** | **$3,420,000** | **$4,147,454** |

b. a copy of the calculations and supporting documentation used to determine the number of units (4 Facilities) and unit cost of "Electrical Equipment" in SCG's forecast;

**SoCalGas Response 2b:**

SoCalGas owns and operates four aboveground storage facilities that contain electrical equipment which will be inspected as a component of the FIMP. Electrical equipment count was not available at the time of this forecast; therefore, a unit is represented by a single storage facility. The unit cost for each storage facility is based on third party cost estimates and subject matter expert input. Below table provides the unit cost breakdown for this category.

| Unit = Storage Facility (Location of Electrical Equipment) | Unit Cost Estimated Cost Per Location |
|---|---|
| Aliso Canyon (Non-Labor) | $288,860 |
| Gas Engr Support (Non-Labor) | $24,000 |
| Labor | $90,000 |
| Honor Rancho (Non-Labor) | $106,569 |
| Gas Engr Support (Non-Labor) | $24,000 |
| Labor | $90,000 |
| La Goleta (Non-Labor) | $106,570 |
| Gas Engr Support (Non-Labor) | $24,000 |
| Labor | $90,000 |

**SoCalGas Response 2b:-Continued**

| | |
|---|---|
| Playa Del Rey (Non-Labor) | $87,689 |
| Gas Engr Support (Non-Labor) | $24,000 |
| Labor | $90,000 |
| Total | $1,045,688 |

*Note 1: Gas Engineering Non-Labor Support was estimated at $96,000. This cost was split evenly between four facilities.*
*Note 2: 3FTE's (3x$120,000 per FTE = $360,000) were estimated to support this component. This cost was split evenly between four facilities.*

c. the total number of SCG's Storage Facilities recorded each year from 2017-2022 YTD;

**SoCalGas Response 2c:**

SoCalGas interprets this question to the number of storage facilities owned and operated by SoCalGas each year from 2017-2022. SoCalGas owned and operated the following four Storage Facilities from 2017 to 2022.

- Aliso Canyon
- Playa del Rey
- La Goleta
- Honor Rancho

d. the authorized and recorded expenses of (i) planning and scheduling support for inspections, (ii) inspections, (iii) repairs/remediations, and (iv) Data Management of SCG's Storage Facilities each year from 2017-2022 YTD;

**SoCalGas Response 2d:**

Authorized and recorded expenses for maintenance and inspection activities for Storage Facilities and its compressors can be found in the Gas Storage testimony Exhibit SCG-10-R.

FIMP is proposing an incremental safety program in accordance with the American Petroleum Institute (API) 510 Pressure Vessel Inspection Code and API Recommended Best Practices 572 Inspection Practices for Pressure Vessels, tank integrity inspections and piping integrity inspections based on API 653 - Tank Inspection, Repair, Alteration, and Reconstruction and API 570 – Piping Inspection Code under fixed equipment, electrical equipment inspections and maintenance based on NFPA 70B for electrical equipment, for (i) planning and scheduling support for inspections, (ii) inspections, (iii) repairs/remediations, and (iv) Data Management of SCG's Storage Facilities and its

**SoCalGas Response 2d:-Continued**

compressors. Refer to Exhibit SCG-09, AK-TS-53 to AK-TS-55. NFPA 70B activities are outside of activities reported on General Order 165, FIMP does not include assets that are currently covered under General Order 95.

The FIMP inspections will focus on identifying, remediating, and preventing equipment integrity issues and promoting safer operations. The FIMP activities are incremental and separate from routine maintenance activities and separate from inspections referenced in Exhibit SCG-10-R. For example, if a pressure vessel, pipe, or tank inspection was warranted during routine maintenance activities or due to operational issues, it would be separate from the FIMP planned inspections. FIMP intends to perform inspections and assessments programmatically on a more regular basis.

e. a copy of the calculations and supporting documentation used to determine the inspection and repair costs for the 6 compressor stations in SCG's forecast;

**SoCalGas Response 2e:**

SoCalGas owns and operates four storage facilities, containing six compressor stations within them. SoCalGas interprets Question 2e to seek the cost of inspection and repair for rotating equipment within the six compressor stations at Storage facilities. Rotating equipment currently includes compressors; however, rotating equipment can include pumps and generators as well. SoCalGas plans to develop incremental programs under FIMP to address rotating equipment integrity. As such, SoCalGas recommends a two-way balancing account to be adopted as costs presented below are variable and dependent on program development. The cost forecast for rotating equipment inspection and repair is based on subject matter expert input. Labor cost forecast includes an estimate for one FTE for inspection, maintenance, and repair support at a salary of $120,000. The non-labor forecast is 80% of the total Gas Engineering Rotating equipment cost in Table 3 of the supplemental workpaper 2TD004.000 (0.8 x $300,000=$240,000). Adding labor ($120,000) and non-labor ($240,000) forecasts adds up to $360,000.

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f. the number of compressor stations in SCG's territory recorded each year from 2017-2022 YTD;

**SoCalGas Response 2f:**

SoCalGas interprets this request to seek the number of compressor stations located at the storage facilities. As stated in SoCalGas's response to Question 2e below, SoCalGas owns and operates four Storage facilities, containing six compressor stations from 2017 to 2022. Transmission Compressor Stations are included in SoCalGas's response to Question 3 above.

g. the authorized and recorded expenses of (i) planning and scheduling support for inspections, (ii) inspections, and (iii) repairs/remediations of SCG's compressor stations each year from 2017-2022 YTD;

**SoCalGas Response 2g:**

See SoCalGas's response to Question 2d above.

h. a copy of the calculations and supporting documentation showing how SCG determined the number of units (520 equipment) and unit cost for "Fixed Equipment"; and

**SoCalGas Response 2h:**

Approximately 520 units of equipment are currently estimated. The fixed equipment included in the inventory for storage facilities are piping, aboveground storage tanks, and pressure vessels. Approximately 520 units of equipment are planned for inspection in 2024 at this time. Tables 2h-1 and 2h-2 below present the cost breakdown.

**Table 2h-1: Cost Breakdown for Storage Fixed Equipment (SCG O&M)**

| Category | Work description | Units | Unit Cost | Total Non-Labor (Units x Unit Cost) | Labor | Total |
|---|---|---|---|---|---|---|
| Storage Fixed equipment | Pressure vessel inspections (Note 1) | 150 | $3,000 | $450,000 | $0 | $450,000 |
| | Tank inspections (Note 2) | 10 | $3,000 | $30,000 | $0 | $30,000 |
| | Pipe inspections (Note 3) | 360 | $1,758 | $633,000 | $0 | $633,000 |
| | CAT Scan of internals for 2 vessels (Note 4) | 2 | $21,398 | $42,796 | $0 | $42,796 |

**SoCalGas Response 2h:-Continued**

| | | | | | | |
|---|---|---|---|---|---|---|
| | Inspection of underground piping; (Note 5) | | | $1,500,000 | $0 | $1,500,000 |
| | Pressure vessel, tank, and pipe repairs (Note 6) | 15 | | $150,000 | $0 | $150,000 |
| | Inspection, maintenance, and repairs labor support (Note 7) | | | $0 | $240,000 | $240,000 |
| | Piping in line inspection (Note 8) | 6 | $250,000 | $1,500,000 | $0 | $1,500,000 |
| | 80% of total Gas Engineering fixed equipment cost (Table 2h-2) (0.8x$240,000) | | | $192,000 | $0 | $192,000 |
| **Total Storage Fixed Equipment cost** | | | | **$4,497,796** | **$240,000** | **$4,737,796** |

*Note 1: Unit cost is estimated per historical inspection costs. Inspection costs vary significantly depending on vessel size, inspection type.*

*Note 2: Unit cost is estimated per historical inspection costs. Inspection costs vary significantly depending on tank size, inspection type.*

*Note 3: Unit cost is estimated per historical inspection costs. Inspection costs vary significantly depending on pipe length.*

*Note 4: Unit cost is based on third party cost estimate.*

*Note 5: Unit cost is based on SME input. Inspection methodology will determine cost.*

*Note 6: O&M repairs as a result of inspections have been estimated at $10,000 per unit based on historical costs.*
*Note 7: Estimated salary at $120K per FTE to provide support for FIMP inspections and remediation activities. $120,000x2FTE.*

*Note 8: Unit cost is estimated based on historical inspections.*

| Table 2h-2: Cost Breakdown for Gas Engineering Fixed Equipment (O&M) | | | | |
|---|---|---|---|---|
| **Category** | **Work description** | **Non-Labor** | **Labor** | **Total** |
| Gas Engineering Fixed Equipment Cost | In-service inspections and NDE oversight | $240,000 | 0 | $240,000 |

i. the authorized and recorded expenses for work activities associated with “Fixed Equipment” for each year from 2017-2022 YTD.

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**SoCalGas Response 2i:**

See above response to Question 2d.

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3. Referring to the Transmission portion of the spreadsheet, please provide the following information:

a. a copy of the calculations and supporting documentation used in determining the cost forecasts for (i) Data Management and (ii) Program Management;

**SoCalGas Response 3a:**

Data management and program management cost forecasts are based on third party cost estimates and subject matter expert input. These costs are variable and dependent on program development and as such, SoCalGas recommends a two-way balancing account treatment for the program. Refer to the table below for breakdown of activities.

