Company: San Diego Gas & Electric Company (U 902 M)
Proceeding: 2024 General Rate Case
Application: A.22-05-016
Exhibit: SDG&E-09-R

REVISED

PREPARED DIRECT TESTIMONY OF

AMY KITSON AND TRAVIS SERA

(GAS INTEGRITY MANAGEMENT PROGRAMS)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

August 2022

TABLE OF CONTENTS

SUMMARY

GAS INTEGRITY MANAGEMENT PROGRAMS In 2021 $ (000s)			
	2021 Adjusted-Recorded	**TY2024 Estimated**	**Change**
Total Non-Shared Services	11,026	12,768	1,742
Total Shared Services (Incurred)	0	0	0
Total O&M	**11,026**	**12,768**	**1,742**

GAS INTEGRITY MANAGEMENT PROGRAMS In 2021 $ (000s)				
	2021 Adjusted-Recorded	**Estimated 2022**	**Estimated 2023**	**Estimated 2024**
Total CAPITAL	**60,547**	**81,707**	**86,876**	**107,125**

SUMMARY OF REQUESTS

In total, San Diego Gas & Electric (SDG&E or the Company) requests that the California Public Utilities Commission (CPUC or Commission) adopt the Gas Integrity Management Programs Test Year 2024 (TY2024) forecast of $12,768,000 for operations and maintenance (O&M) expenses, which is composed of non-shared service activities. SDG&E further requests the Commission adopt the forecast for Gas Integrity Management capital expenditures in 2022, 2023, and 2024 of $81,707,000, $86,876,000, and $107,125,000, respectively.

The Gas Integrity Management Programs are founded upon a commitment to provide safe, clean, and reliable service at reasonable rates through a process of continual safety enhancements by regularly identifying, evaluating, and reducing integrity risks for the natural gas system.

Through the Transmission Integrity Management Program (TIMP), per 49 Code of Federal Regulations (CFR) § 192, Subpart O,[1] SDG&E is federally mandated to identify threats to transmission pipelines in High Consequence Areas (HCAs), determine the risk posed by these threats, schedule prescribed assessments to evaluate these threats, collect information about the condition of the pipelines, take actions to minimize applicable threat and integrity concerns to

1 Transportation of Natural and Other Gas By Pipeline: Minimum Federal Safety Standards, 49 CFR § 192 *et seq*.

reduce the risk of a pipeline failure, and report findings to regulators. Additionally, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published the first part of the Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines (also referred to by SDG&E as the Gas Transmission Safety Rule (GTSR) Part 1),[2] which expands requirements for gas transmission operators including those related to the TIMP. The funding level requested for the TIMP is to primarily meet the requirements of 49 CFR § 192, Subpart O, as well as other subparts impacting the TIMP.

Through the Distribution Integrity Management Program (DIMP), under 49 CFR § 192, Subpart P, SDG&E is federally mandated to collect information about its distribution pipelines, identify additional information needed and provide a plan for gaining that information over time, identify and assess applicable threats to its distribution system, evaluate and rank risks to the distribution system, determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline and evaluate the effectiveness of those measures, develop and implement a process for periodic review and refinement of the program, and report findings to regulators. SDG&E continues to identify prospective Projects and Activities Addressing Risk (PAARs) and enhance its current portfolio of PAARs under the DIMP and the funding level requested is to continue to meet the requirements of 49 CFR § 192, Subpart P.

The Gas Safety Enhancement Programs (GSEP) consist of activities incremental to existing TIMP and DIMP that were scoped to comply with federal regulations. The activities and forecasted costs are based on compliance with Part 1 and Part 2 of PHMSA's Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines rulemaking,[3] as well as PHMSA's Valve Installation and Minimum Rupture Detection Standards rule (Valve Rule).[4] The GTSR Part 1, titled *Pipeline Safety: Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure (MAOP) Reconfirmation, Expansion of Assessment Requirements, and Other*

[2] 84 Fed. Reg. (FR) 52180 (October 1, 2019).

[3] SDG&E determined that Part 3 of the Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines rulemaking (86 FR 63266, *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments*) does not apply to its operations.

[4] Valve Installation and Minimum Rupture Detection Standards final rule, available at (https://www.federalregister.gov/documents/2022/04/08/2022-07133/pipeline-safety-requirement-of-valve-installation-and-minimum-rupture-detection-standards).

Related Amendments, was issued in October of 2019 and, along with the Test Year (TY) 2019 General Rate Case (GRC) Decision (D.19-09-051) which directed SoCalGas and SDG&E to propose a Pipeline Safety Enhancement Plan (PSEP) Phase 2B implementation plan, is driving our request to establish an Integrated Safety Enhancement Plan (ISEP) that will evaluate transmission pipeline segments not currently authorized under the PSEP. GTSR Part 2, titled *Pipeline Safety: Safety of Gas Transmission Pipelines: Discretionary Integrity Management Improvements*, is expected to be published in June of 2022, so while prospective impacts have been forecasted, requirements and actual costs are subject to change. Additionally, the Valve Rule was recently issued in March of 2022, and SDG&E has forecasted activities and costs based on a preliminary evaluation of requirements and impacts. The funding level requested for the GSEP is to comply with new regulatory requirements, as well as regulatory requirements that have not been issued but are expected to be in effect during this GRC cycle. However, forecasted activities for the GSEP are subject to change as SDG&E continues to evaluate and implement the requirements of these regulations.

Lastly, the Facilities Integrity Management Program (FIMP) is a newly proposed program modeled after SDG&E's TIMP and DIMP. The purpose of the FIMP is to provide a comprehensive, systematic, and integrated approach for managing and enhancing the safety and integrity of facilities and associated equipment. The FIMP is based on recommended practices published by the Pipeline Research Council International[5] (PRCI) and Canadian Energy Pipeline Association[6] (CEPA) for pipeline companies and as a best practice, SDG&E plans to adopt the recommended onshore pipeline safety practices for facilities. The program's objective is to identify and mitigate potential risks to equipment within facilities, including compressor stations, renewable natural gas compression facilities, pressure limiting stations and natural gas vehicle fueling stations, through data gathering and analysis, integrity assessments, utilization of preventive and mitigative measures, and feedback-informed processes. The funding level requested for the FIMP allows for comprehensive risk management to enhance and maintain safety and reliability as informed by industry recommended practices.

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[5] PRCI, Facility Integrity Management Program Guidelines – PRCI IM-2-1, Release Date: December 23, 2013.

[6] CEPA, Facilities Integrity Management Program Recommended Practice, 1st Edition, May 2013.

In addition to the approval of forecasted costs presented at the beginning of this summary, SDG&E also requests that the Commission approve the post-test year forecasts for the Gas Integrity Management Programs, which are presented in Section VI-F of our testimony. Furthermore, SDG&E proposes the continuance of two-way balancing mechanism for the Transmission Integrity Management Program Balancing Account (TIMPBA) and Distribution Integrity Management Program Balancing Account (DIMPBA), and requests the addition of a Facilities Integrity Management Program Balancing Account (FIMPBA) and Gas Safety Enhancement Programs Balancing Account (GSEPBA). Due to the variability of activities and costs associated with the Gas Integrity Management Programs and the continuous evolution of federal and state regulations, the two-way balancing mechanism would allow for reasonable recovery of SDG&E's costs.

REVISED PREPARED DIRECT TESTIMONY OF
AMY KITSON AND TRAVIS SERA
(GAS INTEGRITY MANAGEMENT PROGRAMS)

I. INTRODUCTION

A. Summary of Gas Integrity Management Programs Costs and Activities

Our testimony supports the Test Year (TY) 2024 forecasts for operations and maintenance (O&M) costs for both non-shared and shared services, and capital costs for the forecast years 2022 through 2027, associated with the Gas Integrity Management Programs area for SDG&E. Table KS-1 summarizes our sponsored costs.

TABLE KS-1
Test Year 2024 Summary of Total Costs

GAS INTEGRITY MANAGEMENT PROGRAMS In 2021 $ (000s)			
	2021 Adjusted-Recorded	TY2024 Estimated	Change
Total Non-Shared Services	11,026	12,768	1,742
Total Shared Services (Incurred)	0	0	0
Total O&M	**11,026**	**12,768**	**1,742**

GAS INTEGRITY MANAGEMENT PROGRAMS In 2021 $ (000s)				
	2021 Adjusted-Recorded	Estimated 2022	Estimated 2023	Estimated 2024
Total CAPITAL	**60,547**	**81,707**	**86,876**	**107,125**

SDG&E is founded upon a commitment to provide safe, clean, and reliable service at reasonable rates. This commitment requires SDG&E to execute the Gas Integrity Management Programs to continually reduce the overall system risk through a process of continual safety enhancements by identifying, evaluating, and reducing pipeline integrity risks for its gas system. Specifically, the activities discussed herein:

- maintain and enhance safety;
- are consistent with, or exceed, local, state, and federal regulatory and legislative requirements;
- maintain overall system integrity and reliability; and
- support SDG&E's commitment to mitigate risks associated with hazards to customer/public safety, infrastructure integrity, and system reliability.

This testimony discusses non-shared and shared expenses and capital investments in support of functions for the different Integrity Management Programs. In addition to this testimony, please also refer to our workpapers, Exhibit SDG&E-09-WP (O&M) and capital workpaper (CWP) Exhibit SDG&E-09-CWP (Capital) for additional information on the activities described.

The Gas Integrity Management Programs organization is responsible for implementing and managing the requirements set forth in 49 CFR § 192, Subpart O – Gas Transmission Pipeline Integrity Management and Subpart P – Gas Distribution Integrity Management. Under Subpart O, SDG&E is required to continually identify threats to its pipelines in HCAs, determine the risk posed by these threats, schedule and track assessments to address threats, conduct an appropriate assessment in a prescribed timeline, collect information about the condition of the pipelines, take actions to minimize applicable threats and integrity concerns to reduce the risk of a pipeline failure, and report findings to regulators.

SDG&E operates approximately 175 HCA miles out of 215 miles of transmission pipelines as defined by the United States Department of Transportation (DOT).[7] SDG&E's size and location of operations has a direct and significant bearing on overall costs to comply with federal TIMP requirements.

SDG&E's TIMP is designed to meet these objectives by continually reviewing, assessing, and remediating pipelines operating in HCAs and non-HCAs. These activities are required to remain in compliance with federal regulations, and provide safe, clean, and reliable service to its customers at reasonable rates. Although 49 CFR § 192, Subpart O only requires baseline assessments of transmission pipelines operated in HCAs, PHMSA introduced – through 49 CFR § 192.710 – a new requirement to assess transmission pipelines operated in moderate consequence areas (MCAs) and Class 3 and Class 4 locations. Additionally, in an effort to further enhance the safety and reliability of the system, SDG&E assesses non-HCA pipelines that are contiguous to or near HCA pipelines on a case-by-case basis.

Under 49 CFR § 192, Subpart P, operators of gas distribution pipelines are required to collect information about distribution pipelines, identify additional information needed and provide a plan for gaining that information over time, identify and assess applicable threats to its

[7] 49 CFR § 192.3.

distribution system, evaluate and rank risks to the distribution system, determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline and evaluate the effectiveness of those measures, develop and implement a process for periodic review and refinement of the program, and report findings to regulators.

In contrast to the TIMP, DIMP focuses on the entire distribution system since distribution pipelines are largely in developed, more-populated areas to deliver gas to those populations. SDG&E operates approximately 15,330 miles of interconnected gas mains and services. SDG&E's size and location of operations has a direct and significant bearing on overall costs to comply with federal DIMP requirements. SDG&E's DIMP is designed to meet these objectives to remain in compliance with federal regulations and to promote safety and reliability to its customers at reasonable rates.

SDG&E continues to enhance its safety and mitigation activities whether through advancements in risk identification and analysis processes, the development of a new integrity management program (i.e., FIMP), or compliance with emerging regulations (e.g., PIPES Act). SDG&E has recently updated the Distribution Risk Evaluation and Monitoring System (DREAMS) risk model used to inform the Vintage Integrity Plastic Plan (VIPP), which is further described in Section IV-B of our testimony. Additionally, SDG&E began pilot projects to inform a new FIMP.

Incremental O&M and capital funding associated with a new safety, integrity and risk management initiative, FIMP, is proposed for SDG&E owned facilities including transmission compressor stations, natural gas vehicle (NGV) fueling stations, and pressure limiting stations. Based on industry definitions, there are various types of facilities which are highly complex and include a range of equipment/asset types. In the context of the FIMP, building structures are not considered to be applicable facilities.

The FIMP allows for the early identification of potential safety related risks. As facilities continue to age, SDG&E is seeking to exceed regularly required maintenance to manage the safety and integrity of its system. The FIMP would include additional inspections and expand the scope to equipment beyond what is currently required. The program is not intended to duplicate or cover equipment already assessed under existing Gas Integrity Management Programs (i.e., TIMP or DIMP).

Lastly, the GSEP that will be described in this testimony have been, or will be, initiated as a result of new safety regulations. On October 1, 2019, PHMSA issued the Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments final rule, GTSR Part 1).[8] Published as the first of three parts of the Gas Transmission and Gathering Rulemaking, the GTSR Part 1 updates sections of 49 CFR Parts 191 and 192 and mandates gas operators to update or implement procedures accordingly. The GTSR Part 1 imposes significant new safety and integrity requirements to gas transmission pipelines under PHMSA's jurisdiction.[9] These changes took effect July 1, 2020 and mandate certain compliance obligations commencing July 1, 2021.[10] To comply with these new safety requirements, SDG&E will undertake activities including – but not limited to – the following:

- Where MAOP reconfirmation is required for segments not in the scope of the authorized PSEP phases, implementing procedures to reconfirm MAOP in accordance with 49 CFR § 192.624;
- Assessments on segments outside of HCAs as required in 49 CFR § 192.710, which – in alignment with the requirements driving the TIMP activities and scope – will be managed under the TIMP; and
- Implementing procedures in accordance with 49 CFR § 192.607 to opportunistically verify – through nondestructive or destructive testing, examinations, and assessments – the material properties and attributes of transmission pipelines and associated components that do not have "traceable, verifiable, and complete"[11] records, which will also be managed under the TIMP.

In Sections IV-D-1 and V-D-1 of our testimony, we further explain the activities and costs associated with the GTSR Part 1 implementation. Activities that support the TIMP are forecasted accordingly while activities that have been determined to be incremental to existing and authorized company programs and activities are forecasted separately under ISEP.

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8 On April 8, 2016, PHMSA published an Advance Notice of Proposed Rulemaking (ANPRM), 81 FR 20722, proposing to revise the Pipeline Safety Regulations, which resulted in the GTS Rule Part 1.

9 A transmission pipeline under PHMSA's oversight is defined as "a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field." 49 CFR § 192.3.

10 *See* 49 CFR § 192.624(b) ("Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by July 1, 2021.").

11 84 FR 52218-52219 (October 1, 2019).

Additionally, PHMSA issued the Valve Installation and Minimum Rupture Detection Standards rule, as of March 31, 2022, which was published in the Federal Register on April 8, 2022, and the GTSR Part 2 rule is under review by the Office of Management and Budget (OMB) and is expected to be issued by the end of June 2022.

B. Support To and From Other Witnesses

Our testimony also references the testimony and workpapers of several other witnesses, either in support of their testimony or as referential support for ours:

- Exhibit SDG&E-02 - Sustainability Policy testimony of Estela de Llanos
- Exhibit SCG-03/SDG&E-03, Chapter 2 - RAMP to GRC Testimony of Gregory Flores and R. Scott Pearson
- Exhibit SDG&E-05 - Gas System Staff and Technology Testimony of Wallace Rawls
- Exhibit SDG&E-08 - Pipeline Safety Enhancement Plan (PSEP) Testimony of Norm Kohls
- Exhibit SDG&E-31- Safety, Risk and Asset Management Systems Testimony of Kenneth J. Deremer
- Exhibit SDG&E-43 – Regulatory Accounts Testimony of Jason Kupfersmid
- Exhibit SDG&E-45 Post-Test Year Ratemaking Testimony of Melanie Hancock

C. Organization of Testimony

My testimony is organized as follows:

- Introduction
- Risk Assessment Mitigation Phase Integration
- Sustainability and Safety Culture
- Non-Shared Costs
- Shared Costs
- Capital Costs
- Conclusion

II. RISK ASSESSMENT MITIGATION PHASE INTEGRATION

Certain costs supported in our testimony are driven by activities described in SoCalGas and SDG&E's May 17, 2021 Risk Assessment Mitigation Phase (RAMP) Report (2021 RAMP

Report).[12] The 2021 RAMP Report presented an assessment of the key safety risks of SDG&E and proposed plans for mitigating those risks. As discussed in the testimony of the RAMP to GRC Integration witness Gregory Flores and R. Scott Pearson (Ex. SCG-03/SDG&E-03, Chapter 2), the costs of risk mitigation projects and programs were translated from the 2021 RAMP Reports into the individual witness areas.

In the course of preparing the Gas Integrity Management Programs' GRC forecasts, priority was given to current and incremental mitigation activities which address these key areas of risk; SDG&E continued to evaluate the scope, schedule, resource requirements, and synergies of RAMP-related projects and programs. Therefore, the final representation of RAMP costs may differ from the ranges shown in the original 2021 RAMP Report.

Table KS-2 and KS-3 provide a summary of the RAMP-related costs supported in our testimony by RAMP risk:

[12] *See* Application (A.) 21-05-011/-014 (cons.) (RAMP Proceeding. Please refer to the Risk Management/RAMP to GRC Integration testimony of Gregory Flores and R. Scott Pearson (Exhibit SCG-03/SDG&E-03, Chapter 2) for more details regarding the utilities' RAMP Report.

