Application: A.25-04-XXX
Exhibit No.: SCG-02
Witnesses: J. Zeoli, F. Galvan, and T. Sera

Application of Southern California Gas Company (U 904 G) to Recover Costs Recorded in the Transmission Integrity Management Program Balancing Account from January 1, 2019 to December 31, 2023.	A.25-04-XXX

CHAPTER II

PREPARED DIRECT TESTIMONY OF

JORDAN A. ZEOLI, FIDEL GALVAN, AND TRAVIS T. SERA

(TECHNICAL – PROJECT EXECUTION AND MANAGEMENT)

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

April 30, 2025

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CHAPTER II
PREPARED DIRECT TESTIMONY OF
JORDAN A. ZEOLI, FIDEL GALVAN, AND TRAVIS T. SERA
(Technical – Project Execution and Management)

I. PURPOSE AND OVERVIEW OF TESTIMONY

The purpose of our prepared direct testimony is to describe Southern California Gas Company's (SoCalGas) execution of the "Assessment and Remediation" component of the Transmission Integrity Management Program (TIMP). This cost category comprises of TIMP In-Line Inspection (ILI), External Corrosion Direct Assessment (ECDA), and Stress Corrosion Cracking Direct Assessment (SCCDA) projects which resulted in a total of $473.0 million in capital expenditures and $401.9 million in O&M expenses for the entire five-year Test Year (TY) 2019 General Rate Case (GRC) cycle (2019-2023).

Our testimony and supporting workpapers will discuss the inspections completed during the TY 2019 GRC cycle to enhance pipeline safety and comply with federal and state regulations while minimizing customer impacts and maximizing cost effectiveness.[1] The discussion will cover: (1) how SoCalGas TIMP Assessment and Remediation activities are executed and managed; (2) how the regulatory changes initiated by the first part of the Gas Transmission Safety Rule[2] (GTSR Part 1) impacted the Assessment and Remediation component of the TIMP; and (3) how assessing the high volume and complexity of corrosion on SoCalGas pipelines located in desert environments impacted overall TIMP costs.

II. TIMP ASSESSMENTS AND REMEDIATION

As described in the Prepared Direct Testimony of Travis T. Sera (Chapter I), SoCalGas's TIMP was designed to comply with the requirements of Title 49 of the Code of Federal Regulations (CFR) – specifically Part 192, Subpart O – Gas Transmission Pipeline Integrity Management, and later 49 CFR § 192.710 – and is comprised of activities such as threat identification, risk analysis, pipeline assessments, and other actions taken to minimize threat and

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1 Workpapers were only prepared for ILI projects costing at least $1 million, Retrofit Projects and Direct Assessment projects that primarily incurred costs from January 1, 2019, to December 31, 2023 (Ex. SCG-02-WP).

2 Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 FR 52180, October 1, 2019.

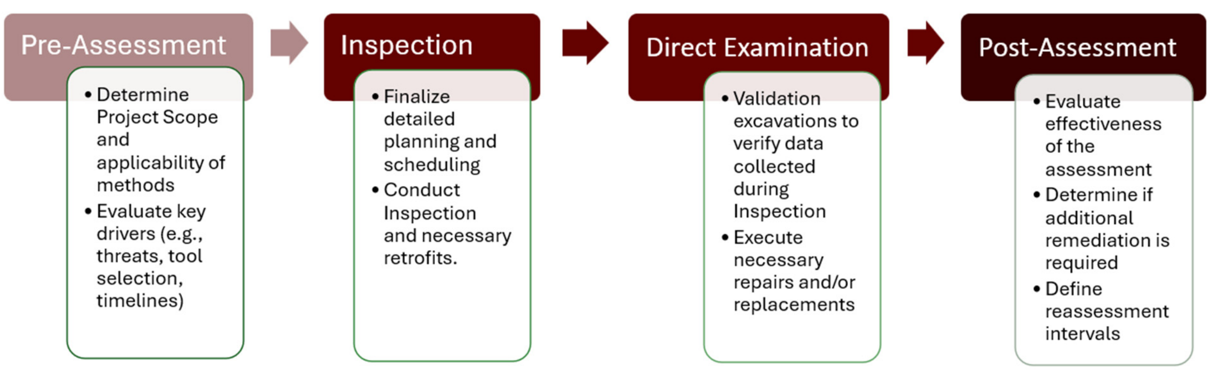
integrity concerns in order to reduce the risk of pipeline failure. Assessment and Remediation is one of four cost components of the TIMP[3] and is focused on the pipeline assessments and remediation activities that are prescribed by 49 CFR §§ 192.710, 192.921, 192.933, 192.937, and 192.939. The O&M and capital expenditures for the Assessments and Remediation activities are summarized in Table ZGS-1.