**Table 3a-1: Estimated Cost Breakdown for Transmission Data Management and Program Management (SCG O&M)**

| Category | Work Description | Non-Labor | Labor | Total |
|---|---|---|---|---|
| Storage Data Management | 19.5% and 17.5% of total IM&SP data management non-labor and labor costs, respectively (Table 2). | $88,920 | $273,000 | $361,920 |
| Storage Program Management | 19.5% and 17.5% of total IM&SP Program Management non-labor and labor costs, respectively (Table 2). | $141,854 | $598,500 | $740,354 |

**Table 3a-2: Estimated Cost Breakdown of IM&SP Data management and Program Management (O&M)**

| Category | Work Description | Non-Labor | Labor | Total |
|---|---|---|---|---|
| IM&SP Data Management | Data integration and records management | $250,000 | $480,000 | $730,000 |
| | Inspection workflow management tool | $130,000 | $0 | $130,000 |
| | Fixed equipment data management and resource planning | $0 | $1,080,000 | $1,080,000 |
| | Development of dashboards | $76,000 | $0 | $76,000 |
| **Total IM&SP Data Management** | | **$456,000** | **$1,560,000** | **$2,016,000** |
| IM&SP Program Management | FIMP program management (including training). | $100,000 | $240,000 | $340,000 |
| | Program development, governance, and engineering | $150,000 | $780,000 | $930,000 |
| | Program analytics and performance monitoring | $100,000 | $720,000 | $820,000 |
| | Risk framework and risk model development | $100,000 | $480,000 | $580,000 |
| | Quality assurance | $250,000 | $0 | $250,000 |
| | Assessment analysis | $0 | $600,000 | $600,000 |
| | Assessment planning and scheduling | $27,454 | $600,000 | $627,454 |
| **Total IM&SP Program Management** | | **$727,454** | **$3,420,000** | **$4,147,454** |

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b. the recorded and authorized funding amounts for (i) Data Management and (ii) Program Management each year from 2017-2022 YTD;

**SoCalGas Response 3b:**

The FIMP is a new program being proposed in the TY2024 GRC that would introduce a comprehensive program and incremental FIMP data management and program management activities. Refer to Exhibit SCG-09, AK-TS-53 to AK-TS-55.

c. a copy of the calculations and supporting documentation used to determine the number of units (9 compressors) and the unit cost of "Electrical Equipment";

**SoCalGas Response 3c:**

SoCalGas has nine active compressor stations and four renewable natural gas facilities with compression within the transmission territory. These are independent from the six Storage compressor stations. Per National Fire Protection Association (NFPA) 70B best practices, the inspection intervals for electrical equipment vary per equipment type. SoCalGas developed a three-year cycle to develop an inspection/testing plan in the first year (2023), conduct inspections and testing in the second and third years (2024 and 2025) at nine compressor stations in 2024 and four compressors in 2025, respectively.

9 and 4 were chosen to distribute the workload over a period of two years. The unit cost for electrical equipment is estimated based on third party and subject matter expert as show in the table below.

| **Cost Category** | **Cost Assumptions** | **Estimated Cost** |
|---|---|---|
| NFPA 70B inspections and testing - Compressor stations (non-Labor) | 5 Compressor stations | $25,000 |
| NFPA 70B inspections and testing - RNG facilities (non-Labor) | 4 RNG facilities | $36,000 |
| O&M repairs - Compressor stations (non-Labor) | 5 Compressor stations | $341,300 |
| O&M repairs - RNG facilities (non-Labor) | 4 RNG facilities | $21,500 |
| Gas Engineering support (non-Labor) | 19.5% of Gas Engineering Electrical equipment non-labor cost | $23,400 |
| Labor Cost | 2 FTEs | $240,000 |
| **Total** | | **$687,200** |

d. the recorded number of compressor stations and natural gas facilities in SCG's system each year from 2017-2022 YTD;

**SoCalGas Response 3d:**

SoCalGas interprets this request to seek information related to the number of compressor stations and renewable natural gas compression stations. The list below shows the number of compressor stations and renewable natural gas compression stations within the current scope of FIMP. Number of stations included in the FIMP are subject to change upon further scoping and data collection.

| Year | Compressor Station | Renewable Natural Gas Compression Stations |
|---|---|---|
| 2017 | 9 | 0 |
| 2018 | 9 | 0 |
| 2019 | 9 | 0 |
| 2020 | 9 | 0 |
| 2021 | 9 | 3 |
| 2022 | 9 | 4 |

e. the recorded and authorized expenses for the (i) planning and scheduling support for inspections, (ii) inspections, and (iii) repairs/remediations of SCG's compressor stations and natural gas facilities as categorized under "Electrical Equipment";

**SoCalGas Response 3e:**

Recorded and authorized expenses can be found in the Gas Transmission Operations testimony Exhibit SCG-06-R.

For electrical equipment, (i) planning and scheduling support for inspections, (ii) inspections, and (iii) repairs/remediations of SCG's compressor stations and natural gas facilities are part of NFPA 70B FIMP activities. NFPA 70B activities are wholly incremental and new for Transmission and outside of activities reported on General Order 165. FIMP does not include assets that are currently covered under General Order 95.

The FIMP is a new program that will enhance safety and is being proposed in the TY2024 GRC as a comprehensive integrity program. Refer to Exhibit SCG-09, AK-TS-55.

f. a copy of the calculations and supporting documentation used to determine the number of units (5 compressors) and the unit cost of "Rotating Equipment";

**SoCalGas Response 3f:**

The number of units for inspection and unit cost forecast are based on subject matter expert input. Labor cost forecast includes an estimate for one FTE for inspection, maintenance, and repair support at a salary of $120,000. The non-labor forecast is 20% of the total Gas Engineering Rotating equipment cost in Table 3 of the supplemental workpaper 2TD004.000 (0.2 x $300,000=$60,000) and inspection non labor support is estimated at an additional $50,000. Adding labor ($120,000) and non-labor ($60,000+$50,000) forecasts adds up to $230,000.

g. the recorded and authorized expenses for the (i) planning and scheduling support for inspections, (ii) inspections, and (iii) repairs/remediations of SCG's compressor stations as categorized under "Rotating Equipment";

**SoCalGas Response 3g:**

Recorded and authorized expenses can be found in the Gas Transmission Operations testimony Exhibit SCG-06-R.

Integrity activities on rotating equipment included in the cost estimate will vary as the program is further developed and activities including (i) planning and scheduling support for inspections, (ii) inspections, and (iii) repairs/remediations will be incremental to current routine maintenance. The FIMP is a new program being proposed in the TY2024 GRC that would introduce a comprehensive integrity program for facilities. Refer to Exhibit SCG-09, AK-TS-52.

h. a copy of the calculations and supporting documentation used in determining the cost forecasts for "Fixed Equipment"; and

**SoCalGas Response 3h:**

Approximately 75 units of equipment are estimated based on current available information. The fixed equipment included in the inventory for Transmission include pressure vessels, above ground storage tanks and piping. Approximately 75 units of equipment are planned for inspection in 2024, subject to change as the program is further developed. Inspection costs vary by equipment type and size. Table below shows assumptions included in the cost forecast.

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**SoCalGas Response 3h:-Continued**

| Table 3h-1: Cost Breakdown for Transmission Fixed Equipment (SCG O&M) | | | | | | |
|---|---|---|---|---|---|---|
| **Category** | **Work description** | **Units** | **Unit Cost** | **Total Non-Labor (Units x Unit Cost)** | **Labor** | **Total** |
| Transmission Fixed equipment | Pressure vessel inspections (Note 1) | 40 | $3,000 | $120,000 | $0 | $120,000 |
| | Tank inspections (Note 2) | 15 | $3,000 | $45,000 | $0 | $45,000 |
| | Material Verification (Note 3) | 10 | $5,000 | $50,000 | $0 | $50,000 |
| | Pressure vessel and tank repairs (Note 4) | 10 | $8,000 | $80,000 | $0 | $80,000 |
| | Inspection, maintenance, and repair support (Note 5) | | | $0 | $120,000 | $120,000 |
| | 19.5% of total Gas Engineering fixed equipment Non-labor. (Table 3h-2) (0.195x$240,000) | | | $46,800 | $0 | $46,800 |
| **Total Transmission Fixed Equipment cost** | | | | **$341,800** | **$120,000** | **$461,800** |

*Note 1: Unit cost is estimated per historical inspection costs. Inspection costs vary significantly depending on vessel size, inspection type.*
*Note 2: Unit cost is estimated per historical inspection costs. Inspection costs vary significantly depending on tank size, inspection type.*
*Note 3: Unit cost is based on historical costs, unit cost is estimated at $5000 per unit. Cost vary significantly depending on equipment size.*
*Note 4: O&M repairs as a result of inspections have been estimated at $8,000 per unit based on Storage historical costs.*
*Note 5: Estimated salary at $120K per FTE to provide support for FIMP inspections and remediation activities. $120,000x1FTE.*

| Table 3h-2: Cost Breakdown for Gas Engineering Fixed Equipment (O&M) | | | |
|---|---|---|---|
| **Category** | **Work description** | **Non-Labor** | **Labor** |
| Gas Engineering Fixed Equipment Cost | In-service inspections and NDGE oversight | $240,000 | 0 |

i. the recorded and authorized expenses for “Fixed Equipment” each year from 2017- 2022 YTD.

**SoCalGas Response 3i:**

Recorded and authorized expenses can be found in the Gas Transmission Operations testimony Exhibit SCG-06-R.

**SoCalGas Response 3i:-Continued**

FIMP is proposing an incremental safety program in accordance with the American Petroleum Institute (API) 510 Pressure Vessel Inspection Code and API Recommended Best Practices 572 Inspection Practices for Pressure Vessels, tank integrity inspections based on API 653 - Tank Inspection, Repair, Alteration, and Reconstruction and certain piping inspections under fixed equipment. Refer to Exhibit SCG-09, AK-TS-53 to AK-TS-55. The FIMP inspections will focus on identifying, remediating, and preventing equipment integrity issues and promoting safer operations.

The FIMP activities are incremental and separate from routine maintenance activities and separate from inspections referenced in Exhibit SCG-06-R. For example, if a pressure vessel inspection was warranted during routine maintenance activities or due to operational issues, it would be performed by the Gas Engineering group and separate from the FIMP planned inspections.

**Data Request Number:** PAO-SCG-036-DAO
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**Proceeding Number:** A2205015_016 2024 GRC
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4. Identify the data management system used for Transmission Integrity Management Program (TIMP) or Distribution Management Program (DIMP).

**SoCalGas Response 4:**

As stated in the testimony (Ex. SCG-09), SoCalGas manages two GIS systems for TIMP and DIMP: the High Pressure Pipeline Database (HPPD) for high pressure assets and the eGIS for medium pressure assets. In addition, SoCalGas is developing a new Enterprise Asset Management data lake.

5. Is SCG proposing a different data management system for Facilities Integrity Management Program (FIMP)? If yes, please identify the data management system proposed for FIMP. If no, please state whether SCG has performed any cost savings studies associated with the sharing of data management costs across programs and provide a copy of the analysis/studies.