TABLE KS-2

Summary of RAMP O&M Costs
In 2021 $ (000s)

	BY2021 Embedded Base Costs	TY2024 Estimated Total	TY2024 Estimated Incremental
RAMP Risk Chapter:			
SDG&E-Risk-3 Incident Related to the High Pressure System (Excluding Dig-in)	8,772	9,902	1,130
SDG&E-Risk-9 Incident Related to the Medium Pressure System (Excluding Dig-in)	2,254	2,866	612
Sub-total	11,026	12,768	1,742
RAMP Cross-Functional Factor (CFF) Chapter:			
Sub-total	0	0	0
Total RAMP O&M Costs	**11,026**	**12,768**	**1,742**

TABLE KS-3
Summary of RAMP Capital Costs
In 2021 $ (000s)

	2022 Estimated RAMP Total	2023 Estimated RAMP Total	2024 Estimated RAMP Total	2022-2024 Estimated RAMP Total
RAMP Risk Chapter:				
SDG&E-Risk-3 Incident Related to the High Pressure System (Excluding Dig-in)	21,477	22,393	36,591	80,461
SDG&E-Risk-9 Incident Related to the Medium Pressure System (Excluding Dig-in)	60,230	64,482	70,534	195,246
Sub-total	81,707	86,875	107,125	275,707
RAMP Cross-Functional Factor (CFF) Chapter:				
Sub-total	0	0	0	
Total RAMP Capital Costs	**81,707**	**86,875**	**107,125**	**275,707**

A. RAMP Risk Overview

As summarized in Tables KS-2 and KS-3 above, our testimony includes costs to mitigate the safety-related risks included in the RAMP report. These risks are further described in Table KS-4 below:

TABLE KS-4
RAMP Risk Chapter Description

SDG&E-Risk-3 – Incident Related to the High Pressure System (Excluding Dig-In)	This addresses the risk of failure of a high pressure pipeline,[13] which results in serious injuries, or fatalities, and/or damage to infrastructure. For purposes of this Chapter, the failure event would be from one of eight threats identified by PHMSA.
SDG&E-Risk-9 – Incident Related to the Medium Pressure System (Excluding Dig-In)	This addresses the risk of asset failure, caused by a medium pressure pipeline system[14] event, which results in serious injuries or fatalities. This risk concerns a gas public safety event on a medium pressure distribution plastic or steel pipeline and/or its appurtenances (*e.g.*, valves, meters, regulators, risers) as well as on and beyond the customer meter.

The testimony of RAMP-to-GRC Integration witnesses Gregory Flores and R. Scott Pearson (Ex. SCG-03/SDG&E-03, Chapter 2) describe all the risks and factors included in the RAMP report and the process utilized for RAMP-to-GRC integration.

B. GRC Risk Controls and Mitigations

Table KS-5 below provides a summary of the RAMP activities that will be sponsored in this testimony. Specific risks, mitigating measures, and associated costs are further discussed in Sections IV and VI.

13 MAOP at higher than 60 psig.

14 *Id.*

TABLE KS-5
Summary of RAMP Risk Activities

RAMP ID	Activity	Description
SDG&E-Risk-3 - C15-T1	Integrity Assessments and Remediation - TIMP	The TIMP was established pursuant to 49 CFR Part 192, Subpart O and includes threat identification and evaluation, pipeline assessments at least every seven years, and remediation activities on pipelines in populated areas – namely High Consequence Areas (HCAs).
SDG&E-Risk-3 - C15-T2	Integrity Assessments and Remediation – Assessments Outside of HCAs	SDG&E has conducted non-HCA assessments as part of the TIMP; however, assessments outside of HCAs were also newly required by the GTSR Part 1 (49 CFR § 192.710) effective July 1, 2020. Pipelines in Moderate Consequence Areas (MCAs) and Class 3 and 4 locations must be assessed on a 10-year cycle at minimum.
SDG&E-Risk-3 - M02-T1	Gas Transmission Safety Rule Implementation – MAOP Reconfirmation (HCA)	Pursuant to 49 CFR § 192.624, SDG&E is required to reconfirm – by July 2035 – the MAOP of transmission lines that either: 1) do not have traceable, verifiable, or complete pressure test records to establish MAOP in accordance with 49 C.F.R § 192.619(a) and are located in HCAs or Class 3 or 4 locations, or 2) have an MAOP established in accordance with 49 CFR § 192.619(c), have an MAOP greater than 30% SMYS, and are located in HCAs, Class 3 or 4 locations, or – where the segment can accommodate an in-line inspection (ILI) tool – MCAs. This tranche captures the projected HCA portion of the scope.
SDG&E-Risk-3 - M02-T2	Gas Transmission Safety Rule Implementation – MAOP Reconfirmation (Non-HCA)	Refer to SDG&E-Risk-3-M02-T1. This tranche captures the projected non-HCA portion of the scope.
SDG&E-Risk-9 - C16 T1	Distribution Integrity Management Program (DIMP)	The primary Projects and Activities to Address Risk (PAARs) that is currently driving the DIMP mitigation is the Vintage Integrity Plastic Plan (VIPP) under the umbrella of the Distribution Risk Evaluation and Monitoring System (DREAMS). the program and tool developed and managed as part of the DIMP which is used to prioritize risk mitigation on early vintage pipeline segments. The VIPP focuses on non-state-of-the-art plastic pipe installed prior to 1986.

RAMP ID	Activity	Description
SDG&E-Risk-3 - M01-T1	Pipeline Safety Enhancement Plan (PSEP) - Phase 2B – Replacement (HCA)	The Pipeline Safety Enhancement Plan (PSEP) is an ongoing effort to replace or pressure test all of the natural gas transmission pipelines that have not been tested or for which reliable records are not available as directed by the Commission in D.11-06-017 and later codified in California Public Utilities Code (PUC) Sections 957 and 958. This Phase 2B tranche would consist of replacement projects that SDG&E recommends to include in the PSEP based on an evaluation of transmission pipelines not included in the authorized Phase 1A, 1B, and 2A scopes. Refer to Section II-D for the change from the RAMP report that will be detailed in our testimony.
SDG&E-Risk-3 - M01-T2	Pipeline Safety Enhancement Plan (PSEP) - Phase 2B – Replacement (Non-HCA)	Refer to SDG&E-Risk-3-M01-T1. This tranche captures the projected non-HCA portion of the scope.
SDG&E-Risk-3 - M01-T3	Pipeline Safety Enhancement Plan (PSEP) - Phase 2B – Hydrotesting (HCA)	Refer to SDG&E-Risk-3-M01-T1. This tranche captures the projected HCA portion of the hydrotesting projects scope.
SDG&E-Risk-3 - M01-T4	Pipeline Safety Enhancement Plan (PSEP) - Phase 2B – Hydrotesting (Non-HCA)	Refer to SDG&E-Risk-3-M01-T1. This tranche captures the projected non-HCA portion of the hydrotesting projects scope.

Tables KS-6 and KS-7 below summarize the TY 2024 forecast by workpaper associated with the RAMP activities.

TABLE KS-6
Summary of Safety Related Risk Mitigation O&M Costs by Workpaper
In 2021 $ (000s)

Workpaper	RAMP ID	Description	BY2021 Embedded Base Costs	TY2024 Estimated Total	TY2024 Estimated Incremental	GRC RSE
1TD001.000	SDG&E-Risk-3 - C15 & M3 T1-T2	Integrity Assessments & Remediation (HCA and Non-HCA)	8,772	9,514	742	T1 - 19.8 T2 - 9.2

Workpaper	RAMP ID	Description	BY2021 Embedded Base Costs	TY2024 Estimated Total	TY2024 Estimated Incremental	GRC RSE
1TD002.000	SDG&E-Risk-9 - C16 T1	Distribution Integrity Management Program (DIMP)	2,254	2,866	612	0.2
1TD004.000	SDG&E-Risk-3 - NEW 01	NEW - Facility Integrity Management Program (FIMP) - Distribution	0	218	218	20.7
1TD004.000	SDG&E-Risk-3 - NEW 04	NEW - Facility Integrity Management Program (FIMP)-Transmission	0	40	40	37
1TD005.000	SDG&E-Risk-3 - M02 T1-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA and Non-HCA)	0	90	90	T1 – 5.4 T2 – 7.6
1TD005.000	SDG&E-Risk-3 - NEW 02	NEW - Valve Rule	0	24	24	
1TD005.000	SDG&E-Risk-3 - NEW 03	NEW - Gas Transmission Safety Rule (GTSR) Part 2	0	16	16	
Total			**11,026**	**12,768**	**1,742**	

TABLE KS-7
Summary of Safety Related Risk Mitigation Capital Costs by Workpaper
In 2021 $ (000s)

Workpaper	RAMP ID	Description	2022 Estimated RAMP Total	2023 Estimated RAMP Total	2024 Estimated RAMP Total	GRC RSE
034680.001	SDG&E-Risk-3 - C15 & M3 T1-T2	Integrity Assessments & Remediation (HCA and Non-HCA)	21,477	19,172	9,290	T1 - 19.8 T2 - 9.2
095460.001	SDG&E-Risk-9 - C16 T1	Distribution Integrity Management Program (DIMP)	60,230	64,482	70,534	0.2
214770.001	SDG&E-Risk-3 - M02 T1-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA and Non-HCA)	0	2,343	26,361	T1 – 5.4 T2 – 7.6
214770.003	SDG&E-Risk-3 – NEW 03	NEW - Gas Transmission Safety Rule (GTSR) Part 2	0	265	333	
214770.005	SDG&E-Risk-3 – NEW 02	NEW - Valve Rule	0	613	462	
214780.001	SDG&E-Risk-3 - NEW 01	NEW - Facility Integrity Management (FIMP)-Distribution	0	0	100	20.7

Workpaper	RAMP ID	Description	2022 Estimated RAMP Total	2023 Estimated RAMP Total	2024 Estimated RAMP Total	GRC RSE
214780.002	SDG&E-Risk-3 - NEW 04	NEW - Facility Integrity Management (FIMP)-Transmission	0	0	45	37
Total			**81,707**	**86,875**	**107,125**	

For each of the workpapers identified above, additional descriptions of the RAMP controls and mitigations that comprise these forecasts are discussed within the cost category sections to follow.

The costs for these activities are shown as adjustments to our forecasts and are provided in greater detail in our workpapers. In our workpapers, RAMP mitigation costs are presented as "RAMP-Base" to represent the RAMP-related costs that are embedded in the Base Year (BY) 2021 adjusted-recorded costs and "RAMP-Incremental" to represent TY 2024 estimated incremental costs.

C. Changes from RAMP Report

As discussed in more detail in the RAMP to GRC Integration testimony of Messrs. Pearson and Flores (Ex. SCG-03/SDG&E-03, Chapter 2), in the RAMP Proceeding, the Commission's Safety Policy Division (SPD) and intervenors provided feedback on the Companies' 2021 RAMP Reports. Appendix B in Ex. SCG-03/SDG&E-03, Chapter 2 provides a complete list of the feedback and recommendations received and the Companies' responses.

Generally, changes from the 2021 RAMP Report are related to the scoping of the various mitigations in our testimony and workpapers. Other than as discussed below and in our workpapers, the RAMP-related activities described in my GRC testimony are consistent with the activities presented in the 2021 RAMP Report. General changes to risks scores or Risk Spend Efficiency (RSE) values are primarily due to changes in the Multi-Attribute Value Framework (MAVF) and RSE methodology, as discussed in the RAMP to GRC Integration testimony (Ex. SCG-03/SDG&E-03, Chapter 2).

1. TIMP

The primary change from the 2021 RAMP Report as it relates to the Integrity Assessments and Remediation mitigation (C15) in Chapter SDG&E-Risk-3 is the inclusion of GTSR Part 1 requirements previously identified as a separate mitigation (M03), as well as the inclusion of additional scope and costs stemming from changes to 49 CFR § 192.917(e), the impacts of which had not been fully determined at the time of the RAMP report.

The verification of material properties and attributes in accordance with 49 CFR § 192.607 was previously separated as a new mitigation in the 2021 RAMP Report (M3); however, upon further evaluation of the requirements and scope, SDG&E has determined that the requirements expand existing activities performed in support of TIMP data gathering and evaluation processes. The material verification activity has been added to the scope of the Integrity Assessments and Remediation mitigation (C15) and further information can be found in our workpapers (Ex. SDG&E-09-WP -Gas Integrity Management Programs).

Additionally, SDG&E continued to analyze and implement GTSR Part 1 requirements and the extent to which 49 CFR § 192.917(e)(3) impacts the scope of TIMP assessments in forecasted years was updated. SDG&E determined that several pipeline segments with assessments due in 2022-2024 would likely have reactivated manufacturing and construction threats that would result in additional assessments. Though this does not necessarily expand the scope of the integrity Assessments and Remediation mitigation, it does increase the costs of this mitigation as discussed in Section IV of our testimony.

2. DIMP

Other than the changes noted in our workpapers, there were no significant changes to the scope of the DIMP mitigation in Chapter SDG&E-Risk-9.

3. FIMP

Since the 2021 RAMP Report, SDG&E has incorporated the scope of the FIMP, adding two mitigations (New01, New04) to address the risks identified in Chapters SDG&E-Risk-3 and SDG&E-Risk-9. More specifically, the program was expanded to include additional facilities such as natural gas vehicle fueling stations, pressure limiting stations, and equipment types such as electrical equipment and rotating equipment. These activities and costs were not included in the 2021 RAMP Report but are presented in our testimony and workpapers.

4. GSEP

Since the 2021 RAMP Report, PHMSA issued the Valve Installation and Minimum Rupture Detection Standards rule and is expecting to publish the GTSR Part 2 by the end of June of 2022; a preliminary forecast of activities and costs are newly presented (New02, New03) in our testimony and workpapers. Impacts are still being analyzed at the time of filing so RSE scores have not been included and our testimony will also explain the need for a two-way balancing account to comply with new gas safety regulations in Sections IV and VI.

Additionally, as previously explained in the changes to the Integrity Assessments and Remediation control (C15), SDG&E has determined that the material verification activity in accordance with 49 CFR § 192.607 is more appropriately presented with the TIMP activities due to SDG&E's existing practice to verify material properties and attributes; however, the GTSR Part 1 impacts the existing level of activity through expansion of scope and new sampling and testing requirements.

Furthermore, as a result of SDG&E's continued evaluation of how best to address the requirements associated with the Gas Transmission Safety Requirements (GTSR), SDG&E is no longer distinguishing mitigations specific to PSEP Phase 2 (SDG&E-Risk-3 M01-T1.1 thru T1.4) and MAOP Reconfirmation (SDG&E-Risk-3 M02-T1 & T2). As discussed in Section V-D-1 of our testimony, the funding request for the ISEP represents the hydrotesting and replacement projects that should be authorized in addition to the scope already authorized under PSEP's Phases 1A, 1B, and 2A.

Lastly, the MAOP reconfirmation (49 CFR § 192.624) activities and costs – presented in the RAMP report as the GTSR - MAOP Reconfirmation mitigation (M2) – have been updated in accordance with the Federal Energy Regulatory Commission (FERC) accounting guidance issued in June of 2020.[15] SDG&E is proposing the capitalization of pressure testing of pipeline segments in scope for MAOP reconfirmation based on test record traceability, verifiability, and completeness and this is discussed in more detail in Section IV and VI of our testimony.

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[15] See FERC Docket No. AI20-3-000, Accounting for Pipeline Testing Costs Incurred to Comply with New Federal Safety Standards issued June 23, 2020 (FERC Accounting Guidance), https://www.ferc.gov/sites/default/files/2020-06/AI20-3-000.pdf.

III. SUSTAINABILITY AND SAFETY CULTURE

Sustainability, safety, and reliability are the cornerstones of SDG&E's core business operations and are central to SDG&E's GRC presentation. SDG&E is committed to not only deliver clean, safe, and reliable electric and natural gas service, but to do so in a manner that supports California's climate policy, adaptation, and mitigation efforts. In support of the legal and regulatory framework set by the state, SDG&E has set a goal to reach Net Zero greenhouse gas (GHG) emissions by 2045, adopted a Sustainability Strategy to facilitate the integration of GHG emission reduction strategies into SDG&E's day-to-day operations and long-term planning, and published an economy-wide GHG Study[1] that recommends a diverse approach for California leveraging clean electricity, clean fuels, and carbon removal to achieve the 2045 goals through the lens of reliability, affordability, and equity. As a "living" strategy, SDG&E will continue to update the goals and objectives as technologies, policies, and stakeholder preferences change. See the Sustainability Policy testimony of Estela de Llanos (Ex. SDG&E-02).

In this GRC, SDG&E focuses on three major categories that underpin the Sustainability Strategy: mitigating climate change, adapting to climate change, and transforming the grid to be the reliable and resilient catalyst for clean energy. SDG&E's goal is to contribute to the decarbonization of the economy by way of diversifying energy resources, collaborating with regional partners, and providing customer choice that enables an affordable, flexible, and resilient grid.

Many of the activities described in further detail in our testimony advance the state's climate goals and align with SDG&E's Sustainability Strategy. Specifically, the Gas Integrity Management Programs will drive progress in the areas of Climate Mitigation and Grid Transformation.