TABLE ZGS-1
TIMP – Assessments and Remediation Costs (2019-2023)

	TIMP – Assessments and Remediation Costs						
Direct + V&S Recorded ($000)	**2019**	**2020**	**2021**	**2022**	**2023**	**2024 Adj***	**Total**
O&M	55,608	81,815	79,896	95,960	90,526	(1,854)	401,951
Capital Expenditures	100,108	68,165	106,520	78,688	120,623	(1,085)	473,018

*2024 only includes adjustments for TIMP expenditures through December 31, 2023

TIMP assessments are planned and executed using a four-step process that is implemented and managed by a multidisciplinary inter-organizational team composed of engineers, project managers, construction managers, technical advisors, project specialists, and other employees with varying degrees of responsibility reporting to two primary organizations: the High Pressure Integrity Assessments (HPIA) team and the Pipeline Integrity (PI-Ex) team (collectively, Project Team). The four-step Assessment and Remediation process includes: (1) Pre-Assessment; (2) Inspection; (3) Direct Examination; and (4) Post-Assessment.



[3] The four components of TIMP, as discussed in the Prepared Direct Testimony of Travis T. Sera (Chapter I), consists of: (1) Assessments and Remediations; (2) Preventative and Mitigative Measures; (3) Data and Geographic Information Systems; and (4) Program Management and Support/Risk and Threat.

Throughout this four-step assessment process, SoCalGas implemented cost efficiency measures to balance safety and reliability with affordability for its customers in support of the Commission's affordability objectives. For example, as part of the scoping and planning process, PI-Ex collaborates with stakeholders to identify other ongoing SoCalGas work where efficiencies such as the same mobilization/demobilization timeframe and associated resources can be leveraged, temporary equipment from other TIMP projects can be reused to minimize material and contractor costs, and impacts to customers can be minimized. SoCalGas also negotiated and leverages fixed price contracts for our short-notice pipeline contractors to perform assessment and remediation activities, which helps with controlling costs particularly in instances where work is immediate and time to identify cost efficiencies is limited (*i.e.*, immediate repair conditions). SoCalGas has implemented a robust system of project governance and controls to promote efficiency and oversight in execution, which includes a dedicated Program Management Office and Stage Gate Review process.[4]

A. Pre-Assessment

The first step of the four-step Assessment and Remediation process is Pre-Assessment. During Pre-Assessment, the Project Team evaluates pipeline operational data and previous assessment results to determine project scope and the applicability of methods for each covered segment as prescribed in 49 CFR §§ 192.921 and 192.937. During this step, HPIA and PI-Ex collaboratively evaluate key drivers for the project, such as: threats on the pipeline to be assessed, tool selection for inspection, and compliance timelines. Simultaneously, PI-Ex also collaborates with various stakeholders throughout SoCalGas to minimize operational disruption to the overall pipeline system and maximize cost efficiencies.

SoCalGas may apply one or more of the following methods to complete an assessment for the threats identified on each covered segment: ILI, pressure testing, spike hydrostatic pressure testing, excavation and in situ direct examination, guided wave ultrasonic testing (GWUT), and direct assessments to address external corrosion, internal corrosion (ICDA), or stress corrosion cracking. Assessment method selection is dependent on specific threats

[4] The Stage Gate Review Process consists of five stages, with specific objectives and an evaluation at the end of each stage by Construction leadership to verify that objectives have been met before proceeding to the next stage.

identified on a pipeline segment and typically will not change throughout the project lifecycle. However, when new information is obtained during an active project – particularly changes to threat identification, the Project Team must re-evaluate whether a change in scope is warranted (*e.g.* change or addition of assessment method). If it is determined that a change or additional assessment method is required, the new or additional assessment method must be completed within the same compliance scope timeframe, as further discussed in Section III. SoCalGas categorizes and plans assessments as follows:

- Baseline assessments: When a newly covered segment has not previously been assessed;
- First-time assessments: When a different assessment method is employed but the covered segment was previously assessed by another method; or
- Reassessments: When an assessment is performed in accordance with 49 CFR §§ 192.710 or 192.939.