**SoCalGas Response 5:**

FIMP plans to utilize existing databases, including the Enterprise Asset Management data lake, to collect and integrate data from multiple sources. FIMP will introduce additional workflow management tools, inspections maintenance and scheduling software, and dashboards to improve processes, trend, and visualize data for analysis.

**<u>SCG-SDGE-TURN-009</u>**

**REQUEST:**

Please provide the following:

1. The supporting data and calculations used to derive the values for Table 14, Exhibit TURN-05/Walker, page 73.
2. Please confirm that data request TURN-106, Q15 (cited at footnote 85 in TURN-05/Walker) is a data request issued to SDG&E in A.22-05-15, and if it is, please submit a copy of SDG&E's response.

**RESPONSE:**

1. In preparing this response, TURN discovered that Table 14 contained incorrect values for the Year and "Total Aldyl-A leaks (SCG)" rows. By extension, this also impacted the "Aldyl-A %" row. The corrected Table 14 is provided below:

| | SoCalGas Leak Count (Repaired Year) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **Total Aldyl-A Leaks** | 1,156 | 1,410 | 1,625 | 1,293 | 1,441 | 1,577 | 1,878 | 2,045 | 2,179 | 1,803 |
| **Total System Leaks** | 11,028 | 17,863 | 34,350 | 41,625 | 41,316 | 42,119 | 43,419 | 46,076 | 45,929 | 42,551 |
| **Aldyl-A %** | 10% | 8% | 5% | 3 % | 3% | 4% | 4% | 4% | 5% | 4% |

Please also see Attachment 01 SCG-SDGE-TURN-009 which contains a redline edit of the surrounding pages to Table 14 and reflects the corrected values provided in this response.

Supporting data for the revised Table 14 was taken from the Company's supplemental response to TURN-SEU-023-002 and from the Company's 2012-2021 F7100.1-1 reports filed annually with PHMSA. The calculations that were performed to derive the values for Table 14 were to:

- Sum main and service leak repairs for the rows labeled "Total Aldyl-A Leaks" and "Total System Leaks", and
- Divide Aldyl-A leaks by Total System leaks to derive the row labeled "Aldyl-A %".

Also see SCG-SDGE-TURN-009_ Attachment-02 for calculations & data.

2. The citation to "TURN-106, Q15" was erroneous and should instead cite the Companies' supplemental response to TURN-SEU-023-002.

**Attachment 01 SCG-SDGE-TURN-009: Redline edits to Ex. TURN-05 For pgs. 72-74:**

From ~~1985~~ 2012 to present, the number of leaks that the Company has had to repair has fluctuated year over year as pipe has been replaced and new threats to the system emerge. But across that ~~37+ year~~ period, the percentage of all repaired leaks that occurred on Aldyl-A has ~~remained~~ seen a fairly constant ~~in the 0.5% to 2%~~decline from the 10% to 3%range. For comparison, SoCalGas has approximately 8,032 miles of Aldyl-A main which is approximately 16% of the total system mileage.[1] Comparably, SoCalGas reports 11,052 miles of Aldyl-A services which represent approximately 22% of the total mileage of services in the system.[2] Of note, unprotected steel makes up comparable percentages of the SoCalGas main (15%) and services (17%) yet is responsible for a far higher leak rate as discussed above.

I attempted to graph the percentages of system leaks that were on Aldyl-A vs. all other pipe, but all visualizations failed as the amounts of Aldyl-A leaks per year were too small to see, as the total leak repair number has been approximately ~~45 to 2000~~ 17 to 53 times larger than the Aldyl-A leak repair number as shown in the summary table below. Please note that Table 14 below contains total leak counts that have not been adjusted to remove leaks caused by excavation – a risk that the VIPP does not address; nor have they been adjusted to account for the

[1] TURN-SEU-023, Q2, Supp. And SoCalGas 2021 F7100-1.1 report to PHMSA.
[2] *Id.*

increase in leak survey activities in recent years which will inevitably discover more, smaller leaks.

| | SoCalGas Leak Count (Repaired Year) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **Total Aldyl-A Leaks** | 1,156 | 1,410 | 1,625 | 1,293 | 1,441 | 1,577 | 1,878 | 2,045 | 2,179 | 1,803 |
| **Total System leaks (PHMSA Reports)** | 11,028 | 17,863 | 34,350 | 41,625 | 41,316 | 42,119 | 43,419 | 46,076 | 45,929 | 42,551 |
| **Aldyl-A %** | 10% | 8% | 5% | 3 % | 3% | 4% | 4% | 4% | 5% | 4% |

*Table 14: ~~1985~~2012-202~~0~~1 Aldyl-A Leak Rates*

Even with the inclusion of excavation leaks, the key takeaway from this analysis is that the risk of failure of this subset of pipe is small and is not seeing rapid growth, – even over a long period of time. If anything, this long-term view highlights concerns with bare steel and other metallic piping materials. In addition to total historical leaks on Aldyl-A pipe, the Company provided leaks by Grade on ~~Aldyl-A85~~all pipe in its system~~-~~ which allows us to compare hazardous leaks to the ~~-assess the severity of~~ leaks that occured on Aldyl-A. Looking at the ~~most severe, Grade 1~~ leaks on Aldyl-A, the most recent year that the Company provided~~, was~~ 202~~0~~1, in which there was a total of 1,310 ~~164 Grade 1~~ leaks on ~~pre-~~1985 or older Aldyl-A which required immediate remediation. **For scale, there were approximately ~~9,074~~8,187 (or ~~5,430~~525% more) Grade 1 leaks on the SoCalGas system in 202~~0~~1 alone** – much less total leaks of which there were 42,551 (or 3,148% more). Finally, there is no data (either from the Companies, industry studies, or peers) that suggest that there is potential or likelihood that historical leak rates on Aldyl-A piping will deviate from the historic linear trend and unexpectedly grow.

| Company | Facility | Materials | | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|
| SoCalGas | Main | Aldyl-A Plastic Pre-1973 | Mileage | 404 | 404 | 404 |
| | | | Leak Count | 25 | 19 | 33 |
| | | | Leak Rate | 0.062 | 0.047 | 0.082 |
| | | Aldyl-A Plastic 1973-1985 | Mileage | 7,769 | 7,769 | 7,769 |
| | | | Leak Count | 622 | 773 | 944 |
| | | | Leak Rate | 0.080 | 0.099 | 0.122 |
| | | Modern Plastic 1976-2021 | Mileage | 16,976 | 16,976 | 16,976 |
| | | | Leak Count | 337 | 402 | 409 |
| | | | Leak Rate | 0.020 | 0.024 | 0.024 |
| | Service | Aldyl-A Plastic Pre-1973 | Mileage | 464 | 464 | 464 |
| | | | Leak Count | 15 | 17 | 23 |
| | | | Leak Rate | 0.032 | 0.037 | 0.050 |
| | | Aldyl-A Plastic 1973-1985 | Mileage | 10,360 | 10,360 | 10,360 |
| | | | Leak Count | 494 | 601 | 625 |
| | | | Leak Rate | 0.048 | 0.058 | 0.060 |
| | | Modern Plastic 1976-2021 | Mileage | 20,243 | 20,243 | 20,243 |
| | | | Leak Count | 308 | 397 | 377 |
| | | | Leak Rate | 0.015 | 0.020 | 0.019 |
| SDG&E | Main | Aldyl-A Plastic Pre-1973 | Mileage | 148 | 148 | 148 |
| | | | Leak Count | 8 | 8 | 6 |
| | | | Leak Rate | 0.054 | 0.054 | 0.041 |
| | | Aldyl-A Plastic 1973-1985 | Mileage | 1,397 | 1,397 | 1,397 |
| | | | Leak Count | 66 | 55 | 79 |
| | | | Leak Rate | 0.047 | 0.039 | 0.057 |
| | | Modern Plastic 1976-2021 | Mileage | 3,102 | 3,102 | 3,102 |
| | | | Leak Count | 5 | 8 | 14 |
| | | | Leak Rate | 0.002 | 0.003 | 0.005 |
| | Service | Aldyl-A Plastic Pre-1973 | Mileage | 125 | 125 | 125 |
| | | | Leak Count | 2 | 5 | 6 |
| | | | Leak Rate | 0.016 | 0.040 | 0.048 |
| | | Aldyl-A Plastic 1973-1985 | Mileage | 1,185 | 1,185 | 1,185 |
| | | | Leak Count | 44 | 37 | 60 |
| | | | Leak Rate | 0.037 | 0.031 | 0.051 |
| | | Modern Plastic 1976-2021 | Mileage | 2,995 | 2,995 | 2,995 |
| | | | Leak Count | 39 | 20 | 28 |
| | | | Leak Rate | 0.013 | 0.007 | 0.009 |