The Gas Integrity Management Programs also drive progress towards Grid Transformation due to the focus on the safety of the Company's natural gas system. Safety is a core value of the Company and SDG&E is committed to providing safe and reliable service to all its stakeholders. This safety-first culture is embedded in every aspect of the Company's work. In 2020, SDG&E commenced development and deployment of a Safety Management System (SMS), which better aligns and integrates safety, risk, asset, and emergency management across the entire organization. The SMS takes a holistic and pro-active approach to safety and expands beyond "traditional" occupational safety principles to include asset safety, system safety, cyber safety, and psychological safety for improved safety performance and culture. SDG&E's SMS is a systematic, enterprise-wide framework that utilizes data to collectively manage and reduce risk and promote continuous learning and improvement in safety performance through deliberate, routine, and intentional processes.

The TIMP, DIMP, and newly proposed GSEP are designed to promote a safe and reliable natural gas supply and delivery system. Additionally, the FIMP is a new program SDG&E is proposing that would apply the principles and best practices of the TIMP and DIMP, as well as industry guidelines, to enhance the safety of SDG&E's gas facilities.

The TIMP and DIMP increase safety and reduce emissions. These programs provide an opportunity to continually assess risk on the system and identify areas of improvement -- integrity assessments, informed by continuous data gathering and analysis, are performed regularly and allow the Company to evaluate risks and identify conditions that require remediation. The resulting remediation of conditions mitigates the likelihood of leaks, ruptures, and other safety risks related to the system, which in turn reduces the likelihood of carbon emissions from the SDG&E system.

The implementation of the GSEP as described in Sections IV-D and V-D further supports the Climate Mitigation area of the Company's sustainability strategy. The ISEP focuses on the reconfirmation of pipeline MAOP through methods such as pressure testing and replacement and one of the benefits of recently having pressure-tested or new, state-of-the-art pipe is the ability to reduce the likelihood of emissions resulting from an in-service pipeline rupture. Additionally, the implementation of the PHMSA Valve Rule would further increase the ability of the Company to reduce emissions associated with in-service pipeline ruptures due to the installation of rupture mitigation valves. Further contributing to overall safety, the implementation of additional corrosion control measures required the GTSR Part 2 will enhance current processes already in place.

SDG&E continues to invest in resources that will allow further improvements to the management of system integrity and, as summarized earlier, we are proposing a number of new initiatives in our testimony.

As further discussed in Section IV of our testimony, SDG&E also continues to evaluate and implement enhancements - driven by industry best practices, information gathered about the system, and available tools in order to manage safety risks. Under the DIMP, data and metrics are continually used to inform the development of new PAARs and initiatives to mitigate risks. SDG&E is also transitioning to a quantitative risk analysis methodology for the DREAMS (refer to Section IV-B) to enhance the risk evaluation and prioritization processes driving safety-focused mitigations.

Pertaining to the TIMP, SDG&E continues to improve the TIMP processes by identifying opportunities to introduce programmatic enhancements, such as the expansion of the use of ILI tools capable of detecting cracking risks on transmission pipelines.

Lastly, the proposal of the FIMP further demonstrates the Company's commitment towards innovation of safety measures beyond compliance and is an example of SDG&E's safety culture. The FIMP is based on industry best practices and would increase the contributions of the Gas Integrity Management Programs to the Company's sustainability strategy by expanding both the safety and emissions reduction benefits currently realized through the TIMP and DIMP to gas facilities.

SDG&E remains focused on identifying and implementing the most cost-effective solutions with the potential to make the greatest impact on reducing GHG emissions, while maintaining a safe and reliable energy system. SDG&E believes that safety, reliability, and sustainability are inextricably linked and fundamental to the Company's ability to continue to successfully operate. Please see the Sustainability Policy testimony of Estela de Llanos (Ex. SDG&E-02) for additional detail on SDG&E's Sustainability Strategy and the Safety, Risk and Asset Management Systems testimony of Kenneth J. Deremer (Ex. SDG&E-31) for additional detail of SDG&E's Safety Policy.

IV. NON-SHARED COSTS

"Non-Shared Services" are activities that are performed by a utility solely for its own benefit. Corporate Center provides certain services to the utilities and to other subsidiaries. For purposes of this general rate case, SDG&E treats costs for services received from Corporate Center as Non-Shared Services costs, consistent with any other outside vendor costs incurred by the utility. Table KS-8 summarizes the total non-shared O&M forecasts for the listed cost categories.

TABLE KS-8
Non-Shared O&M Summary of Costs

GAS INTEGRITY PROGRAMS In 2021 $ (000s)			
Categories of Management	**2021 Adjusted-Recorded**	**TY2024 Estimated**	**Change**
A. TIMP	8,772	9,514	742
B. DIMP	2,254	2,866	612
C. FIMP	0	258	258
D. GSEP	0	130	130
Total Non-Shared Services	**11,026**	**12,768**	**1,742**

A. TIMP

1. Description of Costs and Underlying Activities

To comply with 49 CFR § 192, Subpart O – Gas Transmission Pipeline Integrity Management, SDG&E is required to continually identify threats to transmission pipeline located in HCAs, determine the risk posed by these threats, schedule and track assessments to address threats within prescribed timelines, collect information about the condition of the pipelines, take actions to minimize applicable threats and integrity concerns to reduce the risk of a pipeline failure, and report findings to regulators. Additionally, the GTSR Part 1 mandates that operators expand assessments into areas outside of HCAs (49 CFR § 192.710). As described in Section II-C, SDG&E previously conducted assessments under the TIMP on areas outside of HCAs both as a best safety practice and in compliance with 49 CFR § 192, Subpart O; with the issuance of the GTSR Part 1, SDG&E will further expand assessments outside of HCAs. The activities prescribed by Subpart O and 49 CFR § 192.710 are primarily implemented and managed by the TIMP team, which is comprised of engineers, project managers, technical advisors, project specialists, and other employees with varying degrees of responsibility. The forecasted labor and non-labor costs support SDG&E's goals of operating the system safely and with excellence by continually assessing, mitigating, and reducing system risk.

In general, the GTSR Part 1 will expand TIMP activities and result in an increase to resources and program costs. Beyond the expansion of assessments outside of HCAs, other areas of impact include the requirements of 49 CFR § 192.607 ("Verification of Pipeline Material Properties and Attributes") and 49 CFR § 192.917 ("How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?"). While the TIMP team previously conducted testing of pipeline materials to gather data and develop records for use in pipeline analyses on an ad hoc basis, 49 CFR § 192.607 establishes stringent sampling and testing requirements which will increase the number of samples and amount of testing under the TIMP. Additionally, with 49 CFR § 192.917(e)(3), PHMSA has updated the requirements operators must comply with to consider manufacturing or construction related defects stable. Whereas previously, an operator might consider a manufacturing or construction related defect stable if the operating pressure had not increased over the maximum operating pressure used during the five years preceding the identification of the segment as being in an HCA, an operator must now have record of a pressure test satisfying the criteria of 49 CFR Part 192, Subpart J and must not have experienced a reportable incident attributed to a manufacturing or construction related defect since the test. SDG&E continues to evaluate, identify, and update pipeline threats and additional activities to assess manufacturing and construction related defects on segments have been considered in the TIMP O&M and capital forecasts.

The costs of implementing TIMP will be balanced and recorded in a regulatory balancing account, the Transmission Integrity Management Program Balancing Account (TIMPBA), as described in the Regulatory Accounts testimony of Jason Kupfersmid (Ex. SDG&E-43). Should the balance in the TIMPBA exceed the forecast due to unanticipated activities, such as remediation of a pipeline in an environmentally sensitive or difficult to access area, expansion of assessments to further enhance public safety, augmentation of existing pipelines to enable the use of In-Line Inspection (ILI) technology to assess pipeline integrity, or enhancement of data management practices, recovery of account balances above authorized levels could be requested through an advice letter, as described by Mr. Kupfersmid. General activities considered in the development of the TIMP forecast include:

- <u>Threat Identification and Risk Assessment:</u> An operator is required to perform threat identification and risk assessment of its transmission pipelines per Subpart O. Threat identification and risk assessment are considered the starting point in SDG&E's TIMP implementation process. SDG&E uses a prescriptive approach for threat identification, which includes the nine categories of threats described in American Society of Mechanical Engineers (ASME) Standard B31.8S: External Corrosion; Internal Corrosion; Stress Corrosion Cracking; Manufacturing; Construction; Equipment; Third Party; Incorrect Operations; and Weather Related and Outside Force. All pipelines operated in HCAs and in-scope non-HCAs are evaluated for each threat category. A risk assessment of the HCA and non-HCA pipelines and identified threats is done through a relative assessment. The relative assessment integrates relevant threats, industry data, and Company experience to prioritize pipeline segments for baseline and continual reassessment.

- Assessment Plan: Once pipeline threats are identified, a risk assessment is completed, and the HCA and non-HCA pipelines are prioritized, an Assessment Plan is created and maintained to manage the scheduling and due dates for all assessments. In some instances, multiple assessment methods for the same pipeline section may be necessary, depending on the threats that need to be evaluated. For example, if external and internal corrosion are both identified as a threat to a pipeline, this may require concurrent completion of External Corrosion Direct Assessment (ECDA) and Internal Corrosion Direct Assessment (ICDA). The allowable methods prescribed by the DOT Pipeline and Hazardous Material Safety Administration (PHMSA) that may be used for inspecting (assessing) a pipeline are: ILI, Pressure Testing, Spike Hydrostatic Pressure Testing, Excavation and In Situ Direct Examination, and Guided Wave Ultrasonic Testing, Direct Assessment, and Other Technology.[16] Currently, SDG&E has added approximately 3 miles of incremental scope to the TIMP as a result of the GTSR Part 1 – these outside-of-HCA pipeline segments were incorporated into the Assessment Plan and must be assessed by July 3, 2034 in accordance with 49 CFR § 192.710.

- Assessments: The assessment methods employed by SDG&E are ILI, Pressure Testing, External Corrosion Direct Assessment, and Internal Corrosion Direct Assessment. The assessment process includes reviewing and gathering historical data, collecting pipeline samples (in some instances), completing the assessment, and evaluating the results of the assessment. Selection of an assessment method may vary, but these common assessment methods are generally described below:

    - ILI: The ILI method utilizes specialized inspection tools that travel inside the pipeline. SDG&E plans to complete 3, 2, and 3 ILI assessments in 2022, 2023, and 2024, respectively. ILI tools are often referred to as "smart pigs". Smart pigs come in a variety of types and sizes with different measurement capabilities that assist in collecting information about the pipeline. This specialized tool requires that the pipeline be configured to accommodate its passage. As this technology did not exist when many pipelines were constructed, the use of this assessment method often requires pipeline segments to be modified or retrofitted to allow passage of the tool. Retrofits include the replacement of valves, removal of certain bends and any other obstruction for passage, as well as the addition of facilities to insert and remove the tool. Once the pipeline is retrofitted to allow passage of the smart pig, a series of pigs are passed through the pipeline to clean out and collect information about the pipeline. Since the ILI tools are generally run for the length of the pipeline, the benefit is that the assessment provides information for both

[16] *See* 49 CFR §§ 192.710(c) & 192.921(a). As reflected in the workpapers supporting my testimony, SDG&E currently anticipates primarily utilizing ILI and ECDA assessment methods during the GRC cycle. The method used to assess pipeline integrity could change based on a change in threat identification.

HCA and non-HCA transmission pipeline segments. Using ILI, SDG&E has been able to inspect approximately 25 miles of non-HCA transmission pipelines since the inception of the program in 2002. In accordance with D.21-05-003, SDG&E will continue to prioritize assessments based on compliance and threat evaluations.

- <u>Pressure Test:</u> Pressure testing is a method that uses a hydraulic approach by filling the pipeline, usually with water, at a pressure greater than the MAOP of the pipeline for a fixed period of time. In certain circumstances, the pipeline may be temporarily removed from service post construction, pressure-tested, and then returned to service. If a leak occurs during the pressure test, the leak is investigated and remediated prior to continuing or completing a pressure test.

- <u>ECDA:</u> ECDA is a process that seeks to identify external corrosion defects before they grow to a size that can affect the integrity of the inspected pipeline. SDG&E plans to complete 4, 3, and 2 assessments using ECDA in 2022, 2023, and 2024, respectively. The ECDA process requires integration of operating data and the completion of above-ground surveys. This information is used to identify and define the severity of coating faults, diminished cathodic protection (CP), and areas where corrosion may have occurred or may be occurring. Once these areas are identified, excavation of prioritized sites for pipe surface evaluations to validate or re-rank the identified areas is completed. ECDA is labor-intensive and, depending on the location of the excavations, the cost can be significant.

- <u>ICDA:</u> ICDA is a process that assesses and predicts areas where internal corrosion is likely to occur. The process incorporates operating data, elevation profile, flow modeling, and inclination angle analysis. This information is used to identify potential low spots where liquids are most likely to accumulate and where internal corrosion may have occurred or may be occurring. Once these areas are identified excavation of sites validate if internal corrosion exists at the selected sites. ICDA is labor-intensive and, depending on the results of the detailed examination, a significant increase in the number of excavations may be required.

- <u>Remediation:</u> The remediation of a pipeline can occur at different stages depending on the assessment method selected. An ECDA assessment is complete once the areas of concerns identified using the various survey results are excavated and reviewed; the remediation of the pipeline generally occurs in parallel to the assessment being completed. For a pressure test assessment, remediation of the pipeline must be performed ahead of completing a test if an area of concern is discovered. A pressure test cannot be successfully conducted until all remediation work is completed. For an assessment completed using ILI, the remediation occurs after the assessment is complete and the results of the ILI are provided by the vendor. The vendor report provides an overall assessment of the pipeline and possible areas of concern, which can vary greatly from assessment to assessment. Based on data analysis and evaluation, detected anomalies are classified and addressed by severity (i.e., immediate, scheduled, monitored) in accordance with 49 CFR § 192.933 and ASME B31.8, with the most severe requiring immediate action. Possible anomalies may include areas where corrosion, weld or joint failure, or other forces are occurring or have occurred. Once areas of concern are identified, sites are prioritized for pipe surface evaluations to validate or re-rank the identified areas. Post-assessment pipeline repairs or reconditioning (e.g., welded steel sleeve repairs or grinding of a defect), when appropriate, and replacements are intended to increase public and employee safety by reducing or eliminating conditions that might lead to an incident. With the impending publication of the GTSR Part 2, SDG&E has forecasted additional costs for the remediation of non-HCA segments to align with the proposed rule language, which emulates the requirements of 49 CFR § 192.933 and applies them to the non-HCA pipeline segments operators must now assess in compliance with the GTSR Part 1. Capital remediations are discussed in more detail in Section V-A of our testimony.

- <u>Additional Preventative and Mitigative Measures:</u> After the excavations are performed and the assessment is complete, the data is analyzed to determine the need for preventative and mitigative measures and to establish the reassessment interval for the pipeline, up to a maximum of seven years. Preventative and mitigative measures are developed based on the requirements of 49 CFR § 192.935(a). When appropriate, the consideration of additional measures for pipeline segments with similar operating conditions will be undertaken for both HCA and non-HCA pipelines.[17] For 2024, preventative and mitigative measures include the addition of rectifiers, monitoring probes, and additional surveys along the pipelines with similar material coating and environmental characteristics.

- <u>GIS</u>: A GIS is a computer system designed to capture, store, manipulate, analyze, manage, and present all types of geographical data. SDG&E currently manages two GIS, one for medium-pressure pipelines operating at 60 psi or less, and one for high-pressure pipelines operating at greater than 60 psi. In our testimony, the GIS used to manage high-pressure pipelines is referred to as the High-Pressure Pipeline Database (HPPD) and the GIS used to manage medium-pressure pipelines is referred to as the Enterprise GIS (eGIS). The HPPD is at the core of all TIMP activities and houses and maintains the data collected for transmission pipelines during the pre-assessment process, during the various assessments, and remediation efforts completed as part of TIMP. Maintenance of the HPPD is required to continuously reflect changes in the pipeline system based on new construction, replacements, abandonments, or re-conditioning of pipelines for not only TIMP-related projects, but also for all company-wide projects to holistically analyze the entire transmission pipeline system. Various tool sets (applications)

[17] *See, e.g.*, 49 CFR § 192.917(e)(5): "*Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (-conditions specified in § 192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and noncovered)."

used within the HPPD allow for the analysis and determination of HCAs, relative risk evaluation of the transmission system, and the creation of Assessment Plans.

- Auditing and Reporting: On an annual basis, relevant integrity data regarding overall program measures and threat-specific measures is gathered and reported per 49 CFR § 192.945 and ASME/ANSI B31.8S-2004, Section 9.4 to PHMSA with copies provided to the CPUC. The following examples are overall program measures that are reported on an annual basis in Form PHMSA F 7100.2-1 Annual Report for Calendar Year (reporting year) Natural and Other Gas Transmission and Gathering Pipeline Systems:
    - Number of total system miles existing as of the end of the reporting period;
    - Number of total miles inspected during the reporting period;
    - Number of total HCA miles covered by the Integrity Management Program, as of the end of the reporting period;
    - Number of total miles in scope for the 49 CFR § 192.710 assessment requirements; and
    - Number of miles inspected and actions taken via Integrity Management Program assessments during the reporting period.
- Continuous Enhancements: SDG&E continually evaluates pipeline data in compliance with § 192.937(b) and as a best practice, updates its processes and tools accordingly. An example of this is SDG&E's enhanced crack management plan, which was developed in response to a rising awareness of cracking-related anomalies across the industry. SDG&E had developed the plan before the GTSR Part 1 requirements were published in 2019 to manage cracking risks such as long seam cracking or stress corrosion cracking. PHMSA's GTSR Part 1 further solidified the need for this enhancement to the TIMP by introducing 49 CFR § 192.712. SDG&E continues to expand the use of Electro Magnetic Acoustic Transducer (EMAT) tools and Circumferential Magnetic Flux Leakage (CMFL) tools in response to cracking threats. The expanded use of these tools is expected to increase the number of anomalies found and therefore, the amount of pipeline remediation performed by the program as discussed in Section V-A. SDG&E is also using adaptable predicted failure pressure analysis and cyclic fatigue analysis in compliance with 49 CFR § 192.712 to manage reassessment cycles.