While most of SoCalGas's TIMP assessment projects were ILI reassessments during the TY 2019 GRC cycle, there was an increase in first-time ILI assessments due to new regulatory requirements resulting in changes to threat identification, which will be discussed further in Section III of our testimony. For ILI, first-time assessments are similar in nature to baseline assessments because a pipeline may not have the appropriate components (*e.g.* valves, elbows, launchers and receivers) to accommodate the use of a newly applied ILI tool and may require pipeline alterations (or retrofits), as described herein in Section II.B.1.a. Additionally, when employing new methods for assessment, there is a larger amount of data being collected, which in turn increases the likelihood of discoveries requiring action to validate, repair, or remediate.

B. Inspection

The second step of the four-step Assessment and Remediation process is Inspection. During Inspection, PI-Ex finalizes detailed planning and scheduling, oversees vendors and construction contractors, manages project costs, and documents inspection activities. Depending on the scope for each project, activities range widely from strategically sequencing the inspections, consulting with various internal and external stakeholders to obtain appropriate approvals, and, at times, preparing the pipeline for inspection by means of retrofits.

During the TY 2019 GRC cycle, SoCalGas used ILI, ECDA, and SCCDA to comply with federal regulations.

1. ILI

The ILI assessment method utilizes specialized inspection tools, such as "smart tools" or "smart pigs," that travel inside a pipeline to collect information. ILI tools come in various types and sizes with different measurement capabilities, enabling SoCalGas to internally inspect pipelines for an array of potential threats and safety conditions. The tools traverse pipelines using different methods of travel (*e.g.*, free-swimming, robotic, tethered) and each method of travel has advantages and disadvantages that are considered at the time of tool selection. In addition, depending on the tool(s) selected, the factors discussed in this Section add scope and corresponding cost to an assessment project.

a) Retrofits in Preparation for ILI

To enable safe passage for an ILI tool (*i.e.*, make a pipeline piggable), some pipeline segments may require retrofitting. Pipeline features that may inhibit an ILI tool include elbows, unbarred tees, valves, or other features. The type of retrofit varies depending on the inspection method; and retrofits range from installing rated fittings to more substantial modifications such as the removal and replacement of non-piggable features.

b) ILI Facilities and Assemblies

Free-swimming ILIs requires launcher and receiver assemblies where the tool(s) are inserted and extracted from the pipeline. SoCalGas has various facilities with permanent launcher and receiver assemblies,[5] which provide long-term benefits to TIMP projects due to reassessment requirements that necessitate future inspections at these same locations.[6] On the other hand, for pipeline segments in areas that cannot accommodate permanent launcher or receiver assemblies, SoCalGas must construct temporary assemblies every inspection cycle.

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5 Refers to launcher and receiver barrels that are permanently installed within SoCalGas facilities.

6 49 CFR §192.710 requires reassessment intervals of a maximum of ten years for assessments outside of High Consequence Areas (HCAs) and 49 CFR §192.937 requires reassessment intervals of a maximum of seven years for pipeline segments in HCAs.

This is a labor-intensive effort that requires transporting, fabricating, hydrotesting and installing launcher and receiver barrels, filter separators and associated piping at the ends of a segment.

Robotic ILIs, unlike free-swimming tools, require a permanent pressure control fitting (PCF) at one or multiple locations that function as launching and receiving points for the inspection tool. Additionally, robotic ILIs are powered by batteries and require permanent fittings for charging locations approximately every 2,000 feet. These permanent installations require site planning, permitting, and excavations and will similarly help facilitate future inspections to meet reassessment requirements.

Tethered ILIs use a temporary tethered cable and pulley system. This method of assessment requires that the pipeline be out of service during inspection. The isolation and depressurization of the pipeline requires extensive coordination and support including cross compression to reduce methane emissions, potential CNG/LNG support, and pipeline retrofits to install temporary assemblies. Temporary assemblies may include a spool piece adapter that provides a connection for a tethered cable and facilitates the launching and receiving of the inspection tool into and out of the pipeline.

c) ILI Runs

Inspection using the ILI method usually involves more than one tool "run," which is the process wherein a tool enters, traverses, and exits a pipeline. At the start of an ILI project, a series of cleaning tools are run through a pipeline to clear it of debris. Next, a gauge plate tool is run through the pipeline to identify any features that may inhibit passage or damage the ILI tool. Lastly, the ILI smart tool is inserted into the pipeline to collect data.