Leak Fix Year

| 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| 404 | 404 | 404 | 404 | 404 | 385 | 362 |
| 26 | 27 | 41 | 47 | 48 | 40 | 34 |
| 0.064 | 0.067 | 0.101 | 0.116 | 0.119 | 0.104 | 0.094 |
| 7,769 | 7,769 | 7,769 | 7,769 | 7,769 | 7,735 | 7,670 |
| 766 | 829 | 961 | 1,236 | 1,372 | 1,516 | 1,276 |
| 0.099 | 0.107 | 0.124 | 0.159 | 0.177 | 0.196 | 0.166 |
| 16,976 | 16,976 | 16,976 | 16,976 | 16,976 | 17,252 | 17,673 |
| 353 | 412 | 445 | 416 | 439 | 390 | 424 |
| 0.021 | 0.024 | 0.026 | 0.025 | 0.026 | 0.023 | 0.024 |
| 464 | 464 | 464 | 464 | 464 | 466 | 482 |
| 18 | 16 | 26 | 24 | 18 | 21 | 23 |
| 0.039 | 0.034 | 0.056 | 0.052 | 0.039 | 0.045 | 0.048 |
| 10,360 | 10,360 | 10,360 | 10,360 | 10,360 | 10,403 | 10,570 |
| 483 | 569 | 549 | 571 | 607 | 602 | 470 |
| 0.047 | 0.055 | 0.053 | 0.055 | 0.059 | 0.058 | 0.044 |
| 20,243 | 20,243 | 20,243 | 20,243 | 20,223 | 20,708 | 21,431 |
| 374 | 384 | 494 | 443 | 378 | 336 | 216 |
| 0.018 | 0.019 | 0.024 | 0.022 | 0.019 | 0.016 | 0.010 |
| 148 | 148 | 148 | 148 | 148 | 138 | 114 |
| 14 | 16 | 16 | 16 | 17 | 10 | 5 |
| 0.095 | 0.108 | 0.108 | 0.108 | 0.115 | 0.072 | 0.044 |
| 1,397 | 1,397 | 1,397 | 1,397 | 1,397 | 1,406 | 1,397 |
| 86 | 73 | 81 | 103 | 103 | 75 | 88 |
| 0.062 | 0.052 | 0.058 | 0.074 | 0.074 | 0.053 | 0.063 |
| 3,102 | 3,102 | 3,102 | 3,102 | 3,102 | 3,121 | 3,168 |
| 10 | 14 | 6 | 7 | 11 | 11 | 17 |
| 0.003 | 0.005 | 0.002 | 0.002 | 0.004 | 0.004 | 0.005 |
| 125 | 125 | 125 | 125 | 125 | 99 | 84 |
| 7 | 7 | 8 | 4 | 7 | 3 | 1 |
| 0.056 | 0.056 | 0.064 | 0.032 | 0.056 | 0.030 | 0.012 |
| 1,185 | 1,185 | 1,185 | 1,185 | 1,185 | 1,189 | 1,177 |
| 61 | 45 | 55 | 70 | 64 | 46 | 34 |
| 0.051 | 0.038 | 0.046 | 0.059 | 0.054 | 0.039 | 0.029 |
| 2,995 | 2,995 | 2,995 | 2,995 | 2,995 | 3,040 | 3,092 |
| 18 | 14 | 23 | 30 | 30 | 21 | 20 |
| 0.006 | 0.005 | 0.008 | 0.010 | 0.010 | 0.007 | 0.006 |

2. Regarding the Response to TURN DR 013-02: Please provide an excel spreadsheet that shows the number of leak repairs on plastic pipe segregated by year of pipe installation and material subtype (distinguishing between the various types of plastic in the system if possible) for each of the past ten years, separately for SDG&E and SCG.

**SoCalGas Response 2:**

SoCalGas objects to this request on the grounds that it is overly broad and unduly burdensome. Subject to and without waiving the foregoing objections, SoCalGas responds as follows:

For the leak repairs for the past five years (2017-2021), see separately attached TURN-SEU-023_Q2.

**Data Request Number:** TURN-SEU-037

**Proceeding Name:** A2205015_016 - SoCalGas and SDGE 2024 GRC

**Publish To:** The Utility Reform Network

**Date Received:** 2/15/2023

**Date Responded:** 3/2/2023

16. Regarding both Aldyl-A plastic pipe and bare steel pipe in the Company's system, please provide outputs from the Company's risk-ranking efforts that quantifies the relative risk of each material type.

**SoCalGas Response 16:**

See SoCalGas's response to TURN-SEU-011 Q1.

**Data Request Number:** TURN-SEU-011

**Proceeding Name:** A2205015_016 - SoCalGas and SDGE 2024 GRC

**Publish To:** The Utility Reform Network

**Date Received:** 11/18/2022

**Date Responded:** 12/05/2022

1. Please provide re-calculated RSEs for all RSEs calculated in this case with the following changes to the Sempra Utilities' MAVF:

(i) Change the weight of the HEALTH AND SAFETY attribute from 60% to 40% and change the range for this attribute from 0-20 to 0-67 (don't change the sub-attribute values);

(ii) Change the weight of the FINANCIAL attribute from 17% to 25% and keep the range from 0 - $500 million.

(iii) Change the weight of the RELIABILITY attribute from 23% to 35% and keep the range from 0 – 1 (don't change the sub-attribute ranges).

a. Please provide revised Excel workpapers supporting the re-calculated RSEs for any workpapers that are changed by this alternative scenario, including workpapers showing tranche-level results.

b. For this revised MAVF scenario, please provide an Excel spreadsheet that:

i. Shows the aggregated (i.e., not the tranche level) pre-mitigation LoRE and CoRE values for each risk, as compared to those values under Sempra's MAVF; and

ii. Provides a breakdown of the pre-mitigation CoRE values by attribute for each risk (in the aggregate, not at the tranche level), as compared to those values under Sempra's MAVF.

**Data Request Number:** TURN-SEU-011

**Proceeding Name:** A2205015_016 - SoCalGas and SDGE 2024 GRC

**Publish To:** The Utility Reform Network

**Date Received:** 11/18/2022

**Date Responded:** 12/05/2022

**SEU Response 1:**

SoCalGas and SDG&E object to this request to the extent it imposes upon SoCalGas and SDG&E an obligation to generate or create records that do not exist, or which have not been generated or created in its regular course of business. This purported obligation exceeds the requirements provided by the CPUC's Discovery Custom and Practice Guidelines and California Code of Civil Procedure Section 2031.230 (proper response stating inability to comply with discovery request includes a statement that "the particular item or category [of records] has never existed"). *See also* A.05-04-020, *In the Matter of the Joint Application of Verizon Communications Inc. and MCI, Inc.*, Administrative Law Judge's Ruling Addressing Motion of Qwest to Compel Responses, Aug. 5, 2005, at 7 (in relation to motion to compel emphasized that "Verizon is not required to create new documents responsive to the data request") (also available at 2005 WL 1866062); A.05-02-027, *In the Matter of the Joint Application of SBC Communications Inc. and AT&T Corp.*, Administrative Law Judge's Ruling Regarding ORA's Second Motion to Compel, June 8, 2005, at 23 (in ruling on motion to compel stressed that SBC Communications "shall not be required to produce new studies specifically in response to this DR") (also available at 2005 WL 1660395). Subject to and without waiving the foregoing objection, SoCalGas and SDG&E respond as follows:

The information requested can be ascertained via the working Excel spreadsheet format in the Quantitative workpapers (QWP) provided on the SoCalGas/SDG&E Discovery Portal. The Excel files provided are a live format of each risk mitigation broken down by risk chapter. Within each file (on the 'Master Input' tab), intervening Parties may adjust weights, ranges, discount, and readability factors, etc. and determine RSE impacts downstream. Additionally, within the Post Test Year Quantitative Workpapers, the escalation rates can be modified to determine changes in RSE values both with and without the CFF allocations. Lastly, because these documents are live, any combination of sensitivity analysis can be applied with resulting information displayed *i.e.*, pre- and post-CoRE, both at the tranche and aggregated level.

**APPENDIX C**

AACE International, Recommended Practice No. 97R-18
"Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Pipeline Transportation Infrastructure Industries" (Bredehoeft et al.).

AACE INTERNATIONAL RECOMMENDED PRACTICE

# 97R-18

# COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PIPELINE TRANSPORTATION INFRASTRUCTURE INDUSTRIES

AACE INTERNATIONAL

TS-AR-C-2

AACE® International Recommended Practice No. 97R-18

# COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PIPELINE TRANSPORTATION INFRASTRUCTURE INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

Rev. August 7, 2020

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## 1. PURPOSE

As a recommended practice (RP) of AACE International, the *Cost Estimate Classification System* provides guidelines for applying the general principles of estimate classification to project cost estimates (i.e., cost estimates that are used to evaluate, approve, and/or fund projects). The *Cost Estimate Classification System* maps the phases and stages of project cost estimating together with a generic project scope definition maturity and quality matrix, which can be applied across a wide variety of industries and scope content.

This recommended practice provides guidelines for applying the principles of estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) work for the pipeline transportation infrastructure industries. It supplements the generic cost estimate classification RP 17R-97 [1] by providing:

- A section that further defines classification concepts as they apply to the pipeline transportation infrastructure industries.
- A chart that maps the extent and maturity of estimate input information (project definition deliverables) against the class of estimate.

As with the generic RP, the intent of this document is to improve communications among all the stakeholders involved with preparing, evaluating, and using project cost estimates specifically for the pipeline transportation infrastructure industries.

The overall purpose of this recommended practice is to provide the pipeline transportation infrastructure industries with a project definition deliverable maturity matrix that is not provided in 17R-97. It also provides an approximate representation of the relationship of specific design input data and design deliverable maturity to the estimate accuracy and methodology used to produce the cost estimate. The estimate accuracy range is driven by many other variables and risks, so the maturity and quality of the scope definition available at the time of the estimate is not the sole determinate of accuracy; risk analysis is required for that purpose.

This document is intended to provide a guideline, not a standard. It is understood that each enterprise may have its own project and estimating processes, terminology, and may classify estimates in other ways. This guideline provides a generic and generally acceptable classification system for the pipeline transportation infrastructure industries that can be used as a basis to compare against. This recommended practice should allow each user to better assess, define, and communicate their own processes and standards in the light of generally-accepted cost engineering practice.

## 2. INTRODUCTION

For the purposes of this document, the term *pipeline transportation* is assumed to include onshore and offshore pipelines for transportation of gas and liquids in the infrastructure industries. The gas and liquids can be of any type including but not limited to hydrocarbons, chemicals and water. This primarily covers pipelines under pressure (e.g., steel, composite, etc.) and not gravity drainage (e.g., concrete). This excludes piping within a process plant, mining facility, utilities plant or other facility site. It also excludes pumping and compression stations and storage and shipping terminals. The defining deliverables of those excluded process (e.g., plant piping) and civil (e.g., drainage) project scopes are covered in other RPs (e.g., 18R-97 for process plants [2] and 56R-08 [3] for general construction).

Pipeline transportation is considered an element of the infrastructure industry. The Construction Industry Institute has provided a good definition of infrastructure in its Project Definition Rating Index for Infrastructure Projects as follows [4]:

"A capital project that provides transportation, transmission, distribution, collection or other capabilities supporting commerce or interaction of goods, services, or people. Infrastructure projects generally impact multiple jurisdictions, stakeholder groups and/or a wide area. They are characterized as projects with a primary purpose that is integral to the effective operation of a system. These collective capabilities provide a service that is made up of nodes and vectors into a grid or system."