2. Description of RAMP Mitigations

All of the TIMP activities are a mitigation measure addressing safety risks identified in the 2021 RAMP Report: Incident Related to the High-Pressure System (Excluding Dig-In) chapter.

Though SDG&E has identified separate tranches of activity within the TIMP, costs should be reviewed and authorized at the workpaper level since the activities presented in our testimony and workpapers are compliance-driven and must be completed as planned.

Table KS-Table 9 below provides the RAMP activities, their respective cost forecasts, and the RSEs for this workpaper. For additional details on these RAMP activities, please refer to our workpapers (Ex. SDG&E-09-WP).

TABLE KS-9
RAMP Activity O&M Forecasts by Workpaper
In 2021 $ (000s)

Workpaper	RAMP ID	Activity	2021 Embedded-Recorded	TY 2024 Estimated	Change	GRC RSE
1TD001.000	SDG&E-Risk-3 - C15 & M3 T1-T2	Integrity Assessments & Remediation (HCA and Non-HCA)	8,772	9,514	742	T1 – 19.8 T2 – 9.2
		Sub-Total	**8,772**	**9,514**	**742**	

3. Forecast Method

The forecast method developed for this cost category is base-year recorded. This method is most appropriate because the base year best represents the current structure of the organization and costs, with incremental adjustments for future considerations such as enhancements to TIMP processes and tools, as well as the expansion of scope as a result of the GTSR Part 1 (e.g., outside-of-HCA assessments and material verification). Additionally, a base-year recorded forecasting method is most appropriate because the costs directly correlate to the number of assessments conducted each year. With the variability of assessments from year to year due to the maximum seven-year cycle for HCAs and maximum ten-year cycle for non-HCAs in scope for 49 CFR § 192.710, a base-year recorded forecasting method allows SDG&E to use the most recent year of activity and adjust for the changes driven by the number of assessments that are expected. Results from assessments coupled with the regulatory requirements for reassessment intervals establish the reassessment plan (timeline) for pipelines, which cannot be extended.[18] The forecast methodology is fundamentally rooted in average unit cost.

4. Cost Drivers

The cost drivers behind this forecast include both labor and non-labor components. The cost drivers for labor are the Program Management teams required to provide direction, guidance, and oversight to meet compliance and program requirements, as well as supplemental contracted non-labor for process improvement, process guidance, and peak activity level support. The cost drivers are based on the number of assessments (ILI, Direct Assessment, or Pressure Test), repairs – which vary from project to project based on assessment findings, and mitigation activities to achieve compliance. Additionally, SDG&E continues to enhance and employ new assessment processes and tools used to manage different aspects of the program (e.g., threat identification, assessment, and remediation) either as a best practice or in response to new regulations (e.g., the GTSR Parts 1 and 2). Lastly, while SDG&E has identified miles as the primary unit for the purposes of tracking activity and evaluating the RSE of TIMP assessments, costs are primarily driven by the number of projects undertaken rather than the number of miles assessed.

Anticipated cost drivers that have not been incorporated in the TIMP forecasted costs are related to the PIPES Act of 2020 – new regulations may affect the TIMP but proposed changes are not well-defined at this time, though their existence is not speculative. Refer to Section IV-D for additional information. Additionally, once published by PHMSA in June of 2022, it is possible that the GTSR Part 2 may have additional impacts on the TIMP than what has been forecasted based on the proposed language. Described previously, the TIMPBA would allow actual incremental compliance costs to be balanced and recovered.

B. DIMP

1. Description of Costs and Underlying Activities

The activities described within this section are to comply with 49 CFR § 192, Subpart P – Gas Distribution Pipeline Integrity Management. PHMSA established DIMP requirements to

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[18] *See* 49 CFR § 192.939(a) (establishing express requirements for determining the reassessment interval for covered pipelines, and stipulating that "the maximum reassessment interval by an allowable reassessment method is 7 calendar-years.").

enhance pipeline safety by having operators identify and reduce pipeline integrity risks for distribution pipelines, as required under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006.[19] These costs will be balanced and recorded in the Post-2011 Distribution Integrity Management Program Balancing Account (DIMPBA), as described in the Regulatory Accounts testimony of Mr. Kupfersmid (Ex. SDG&E-43). Should the balance in the DIMPBA exceed the forecast due to unanticipated activities, based on continual threat and risk analysis, recovery of account balances above authorized levels could be requested through an advice letter, as described Mr. Kupfersmid's testimony. These activities are primarily implemented and managed by the DIMP team. The team is comprised of engineers, project managers, technical advisors, project specialists, and other employees with varying degrees of responsibility. These costs support the Company's goals of operating the system safely and with excellence by continually assessing, mitigating, and reducing overall system risk. The following topics and activities are discussed in additional detail below to demonstrate the reasonableness of the labor and non-labor cost forecasts:

- System Knowledge: System knowledge is developed from reasonably available information and is attained through an understanding of system attributes such as design, materials, and construction methods, pipeline condition, past and present operations and maintenance, local environmental factors, and failure data (*e.g.*, leaks). Data collection for SDG&E's approximately 15,330 miles of distribution main and services is an extensive process that is continually being improved upon through targeted research and changes in data capture as needed.

- Threat Identification and Risk Analysis: Threat is defined as a combination of the "Cause" and the "Facility." The major categories of "Causes" are the eight cause categories listed in 49 CFR § 192.1015(a)(2): Excavation Damage; Other Outside Force Damage; Corrosion; Material or Welds; Equipment Failure; Natural Force Damage; Incorrect Operations; and Other. The top-level facilities are defined as main, service, or above-ground facilities. A risk assessment of the distribution system is done through a relative assessment. The relative assessment integrates

[19] *See* PHMSA, Gas Distribution Integrity Management Program: FAQs, Section B: General DIMP Questions, No. B.1.1 "Why did PHMSA mandate integrity management requirements for distribution pipeline systems?" ("The Pipeline Integrity, Protection, Enforcement, and Safety Act of 2006 (PIPES) mandated that PHMSA prescribe minimum standards for integrity management programs for distribution pipelines. The law provided for PHMSA to require operators of distribution pipelines to continually identify and assess risks on their distribution lines, to remediate conditions that present a potential threat to pipeline integrity, and to monitor program effectiveness. Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective …").

several data sets and considers industry data and Company experience to prioritize PAARs.

- Projects and Activities to Address Risk (PAAR): PAARs are intended to address risk above and beyond current regulatory requirements (federal and state), as intended by PHMSA. PAARs are implemented through different avenues, depending on the threat being addressed. A holistic view of the entire pipeline distribution system is used when determining a PAAR and its related funding level. In alignment with PHMSA's intent and recognition that a PAAR needs to be operator-specific, SDG&E develops PAARs that are specific to the SDG&E system.[20] Activities can vary from simple changes (such as changing a drop-down selection in a data acquisition application for the improvement of the data being collected) to staffing (such as the inclusion of damage prevention advisors in the team supporting the DIMP) to entire programs and funding through rate case filings (such as the VIPP). As noted above, PHMSA's stated purpose for the DIMP is to enhance pipeline safety by having operators identify and reduce pipeline integrity risks specifically for distribution pipelines.[21] Since implementing the DIMP, SDG&E has created and completed a number of PAARs to help achieve that objective and in accordance with 49 CFR Part 192, Subpart P, new PAARs will continue to emerge as SDG&E designs and explores prospective PAARs to reduce risks on the gas distribution pipeline system. Costs for prospective PAARs, expected to be developed and implemented during the rate case period to address Distribution risks, are consolidated under Program Management costs and allocated to each PAAR-based tranche and include activities like Cathodic Protection Health Remote Monitoring. PAAR development is a foundational activity under the DIMP and as new PAARs mature, SDG&E will identify them as primary PAARs in rate case filings. While the scope of the primary PAAR is described below, SDG&E continually evaluates and adapts PAARs based on results and program findings to adequately mitigate the risk being addressed.

- The Vintage Integrity Plastic Plan (VIPP) is a multifaceted project based on a foundation of safety and system risk reduction driven by the principles identified in CFR 49 Part 192 Subpart P, the Gas Distribution Integrity Management rule. In this rule an operator must demonstrate a knowledge of their system, identify threats on their system, evaluate and rank risks, and identify and implement measures to address risks. The safety and reliability of SDG&E's distribution system is paramount to the Company's ability to serve customer gas demand. VIPP addresses pipe, weld or joint failure, incorrect operations and natural force damage threats to early vintage plastic mains and services installed from 1969 to

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[20] *Id*.

[21] *Id*. ("PHMSA's regulations in part 192 have contributed to producing an admirable safety record. Nevertheless, incidents continue to occur, some of which involve significant consequences, including death and injury. It is not possible to significantly reduce high consequence pipeline incidents without reducing the likelihood of their occurrence on distribution pipelines.").

1985 manufactured by DuPont with the moniker Aldyl-A. In 2007, PHMSA issued an Advisory Bulletin ADB-07-01,[22] which states that "the number and similarity of plastic pipe accident and non- accident failures indicate past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking for much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s." Further the advisory comments on performing adequate surveillance to identify leaks, having a robust data collection for enhanced knowledge of failures, and performing laboratory testing in circumstances that merit closer instrument analysis, and identifies relatively high localized stress intensification is required for premature cracking. SDG&E has, and continues, to make advances in these areas for early vintage plastic. SDG&E has implemented yearly monitoring through leak survey, enhancing failure reporting, improved failure sample management and laboratory testing, resolved lacking pipeline attribution information, and has incorporated additional factors into risk analytics to better identify premature failures. Leak survey frequency was increased to yearly and are now incorporated into routine surveys as part of Company standard operating practices. SDG&E will continue to make progress in maturing the DREAMS[23]-safety-based risk results, moving from relative risk analysis into quantitative risk analysis, leveraging new factors and knowledge to improve the identification and prioritization of higher-risk pipelines. The aggregation of these efforts illustrates that SDG&E has made and will continue to make considerable progress in the areas PHMSA identified in the advisory bulletin, as well as others, in supporting decisions that are threat based and risk informed.

Starting in 2024, SDG&E plans to target 60 miles of mains and associated services for replacement above and beyond routine replacements in accordance with DIMP regulations, evaluating and prioritizing main replacement based on threat prioritization and risk results. SDG&E anticipates the level of replacement to continue to increase through the authorized period, with increased rates supported by a resource planning team to address operating scalability constraints, both internal and external. Replacement rates will be informed and continually reviewed through monitoring performance and risk benefits attained. SDG&E's long-term strategy will leverage indicators such as leak repair rates, incident rates, and other ongoing efforts to mature the DREAMS quantitative risk results. The knowledge gained will be used to inform risk mitigation options that most efficiently achieve risk targets. Risk targets will be reassessed as advancements in VIPP risk analytics are used to update and drive risk informed decisions – particularly with regard to the prioritization and rate of pipeline replacements. SDG&E forecasts the capital component under Budget Code 277 – Distribution

[22] 72 FR 51301 (September 7, 2007) - "Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe."

[23] In the DIMP, the DREAMS tool is used to prioritize risk mitigation of early vintage pipeline segments, which provides further prioritization for replacement investments based on a leakage root-cause analysis.

Integrity Management Program, which is presented in Section V-B of our testimony.

- GIS: The eGIS houses and maintains pipeline information on all distribution pipelines operating at or below 60 psi and is at the core of all DIMP activities. The HPPD, described in Section IV-A-1, also houses information on high-pressure distribution pipelines operating above 60 psi. The maintenance of these databases, through editing and quality control, must continually reflect changes in the pipeline system based on new construction, replacements, and abandonments for not only DIMP-related projects, but also for all company-wide projects; in order to analyze the entire distribution pipeline system and determine programs and activities needed to address risk, data integrity is imperative. Various tool sets (applications) used within the HPPD and eGIS allow for analysis and a relative risk evaluation of the distribution system. These activities are baseline requirements to adequately maintain the HPPD and eGIS. In contrast, the funding requested by Mr. Rawls (Ex. SDG&E-05) in relation to GIS management is intended to go above and beyond baseline requirements and look for opportunities to integrate these GIS systems with other databases to increase the efficiency of managing pipeline-related records and data analytics.

- Reporting: On an annual basis, relevant integrity data regarding overall program measures is gathered and reported per 49 CFR §§ 192.1007 and 192.1009. The periodic evaluation of performance metrics provides the opportunity to determine whether actions taken to address threats are effective, or whether different actions are needed. An overall decrease in the number and consequences of pipeline incidents is the goal, but it will take many years of accumulating data to determine with confidence that there is a declining trend. The following overall program measures are reported on an annual basis in Form PHMSA F 7100.1-1 Annual Report for Calendar Year (reporting year) Gas Distribution System:

  - Excavation Damages;
  - Leaks Repaired;
  - Number of Hazardous Leaks Repaired; and
  - Mechanical Fitting Failures

2. Description of RAMP Mitigations

All of the DIMP activities are a mitigation measure addressing safety risks identified in the 2021 RAMP Report: Incident Related to the Medium-Pressure System (Excluding Dig-In) chapter.

Table KS-10 below provides the RAMP activities, their respective cost forecasts, and the RSEs for this workpaper. For additional details on these RAMP activities, please refer to our workpapers (Ex. SDG&E-09-WP).

TABLE KS-10
RAMP Activity O&M Forecasts by Workpaper
In 2021 $ ($000)

Workpaper	RAMP ID	Activity	2021 Embedded-Recorded	TY 2024 Estimated	Change	GRC RSE
1TD002.000	SDG&E-Risk-9 - C16 T1	Distribution Integrity Management Program (DIMP)	2,254	2,866	612	0.2
		Sub-Total	**2,254**	**2,866**	**612**	

3. Forecast Method

The forecast method developed for this cost category is base-year recorded with adjustments to account for changes from the base year through forecast years. SDG&E implemented DIMP on August 2, 2011, as mandated by the regulations. Increases in activity such as with DIMP DREAMS plans (e.g., VIPP) and the identification and development of prospective PAARs are all reasons a historical average or linear forecasting method would not be appropriate. The forecast methodology is fundamentally rooted on average unit cost.

4. Cost Drivers

Incidents in the gas industry, such as the failure that occurred in Saint Paul, Minnesota on February 1, 2010, when a contractor cut a natural gas line while attempting to unclog a sewer pipe, causing an explosion and fire, and the explosion that occurred in Cupertino, California on August 31, 2012, when a plastic pipe (Aldyl-A) failed, damaging a condominium,[24] have validated and reinforced the need for Distribution operators to continue investing in PAARs such as the VIPP address risk on an accelerated scale not typically experienced by the industry in decades prior.

The VIPP is the main cost driver for increased cost during this 2024 GRC since the program will continue to ramp-up to address the threat of non-state-of-the-art pipes more

[24] Similar situations have also occurred in the Southern California territory, such as an incident that occurred in Pasadena on November 18, 2018, when a plastic pipe (Aldyl-A) failed, igniting and damaging a home.

vigorously, as recommended in D.19-09-051.[25] The cost drivers behind this forecast include both labor and non-labor components. The cost drivers for labor are the Program Management teams required to provide direction, guidance, and oversight to meet compliance and program requirements, as well as the supplemental contracted non-labor for process improvement, process guidance, and peak activity level support. The cost drivers for the eGIS are based on the activities required to maintain the eGIS, the number of data model changes required to support regulation integration of various databases. The cost drivers for the VIPP and other prospective PAARs is based on the activities required to gather necessary information, integrate and analyze that information, analyze potential mitigation activities, and implement the selected mitigation approach.

C. FIMP

1. Description of Costs and Underlying Activities

The costs associated with implementing a new FIMP promote and support the safety and integrity of the company's facilities, which include compressor stations, renewable natural gas compression facilities, pressure limiting stations and natural gas vehicle fueling stations. The FIMP is based on principles published by the Pipeline Research Council International[26] (PRCI) and Canadian Energy Pipeline Association[27] (CEPA) for pipeline companies. The FIMP differs from other integrity management programs as the type of equipment located within facilities varies substantially (for example, vessels, tanks, piping of different materials/grades, electrical equipment, rotating equipment such as pumps and compressors). The FIMP will include the development and implementation of comprehensive inspection programs for various types of equipment such as fixed equipment. These programs include an American Petroleum Institute (API) 510 pressure vessel inspection program, API 570 piping inspection program, electrical equipment integrity program (based on National Fire Protection Association (NFPA) 70B), and vibration-monitoring rotating equipment programs. The Company will also develop risk models for the various types of facilities equipment to inform preventative or mitigative measures based

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[25] D.19-09-051, p.192

[26] PRCI, Facility Integrity Management Program Guidelines – PRCI IM-2-1, Release Date: December 23, 2013.

[27] CEPA, Facilities Integrity Management Program Recommended Practice, 1st Edition, May 2013

on risk. Under the FIMP, the Company will also enhance data collection and data management activities on its facilities equipment.

The FIMP is expected to begin in 2024 as an incremental safety program. In 2022 and 2023, activities to inform the development of the FIMP will be performed by the Gas Distribution department. Using existing procedures and expertise, these departments will perform select off-cycle inspections with additional measures that align with industry best practices. These pilot projects will be used to develop standardized procedures for the FIMP. Upon the start of the FIMP in 2024, any incremental inspections and remediation as a result of those inspections will be managed by the FIMP organization.