ILI projects may require an increased number of tool runs for a variety of reasons. Pipelines with significant debris require several cleaning runs and even tool recalibration or rebuild on-site, which results in increased costs for company labor, contracted workforce, and other active agreements.[7] In addition, the selection of ILI tools is dependent on the potential threats that need to be assessed. In many cases, multiple types of ILI tools specifically designed to detect particular threats are required to collect the full range of data needed to complete the

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7 Other active agreements refer to external stakeholders that may be involved with a TIMP project (*e.g.*, municipal encroachment permits, right-of-way agreements, additional natural gas to maintain reliability).

assessment project. If the data associated with any ILI tool run is not of acceptable quality, a re-run of the tool(s) may be necessary. If a re-run is necessary, the Project Team evaluates whether additional runs are able to be incorporated into the current schedule, or if the additional run(s) require rescheduling of tools and other resources.

Each run requires active monitoring of the tool within the SoCalGas pipeline system, including on-site tracking of the tool as it navigates the pipeline. Extensive collaboration is required across multiple internal departments and external resources during this process to manage the pipeline system's continued safety and reliability during the operation. The number of runs necessary to execute the assessment and the length of the segment has a direct impact on the labor and resources needed for the ILI project, particularly when it comes to how many validation excavations are necessary. To put it simply, the more data acquired, the more excavations will likely be necessary.

2. ECDA

The ECDA method is described in ANSI/NACE SP0502-2010 as "a structured process that is intended to improve safety by assessing and reducing the impact of external corrosion on pipeline integrity." The ECDA method requires the use of multiple cathodic protection (CP) and other related survey methods – referred to as indirect inspections – to identify locations on the pipeline where external corrosion may be occurring, as well as potential locations of mechanical damage. The data obtained through the indirect inspections is evaluated to select locations for direct examination.

SoCalGas uses the ECDA method for pipelines that cannot accommodate an ILI tool where external corrosion and mechanical damage are the only identified threats on pipeline segments. Planning activities include extensive coordination with various stakeholders, both internal and external, as well as acquisition of approved permits, entry rights, and traffic control plans as required by the governing agencies. A contracted workforce executes multiple indirect inspections. These inspections are performed by walking the pipeline route while recording measurements at regular intervals. The primary indirect inspections that SoCalGas uses during an ECDA indirect inspection are close-interval survey (CIS), Direct Current Voltage Gradient (DCVG) survey, and Alternating Current Voltage Gradient (ACVG). Some of these indirect inspections require soil contact to measure pipe-to-soil potential and necessitates drilling of 1/2" holes every 10 feet, where asphalt or concrete cover is present over the pipeline. In most cases, surveys must be performed in sequence where each survey is completed for the entire extent of the assessment before the next survey takes place. These activities are labor intensive due to their required proximity to the pipeline. The length of the pipeline segment is also a factor on the timeframe needed to complete the inspection. Upon completing the ECDA scope, HPIA confirms all segments requiring inspection have been surveyed and that the data collected is of acceptable quality.

3. SCCDA

The SCCDA method is described in ANSI/NACE SP0204-2008 as "a structured process that is intended to assist pipeline companies in assessing the extent of stress corrosion cracking (SCC) on a section of buried pipeline and thus improve safety by reducing the impact of SCC." SoCalGas uses SCCDA when a crack detection ILI tool capable of assessing the SCC threat is not a practicable option. SCCDA utilizes the results of the indirect inspection tools used in ECDA (CIS, DCVG, and ACVG) as well as measurements of soil resistivity. Factors including the operational history of the pipeline, such as information on pressure cycling, and environmental conditions, such as the location of water crossings or slopes, have the potential to increase the likelihood of SCC being present on a segment of pipe. The results from the CIS, DCVG, ACVG, and soil resistivity results are then integrated with pipeline operational history and environmental conditions to identify locations susceptible to an increased likelihood of SCC, and those locations are further prioritized for direct examination.

C. Direct Examination

The third step of the four-step Assessment process is Direct Examination. During Direct Examination, the pipeline is excavated to complete visual and non-destructive examination to verify Inspection results, and to perform necessary repairs and/or replacements.