Using this definition, pipeline transportation is a vector or linear scope element that connects pumping or compression facilities or storage or shipping terminal nodes at its terminations or intermediate points. The pumping and compression facility nodes are integral elements of pipeline project scope; however, because their design and execution differ greatly from the pipeline itself, they are excluded here. Likewise, terminals (e.g., tank farms) are often associated with pipeline projects, but are excluded. However, incidental valve, monitoring or pigging stations may be included. In any case, pipeline projects are often executed as part of a program that also involves node project scope or facility operational changes (or at least considerations for integrated system commissioning and startup). A key element of defining scope is to study system hydraulics and while station estimate classification is excluded in this RP, the design of pipeline and stations (which can vary in number and placement) are done iteratively [5]. As the definition states, a distinguishing feature of these projects is that they often traverse wide areas, cross country or subsea, which puts an emphasis on the definition of routing, land ownership and conditions, and establishing right-of-way (ROW). Associated scope definition challenges include defining stakeholder, permitting and regulatory requirements (pipeline transportation is usually a regulated industry if not government owned).

The main physical pipeline transportation scope elements are the pipe, fittings, valves and controls as well as associated items for road, rail, water and other crossings including horizontal drilled borings (tunneling is excluded). Surface pipelines also include structural supports. Main installation elements include land clearing if over land (including forestry if applicable), foundation and structure erection if on the surface, or trenching and backfill if buried, and pipe transport and handling, joining (i.e., welding), coating, cathodic protection, insulation and placement. Special scope elements are involved with crossings of water, road, rail and so on and at the pipeline terminations. Environmental, safety and health concerns are paramount with pipelines under pressure, and may carry hazardous materials, therefore, monitoring and control systems are key scope elements as well as inspection and maintenance considerations (e.g., pigging).

In general, the more developed the route, the more complex the installation will be. For urban areas, obstructions with utilities are frequent requiring existing condition studies, coordination with utilities and sometimes relocations. In remote locations and/or difficult or environmentally sensitive terrain, installation has its own challenges. Before any installation work can begin in an area, appropriate land and ROW must be acquired which creates unique scheduling as well as cost challenges.

For the purpose of estimate classification then, the main scope definition deliverables are associated with hydraulic design, defining the throughput capacity (volume/time), pipeline, fitting and control materials, and the routing including its elevation profiles, crossings and other elements. Pipelines materials can vary widely (e.g., steel, plastic, composite, etc.) as do coatings and insulation (if applicable). The pipeline material costs may be 20 to 40% of the total pipeline costs, making these projects highly susceptible to escalation and currency uncertainty. The route's land or subsea characteristics and the nature of developments drive the need for special design features and execution strategies. For each scope definition decision, stakeholder requirements need to be considered.

Pumping, compression, terminal and well site projects are usually associated with pipeline transportation projects. However, these facilities are equipment-centric and located on facility sites that have physical and defining characteristics similar to process plant projects (e.g., reliance on equipment lists, piping and instrumentation diagrams (P&IDs), plot plans, etc.). Therefore, RP 18R-97 for process plants is recommended for classifying those estimates [2]. Pipelines projects may also share right-of-ways with power transmission line projects that are covered in RP 96R-18 [6].

This guideline reflects generally-accepted cost engineering practices. This recommended practice was based upon the practices of multiple pipeline companies as well as published references and standards. Company and public standards were solicited and reviewed, and the practices were found to have significant commonalities. These classifications are also supported by empirical industry research of systemic risks and their correlation with cost growth and schedule slippage [7].

This RP applies to a variety of project delivery methods such as traditional design-bid-build (DBB), design-build (DB), construction management for fee (CM-fee), construction management at risk (CM-at risk), and private-public partnerships (PPP) contracting methods.

## 3. COST ESTIMATE CLASSIFICATION MATRIX FOR PIPELINE TRANSPORTATION INFRASTRUCTURE INDUSTRIES

A purpose of cost estimate classification is to align the estimating process with project stage-gate scope development and decision-making processes.

Table 1 provides a summary of the characteristics of the five estimate classes. The maturity level of project definition is the sole determining (i.e., primary) characteristic of class. In Table 1, the maturity is roughly indicated by a percentage of complete definition; however, it is the maturity of the defining deliverables that is the determinant, not the percent. The specific deliverables, and their maturity or status are provided in Table 3. The other characteristics are secondary and are generally correlated with the maturity level of project definition deliverables, as discussed in the generic RP. [1] Again, the characteristics are typical but may vary depending on the circumstances.

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| | *Primary Characteristic* | *Secondary Characteristic* | | |
|---|---|---|---|---|
| **ESTIMATE CLASS** | **MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition | **END USAGE** Typical purpose of estimate | **METHODOLOGY** Typical estimating method | **EXPECTED ACCURACY RANGE** Typical variation in low and high ranges at an 80% confidence interval |
| **Class 5** | 0% to 2% | Concept screening | Cost/length factors, parametric models, judgment, or analogy | L: -20% to -50%<br>H: +30% to +100% |
| **Class 4** | 1% to 15% | Study or feasibility | Cost/length, factored or parametric models | L: -15% to -30%<br>H: +20% to +50% |
| **Class 3** | 10% to 40% | Budget authorization or control | Semi-detailed unit costs with assembly level line items | L: -10% to -20%<br>H: +10% to +30% |
| **Class 2** | 30% to 75% | Control or bid/tender | Detailed unit cost with forced detailed take-off | L: -5% to -15%<br>H: +5% to +20% |
| **Class 1** | 65% to 100% | Check estimate or bid/tender | Detailed unit cost with detailed take-off | L: -3% to -10%<br>H: +3% to +15% |

**Table 1 – Cost Estimate Classification Matrix for the Pipeline Transportation Infrastructure Industries**

This matrix and guideline outline an estimate classification system that is specific to the pipeline transportation infrastructure industries. Refer to the Recommended Practice 17R-97 [1] for a general matrix that is non-industry specific, or to other cost estimate classification RPs for guidelines that will provide more detailed information for application in other specific industries (e.g., 18R-97 for pumping, compression and terminal facilities [2]). These will provide additional information, particularly the *Estimate Input Checklist and Maturity Matrix* which determines the class in those industries. See Professional Guidance Document 01, *Guide to Cost Estimate Classification.* [8]

Table 1 illustrates typical ranges of accuracy ranges that are associated with the pipeline transportation infrastructure industries. The +/- value represents typical percentage variation at an 80% confidence interval of actual costs from the cost estimate after application of appropriate contingency (typically to achieve a 50% probability of project cost overrun versus underrun) for given scope. Depending on the technical and project deliverables (and other variables) and risks associated with each estimate, the accuracy range for any particular estimate is expected to fall within the ranges identified. However, this does not preclude a specific actual project result from falling outside of the indicated range of ranges identified in Table 1. In fact, research indicates that for weak project systems and complex or otherwise risky projects, the high ranges may be two to three times the high range indicated in Table 1. [9]

In addition to the degree of project definition, estimate accuracy is also driven by other systemic risks such as:

- Level of familiarity with technology and hydraulic conditions.
- Unique/remote nature of project locations and conditions and the availability of reference data for those.
- Complexity of the project and its execution.
- Quality of reference cost estimating data.
- Quality of assumptions used in preparing the estimate.
- Experience and skill level of the estimator.
- Estimating techniques employed.
- Time and level of effort budgeted to prepare the estimate.
- Market and pricing conditions.
- Currency exchange.

- Regulatory, community, landowner, and political risks.

Systemic risks such as these are often the primary driver of accuracy, especially during the early stages of project definition. As project definition progresses, project-specific risks (e.g. risk events and conditions) become more prevalent (or better known) and also drive the accuracy range.

Another concern in estimates is potential organizational pressure for a predetermined value that may result in a biased estimate. The goal should be to have an unbiased and objective estimate both for the base cost and for contingency. The stated estimate ranges are dependent on this premise and a realistic view of the project. Failure to appropriately address systemic risks (e.g. technical complexity) during the risk analysis process, impacts the resulting probability distribution of the estimated costs, and therefore the interpretation of estimate accuracy.

Figure 1 illustrates the general relationship trend between estimate accuracy and the estimate classes (corresponding with the maturity level of project definition). Depending upon the technical complexity of the project, the availability of appropriate cost reference information, the degree of project definition, and the inclusion of appropriate contingency determination, a typical Class 5 estimate for a pipeline transportation industry project may have an accuracy range as broad as -50% to +100%, or as narrow as -20% to +30%. However, note that this is dependent upon the contingency included in the estimate appropriately quantifying the uncertainty and risks associated with the cost estimate. Refer to Table 1 for the accuracy ranges conceptually illustrated in Figure 1. [10]

Figure 1 also illustrates that the estimating accuracy ranges overlap the estimate classes. There are cases where a Class 5 estimate for a particular project may be as accurate as a Class 3 estimate for a different project. For example, similar accuracy ranges may occur if the Class 5 estimate of one project that is based on a repeat project with good cost history and data and, whereas the Class 3 estimate for another is for a project involving new technology. It is for this reason that Table 1 provides ranges of accuracy values. This allows consideration of the specific circumstances inherent in a project and an industry sector to provide realistic estimate class accuracy range percentages. While a target range may be expected for a particular estimate, the accuracy range should always be determined through risk analysis of the specific project and should never be pre-determined. AACE has recommended practices that address contingency determination and risk analysis methods. [11]

If contingency has been addressed appropriately approximately 80% of projects should fall within the ranges shown in Figure 1. However, this does not preclude a specific actual project result from falling inside or outside of the indicated range of ranges identified in Table 1. As previously mentioned, research indicates that for weak project systems, and/or complex or otherwise risky projects, the high ranges may be two to three times the high range indicated in Table 1.