The following initiatives under the FIMP formalize and expand on existing activities which allow for early detection of safety related items:

- Pressure Vessel Integrity Management Program (PV-IMP): To address facility threats such as equipment failure, external and internal corrosion, under FIMP, the company is implementing a comprehensive plan based on API 510 and API RP 572 to manage the integrity of pressure vessels located at its compressor stations, NGV facilities, and other transmission facilities.[28] Under this program, the Company is applying integrity management principles to pressure vessel integrity management by integrating an inventory of its pressure vessels into a Plan Condition Maintenance Software (PCMS), performing baseline inspections, developing policies and procedures to address vessel data management and tracking pre-assessment, assessment and post-assessment processes and projects.

- Aboveground Tank Integrity Management Program (AGT-IMP): For compressor stations, the Company is implementing a systematic and data centric approach to maintain tank integrity under the FIMP to mitigate facility threats such as internal and external corrosion and equipment failure. Currently, inspections are performed to comply with Spill Prevention, Control, and Countermeasure (SPCC) 40 CFR Part 112 requirements. Under the FIMP, the company will collect and verify tank inventory in PCMS for Transmission facilities and formalize a comprehensive approach to tank integrity management by developing policies and procedures to implement a standardized and data centric approach to schedule and perform inspections and track post-inspection projects such as repairs/replacements.

- Material Verification for Transmission Facilities: The Company is engaging in data collection and baseline inspections (positive material identification) for pipe segments under the FIMP for its natural gas containing piping segments within its transmission compressor stations.

[28] Other transmission facilities include, but are not limited to, pressure limiting stations, producer sites, SB 1383 renewable natural gas facilities owned and operated by the company.

- Inspection Workflow Management Tool: This project will develop a work management system to support inspection lifecycle process to enhance coordination, management and tracking of decisions, processes and handoffs between departments. The system will support monitoring of inspections and remediation projects, planning, identification of risks, compliance, and KPI development.
    - *Assessment Planning*: Determine scope for the (annual) assessment cycle of tanks and vessels
    - *Pre-Assessment:* Determine assessment methods and confirm inspection types
    - *Assessment:* Perform inspection; review and document results
    - *Post-Assessment:* Formalize results and deliver to Operations; identify and track remediations
    - *Response to Assessment:* MOC process for remediations requiring non-in-kind repairs/alterations
- Electrical Equipment Integrity Management Program (EEIMP): The Company will develop and implement a new Electrical Equipment Integrity Management program based on NFPA 70B.[29] While electrical equipment is not itself gas carrying equipment, electricity is required to operate certain compressors and other equipment used to detect or control various aspects of gas flow and pressure. To mitigate the risk of equipment failure, under the FIMP, the company is adopting industry best practices including NFPA 70B and ANSI/NETA standards for inspections and maintenance of plant electrical equipment at compressor stations and NGV facilities. In 2021, the Company began data collection to survey and tag electrical equipment for future input into a new database known as PowerDB[30] for inspections and maintenance. The Company plans to procure the new database and launch inspections and maintenance projects at the abovementioned facilities beginning 2022.

SDG&E proposes that these costs be balanced and recorded in a new Facilities Integrity Management Program Balancing Account (FIMPBA), as described in the Regulatory Accounts testimony of Mr. Kupfersmid (Ex. SDG&E-43). Similar to other integrity management balancing accounts, should the balance in the FIMPBA exceed the forecast due to unanticipated activities, such as extensive remediation from inspections or remediation of equipment in an

[29] National Fire Protection Association Recommended Practice for Electrical Equipment Maintenance.

[30] PowerDB is a software package designed to manage test data from electrical equipment maintenance and testing activities.

environmentally sensitive or difficult to access area, increased inspections based on continual threat and risk evaluations, or enhancement of data management practices, recovery of account balances above authorized levels could be requested through an advice letter, as described by Mr. Kupfersmid.

2. Description of RAMP Mitigations

All of the FIMP activities are mitigation measures addressing safety risks identified in the 2021 RAMP Report: Incident Related to the High-Pressure System (Excluding Dig-In) chapter.

Table KS-11 below provides the RAMP activities, their respective cost forecasts, and the RSEs for this workpaper. For additional details on these RAMP activities, please refer to my RAMP workpapers (Ex. SDG&E-09-WP).

TABLE KS-11
RAMP Activity O&M Forecasts by Workpaper
In 2021 $ ($000)

Workpaper	RAMP ID	Activity	2021 Embedded-Recorded	TY 2024 Estimated	Change	GRC RSE
1TD004.000	SDG&E-Risk-3 - NEW 01	NEW - Facility Integrity Management Program (FIMP) - Distribution	0	218	218	20.7
1TD004.000	SDG&E-Risk-3 - NEW 04	NEW - Facility Integrity Management Program (FIMP)- Transmission	0	40	40	37
		Sub-Total	**0**	**258**	**258**	

3. Forecast Method

The forecast method developed for this cost category is zero-based. The FIMP is a new undertaking which applies a systematic approach to managing the company's facilities equipment. Whilst some inspection activities included in the program were performed by other operating organizations, the activities were not organized or integrated under a singular program and cannot be identified or separated from operational costs. Therefore, costs forecasts developed for the program were chosen to be zero-based. Costs from the SoCalGas pilot programs initiated under FIMP beginning in 2019 have been utilized to develop the zero-based forecast.

4. Cost Drivers

The cost drivers behind this forecast include both labor and non-labor components. The cost drivers for labor are driven by the Program Management teams required to provide direction, guidance, and oversight to meet program requirements, as well as supplemental contracted non-labor for process improvement, process and industry best practice guidance, and peak activity level support. In general, the cost drivers are based on the number of inspections, repairs, and mitigation activities to achieve program objectives – namely the adoption of industry recommendations and best practices to enhance the safety and integrity of the company's facilities equipment. While SDG&E has identified facilities and stations as the primary unit for the purposes of tracking activity and evaluating the RSE for FIMP, costs are primarily driven by the number and types of equipment to be inspected.

D. Gas Safety Enhancement Programs

1. Description of Costs and Underlying Activities

Following pipeline incidents that occurred in San Bruno, California and Marshall, Michigan, Congress issued the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act), which contained several mandates to improve pipeline safety.

In 2011, PHMSA issued an Advanced Notice of Proposed Rulemaking (ANPRM) titled "Safety of Gas Transmission and Gathering Pipelines." In March 2018, due to the number of regulatory recommendations and topics, PHMSA announced that they would split the proposed regulations into three categories: Part 1, Part 2, and Part 3.

Part 1 (GTSR Part 1), published in October 2019, included new requirements for MAOP Reconfirmation, Material Properties and Attributes Verification, Analysis of Predicted Failure Pressure, Medium Consequence Areas (MCA), and expanded assessments.

Part 2 (GTSR Part 2), which is expected to be finalized and published in June 2022, includes new requirements for updated repair criteria for non-HCAs, updates to corrosion control requirements, inspection of pipelines following extreme weather events, expansion of Management of Change (MOC) requirements, and strengthening assessment requirements.

Additionally, in December 2020 Congress reauthorized PHMSA's pipeline safety program through a legislative bill called The Protecting Our Infrastructure of Pipelines and

Enhancing Safety (PIPES) Act of 2020.[31] The reauthorization includes congressional mandates based on areas where Congress believes additional oversight, research, or regulation is needed. The PIPES Act approves PHMSA's funding and programs to improve safety and environmental elements of pipelines including strengthening requirements for distribution integrity management programs and mandating the adoption of safety management systems, among other provisions.

The new and impending gas rules and regulations that SDG&E has forecasted and is presented in our testimony include the PHMSA GTSR Parts 1 and 2 and the Valve Rule. While the impacts of the GTSR Part 1 have been assessed and are continually managed and validated by the Integrity Management department and supporting groups, there are requirements stemming from the GTSR Part 2 and Valve rules that will also result in incremental scope and impacts during this GRC period, which are further discussed below in our testimony. Activities and costs associated with the implementation of these three rules are presented in our testimony below and in Section VI, as well as in our workpapers (Ex. SDG&E-09-WP, SDG&E-09-CWP).

a. GTSR Part 1 and the Integrated Safety Enhancement Plan

As introduced in the Pipeline Safety Enhancement Plan testimony of Norm Kohls (Ex. SDG&E-08), SDG&E is proposing an Integrated Safety Enhancement Plan (ISEP) to comply with state and federal transmission pipeline safety regulations. In D.19-09-051, the Commission determined that Phase 2B pipelines must be addressed in the PSEP and required SoCalGas and SDG&E to propose a revised plan for Phase 2B pipeline segments.[32] In the same year, PHMSA published the GTSR Part 1. In addition to the expansion of TIMP activities as described in Section IV-A (e.g., outside-of-HCA assessments, predicted failure pressure analysis, material verification requirements), the GTSR Part 1 also introduced a new federal requirement to reconfirm the MAOP of transmission pipelines that meet the applicability requirements of 49 CFR § 192.624(a).

To comply with both state and federal regulations (PUC § 958 and 49 CFR § 192.624, respectively) and to more efficiently plan, manage, and execute projects for safety, compliance,

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31 H.R. 133 – Consolidated Appropriations Act, 2021; Division R – Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020, available at (https://www.congress.gov/bill/116th-congress/house-bill/133/text/pl?overview=closed).

32 D.19-09-051, Ordering Paragraph 15 at 779-780.

and reliability, SoCalGas proposes in Mr. Kohl's testimony (Ex. SDG&E-08) that the PSEP remain scoped as the authorized Phases 1A, 1B, and 2A, and a new ISEP be authorized to address remaining transmission pipeline segments previously proposed under Phase 2B that have not been authorized.

Based on applicable state and federal requirements, SDG&E reviewed these remaining pipeline segments to determine whether they are in the scope of the ISEP. In addition to the applicability requirements set forth by 49 CFR § 192.624(a), SDG&E considered and prepared responses to the following directives from Ordering Paragraph 15 of D.19-09-051:

a) Identification of all in-service natural gas transmission pipelines (by location and including linear feet and the pipelines' categorization in Class locations 1- 4) that were tested under the American Standards Association (ASA) Code B31.8[33] and for which test records exist (refer to Appendix C of our testimony)

b) Identification of which pipelines for which the Company recommends and does not recommend a re-test and rationale for the recommendations (refer to Appendices B and C of our testimony)

c) Presentation of the pre-1970 ASA Code test records for the pipelines proposed to be re-tested, and direct comparison of the test elements shown in the records to the test elements set out in 49 CFR § 192.619 (refer to Appendix C of our testimony)

d) An evaluation by an independent engineer that the Company's proposed determination of which pipelines to re-test or not to re-test is a reasonable engineering judgement (refer to Appendix D of our testimony)

e) The forecast costs of re-testing (refer to sections IV-E-1-a, VI-E-1-a, and VI-F); and

f) Consistent with the RAMP framework, a complete discussion of the risk-spend efficiency of the dollars proposed to be spent (refer to the testimony of Gregory S. Flores and R. Scott Pearson (Ex. SCG-03/SDG&E-03, Chapter 2) and section II-B of our testimony for more details about RSEs).

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[33] Also referred to as the American Society of Mechanical Engineers B31.8 standard.

SDG&E developed a technical evaluation through an independent engineering firm, the selection of which was shared with the CPUC's Safety Enforcement Division, to assess the necessity of re-testing or replacing pipeline segments proposed previously under PSEP Phase 2B. In compliance with item "d" above, this technical evaluation was reviewed by an independent third-party firm for "reasonable engineering judgment." The technical evaluation was then incorporated into the flow chart presented in Appendix B – *ISEP Scoping Process* which integrates federal requirements and includes a review for traceability, verifiability, and completeness.[34]

Following this flow chart, SDG&E identified approximately 40 miles of transmission pipelines to include in the ISEP, which are further detailed in Appendix C – *Current ISEP Scope*.[35] Based on continuous updates to our database, SDG&E conservatively estimates that approximately 30 miles of transmission pipelines would remain in scope of the ISEP.

On June 23, 2020, shortly after the publication of the GTSR Part 1, FERC issued accounting guidance for pipeline testing costs.[36] In alignment with the FERC accounting guidance, SDG&E plans to capitalize the ISEP costs incurred to reconfirm pipeline MAOP through pressure testing, which are costs incurred for first-time and one-time retesting costs to comply with new federal safety standards.[37] The forecast for the ISEP is based on an assumption that pipeline segments will generally be tested or replaced; however, 49 CFR § 192.624 permits operators to use any of six reconfirmation methods: pressure testing, pressure reduction, engineering critical assessment (ECA), pipe replacement, pressure reduction for pipeline segments with small potential impact radius (PIR), and alternative technology. Final reconfirmation methods for pipeline segments may change subject to a segment- or project-specific evaluation of factors including, but not limited to, safety; constructability; customer, community, and environmental impacts; system reliability; costs.

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34 84 FR 52218-52219 (October 1, 2019).

35 The scope identified is based on data as of February 2022.

36 FERC Accounting Guidance, available at https://www.ferc.gov/sites/default/files/2020-06/AI20-3-000.pdf.

37 FERC Accounting Guidance, p. 2, available athttps://www.ferc.gov/sites/default/files/2020-06/AI20-3-000.pdf.

Capital costs forecasted for the ISEP are further discussed in Section VI-E of our testimony. The O&M costs for the ISEP are based on the expected spend to support activities, such as data and reporting management and training. These activities will be necessary to manage compliance with state and federal requirements, which includes the annual submission of Form PHMSA F 7100.2-1 Annual Report for Calendar Year (reporting year) Natural and Other Gas Transmission and Gathering Pipeline Systems, which was discussed in Section IV-A. The form will include data related to the ISEP, such as the number of system miles that lack sufficient records under the PHMSA definition of traceable, verifiable, and complete,[38] as well as miles that have been reconfirmed via the allowed reconfirmation methods.

The GTSR Part 1 also establishes a set of deadlines for pipeline segments that meet the applicability requirements established in 49 CFR § 192.624(a) – at least 50% of in-scope segments must be reconfirmed by July 3, 2028, while 100% of in-scope segments must be reconfirmed by July 2, 2035 or "as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) … whichever is later."[39] More restrictive than the requirements of PUC § 958 (i.e., "as soon as practicable"), the federal deadlines will challenge SDG&E's ability to manage reconfirmation projects to an annual forecast primarily due to the competing demands of compliance with the 50% and 100% milestones established by PHMSA while balancing SDG&E's obligation to maintain gas system capacity planning to support system reliability. For this reason and reasons described below and in Section VI-E, SDG&E requests authorization to establish a two-way Gas Safety Enhancement Programs Balancing Account (GSEPBA) – as described by Mr. Kupfersmid's testimony of Regulatory Accounts (Ex. SDG&E-43) – to track and recover actual costs incurred to comply with new gas safety regulations. Should the balance in the GSEPBA exceed the forecast due to unanticipated activities or scope, such as the issuance of additional new federal or state regulations, recovery of account balances above authorized levels could be requested through an advice letter, as described by Mr. Kupfersmid.

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[38] 84 FR 52218-52219 (October 1, 2019).

[39] 49 CFR 192.624(b)(2); 84 FR 52247 (October 1, 2019).

b. GTSR Part 2

GTSR Part 2 is expected to be finalized in June 2022 and become effective twelve months later, though this may change pending the final rule language. The GTSR Part 2 NPRM proposed new requirements, further described below, with which SDG&E will need to comply. The regulations in GTSR Part 2 are primarily aimed at managing and mitigating corrosion in gas pipelines, among other safety considerations. New and updated rule sections from GTSR Part 2 are expected to establish additional requirements such as those described below:

- Post-construction surveys to identify coating damage prior to commissioning or following repair/replacement no later than six months after backfilling. Remedial action must be completed within six months following completion of the survey.
- Use of a close interval survey as part of the monitoring, and remediation/ mitigation program to identify and correct deficiencies associated with cathodic protection under Subpart I. Remedial action must be completed within one year following completion of the survey.
- Interference current surveys must be conducted periodically on all pipeline segments near sources of stray current that could reduce the effectiveness of CP. Remedial actions need to be taken within six months of the survey.
- Implement new program to identify potentially corrosive constituents and evaluate effectiveness of the program once each calendar year, not to exceed 15 months.
- Require permanent field repairs on segments in non-HCA areas. The timeline for repairs is based on the type of anomalies found, and includes making [1] immediate repairs, [2] repairs on a two-year timeframe, or [3] on no specified scheduled; however, monitoring of the condition is required as part of ongoing risk and integrity assessments. For immediate repairs, pressure reductions will be required.
- In the event of extreme weather events, operators must inspect facilities to detect conditions that could adversely affect the safe operation of the pipeline. Inspections must be conducted with 72 hours after areas can be safely accessed. Operators must take appropriate remedial action based on the information collected during the inspections.
- Expand MOC process for transmission segments to include those that are currently outside of 49 CFR Part 192, Subpart O.

As the requirements of the GTSR Part 2 are finalized, SDG&E will continue to monitor the final rule language and determine what activities will be impacted. In the meantime, SDG&E has performed a preliminary analysis and the costs presented in workpapers are the minimum incremental costs SDG&E expects to incur in order to comply with the final rule. While most of the GTSR Part 2 incremental costs presented under the GSEP are related to remediation of corrosion-related anomalies, which are further discussed in Section VI-E and presented in Capital workpapers (Ex. SDG&E-09-CWP), SDG&E expects to incur incremental O&M costs driven by engineering and program management activities such as additional surveys, data analysis, data management, materials management, etc. For more detail, refer to our supplemental workpapers (Ex. SDG&E-09-CWP).