1. Excavation Scoping and Planning

To validate the data obtained during Inspection, the Project Team selects locations where pipeline conditions are exposed and evaluated. Each Direct Examination location requires extensive coordination with stakeholders, review of the pipeline system for potential impacts, detailed scope and contingency planning, and permitting for excavations. Once locations are selected and planned for excavation, PI-Ex provides oversight of the contracted workforce that facilitates non-destructive examinations, environmental monitoring, and construction activities at each location.

2. Actions to Address Integrity Issues

As prescribed by 49 CFR § 192.933, SoCalGas makes necessary repairs to address anomalous conditions discovered during assessments. Conditions are classified and addressed as follows: *immediate repair*, *scheduled*, or *monitored*. Immediate repair conditions require prompt response through a temporary pressure reduction or shutdown of the pipeline and/or performance of necessary repairs. Immediate repair conditions require action within expedited timeframes that often require extended work hours from various stakeholders including internal departments, municipal city inspectors, contracted workforce, and construction personnel until the threats to the pipeline are resolved. Scheduled and monitored conditions are planned and managed following standard operating procedures consistent with 49 CFR Part 192, Subpart O.

An excavation typically results in one or a combination of the following repairs:

- Recoat of the pipeline;
- Grinding or "soft pad repair" of the pipeline;
- Installation of a welded steel reinforcement sleeve or "band repair"; and/or
- Pipe replacement.

Additionally, some discoveries may prompt additional remediations after the initial validation digs, as determined during Post-Assessment.

D. Post-Assessment

The final step of the four-step Assessment process is Post-Assessment. During Post-Assessment, HPIA utilizes data collected from the previous three steps (Pre-Assessment, Inspection, and Direct Examination) to evaluate effectiveness of assessment, determine if additional remediation is required,[8] provide feedback for continual programmatic improvement, and define reassessment intervals.

[8] 49 CFR §192.935.

Additional remediation on a pipeline segment may entail expanded pipeline repairs (*e.g.*, repair to seam dents or metal loss that did not meet immediate or other scheduled repair condition criteria) or preventive and mitigative measures including but not limited to permanent installation of pipeline monitoring devices, cathodic protection improvements, or additional valving. For additional remediation efforts, the Project Team plans and executes new projects that are sequenced to consider system constraints, minimize customer impacts, and maximize cost and labor efficiencies. These projects also involve detailed engineering, material acquisition, oversight of contracted workforce, and at times, extended work hours to complete construction activities, which increases TIMP Assessment and Remediation costs.

III. HOW REGULATORY CHANGES AND TECHNOLOGY IMPROVEMENTS IMPACTED THE SCOPE OF TIMP ASSESSMENTS AND REMEDIATION COSTS DURING THE TY 2019 GRC CYCLE

As described in more detail in the Prepared Direct Testimony of Travis Sera (Chapter I), there were two primary drivers that impacted TIMP Assessment and Remediation costs in the TY 2019 GRC Cycle: 1) the GTSR Part 1 which was effective October 1, 2019 and expanded the amount of activity required to execute TIMP through enhanced pipeline safety regulations, and 2) the volume and complexity of corrosion associated with desert region pipelines.

A. Regulatory Changes

The GTSR Part 1 – effective October 1, 2019 – enhanced pipeline safety regulations through dozens of updated or newly introduced sections of federal code. The regulatory changes included several sections that impacted SoCalGas's TIMP assessment and remediation activities. In particular, the two primary sections that increased SoCalGas's TY 2019 GRC cycle costs are:

- 49 CFR §192.917 (e)(3): Operators must have traceable, verifiable, and complete (TVC) record of a Subpart J pressure test to consider Manufacturing (M) and Construction (C) threats on a pipeline segment stable.
- 49 CFR §192.917 (e)(6): If an operator finds evidence of cracks or crack-like defects on a covered segment, the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and uncovered) with similar characteristics associated with the crack or crack-like defect.