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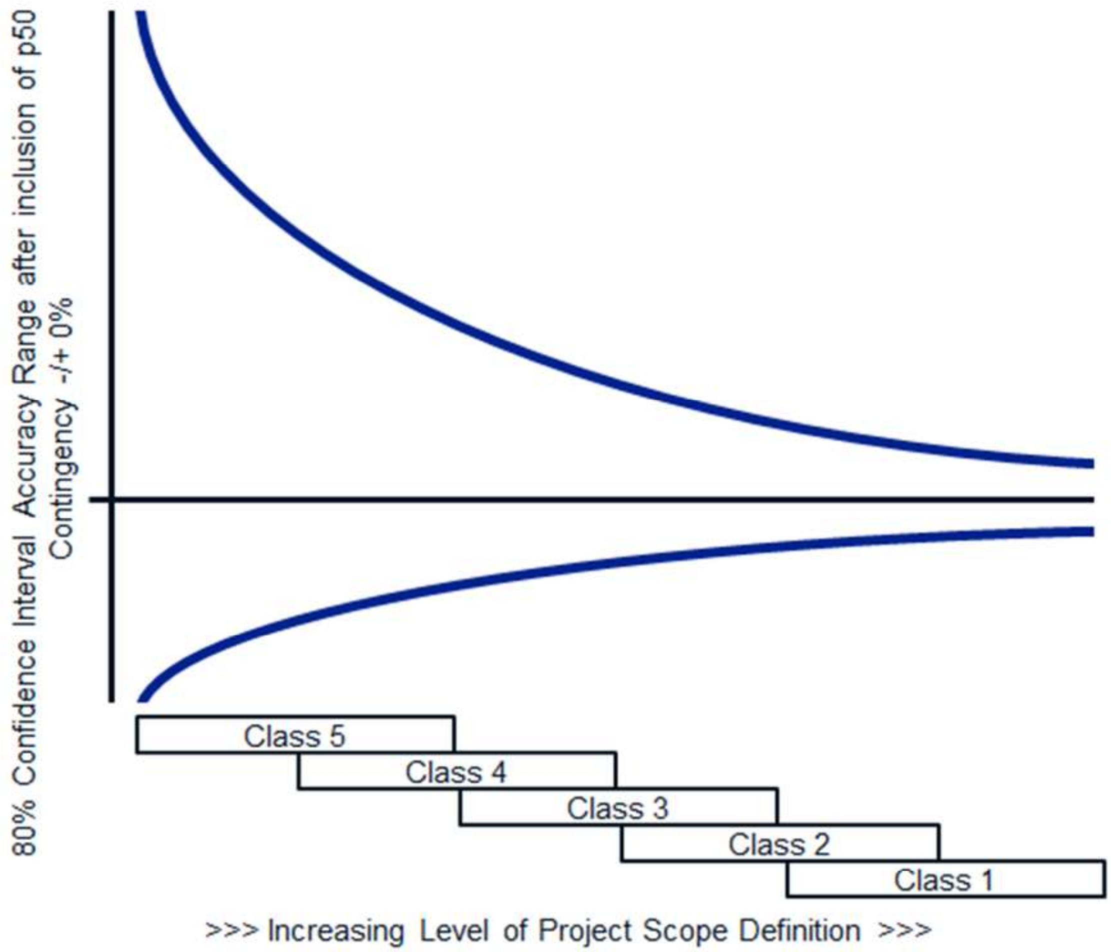


**Figure 1 – Illustration of the Variability in Accuracy Ranges for Pipeline Transportation Infrastructure Industry Estimates**

## 4. DETERMINATION OF THE COST ESTIMATE CLASS

For a given project, the determination of the estimate class is based upon the maturity level of project definition based on the status of specific key planning and design deliverables. The percent design completion may be correlated with the status, but the percentage should not be used as the class determinate. While the determination of the status (and hence the estimate class) is somewhat subjective, having standards for the design input data, completeness and quality of the design deliverables will serve to make the determination more objective.

## 5. CHARACTERISTICS OF THE ESTIMATE CLASSES

The following tables (2a through 2e) provide detailed descriptions of the five estimate classifications as applied in the pipeline transportation infrastructure industries. They are presented in the order of least-defined estimates to the most-defined estimates. These descriptions include brief discussions of each of the estimate characteristics that define an estimate class.

For each table, the following information is provided:

- **Description:** A short description of the class of estimate, including a brief listing of the expected estimate inputs based on the maturity level of project definition deliverables.

- **Maturity Level of Project Definition Deliverables (Primary Characteristic):** Describes a particularly key deliverable and a typical target status in stage-gate decision processes, plus an indication of approximate percent of full definition of project and technical deliverables. Typically, but not always, maturity level correlates with the percent of engineering and design complete.

- **End Usage (Secondary Characteristic):** A short discussion of the possible end usage of this class of estimate.

- **Estimating Methodology (Secondary Characteristic):** A listing of the possible estimating methods that may be employed to develop an estimate of this class.

- **Expected Accuracy Range (Secondary Characteristic):** Typical variation in low and high ranges after the application of contingency (determined at a 50% level of confidence). Typically, this represents about 80% confidence that the actual cost will fall within the bounds of the low and high ranges if contingency appropriately forecasts uncertainty and risks.

- **Alternate Estimate Names, Terms, Expressions, Synonyms:** This section provides other commonly used names that an estimate of this class might be known by. These alternate names are not endorsed by this recommended practice. The user is cautioned that an alternative name may not always be correlated with the class of estimate as identified in Tables 2a-2e.

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| **CLASS 5 ESTIMATE** | |
|---|---|
| **Description:**<br>Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systematic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than an hour to prepare. Often, little more than the proposed throughput capacity, pipe diameter and length over approximate alternate routes on large scale maps is known at the time of estimate preparation.<br><br>**Maturity Level of Project Definition Deliverables:**<br>Key deliverable and target status: Pipeline throughput capacity, general design concepts and routing alternatives agreed by business stakeholders. 0% to 2% of full project definition.<br><br>**End Usage:**<br>Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, routing studies, evaluation of resource needs and budgeting, long-range capital planning, etc. | **Estimating Methodology:**<br>Class 5 estimates generally use stochastic estimating methods such as gross unit costs (cost/length), factoring and other parametric and modeling techniques.<br><br>**Expected Accuracy Range:**<br>Typical accuracy ranges for Class 5 estimates are<br>-20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological and route complexity, and appropriate reference information and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks including volatile commodity markets and escalation (i.e., because of the proportion of commodity material content such as steel). The range values will shift (show bias) to the extent that contingency included in the funding is over or underestimated.<br><br>**Alternate Estimate Names, Terms, Expressions, Synonyms:**<br>Ballpark, conceptual, gross, blue sky, seat-of-pants, rough order of magnitude (ROM), screening, idea study, indicative, scoping, prospect estimate, guesstimate, rule-of-thumb. |

**Table 2a – Class 5 Estimate**

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| CLASS 4 ESTIMATE | |
|---|---|
| **Description:**<br>Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: throughput capacity, preliminary hydraulic design, pipe type and diameter, route topographic mapping with aerial photography, preliminary crossing and control features identified, and major environmental, community, regulatory and ROW concerns identified.<br><br>**Maturity Level of Project Definition Deliverables:**<br>Key deliverable and target status: Preliminary hydraulic design, routing corridors defined with optimization underway, with preliminary crossing and major valve identification and assumed geotechnical conditions. 1% to 15% of full project definition.<br><br>**End Usage:**<br>Class 4 estimates are prepared for a number of purposes, such as but not limited to, detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage or to establish binding contracts with shippers. | **Estimating Methodology:**<br>Class 4 estimates generally use stochastic estimating methods such as adjusted gross unit costs (cost/length) with adjustment for specific design elements or approximate unit or assembly costs for major crossings, controls and other major elements, factored design and installation costs, and other parametric and modeling techniques.<br><br>**Expected Accuracy Range:**<br>Typical accuracy ranges for Class 4 estimates are<br>-15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological and route complexity, and appropriate reference information and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks including volatile commodity markets and escalation (i.e., because of the proportion of commodity material content such as steel). The range values will shift (show bias) to the extent that contingency included in the funding is over or underestimated.<br><br>**Alternate Estimate Names, Terms, Expressions, Synonyms:**<br>Top-down, feasibility, factored, pre-design, advanced study, basic engineering, planning, preliminary funding, concession license. |

**Table 2b – Class 4 Estimate**

| **CLASS 3 ESTIMATE** | |
|---|---|
| **Description:**<br>Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: completed hydraulic study, completed geotechnical study, confirmed optimized route, specific pipe and control materials, long lead orders ready to be placed, controls and supervisory control and data acquisition (SCADA) defined, specific crossings known. Quantities are identified at a reasonable level of detail. ROW title holders defined and negotiation in progress, and regulatory, permitting and stakeholder concerns addressed. Adequate definition to obtain firm construction bid unit pricing with execution and contracting plans defined.<br><br>**Maturity Level of Project Definition Deliverables:**<br>Key deliverable and target status: Completed hydraulic study, completed geotechnical study, route conditions confirmed by survey; pipe, coatings, valves and crossings defined; long lead pipe quoted and ready to order, all ROW title holders identified and ready to begin negotiations, major permit applications prepared, license applications and environmental impact statement (EIS) prepared, and execution plans agreed. 10% to 40% of full project definition.<br><br>**End Usage:**<br>Class 3 estimates are typically prepared to support full project funding requests and become the first of the project phase control estimates against which all actual costs and resources will be monitored for variations to the budget. They are used as the project control budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate is often the last estimate required and could very well form the only basis for cost/schedule control. | **Estimating Methodology:**<br>Class 3 estimates generally involve more deterministic estimating methods than stochastic methods. They usually involve predominant use of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less-significant areas of the project.<br><br>**Expected Accuracy Range:**<br>Typical accuracy ranges for Class 3 estimates are<br>-10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological and route complexity, and appropriate reference information and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks including volatile commodity markets and escalation (i.e., because of the proportion of commodity material content such as steel). However, projects in existing, developed ROW may have tighter ranges. The range values will shift (show bias) to the extent that contingency included in the funding is over or underestimated.<br><br>**Alternate Estimate Names, Terms, Expressions, Synonyms:**<br>Budget, scope, sanction, semi-detailed, forced detail, authorization, preliminary control, front-end engineering and design (FEED), target estimate, concession license, bid, tender. |