SDG&E does not believe there will be significant incremental costs associated with some elements of the GTSR Part 2 since certain activities are already in place and SDG&E expects that the incremental activities for the following requirements will be limited to policy and procedural updates:

- Inspection of Pipelines Following Extreme Weather Events –49 CFR § 192.613
- Expanding Management of Change Procedures – 49 CFR § 192.13, 49 CFR § 192.911
- Internal Corrosion – 49 CFR § 192.478, 49 CFR § 192.927
- Development of SCCDA Procedures must meet NACE SP0204-2008 – 49 CFR § 192.929

As stated before, the GTSR Part 2 has not been published and the activities and costs discussed in our testimony and workpapers are based on a preliminary analysis of draft rule language and are subject to change. Taking the uncertainty of final impacts into consideration, SDG&E believes that a GSEPBA is appropriate for the activities described in this section due to the safety- and compliance-driven nature of the work.

c. Valve Rule

Section 4 of the 2011 Pipeline Safety Act required PHMSA to issue regulations, if appropriate, requiring the use of automatic or remote-controlled shut-off valves (collectively, Rupture Mitigation Valves [RMV]), or equivalent technology, on newly constructed, or replaced natural gas or hazardous liquid pipeline facilities. Beginning in February 2020, PHMSA initiated the Valve Installation and Minimum Rupture Detection Standards rulemaking. The final rule was published in the Federal Register on April 8, 2022[40] and takes effect on October 5, 2022, with some sections taking effect on April 10, 2023.

The Valve Rule requires operators to install RMV on onshore gas transmission pipelines that have nominal diameters greater than or equal to 6 inches in diameter that are either newly constructed, or entirely replaced transmission pipeline segments (defined to be where more than two miles, in the aggregate, or pipeline is replaced within any five contiguous miles within any 24-month period).[41] In addition, the Valve Rule specifies spacing intervals from eight to twenty miles based on class location.[42] PHMSA has also revised the regulations regarding the identification of potential ruptures, notifications to public safety agencies, among other requirements. The final requirements address congressional mandates, incorporate recommendations from the National Transportation Safety Board, and are necessary to reduce the consequences of large-volume, uncontrolled releases of natural gas and hazardous liquid pipeline ruptures.

SDG&E has performed a preliminary analysis of the final rule language and the costs presented in our workpapers are the minimum incremental costs SDG&E expects to incur in order to comply with the final rule.

The Valve Rule will drive additional scope as pipeline projects meeting the applicability requirements will require the installation of RMV above and beyond those installed by SDG&E under the PSEP Valve Enhancement Plan (VEP), which is addressed in Mr. Kohls's testimony of Pipeline Safety Enhancement Plan (Ex. SDG&E-08).

As part of its PSEP filing for Rulemaking 11-02-019, SDG&E submitted the VEP in response to the Commission's direction for the installation of "automated or remote-controlled shut-off valves" in proposed implementation plans.[43] The VEP works in concert with the PSEP to enhance system safety by augmenting existing valve infrastructure to accelerate SDG&E's ability to identify, isolate, and contain escaping gas in the event of a pipeline rupture.

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[40] Valve Installation and Minimum Rupture Detection Standards final rule, available at (https://www.federalregister.gov/documents/2022/04/08/2022-07133/pipeline-safety-requirement-of-valve-installation-and-minimum-rupture-detection-standards).

[41] 87 FR 20983 (April 8, 2022).

[42] 87 FR 20983 (April 8, 2022).

[43] D.11-06-017 at 21, Conclusion of Law 9 at 30, and Ordering Paragraph 8 at 32.

While both the Valve Rule and the VEP aim to accomplish the same objective of identifying and isolating pipelines in the event of a rupture, the VEP preceded the Valve Rule by approximately 10 years and is narrower in scope. The requirements of the Valve Rule and the VEP are summarized in Table KS-12 below.

TABLE KS-12

Valve Rule and PSEP VEP Comparison

	Valve Rule	**PSEP VEP**
Type of Project	New or Replacement	Replacement
OD Threshold	≥6”	≥12”
SMYS Threshold	20%	30% or ≥200 psig
Class Location	Class 3 or 4 OR HCA	Class 3 or 4 OR HCA
Interval	20, 15, 8 Miles, Depending on Class Location	8 Miles

Since the Valve Rule requirements impact additional scope of transmission pipelines, and for the fact that the VEP was not scoped to continue after the completion of the authorized PSEP replacement projects, the VEP alone does not comply with the Valve Rule and SDG&E will incur incremental costs above and beyond those requested under the VEP.

While most of the Valve Rule incremental costs presented under the GSEP are related to valve installations, which are further discussed in Section VI-E and presented in our Capital workpapers (Ex. SDG&E-09-CWP), SDG&E expects to incur incremental O&M costs related to risk analysis, project management, engineering and design, environmental requirements, construction management, and updates to policies and procedures. Other requirements considered include O&M impacts of testing newly installed valves. For more detail, refer to our supplemental workpapers (Ex. SDG&E-09-CWP).

In the event of a rupture, failure, or other incident, the Valve Rule requires investigations of failures and incidents including lessons learned, analysis and post-incident summaries. The costs associated with these activities are difficult to forecast since they are based on the relative size of an incident. In addition, any project scope changes, or new projects not currently forecasted, resulting in an increased number of valves may impact O&M costs related to project management, engineering and design, environmental, and construction management. Taking these challenges of forecasting safety requirements into consideration, including those described in Section VI-E-1, SDG&E believes that a GSEPBA is appropriate for the activities described in this section due to the safety- and compliance-driven nature of the work.

d. PIPES Act of 2020

While additional regulations currently under consideration of the PHMSA have not been forecasted and presented in our testimony and workpapers, it is not speculative that new rules and regulations will continue to impact SDG&E's operations. As discussed earlier in this section, the PIPES Act of 2020 mandates additional safety regulations, research, etc. from PHMSA and current projections indicate many of the new regulations will be published in the next couple of years.[44] These regulations are expected to result in incremental safety and compliance activities which SDG&E must undertake. Without certainty of the details of the final requirements, but with a certainty that new safety and compliance requirements will take effect during the GRC period, SDG&E strongly recommends that a new GSEPBA – as described in Mr. Kupfersmid's testimony of Regulatory Accounts (Ex. SDG&E-43) – be approved so that costs incurred due to compliance with safety regulations can be balanced and recorded.

2. Description of RAMP Mitigations

All of the GTSR implementation activities are mitigation measures addressing safety risks identified in the 2021 RAMP Report: Incident Related to the High-Pressure System (Excluding Dig-In) chapter.

Table KS-13 below provides the RAMP activities, their respective cost forecasts, and the RSEs for this workpaper. For additional details on these RAMP activities, please refer to our RAMP workpapers (Ex. SDG&E-09-WP).

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[44] PHMSA, PIPES Act 2020 Web Chart (April 8, 2022), available at (https://www.phmsa.dot.gov/legislative-mandates/pipes-act-web-chart).

TABLE KS-13
RAMP Activity O&M Forecasts by Workpaper
In 2021$ $ (000s)

Workpaper	RAMP ID	Activity	2021 Embedded-Recorded	TY 2024 Estimated	Change	GRC RSE
1TD005.000	SDG&E-Risk-3 - M02 T1-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA and Non-HCA)	0	90	90	T1 - 5.4 T2 - 7.6
1TD005.000	SDG&E-Risk-3 - NEW 02	NEW - Valve Rule	0	24	24	
1TD005.000	SDG&E-Risk-3 - NEW 03	NEW - Gas Transmission Safety Rule (GTSR) Part 2	0	16	16	
		Sub-Total	**0**	**130**	**130**	

3. Forecast Method

The forecast method developed for this cost category is zero-based because it is a new set of programs without historical costs. Historical data from existing projects was generally used to develop the GSEP O&M forecasts; refer to our supplemental workpapers for additional information (Ex. SDG&E-09-WP, 2TD005.000). Due to the variability described in Section IV-D-1, zero-based forecasting is most appropriate.

4. Cost Drivers

The cost forecast is based on compliance with federal safety regulations and cost drivers include labor and non-labor components. ISEP costs are primarily driven by program management requirements (e.g., reporting, training needs). For the GTSR Part 2, costs are primarily driven by the expected amount of pipeline surveys that will be required as currently indicated by proposed rule language. For the Valve Rule, costs are primarily driven by program management needs (e.g., development of procedures, training). Documentation of these cost drivers are included as supplemental workpapers (Ex. SDG&E-09-WP).

V. CAPITAL

Table KS-14 summarizes the total capital forecasts for 2022, 2023, and 2024.

TABLE KS-14
Capital Expenditures Summary of Costs

GAS INTEGRITY PROGRAMS In 2021$ (000s)				
Categories of Management	**2021 Adjusted-Recorded**	**Estimated 2022**	**Estimated 2023**	**Estimated 2024**
A. TIMP	2,287	21,477	19,173	9,290
B. DIMP	58,260	60,230	64,482	70,534
C. FIMP	0	0	0	145
D. GSEP	0	0	3,221	27,156
Total	**60,547**	**81,707**	**86,876**	**107,125**

A. TIMP (Budget Code 3468)

1. Description of Costs and Underlying Activities

Budget Code 3468 captures all TIMP-related capital costs for pipelines defined as transmission under DOT regulations and operated by the Gas Distribution organization within SDG&E. The forecast for this budget code for 2022, 2023, and 2024 is $21,477,000, $19,172,000, and $9,290,000, respectively.

As previously discussed in Sections I and IV, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risks posed by these threats, assess the physical condition of their pipelines, and take actions, where possible, to address potential threats and integrity concerns before pipeline incidents occur. SDG&E has focused on the ability of assessing pipelines using ILI with approximately 67% of transmission pipelines operated by SDG&E in HCAs, and approximately 67% of the entire transmission system able to accommodate ILI tools as of the end of year 2021. As the TIMP evolves and new pipeline segments are included, SDG&E continues to identify opportunities for expanding ILI assessments.

In general, ILI pipeline assessments – a predominantly O&M activity described in Section IV-A of our testimony – are performed using specialized devices that internally traverse the pipeline to collect information that is used to assess the pipeline condition, though some pipelines were not designed to accommodate these inspection tools. In order to conduct ILI assessments on these pipelines, retrofitting along the pipeline route – a predominantly capital activity – is sometimes necessary to allow sufficient clearance for the tool during inspection. A typical retrofit may include replacing valves with less-restrictive valves that allow inspection devices to traverse internally, insertion of tees with bars, and the change-out of bends and other fittings that may impede the progress of the inspection tool. Costs to retrofit pipeline segments are in addition to the installation of the tool launcher and receiver typically installed near the time of inspection. Once the retrofit is completed, the inspection tool is run, followed by excavations to both validate the inspection findings and determine necessary repairs, if needed. Conversely, SDG&E may elect to alter or replace a pipeline segment if this option is more economically feasible compared to ILI and when construction can be implemented within the mandated TIMP assessment schedule, thereby enabling future ILI assessments. Although the cost of retrofitting or replacing a pipeline to allow for ILI may be higher than alternative assessment methods, the condition information obtained through an ILI is extensive and can greatly facilitate analysis of time-dependent threats such as external and internal corrosion; additionally, new ILI tools continue to become available to operators and provide enhanced data-gathering opportunities.

Once pipelines have been assessed through any of the PHMSA-approved methods, remediation measures are evaluated and may sometimes include the replacement of pipeline segments as detailed in Section IV-A-1 of this testimony. If replacement of pipe is necessary, SDG&E also evaluates the segment to determine if fiber optics cables should be installed. The installation of fiber optics technology allows SDG&E to detect construction activity or other external forces that could damage the pipeline and monitor changes that potentially indicate a leak, rupture, or pipeline movement.

Summarized previously in Section IV-A-1, SDG&E continues to evaluate and implement enhanced TIMP processes and tools to maintain the integrity of the gas transmission pipeline system. Employing ILI tools capable of assessing cracks and crack-like features (e.g., CMFL) are an added value to the TIMP and may result in additional retrofitting when pipeline segments that were not previously ILI-capable, or were ILI-capable but not compatible with crack detection tools, are considered potential candidates for cracking risks. Costs presented in our workpapers (Ex. SDG&E-09-CWP) for the TIMP also include a forecast of expected impacts from the GTSR Part 2 Final Rule based on a preliminary analysis of proposed rule language. The rule, while not yet published, is expected to take effect in 2023 and will add additional clarifications and enhancements to existing requirements related to integrity assessments, such as changes to repair criteria for certain transmission lines in non-HCAs in a manner similar to what is currently established in 49 CFR § 192.933. Like with the HCA repairs, actual capital costs related to repair criteria for non-HCA transmission lines would be driven by pipeline assessments and findings.

The forecasted TIMP capital expenditures support the Company's core goals of providing safe, clean, and reliable service at reasonable rates. Through the TIMP, SDG&E continually evaluates the transmission pipeline system and acts through inspections, replacements, and other remediation activities to improve the safety and reliability of the system. Actual TIMP capital costs will be balanced and recorded in the TIMPBA, as described by Mr. Kupfersmid's testimony of Regulatory Accounts (Ex. SDG&E-43).

2. Description of RAMP Mitigations

All of the TIMP activities are a mitigation measure addressing safety risks identified in the 2021 RAMP Report: Incident Related to the High-Pressure System (Excluding Dig-In) chapter.

As stated in Section IV-A, though SDG&E has identified separate tranches of activity within the TIMP, costs should be reviewed and authorized at the workpaper level since the activities presented in our testimony and workpapers are compliance-driven and must be completed as planned.

Table KS-15 below provides the RAMP activities, their respective cost forecasts, and the RSEs for this workpaper. For additional details on these RAMP activities, please refer to our workpapers (Ex. SDG&E-09-CWP).

TABLE KS-15
RAMP Activity Capital Forecasts by Workpaper
In 2021$ (000s)

Workpaper	RAMP ID	Activity	2022 Estimated RAMP Total	2023 Estimated RAMP Total	2024 Estimated RAMP Total	GRC RSE
034680.001	SDG&E-Risk-3 - C15 & M3 T1-T2	Integrity Assessments & Remediation (HCA and Non-HCA)	21,477	19,172	9,290	T1 – 19.8 T2 – 9.2
		Sub-Total	**21,477**	**19,172**	**9,290**	

3. Forecast Method

The forecast method developed for this cost category is base-year recorded. The base-year recorded method is most appropriate because the costs directly correlate to the number of assessments conducted each year, which varies from year to year. Results from assessments, coupled with the regulatory requirements for reassessment intervals, establish the reassessment plan (timeline) for pipelines, which cannot be extended.[45] Construction cost estimates are based on experience gained working on projects of similar scope in similar settings. The forecast methodology is fundamentally rooted in average remediation assumptions and costs and adjustments to the recorded base year cost is the most accurate representation.

4. Cost Drivers

The primary underlying cost drivers for Budget Code 3468 relate to the number of required assessments and resulting activities as described in Section V-A-1; retrofitting of pipelines, repairs, and replacements all drive capital costs. Additionally, while PHMSA has not yet published the GTSR Part 2 at the time of filing, it is expected to take effect no later than 2023 and impacts of the proposed language have been preliminarily assessed and incorporated into the TIMP forecasted costs. Based on an analysis of the proposed language, SDG&E expects and has forecasted an increase in remediation activities on pipeline segments in areas outside of HCAs. However, changes in the final language or actual findings of pipeline assessments may result in

[45] *See* 49 CFR § 192.939(a) (establishing express requirements for determining the reassessment interval for covered pipelines, and stipulating that "the maximum reassessment interval by an allowable reassessment method is 7 calendar-years.").

additional costs. As stated in Section IV-A-3, the TIMPBA will allow SDG&E to balance and recover actual incremental compliance costs resulting from the GTSR Part 2 regulation.

B. DIMP (Budget Code 9546)

1. Description of Costs and Underlying Activities

Budget Code 9546 captures the capital costs related to DIMP that may be incurred as a result of PAARs and other activities. The forecast for this budget code for 2022, 2023, and 2024 is $60,230,000, $64,482,000, and $70,534,000, respectively.

As previously discussed, operators of gas distribution pipelines are required to identify, evaluate, risk rank, and mitigate the threats to their pipelines. This forecast is based on the recommendation to replace identified system components at an accelerated rate. The DREAMS-driven main and service replacement plan, VIPP, represents activity that is incremental to routine replacement work and is required to maintain system integrity. These replacements are a primary activity driving capital forecasts and were discussed in Section IV-B of our testimony. As discussed in Section IV-B, the rate of VIPP replacements will be increased based on current quantitative risk results.

These forecasted capital expenditures support the Company's goals of providing safe, clean, and reliable service at reasonable rates. Actual DIMP-related capital costs will be balanced and recorded in the Post-2011 DIMPBA, as described by Mr. Kupfersmid's testimony of Regulatory Accounts (Ex. SDG&E-43). Specific details regarding Budget Code 277 and Budget Code 756 may be found in our capital workpapers, Ex. SDG&E-09-CWP.

2. Description of RAMP Mitigations

All of the DIMP activities are mitigation measures addressing safety risks identified in the 2021 RAMP Report: Incident Related to the Medium-Pressure System (Excluding Dig-In) chapter.

Table KS-16 below provides the RAMP activities, their respective cost forecasts, and the RSEs for this workpaper. For additional details on these RAMP activities, please refer to our workpapers (Ex. SDG&E-09-CWP).