Additionally, in 2021, the Pipeline and Hazardous Materials Safety Administration (PHMSA) provided its interpretation to Pacific Gas & Electric Company (PG&E) that further explained the agency's expectations of compliance with 49 CFR §192.939 for threats newly categorized as active.[9] In instances where M, C, or crack-related threats are active, operators are required to incorporate applicable inspection methods for these threats within the current reassessment cycle. This interpretation was confirmed by the California Public Utilities Commission (CPUC). As a result, SoCalGas's project scopes changed and expanded from the previous assessments that informed the initial TY 2019 GRC forecasting. The newly enhanced regulations and requirements resulted in:

- Increased inspections due to the expansion of threats, which included new ILI assessments needing retrofitting or replacement.
- Increased volume of excavations due to the increase in required inspections.

B. Continuous Improvement to Inspection Technology

As discussed in the Prepared Direct Testimony of Travis Sera (Chapter I), the assessment of desert pipelines is made difficult by the high volume and complexity of corrosion present in the desert. Improvements in the ability of ILI tools to detect areas of shallow corrosion, combined with the limitations of these same tools to accurately distinguish the characteristics of individual corrosion anomalies nested within larger areas of wall loss, has led to increase in the number of areas on the pipelines identified as having segments with a high volume and complexity of corrosion. The difficulty of the ILI tools to characterize the depth of the corrosion in areas with a high volume and complexity of corrosion required SoCalGas to perform an increased number of direct examinations on desert pipelines.

The desert terrain associated with these projects brought unique challenges such as remote work sites, timeline delays, and extreme temperatures. Remote worksites were difficult to access, and the safety measures required to deal with extreme temperatures imposed time limits on the amount of exposure to heat allowed for workers. Additionally, environmental

[9] PHMSA, John A. Gale, Director of Office of Standards and Rulemaking at PHMSA Letter to Christine Cowsert VP, Gas Asset Mgmt. & System Operations at PG&E (June 23, 2021), *available at:* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/standards-rulemaking/pipeline/interpretations/75361/pacific-gas-and-electric-company-pi-21-0004-06-24-2021-part-192939.pdf.

permit conditions imposed by state and federal agencies lengthens the duration of construction activities in desert environments and has led to schedule delays on inspections. Employees and contractors were required to traverse through unpaved, rough, and narrow rights-of-way in areas with endangered wildlife and at-risk species, which often required driving at low speeds, escorted by a biologist, to check that endangered species are not at risk. These factors added significant cost to assessments of desert pipelines that, due to the improvement in the ILI tool's ability to identify areas with a high volume and complexity of corrosion, required more direct examinations than were anticipated in the TY 2019 GRC.

C. Impacts on the Scope of TIMP Assessment and Remediation Costs

The changes in regulations and increased identification of segments with a high volume of complex corrosion led to an increase in the amount of work required to execute the TIMP. These increases consisted of:

1. First-Time ILI Assessments to Address Expanded Threats

Following a change to 49 CFR § 192.917(e)(3) contained in GTSR Part 1 as well as PHMSA Advisory Bulletin Federal Register 2017-05262, SoCalGas updated the assessment methods used for various pipelines to assess for M, C, and SCC threats newly categorized as active. During the TY 2019 GRC cycle, there was an overall increase in the number of ILI tool runs to meet the expanded scheduling and threat assessment requirements, which in turn prompted additional direct examinations. The increase in required ILI runs resulted in additional cost expenditures in two areas.

a) Retrofits for First-Time ILI Assessments

Pipelines with M, C, and/or SCC threats newly categorized as active required inspection by ILI tools that detect crack-like anomalies. Pipelines that had been assessed by Direct Assessment during the previous assessment required retrofitting to accommodate inspection by ILI. These retrofits commonly include installing launchers and receivers as well as valves, fittings, and stopples that accommodate the ILI tools. For some pipelines that could not be retrofitted for the use of free-swimming ILI tools, the utilization of robotic inspection ILI was necessary. The use of robotic inspection increased during the TY 2019 GRC cycle, and these tools required the installation of charging stations and stopple fittings. These retrofit efforts for new first-time ILI assessments allow SoCalGas to use one mobilization to perform multiple ILI tool runs for a variety of threats.

b) Increase in Assessment Tools

The changes in regulations that broadened threat identification during the existing assessment cycle increased the number of assessments performed on some pipelines, significantly impacting the total assessment cost. For example, due to the identification of new M and SCC threats, SoCalGas determined that a pipeline previously assessed using an axial magnetic flux leakage (AMFL) tool, required additional ILI tools to address the M and SCC threats. This prompted a first-time use of the circumferential magnetic flux leakage (CMFL) and electromagnetic acoustic transducer (EMAT) tools to meet assessment requirements.