**Table 2c – Class 3 Estimate**

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| CLASS 2 ESTIMATE | |
|---|---|
| **Description:**<br>Class 2 estimates are generally prepared to form a detailed contractor control baseline (and update the owner control baseline) against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the bid estimate to establish contract value. Typically, engineering is from 30% to 75% complete, and would comprise at a minimum the following: pipe and valves ordered and fabrication begun, final routing, specific crossing designs, most ROW obtained, permits and licenses obtained, contracts in place and construction in progress.<br><br>**Maturity Level of Project Definition Deliverables:**<br>Key deliverable and target status: Specific route conditions surveyed, specific crossing designs; most ROW, permits, and licenses obtained; and supply and installation contracts issued. 30% to 75% of full project definition.<br><br>**End Usage:**<br>Class 2 estimates are typically prepared as the detailed contractor control baseline (and update the owner control baseline) against which all actual costs and resources will now be monitored for variations to the budget and form a part of the change management program. | **Estimating Methodology:**<br>Class 2 estimates generally involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve tens of thousands of unit cost line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed to use as line items in the estimate instead of relying on factoring methods.<br><br>**Expected Accuracy Range:**<br>Typical accuracy ranges for Class 2 estimates are -5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological and route complexity, and appropriate reference information and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. The range values will shift (show bias) to the extent that contingency included in the funding is over or underestimated.<br><br>**Alternate Estimate Names, Terms, Expressions, Synonyms:**<br>Detailed control, execution phase, master control, engineering, tender, change order estimate. |

**Table 2d – Class 2 Estimate**

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| CLASS 1 ESTIMATE | |
|---|---|
| **Description:**<br>Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor's bid estimate, or to evaluate/dispute change orders and claims. Typically, overall engineering is from 65% to 100% complete (some parts or packages may be complete and others not) and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans.<br><br>**Maturity Level of Project Definition Deliverables:**<br>Key Deliverable and Target Status: All deliverables in the maturity matrix complete. 65% to 100% of full project definition.<br><br>**End Usage:**<br>Generally, owners and EPC contractors use Class 1 estimates to support their change management process. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution.<br><br>Construction contractors may prepare Class 1 estimates to support their bidding and to act as their final control baseline against which all actual costs and resources will now be monitored for variations to their bid. During construction, Class 1 estimates may be prepared to support change management. | **Estimating Methodology:**<br>Class 1 estimates generally involve the highest degree of deterministic estimating methods and require the greatest amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities.<br><br>**Expected Accuracy Range:**<br>Typical accuracy ranges for Class 1 estimates are<br>-3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological and route complexity, and appropriate reference information and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. The range values will shift (show bias) to the extent that contingency included in the funding is over or underestimated.<br><br>**Alternate Estimate Names, Terms, Expressions, Synonyms:**<br>Full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate. |

**Table 2e – Class 1 Estimate**

## 6. ESTIMATE INPUT CHECKLIST AND MATURITY MATRIX

Table 3 maps the extent and maturity of estimate input information (deliverables) against the five estimate classification levels. This is a checklist of basic deliverables found in common practice in the pipeline transportation infrastructure industries. The maturity level is an approximation of the completion status of the deliverable. The degree of completion is indicated by the following descriptors:

General Project Data:

- **Not Required (NR):** May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Preliminary (P)**: Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- **Defined (D)**: Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables:

- **Not Required (NR)**: Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Started (S):** Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- **Preliminary (P):** Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- **Complete (C):** The deliverable has been reviewed and approved as appropriate.

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| MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES | ESTIMATE CLASSIFICATION | | | | |
|---|---|---|---|---|---|
| | CLASS 5 | CLASS 4 | CLASS 3 | CLASS 2 | CLASS 1 |
| | 0% to 2% | 1% to 15% | 10% to 40% | 30% to 75% | 65% to 100% |
| **GENERAL PROJECT DATA:** | | | | | |
| **A. SCOPE:** | | | | | |
| Project Scope of Work Description | P | P | D | D | D |
| Site Infrastructure (Access, Construction Power, Camp etc.) | NR | P | D | D | D |
| **B. CAPACITY:** | | | | | |
| Flow and Commodity Characteristics | P | P | D | D | D |
| Electrical Power Requirements (when not the primary capacity driver) | NR | P | D | D | D |
| **C. PROJECT LOCATION:** | | | | | |
| Station, Terminal and Tie-in | P | P | D | D | D |
| **D. REQUIREMENTS:** | | | | | |
| Codes and/or Standards | NR | P | D | D | D |
| Communication Systems | NR | P | D | D | D |
| Environmental Monitoring | NR | NR | P | P | D |
| **E. TECHNOLOGY SELECTION:** | | | | | |
| N/A | | | | | |
| **F. STRATEGY:** | | | | | |
| Right-of Way (ROW) | P | P | D | D | D |
| Contracting / Sourcing | NR | P | D | D | D |
| Escalation | NR | P | D | D | D |
| **G. PLANNING:** | | | | | |
| Logistics Plan | P | P | P | D | D |
| Integrated Project Plan[1] | NR | P | D | D | D |
| Project Code of Accounts | NR | P | D | D | D |
| Project Master Schedule | NR | P | D | D | D |
| Regulatory Approval & Permitting | NR | P | D | D | D |
| Risk Register | NR | P | D | D | D |
| Stakeholder Consultation / Engagement / Management Plan | NR | P | D | D | D |
| Utility Coordination / Agreements | NR | P | D | D | D |
| Work Breakdown Structure | NR | P | D | D | D |
| Startup and Commissioning Plan | NR | P | P/D | D | D |

[1] The integrated project plan (IPP), project execution plan (PEP), project management plan (PMP), or more broadly the project plan, is a high-level management guide to the means, methods and tools that will be used by the team to manage the project. The term integration emphasizes a project life cycle view (the term execution implying post-sanction) and the need for alignment. The IPP covers all functions (or phases) including engineering, procurement, contracting strategy, fabrication, construction, commissioning and startup within the scope of work. However, it also includes stakeholder management, safety, quality, project controls, risk, information, communication and other supporting functions. In respect to estimate classification, to be rated as *defined*, the IPP must cover all the relevant phases/functions in an integrated manner aligned with the project charter (i.e., objectives and strategies); anything less is *preliminary*. The overall IPP cannot be rated as *defined* unless all individual elements are defined and integrated.

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| MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES | ESTIMATE CLASSIFICATION | | | | |
|---|---|---|---|---|---|
| | CLASS 5 | CLASS 4 | CLASS 3 | CLASS 2 | CLASS 1 |
| | 0% to 2% | 1% to 15% | 10% to 40% | 30% to 75% | 65% to 100% |
| **GENERAL PROJECT DATA:** | | | | | |
| **H. STUDIES:** | | | | | |
| Routing Options | P | P | D | D | D |
| Topography and/or Bathymetry | P | P | P/D | D | D |
| Environmental Impact / Sustainability Assessment | NR | P | D | D | D |
| Environmental / Existing Conditions | NR | P | D | D | D |
| Meteorology and/or Oceanographic / Subsea | NR | P | D | D | D |
| Soils and Hydrology | NR | P | D | D | D |
| **TECHNICAL DELIVERABLES:** | | | | | |
| Hydraulic Design | S | P | C | C | C |
| Piping Discipline Drawings | S | P | P | C | C |
| Piping Schedules | S | P | P | C | C |
| Route Alignment Sheets | S/P | P/C | C | C | C |
| Route Mapping / Survey | S/P | P/C | C | C | C |
| Design Specifications | NR | S/P | C | C | C |
| Electrical One-Line Drawings | NR | S/P | C | C | C |
| Instrument List | NR | S/P | C | C | C |
| Utilities Systems Plans including Relocation | NR | S/P | C | C | C |
| Construction Permits | NR | S/P | P/C | C | C |
| Geometric Layout. Alignment, Profile, Cross Section | NR | S/P | P/C | C | C |
| Land / ROW Title Negotiation | NR | S/P | P/C | C | C |
| Civil / Site / Structural / Architectural Discipline Drawings | NR | S/P | P | C | C |
| Crossings and Borings Designs and Drawings | NR | S/P | P | C | C |
| Demolition Plan and Drawings | NR | S/P | P | C | C |
| Erosion Control Plan and Drawings | NR | S/P | P | C | C |
| Station / Terminal Interface Design | NR | S | P | C | C |
| Electrical Schedules | NR | NR/S | P | P/C | C |
| Instrument and Control Schedules | NR | NR/S | P | P/C | C |
| Instrument Datasheets | NR | NR/S | P | P/C | C |
| Electrical Discipline Drawings | NR | NR | S/P | P/C | C |
| Instrumentation / Control System Discipline Drawings | NR | NR | S/P | P/C | C |

**Table 3 – Estimate Input Checklist and Maturity Matrix (Primary Classification Determinate)**

## 7. BASIS OF ESTIMATE DOCUMENTATION

The basis of estimate (BOE) typically accompanies the cost estimate. The basis of estimate is a document that describes how an estimate is prepared and defines the information used in support of development. A basis document commonly includes, but is not limited to, a description of the scope included, methodologies used, references and defining deliverables used, assumptions and exclusions made, clarifications, adjustments, and some indication of the level of uncertainty.

The BOE is, in some ways, just as important as the estimate since it documents the scope and assumptions; and provides a level of confidence to the estimate. The estimate is incomplete without a well-documented basis of estimate. See AACE Recommended Practice 34R-05 *Basis of Estimate* for more information. [12]

## 8. PROJECT DEFINITION RATING SYSTEM

An additional step in documenting the maturity level of project definition is to develop a project definition rating system. This is another tool for measuring the completeness of project scope definition. Such a system typically provides a checklist of scope definition elements and a scoring rubric to measure maturity or completeness for each element. A better project definition rating score is typically associated with a better probability of achieving project success.

Such a tool should be used in conjunction with the AACE estimate classification system; it does not replace estimate classification. A key difference is that a project definition rating measures overall maturity across a broad set of project definition elements, but it usually does not ensure completeness of the key project definition deliverables required to meet a specific class of estimate. For example, a good project definition rating may sometimes be achieved by progressing on additional project definition deliverables, but without achieving signoff or completion of a key deliverable.

AACE estimate classification is based on ensuring that key project deliverables have been completed or met the required level of maturity. If a key deliverable that is indicated as needing to be complete for Class 3 (as an example) has not actually been completed, then the estimate cannot be regarded as Class 3 regardless of the maturity or progress on other project definition elements.