TABLE KS-16
RAMP Activity Capital Forecasts by Workpaper
In 2021 $ ($000)

Workpaper	RAMP ID	Activity	2022 Estimated RAMP Total	2023 Estimated RAMP Total	2024 Estimated RAMP Total	GRC RSE
095460.001	SDG&E-Risk-9 - C16 T1	Distribution Integrity Management Program (DIMP)	60,230	64,482	70,534	0.2
		Sub-Total	**60,230**	**64,482**	**70,534**	

3. Forecast Method

The forecast method developed for this cost category is base-year recorded since the primary driver for cost are activities, projects, or programs that may change or be completed from year to year. Construction cost estimates are based on experience gained working on projects of similar scope in similar settings. DIMP forecasts also consider development of prospective PAARs that might not have existed in previous years. The forecast methodology is fundamentally rooted on average unit cost and adjustments to the recorded base year cost is the most accurate representation.

4. Cost Drivers

The cost drivers behind this forecast include both a labor and non-labor component. The cost drivers for the labor component include the Program Management Teams required to provide direction, guidance, and oversight to meet compliance and program requirements, as well as the supplemental contracting non-labor for process improvement, process guidance, and peak activity level support. The underlying cost drivers for the non-labor component relate to the miles of mains and number of services targeted for replacement. Documentation of these cost drivers is provided in our capital workpapers, Ex. SDG&E-09-CWP. The VIPP is the main cost driver for the increased cost during this 2024 GRC since the program will continue to ramp-up to address the threat of non-state-of-the-art pipe more expeditiously, as recommended by the CPUC in D.21-05-003.

C. FIMP (Budget Code 21478)

1. Description of Costs and Underlying Activities

Activities and costs presented in Budget Code 21478 relate to remediation of conditions found through the incremental inspections performed on facility equipment for Distribution and Transmission. The forecast for Budget Code 21478 for 2024 is $145,000.

The inspections are safety-driven and reinspection cycles will be based on industry recommendations and threat evaluation. Capital forecasts associated with FIMP include upgrades of fixed and electrical equipment as a result of conditions found during integrity inspections. Examples of remediation activities that can reduce the risk of failure include replacement of internal coating of tanks and vessels.

Like with TIMP, remediations and associated costs resulting from inspections will vary from equipment to equipment. Therefore, a two-way balancing account is appropriate for the FIMP. We propose that actual FIMP-related capital costs be balanced and recorded in a FIMPBA, as described by Mr. Kupfersmid's testimony of Regulatory Accounts (Ex. SDG&E-43). Specific details regarding Budget Codes 240, 370, and 460 may be found in our capital workpapers, Ex. SDG&E-09-CWP.

2. Description of RAMP Mitigations

All of the FIMP activities are mitigation measures addressing safety risks identified in the 2021 RAMP Report: Incident Related to the High-Pressure System (Excluding Dig-In).

Table KS-17 below provides the RAMP activities, their respective cost forecasts, and the RSEs for this workpaper. For additional details on these RAMP activities, please refer to our workpapers (Ex. SDG&E-09-CWP).

TABLE KS-17
RAMP Activity Capital Forecasts by Workpaper
In 2021 $ ($000)

Workpaper	RAMP ID	Activity	2022 Estimated RAMP Total	2023 Estimated RAMP Total	2024 Estimated RAMP Total	GRC RSE
214780.001	SDG&E-Risk-3 - NEW 01	NEW - Facility Integrity Management (FIMP)-Distribution	0	0	100	20.7
214780.002	SDG&E-Risk-3 - NEW 04	NEW - Facility Integrity Management (FIMP)-Transmission	0	0	45	37
		Sub-Total	**0**	**0**	**145**	

3. Forecast Method

The forecast method developed for this cost category is zero-based because it is a new program without historical costs. Informed by the pilot projects conducted by SoCalGas, an average cost per unit approach was used to develop the FIMP forecast. Due to the variability described above, zero-based forecasting is most appropriate.

4. Cost Drivers

Capital costs associated with the remediation activities are expected to be variable but dependent on the nature or type of equipment and the number of O&M inspections and testing completed. As the program matures, these costs will be tracked for development of future forecasts. More detail can be found in our supplemental workpapers (Ex. SDG&E-09-CWP).

D. Gas Safety Enhancement Programs (Budget Code 21477)

1. Description of Costs and Underlying Activities

Activities and costs presented in Budget Code 367 consist of those forecasted for compliance with Parts 1 and 2 of the GTSR, as well as the Valve Rule. The forecast for Budget Code 367 for 2022, 2023, and 2024 is $6,936,000, $48,340,000, and $108,588,000, respectively.

a. GTSR Part 1 and the ISEP

As discussed in Section IV-E-1, SDG&E is proposing to manage both federal regulation requirements (GTSR Part 1 [specifically MAOP reconfirmation]) and state requirements (PSEP Phase 2B) under an overarching Integrated Safety Enhancement Plan (ISEP) to plan, manage, and execute projects for safety, compliance, and reliability more efficiently. The capital forecast for the ISEP was developed using the information and assumptions presented in our supplemental workpapers (Ex. SDG&E-09-CWP) and is primarily driven by the July 3, 2028 deadline to complete at least 50% of scope that meets the applicability requirements (49 CFR § 192.624(b)(1)) established by PHMSA. It is important to note that the federal timeline to complete reconfirmation increases the scope of work SDG&E must complete over the next 15 or more years; whereas PUC § 958 requires operators to complete pipeline retesting and replacement "as soon as practicable." In addition, 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."[46] For this reason, SDG&E anticipates an increase to both internal and external resources (e.g., labor, materials) to support the implementation and continued compliance of the ISEP in parallel to the previously authorized phases (Phase 1A, 2A, and 1B) of the PSEP.

As stated in Section IV-D of our testimony, SDG&E plans to capitalize costs incurred to reconfirm pipeline MAOP through pressure testing in accordance with FERC's accounting guidance issued on June 23, 2020,[47] which determined that first-time and one-time retesting costs to comply with new federal safety standards can be capitalized.[48] The capital forecast assumes that projects will generally be tested or replaced, like with the PSEP, and applies the FERC accounting guidance to the pressure test projects. However, the final reconfirmation method – as stated in Section IV-E – may change during project planning due to a myriad of considerations; should other PHMSA-allowable methods such as pressure reductions, engineering critical assessments, or alternative technologies be viable options, costs may decrease on a project-by-project basis and would no longer be capitalized.

Due to the high variability of year-to-year project planning to both comply with the federal deadlines and balance system planning constraints to support gas system reliability, as well as the possibility for reconfirmation methodologies to change for selected ISEP projects, SDG&E requests authorization of a two-way balancing account (i.e., GSEPBA) as proposed in Section IV-E of our testimony and in Mr. Kupfersmid's testimony of Regulatory Accounts (Ex. SDG&E-43).

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[46] 49 CFR 192.624(b)(2); 84 FR 52247 (October 1, 2019).

[47] FERC Accounting Guidance.

[48] FERC Accounting Guidance, p. 2.

b. GTSR Part 2

As stated in Section IV-E-1, most of the costs associated with incremental GTSR Part 2 activities are expected to be Capital costs. While the incremental costs associated with updated repair criteria for non-HCA transmission segments have been discussed and presented under the TIMP, incremental costs for corrosion-related requirements are presented under the GSEP and discussed below.

Corrosion control costs will be driven by mitigation activities informed by various surveys. These repairs are expected to expand capital activities due to the proposed requirements of remediating issues found during additional surveys such as:

- Remediation of severe coating damage found in post-construction surveys on transmission lines, which could involve digging around the pipeline and recoating where specific damage is found;
- Remediation of deficiencies in cathodic protection under 49 CFR Part 192, Subpart I; and
- Implementation of an interference survey program to discover and remediate foreign currents which reduce CP effectiveness. The remediation of foreign currents would be performed on a custom basis dependent on pipeline configurations and changing environmental factors.

Forecasted costs include overall program management, project management, engineering and design, environmental, and construction management activities of company employees to implement requirements for newly defined anomaly criteria, as well as contracted labor, permitting, overheads, and materials. Historical costs from current remediation projects have been used to estimate expected capital activities and more detail can be found in our supplemental workpapers (Ex. SDG&E-09-CWP).

Aside from the rule language not having been finalized, there is an inherent challenge associated with estimating the costs of corrosion survey related repairs like with forecasting remediation costs for the TIMP. Remediation of corrosion issues will be performed on a project-to-project basis and remediation is based on what is discovered during pipeline surveys. The cost to remediate will also vary based on class locations, physical locations, and situational elements such as, permitting, and the need for specialists (e.g., biologist, archeologists, animal control). As such, a two-way balancing account (i.e., the GSEPBA) would enable SDG&E to recover actual compliance costs above and beyond the preliminary forecast through the cost recovery mechanism described by Mr. Kupfersmid's testimony of Regulatory Accounts (Ex. SDG&E-43).

c. Valve Rule

As discussed in Section IV-E-1, the Valve Rule is a newly issued rule and most of the impacts are expected to be capital costs. The forecasted costs were developed based on a preliminary analysis of the requirements as issued on March 31, 2022, and implementation is expected to evolve as SDG&E evaluates scope impacts to pipeline construction projects.

The elements that are included in the estimated costs are valves, sensors, communications equipment, and labor associated with incremental valve installations. The installation costs of RMV installations from previous PSEP valve projects were used to estimate capital costs of valve installations and more detail can be found in our supplemental workpapers (Ex. SDG&E-09-CWP). As explained in Section IV-E-1 of our testimony, the Valve Rule will drive additional scope beyond SDG&E's PSEP VEP.

With the Valve Rule recently issued, SDG&E is still in the process of evaluating the impacts of the requirements and anticipates that activities and costs could change – potentially significantly – from the preliminary cost forecasts presented in our testimony and workpapers. Additionally, a requirement that creates a challenge in forecasting costs for the GRC period is the requirement that operators must perform risk analyses and assessments on in-scope pipelines prior to placing them back into service. Based on these analyses, as well as consideration for additional factors such as consequence areas and class locations, additional RMVs may need to be installed to provide added protections for pipelines in HCAs. Scope changes on forecasted projects may also trigger the need to adjust the total number of valves installed. As such, a two-way balancing account (i.e., the GSEPBA) would enable SDG&E to recover actual compliance costs above and beyond the preliminary forecast through the cost recovery mechanism described by Mr. Kupfersmid's testimony of Regulatory Accounts (Ex. SDG&E-43).

d. PIPES Act of 2020

Lastly, impacts of new impending regulations such as those stemming from the PIPES Act of 2020 cannot be fully evaluated and understood at this time but are expected to substantially influence cost variability in the GRC period. Therefore, a two-way balancing account is appropriate for the projected GSEP implementation activities, as well as implementation of future gas rules and regulations. We propose that actual GSEP capital costs be balanced and recorded in a GSEPBA, as described by Mr. Kupfersmid's testimony of Regulatory Accounts (Ex. SDG&E-43).

2. Description of RAMP Mitigations

All of the GTSR implementation activities are mitigation measures addressing safety risks identified in the 2021 RAMP Report: Incident Related to the High-Pressure System (Excluding Dig-In) chapter.

Table KS-18 below provides the RAMP activities, their respective cost forecasts, and the RSEs for this workpaper. For additional details on these RAMP activities, please refer to our workpapers (Ex. SDG&E-09-CWP).

TABLE KS-18
RAMP Activity Capital Forecasts by Workpaper
In 2021 $ (000s)

Workpaper	RAMP ID	Activity	2022 Estimated RAMP Total	2023 Estimated RAMP Total	2024 Estimated RAMP Total	GRC RSE
214770.001	SDG&E-Risk-3 - M02 T1-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA and Non-HCA)	0	2,343	26,361	T1 - 5.4 T2 - 7.6
214770.003	SDG&E-Risk-3 - NEW	NEW - Gas Transmission Safety Rule (GTSR) Part 2	0	265	333	
214770.005	SDG&E-Risk-3 - NEW	NEW - Valve Rule	0	613	462	
		Sub-Total	**0**	**3,221**	**27,156**	

3. Forecast Method

The forecast method developed for this cost category is zero-based because it is a new program without historical costs. Using historical data from existing hydrotesting projects, survey remediation projects, and valve installation projects, an average cost per unit approach was generally used to develop the ISEP, GTSR Part 2, and Valve Rule forecasts. Due to the variability described above, zero-based forecasting is most appropriate.

4. Cost Drivers

The underlying cost drivers for Budget Code 21477 are the requirements of federal safety regulations as discussed in Section V-D-1. For the ISEP, costs are primarily driven by the number of projects and miles that must be completed to comply with federal and state regulations and, as discussed previously, the timeline by when pipeline segments must be reconfirmed. Forecasted costs to implement GTSR Part 2 are primarily driven by the amount of pipelines SDG&E believes will be affected by the corrosion management requirements, but are subject to change based on the final language that is expected to be published in June of 2022. Lastly, costs to implement the Valve Rule are driven by the number of valves SDG&E anticipates installing based on expected future projects. Documentation of these cost drivers are included as supplemental workpapers (Ex. SDG&E-09-CWP).

E. Post-Test Year Forecasts

In support of the revenue requirement requested in the Post-Test Year Ratemaking testimony of Melanie Hancock (Ex. SDG&E-45), SDG&E has prepared capital cost forecasts for each of the programs listed below in Table KS-19 for the years of 2025-2027. These cost forecasts have been developed leveraging the information and assumptions explained in the sections above that were used to develop the 2022-2024 forecasts and are reflective of the anticipated levels of activity in these post-test years.

TABLE KS-19
Gas Integrity Management Programs – Capital Expenditures Post-Test Year Forecast
Direct Costs in 2021 $ (000's)

	2025	2026	2027
TIMP	$7,575	$8,170	$5,992
DIMP	$76,722	$86,096	$90,050
FIMP	$145	$145	$145
GSEP	$32,805	$26,393	$21,618

VI. CONCLUSION

The funding requested for the Gas Integrity Management Programs is reasonable to support the activities that are intended to meet federal and state requirements as described within our testimony and should be adopted by the Commission.

SDG&E's TIMP and DIMP were established, and continue to evolve, in accordance with PHMSA's 49 CFR Part 192. Both programs were designed to continually identify and assess risks, remediate conditions that present a potential threat to pipeline integrity, monitor program effectiveness, and promote safety and reliability to its customers.

Similarly, SDG&E's implementation plans for GTSR Parts 1 and 2 and the Valve Rule are compliance initiatives that are required by PHMSA to increase the safety of transmission pipelines. SDG&E will implement an ISEP to reconfirm pipelines not already authorized under the PSEP, install valves and respond to leak detection as required by the Valve Rule, and plan and implement processes and programs to comply with GTSR Part 2 upon publication.

Lastly, the company's adoption of industry best practices with the FIMP demonstrates its commitment to protect the health and safety of the public, its employees, and the environment. As FIMP continues to grow and evolve, implementation of proven integrity, reliability and data management practices will enhance the safety and integrity of the company's facilities.

This concludes our prepared direct testimony.

VII. WITNESS QUALIFICATIONS

AMY KITSON

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

I graduated from California State University Northridge in 2009 with a Master of Science degree in Engineering Management and from Michigan State University in 2003 with a Bachelor of Science degree in Mechanical Engineering.

I joined SoCalGas in 2005 as an engineer in the Gas Operations organization supporting the Transmission Integrity Management Program. Since that time, I have held numerous positions with increasing levels of responsibility including Project Manager, Technical Services Manager, Storage Engineering Manager, Risk Assessment & Controls Manager, and Director of Storage Risk Management within Storage Operations. I currently hold the position of Director of Integrity Management and Strategic Planning. In this position, my responsibilities include overseeing the Storage Integrity Management Program, Facilities Integrity Management Program for SoCalGas, and risk strategy for Gas Integrity Management Programs.

Prior to joining SoCalGas, I worked at Consumers Energy in Michigan. There, I held several positions including Mechanical Engineer, Employee Development Coordinator, and Engineering Team Leader.

I have previously testified before the Commission.

TRAVIS SERA

My name is Travis Sera. I am employed by SoCalGas as the current 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 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 National Association of Corrosion Engineers (NACE).

I have previously testified before the Commission.