Most pipelines are assessable using an AMFL ILI tool. After the regulatory change that expanded threat identification requirements, pipelines with M, C, and/or SCC threat newly categorized as activate required additional ILI tools, such as CMFL and EMAT, to complete the assessment. For example, to assess for SCC and crack related threats, SoCalGas procured EMAT tools for an expanded number of TIMP projects. The use of EMAT tools, which has an average cost of $1MM per project, is a significant cost driver to overall program costs. The EMAT tool has a high cost per run compared to other smart tools and has different accessibility and passage requirements with the potential to require additional retrofits to the launcher and receiver assemblies and pipeline prior to deployment.

Pipelines with a SCC threat that cannot be assessed using ILI may be assessed using SCCDA. SCCDA utilizes a combination of data acquired by ECDA, ILI, and soil sampling to identify regions of the pipe most susceptible to have SCC. These regions of the pipe must be directly examined to determine whether SCC is present.

2. Increase in Assessment Excavations

Each ILI tool requires a dedicated series of direct examinations to assess the pipeline for the targeted threat. The more tools used to complete an assessment; the more direct examinations are required. For example, a pipeline inspected by an AMFL tool would have direct examinations assigned based on the AMFL inspection results. After the change in regulations regarding the M, C, and SCC threats, some pipelines previously inspected by AMFL now required inspection utilizing additional ILI tools due to crack-related threats newly categorized as active. For each additional ILI tool deployed (CMFL and EMAT), a dedicated series of validation direct examinations are necessary, which increases the number of direct examinations required to complete the pipeline assessment.

The EMAT tool is designed to detect and size cracks in the pipeline. This inspection tool and other crack-detection tools identify a large volume of crack-like features that require direct examinations to confirm inspection findings and characterize anomalous conditions that may require mitigation. The overall increase in smart tool runs, such as the EMAT and other crack-detection ILI tools, during the TY 2019 GRC cycle resulted in an increase in the overall volume of direct examinations.

3. Installation of Permanent Launchers and Receivers

SoCalGas performed retrofit projects that were driven by opportunities to install permanent launchers and receivers in a facility to improve safety, reduce community impact, and reduce long-term costs. For these projects, SoCalGas further reduced costs by making every effort to coordinate these retrofits with the assessment cycle and associated ILI inspection, as well as other local pipeline projects. This approach reduces the need for multiple construction mobilizations and provides overall project efficiencies such as a reduction in pipeline isolations/system impacts, labor and non-labor costs, and SoCalGas Transmission District support.

For example, at one location in a busy roadway, SoCalGas historically used temporary launcher/receiver assemblies to conduct assessments due to space constraints that rendered permanent assemblies impracticable. ILI assessments at this location required excavation, fabrication, and deconstruction of temporary receiver assemblies within a heavily traveled section of the city, which substantially impacts the community and presents safety risks for employees and the public for the duration of these assessments. When it became feasible, SoCalGas installed permanent launcher, receiver, and filter assemblies for these pipelines to reduce traffic and community impacts for future inspections and give SoCalGas more control over recurring costs.

IV. OTHER TIMP COST DRIVERS

While SoCalGas forecasts projects based on prior experience, actual pipeline and construction conditions may vary due to new threats, new scopes of work, and other factors and unforeseeable circumstances. Some other examples of circumstances that impacted cost of TIMP projects during the TY 2019 GRC cycle include:

- Targeted anomal~~i~~es that, upon excavation and exposure, required more extensive action than anticipated based on data analysis.
- The identification of immediate conditions (immediate repair conditions or safety related conditions) that required an immediate response. Often, these require expedited action which includes permitting, scheduling, and contractor and SoCalGas stakeholder support to execute the required pressure reduction and subsequent remediation of the identified condition(s).
- System constraints due to weather, existing/pending outages, scheduled work on the pipeline system, customer usage requirements, etc. have the potential to dictate the execution scope and timeline of a project. In some cases, this includes the requirement to install bypasses on the pipeline to maintain system throughput or the rescheduling of a project which results in additional mobilization/demobilization efforts, stakeholder engagement, agency and customer notifications/coordination.
- Projects in suburban areas which often include permitting requirements such as restricted work schedules and/or night work, extensive traffic control, and unknown substructures which impact validation/repair efforts. These factors impact the execution timeline of projects and have a direct impact on overall costs.
- An overall increase in the costs associated with planning and executing TIMP activities. This is attributed to factors such as an increase in contractor labor and equipment rates, material costs, smart tool vendor rates, amongst others, which have been experienced throughout the industry during the 2019-2023 period.