An example of a project definition rating system is the *Project Definition Rating Index* developed by the Construction Industry Institute. It has developed several indices for specific industries, such as IR113-2 [13] for the process industry and IR115-2 [14] for the building industry. Similar systems have been developed by the US Department of Energy. [15]

## 9. CLASSIFICATION FOR LONG-TERM PLANNING AND ASSET LIFE CYCLE COST ESTIMATES

As stated in the Purpose section, classification maps the phases and stages of project cost estimating. Typically, in a phase-gate project system, scope definition and capital cost estimating activities flow from framing a business opportunity through to a capital investment decision and eventual project completion in a more-or-less steady, short-term (e.g., several years) project life-cycle process.

Cost estimates are also prepared to support long-range (e.g., perhaps several decades) capital budgeting and/or asset life cycle planning. Asset life cycle estimates are also prepared to support net present value (e.g., estimates for initial capital project, sustaining capital, and decommissioning projects), value engineering and other cost or economic studies. These estimates are necessary to address sustainability as well. Typically, these long-range estimates are based on minimal scope definition as defined for *Class 5*. However, these asset life cycle "conceptual" estimates are prepared so far in advance that it is virtually assured that the scope will change from even the minimal level of definition assumed at the time of the estimate. Therefore, the expected estimate accuracy values reported in Table 1 (percent that actual cost will be over or under the estimate including contingency) are not meaningful because the Table 1 accuracy values explicitly *exclude scope change*. For long-term estimates, one of the following two classification approaches is recommended:

- If the long-range estimate is to be updated or maintained periodically in a controlled, documented life cycle process that addresses scope and technology changes in estimates over time (e.g., nuclear or other licensing may require that future decommissioning estimates be periodically updated), the estimate is rated as *Class 5* and the Table 1 accuracy ranges are assumed to apply for the specific scope included in the estimate at the time of estimate preparation. Scope changes are explicitly excluded from the accuracy range.

- If the long-range estimate is performed as part of a process or analysis where scope and technology change is not expected to be addressed in routine estimate updates over time, the estimate is rated as *Unclassified* or as *Class 10* (if a class designation is required to meet organizational procedures), and the Table 1 accuracy ranges cannot be assumed to apply. The term *Class 10* is specifically used to distinguish these long-range estimates from the relatively short time-frame *Class 5* through *Class 1* capital cost estimates identified in Table 1 and this RP; and to indicate the order-of-magnitude difference in potential expected estimate accuracy due to the infrequent updates for scope and technology. Unclassified (or Class 10) estimates are not associated with indicated expected accuracy ranges.

In all cases, a *Basis of Estimate* should be documented so that the estimate is clearly understood by those reviewing and/or relying on them later. Also, the estimating methods and other characteristics of Class 5 estimates generally apply. In other words, an *Unclassified* or *Class 10* designation must not be used as an excuse for unprofessional estimating practice.

## REFERENCES

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## APPENDIX: UNDERSTANDING ESTIMATE CLASS AND COST ESTIMATE ACCURACY

Despite the verbiage included in the RP, often, there are still misunderstandings that the class of estimate, as defined in the RP above, defines an expected accuracy range for each estimate class. This is incorrect. The RP clearly states that "while a target range may be expected for a particular estimate, the accuracy range should always be determined through risk analysis of the specific project and should never be predetermined." Table 1 and Figure 1 in the RP are intended to illustrate only the general relationship between estimate accuracy and the level of project definition. For the pipeline transportation infrastructure industries, typical estimate ranges described in RP 97R-18 above are shown as a range of ranges:

- Class 5 Estimate:
    - High range typically ranges from +30% to +100%
    - Low range typically ranges from -20% to -50%
- Class 4 Estimate:
    - High range typically ranges from +20% to +50%
    - Low range typically ranges from -15% to -30%
- Class 3 Estimate:
    - High range typically ranges from +10% to +30%
    - Low range typically ranges from -10% to -20%
- Class 2 Estimate:
    - High range typically ranges from +5% to +20%
    - Low range typically ranges from -5% to -15%
- Class 1 Estimate:
    - High range typically ranges from +3% to +15%
    - Low range typically ranges from -3% to -10%

As indicated in the RP, these +/- percentage members associated with an estimate class are intended as rough indicators of the accuracy relationship. They are merely a useful simplification given the reality that every individual estimate will be associated with a unique probability distribution correlated with its specific level of uncertainty. As indicated in the RP, estimate accuracy should be determined through a risk analysis for each estimate.

It should also be noted that there is no indication in the RP of contingency determination being based on the class of estimate. AACE has recommended practices that address contingency determination and risk analysis methods (for example RP 40R-08, *Contingency Estimating – General Principles* [16]). Furthermore, the level of contingency required for an estimate is not the same as the upper limits of estimate accuracy (as determined by a risk analysis).

The results of the estimating process are often conveyed as a single value of cost or time. However, since estimates are predications of an uncertain future, it is recommended that all estimate results should be presented as a probabilistic distribution of possible outcomes in consideration of risk.

Every estimate is a prediction of the expected final cost or duration of a proposed project or effort (for a given scope of work). By its nature, an estimate involves assumptions and uncertainties. Performing the work is also subject to risk conditions and events that are often difficult to identify and quantify. Therefore, every estimate presented as a single value of cost or duration will likely deviate from the final outcome (i.e., statistical error). In simple terms, this means that every point estimate value will likely prove to be wrong. Optimally, the estimator will analyze the uncertainty and risks and produce a probabilistic estimate that provides decision makers with the probabilities of over-running or under-running any particular cost or duration value. Given this probabilistic nature of an estimate, an estimate should not be regarded as a single point cost or duration. Instead, an estimate actually reflects a range of potential outcomes, with each value within this range associated with a probability of occurrence.

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Individual estimates should always have their accuracy ranges determined by a quantitative risk analysis study that results in an estimate probability distribution. The estimate probability distribution is typically skewed. Research shows the skew is typically to the right (positive skewness with a longer tail to the right side of the distribution) for large and complex projects. In part, this is because the impact of risk is often unbounded on the high side.

High side skewness implies that there is potential for the high range of the estimate to exceed the median value of the probability distribution by a higher absolute value than the difference between the low range of the estimate and the median value of the distribution.

Figure A1 shows a positively skewed distribution for a sample cost estimate risk analysis that has a point base estimate (the value before adding contingency) of $89.5. In this example, a contingency of $4.5 (approximately 5%) is required to achieve a 50% probability of underrun, which increases the final estimate value after consideration of risk to $93. Note that this example is intended to describe the concepts but not to recommend specific confidence levels for funding contingency or management reserves of particular projects; that depends on the stakeholder risk attitude and tolerance.

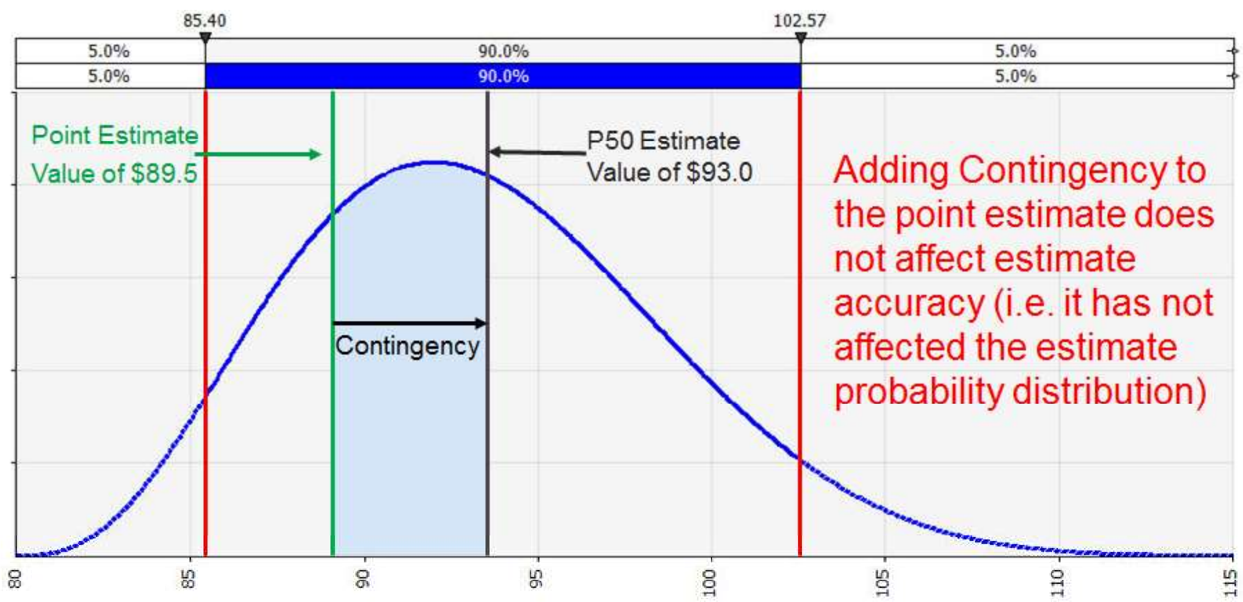


**Figure – A1: Example of an Estimate Probability Distribution at a 90% Confidence Interval**

Note that adding contingency to the base point estimate does not affect estimate accuracy in absolute terms as it has not affected the estimate probability distribution (i.e., high and low values are the same). Adding contingency simply increases the probability of underrunning the final estimate value and decreases the probability of overrunning the final estimate value. In this example, the estimate range with a 90% confidence interval remains between approximately $85 and $103 regardless of the contingency value.

As indicated in the RP, expected estimate accuracy tends to improve (i.e., the range of probable values narrows) as the level of project scope definition improves. In terms of the AACE International estimate classifications, increasing levels of project definition are associated with moving from Class 5 estimates (lowest level of scope definition) to Class 1 estimates (highest level of scope definition), as shown in Figure 1 of the RP. Keeping in mind that accuracy is an expression of an estimate's predicted closeness to the final actual value; anything included in that final actual cost, be it the result of general uncertainty, risk conditions and events, price escalation, currency or anything else within the project scope, is something that estimate accuracy measures must communicate in some manner. With that in mind, it should be clear why standard accuracy range values are not applicable to individual estimates.

The level of project definition reflected in the estimate is a key risk driver and hence is at the heart of estimate classification, but it is not the only driver of estimate risk and uncertainty. Given all the potential sources of risk and uncertainty that will vary for each specific estimate, it is simply not possible to define a range of estimate accuracy solely based on the level of project definition or class of estimate.