SoCalGas continues to apply program governance and management best practices to achieve its goal of cost-effectively managing pipeline integrity and enhancing safety.

V. CONCLUSION

As discussed in our testimony, regulatory changes and the high volume and complexity of corrosion in the desert region have impacted the scope of TIMP projects undertaken during the TY 2019 GRC cycle. New assessment methods, increasingly complex engineering analysis, and the resulting increase in validation and remediation activities were not anticipated during the TY 2019 GRC and impacted actual TIMP costs. Further, the TIMP is complex and as projects progress, changes due to engineering analysis and actual pipeline conditions are common and result in cost variability.

This concludes our prepared direct testimony.

VI. WITNESS QUALIFICATIONS

A. Jordan A. Zeoli

My name is Jordan A. Zeoli. I am employed by SoCalGas as the Senior Manager of Pipeline Integrity- Execution. My business address is 8101 Rosemead Boulevard, Pico Rivera, California 90660.

My employment with SoCalGas began in 2000 with the title of Meter Reader, which led me to Distribution Operations in 2002. I've held various represented positions within Distribution Operations such as Construction Technician, Energy Technician-Distribution, Welder, and Crew Leader. In 2012, I transitioned into Management as an Operator Qualifications Inspector and have since held numerous positions with increasing levels of responsibility and leadership including Field Operations Supervisor, PSEP Construction Manager, PSEP Construction Team Lead, Transmission District Operations Manager, Pipeline Integrity Operations Manager, and most recently, as Senior Manager of Pipeline Integrity-Execution. My responsibilities as the Senior Manager include overseeing the teams who plan and execute the projects that are identified by Integrity Management as requiring assessments, validation and/or remediation. My teams are responsible for the planning, coordination, and execution of field activities including survey, construction, material procurement, and project reconciliation/closeout including the traceable, verifiable, and complete records for these Transmission Integrity Management Program (TIMP) driven projects.

I have not previously testified before the Commission.

B. Fidel Galvan

My name is Fidel Galvan. I am employed by SoCalGas as the Engineering & Project Management Manager for Gas Transmission Operations. My business address is 1981 W. Lugonia Avenue, Redlands, California 92374.

I have been employed by SoCalGas since 2006 and have held various positions within Operations and Engineering. I've been responsible for planning and managing both Gas Distribution and Gas Transmission high pressure projects as well as the implementation of project controls within those activities. I've also supported the 2019 GRC as the lead planner for Gas Distribution. My previous role was the Planning Manager of Pipeline Integrity Execution where my responsibilities included overseeing the scheduling and planning of assessment projects identified by Integrity Management. I currently support Gas Transmission Operations in the planning and execution of various activities ranging from leak repairs, cathodic protection remediation, valve replacements, pressure limiting station redesigns, and pipeline mitigations.

I hold a Bachelor of Science degree in Mechanical Engineering from California State University Northridge and a Masters's degree in Business Administration from California State University Long Beach.

I have not previously testified before the Commission.

C. Travis T. Sera

My name is Travis T. Sera. I am employed by SoCalGas as the Director of Integrity Management for SoCalGas and SDG&E. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011.

I joined SoCalGas as a full-time employee in 1995 and have held various positions of increasing responsibility within the Gas Engineering and System Integrity department. I left SoCalGas briefly, from 2003 to 2005, and during this time held the title of Senior Consulting Engineer for Structural Integrity Associates, an engineering consulting firm to the nuclear, petro-chemical, and pipeline industries.

I have been in my current position at SoCalGas since 2019. My responsibilities include oversight of the Transmission Integrity Management Program and the Distribution Integrity Management Program, in addition to the broad application of Integrity Management principles across various departments within SoCalGas and SDG&E. I have a Bachelor of Science degree in Materials Engineering from California Polytechnic State University - San Luis Obispo, I am a registered Professional Metallurgical Engineer in the State of California, and I hold a CP4 - Cathodic Protection Specialist certification from the Association of Materials Protection and Performance (AMPP).

I have previously testified before the Commission.