APPENDIX A

GLOSSARY OF TERMS

APPENDIX A

GLOSSARY OF TERMS

ACRONYM	**DEFINITION**
ASA Code	American Standards Association B31.8 Standard
ASME	American Society of Mechanical Engineers
ASV	Automatic Shut-Off Valve
CARB	California Air Resources Board
CP	Cathodic Protection
DOT	Department of Transportation
DIMP	Distribution Integrity Management Program
DIMPBA	Distribution Integrity Management Program Balancing Account
DREAMS	Distribution Risk Evaluation and Monitoring System
ECA	Engineering Critical Assessment
ECDA	External Corrosion Direct Assessment
eGIS	Enterprise GIS
FIMP	Facilities Integrity Management Program
GSEP	Gas Safety Enhancement Programs
GSEPBA	Gas Safety Enhancement Programs Balancing Account
GTSR	Gas Transmission Safety Rule
HCA	High Consequence Areas
HPPD	High-Pressure Pipeline Database
ICDA	Internal Corrosion Direct Assessment
ILI	In-line inspection
ISEP	Integrated Safety Enhancement Plan
LDIW	Low Ductile Inner Wall
MFL	Magnetic Flux Leakage
MAOP	Maximum Allowable Operating Pressure
MOC	Management of Change
NGV	Natural Gas Vehicle
PAAR	Projects and Activities to Address Risk
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act of 2020	Pipeline Integrity, Protection, Enforcement and Safety Act of 2020
PIR	Potential Impact Radius
RCV	Remote-Controlled Valve
RDMS	Record Document Management System
RMV	Rupture Mitigation Valve
RNG	Renewable Natural Gas
SED	CPUC's Safety Enforcement Division
TIMP	Transmission Integrity Management Program

ACRONYM	DEFINITION
UT	Ultrasonic Testing
VIPP	The Vintage Integrity Plastic Plan

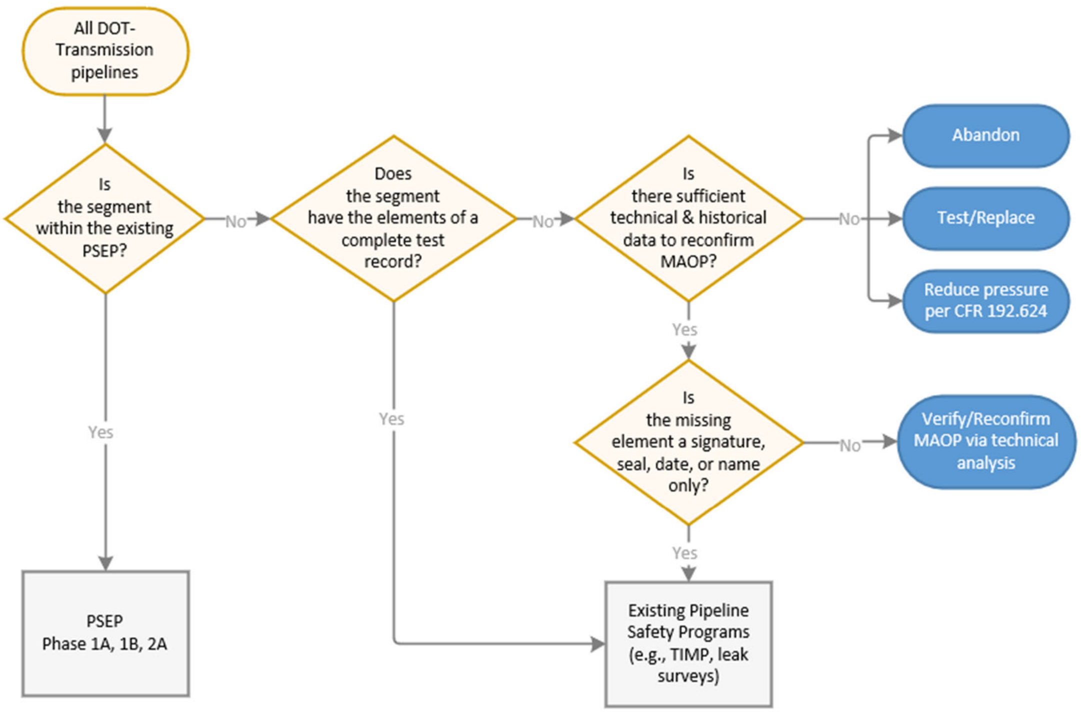
APPENDIX B

ISEP SCOPING PROCESS

APPENDIX B

ISEP SCOPING PROCESS

In response to Ordering Paragraph 15 of D.19-09-051 and federal requirements, the below flowchart presents the rationale for the identification of pipelines for which SDG&E recommends and does not recommend a re-test:



APPENDIX C

CURRENT ISEP SCOPE

APPENDIX C

CURRENT ISEP SCOPE

Appendix C addresses the following directives of Ordering Paragraph 15 of D.19-09-051:

- Identification of all in-service natural gas transmission pipelines (by location and including linear feet and the pipelines' categorization in Class locations 1- 4) that were tested under the ASA Code and for which test records exist (Table KS-APP-1)

- Identification of pipelines for which the Company recommends and does not recommend a re-test (Table KS-APP-2)

- Presentation of the pre-1970 ASA Code test records for the pipelines proposed to be re-tested, and direct comparison of the test elements shown in the records to the test elements set out in 49 CFR 192.619 (Table KS-APP-3)

TABLE KS-APP-1
SDG&E Transmission Pipelines with ASA Code Pressure Test

Class Location	**Linear Feet** *(rounded to nearest whole ft.)*	**Miles** *(rounded to nearest whole mi.)*
CLASS 1	93,917	18
CLASS 2	47,462	9
CLASS 3	574,914	109
CLASS 4	22,364	4
Grand Total	**738,657**	**140**

As discussed in Section IV-E of our testimony, SDG&E is proposing the ISEP in place of a PSEP Phase 2B and Table KS-APP-2 summarizes the scope of the ISEP, which integrates federal requirements. Refer to Appendix B – *ISEP Scoping Process* for how the scope was determined.

TABLE KS-APP-2
Proposed ISEP Scope[49]

Class Location	**Linear Feet** *(rounded to nearest whole ft.)*	**Miles** *(rounded to nearest whole mi.)*
Reconfirmation Recommended	188,123	36
Reconfirmation Not Recommended	-	-

49 The proposed ISEP was scoped as described in Section IV-E and VI-E of our testimony; the scope incorporates state and federal requirements and is not limited by test vintage.

TABLE KS-APP-3
ISEP Pre-1970[50] Scope with Pressure Test Record Elements

	Linear Feet *(rounded to nearest whole ft.)*	**Miles** *(rounded to nearest whole mi.)*	**Percentage of Total Pre-1970 Scope**
TOTAL SCOPE	**180,740**	**34**	**100%**
Test Record Elements Captured:			
TEST PRESSURE*	163,546	31	90%
TEST DURATION	153,368	29	85%
COMPANYNAME	180,740	34	100%
OPERATOR EMPLOYEE/SIGNED	57,836	11	32%
TEST COMPANY	83,323	16	46%
TEST MEDIUM*	163,546	31	90%
CHART	74,459	14	41%
ELEVATION VARIATIONS**	15,126	3	8%

**Test Pressure and Test Medium were recordkeeping elements required by the ASA Code; all others are additionally required by 49 CFR Part 192, Subpart J*
***Elevation variation only noted if significant for the particular test (49 § CFR 192.517[a][6])*

[50] Pipeline segments with pre-1970 ASA Code pressure tests.

APPENDIX D

INDEPENDENT ENGINEER EVALUATION

A. RCP Evaluation

B. RSI Pipeline Solutions Comments in Response to RCP's Evaluation

APPENDIX D
INDEPENDENT ENGINEER EVALUATION

A. RCP Evaluation

RCP

Professional Engineers. Regulatory Experts. Trusted Partners.

Southern California Gas Company®

A Sempra Energy℠ company

Phase 2B Decision Tree Assessment

June 7, 2021

Table of Contents

Background

The California Public Utility Commission (CPUC) has issued an order to Southern California Gas Company (herein SoCal) and other gas utility companies over which they have jurisdiction to ensure all natural gas transmission pipelines have a recorded pressure test to substantiate their Maximum Allowable Operating Pressure (MAOP) as established under 49 CFR 192.619(a). That order is further codified in §958 of the California Public Utility Code, requiring all intrastate natural gas transmission pipelines to either pressure test those lines or to replace all segments of intrastate transmission lines that were not pressure tested or that lack sufficient details related to performance of pressure testing.

In Decision 19-09-051 (the 2019 General Rate Case Decision), the CPUC determined that SoCal's Phase 2B pipelines must be addressed in SoCal's Pipeline Safety Enhancement Plan (PSEP) and required SoCal to include an assessment and remediation plan for Phase 2B pipeline segments in its next General Rate Case (GRC) application. The 2019 GRC Decision further required that SoCal obtain an evaluation by an independent engineer that SoCal's proposed assessment and remediation plan is a reasonable engineering judgement.

SoCal has developed a decision tree that includes an alternative integrity management approach for certain Phase 2B pipeline segments, in addition to pressure testing and replacement. SoCal has engaged RCP (Chris Foley and Trang Pham) to perform an independent engineering evaluation as required within the 2019 GRC Decision.

Executive Summary

RCP was engaged by SoCal to evaluate a decision tree that was developed to comply with the 2019 GRC Decision for their Phase 2B pipeline segments (approximately 1,129 miles). The decision tree includes three alternative options to evaluate a segment's integrity in lieu of pressure testing or replacement. The alternative integrity management options outlined in the decision tree include pathways for Non-Destructive Examination (NDE), In Line Inspection (ILI), or evidence of a past Spike Pressure Test (SPT) meeting criteria outlined in a report (TTO-6[1]) sanctioned by the Office of Pipeline Safety in 2004. These decision pathways take an alternative integrity management approach to pressure testing or replacement which are commonly performed today as accepted pipeline integrity assessment methods to address specific threats to a pipeline.

The result of the evaluation of the proposed Decision Tree is that these methods are generally reasonable alternatives to testing or replacement, given the pathways depicted in the decision tree, with additional clarification and edits. It is important to note that once a segment is assessed with these alternative integrity management options, the captured data must be thoroughly analyzed through a detailed engineering assessment to identify any critical anomalies that threaten the continued safe operation of the segment and remediate those anomalies in accordance with SoCal gas transmission integrity management plan requirements. Following that effort, the segment is removed from PSEP scope and returned

[1] Technical Task Order Number 6 (TTO 6) "Spike Hydrostatic Test Evaluation", July 16, 2004

to regular regulatory compliance processes, which include continued integrity management, inspection, assessment and remediation, as needed.

Decision Tree Analysis

RCP reviewed all pathways in which a Phase 2B segment could navigate through the decision tree and reviewed observations with SoCal pipeline integrity personnel. There are several factors that determine whether a Phase 2B segment must be pressure tested, replaced or eligible for the alternative integrity management approach. If required information is unavailable, the more conservative choice (ex. E<1.0, TPR<1.25, t<8, etc.) should be made at any decision point that requires the missing information. These factors include:

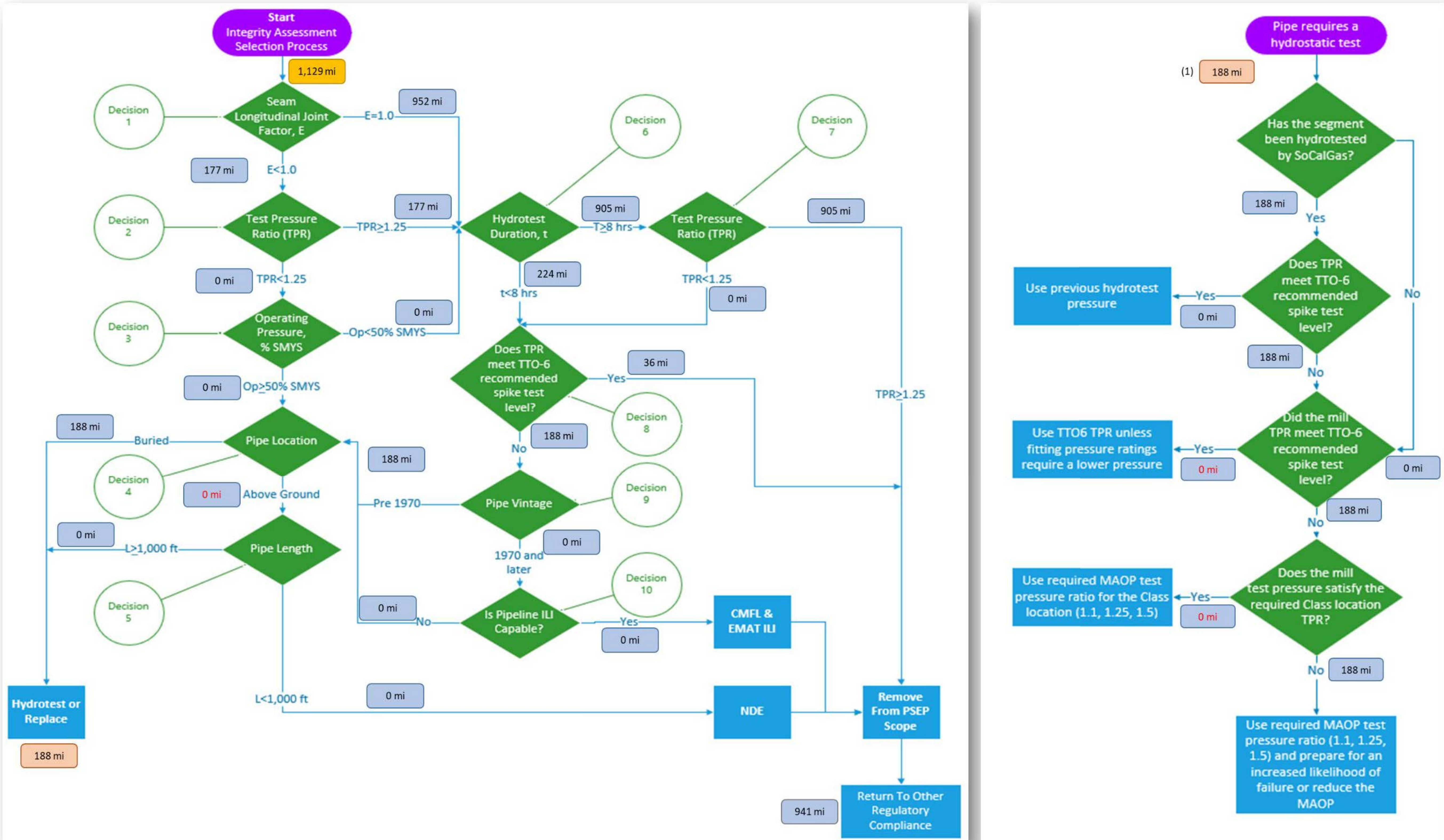
- longitudinal seam factor (E);
- hydrostatic test pressure divided by maximum allowable operating pressure (test pressure ratio, TPR);
- maximum operating pressure as a percent of specified minimum yield strength (%SMYS);
- pressure test duration (t);
- whether a prior spike pressure test (pipe manufacture, new construction or subsequent pressure test) meets the recommendation of TTO-6;
- segment vintage (i.e., installation date before or after 1970);
- whether the segment is buried or located above ground;
- segment length (feet); and
- whether the segment is capable of passage of an ILI tool.

SoCal supplied a pipeline data set[2] that included the Phase 2B segment inventory. The data set included certain fields that would allow RCP to evaluate which pathway each segment could navigate to determine which method (test, replace, NDE, ILI, spike test meeting TT0-6 criteria) was possible for removal from the PSEP scope.

Figure 1 depicts the number of miles of applicable pipeline mileage that navigates through the decision tree nodes. According to the data set provided by SoCal, there are 1,129 miles that start at the beginning of the Phase 2B decision tree. There are 905 miles that meet 49 CFR 192 Subpart J Pressure Test requirements (i.e., TPR>1.25 and t>8 hours) and should be eligible for removal from PSEP scope. There are 36 miles that would be eligible for removal from PSEP scope due to meeting the spike pressure test criteria in TT0-6[3]. Based upon the data provided by SoCal, no Phase 2B pipeline mileage qualifies for NDE or ILI as a pathway for removal from PSEP scope. There are 188 miles that will require pressure testing or replacement.

[2] Confidential_2018HPPD Dataset Run9-19-19.xls
[3] (HTP/MOP) = −0.02136 (% SMYS at MOP) + 3.068 when SCC or selective seam corrosion are anticipated

Figure 1 –



NOTE: XXXX mi No data from SoCal, conservative selection was used for decision tree

(1) Assumption with no Replacement Planning indicated from SoCal, all segments from Phase 2B - HydroTest or Replace will go to HydroTest selection process

Decision Tree Evaluation

Pressure Testing

The original Order and §958 required pipeline replacement, which includes a pressure test of the new pipe, or pressure testing of existing intrastate gas transmission pipelines that lack evidence of a test meeting 49 CFR 192 Subpart J requirements. Since federal regulations for natural gas pipelines were effective (November 1970), pressure tests have been required for all newly constructed pipelines and replacements. Many pipeline operators have subsequently retested portions of their pipeline facilities to evaluate the integrity of the pipeline facilities. The fundamental purpose of a pressure test is to 1) assess the material strength of the pipeline and to 2) identify any potentially hazardous leaks that may be present. Pressure testing is an acceptable means of addressing integrity threats, such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage.

The analysis of the SoCal database resulted in 188 miles of Phase 2B pipelines that will require either replacement or pressure test. If a pressure test is planned, a separate decision tree depicts the applicable options for designing the minimum test pressure for each applicable pipeline segment. The data set that SoCal provided does not include information about mill test pressures, which is one of the factors that could be used to determine the appropriate minimum test pressure for an applicable segment before removal from PSEP scope. Based on this, the affected mileage could not be determined for the mill test option. Regardless, all the minimum test pressure options depicted in the separate decision tree appear reasonable, although the last node of Figure 1 depicts an MAOP test pressure ratio of 1.1, 1.25 and 1.5. PHMSA recently updated the gas transmission pipeline regulations, eliminating the test pressure ratio of 1.1 for newly constructed gas transmission pipelines. SoCal should consider testing these segments to either 1.25 for class 1 and 2 locations or 1.5 for class 3 and 4 locations.

Pipe Replacement

Pipe replacement is typically performed when there are opportunities to eliminate legacy pipelines with a history of leaks or are at a higher risk of failure due to anomalous conditions that would be more advantageous to replace versus repair. The analysis of the SoCal database resulted in 188 miles of Phase 2B pipelines that will require either replacement or pressure test.

Non-Destructive Examination

Non-Destructive Examination (NDE) is a testing and analysis technique used by industry to evaluate the properties of a material, component, structure or system for characteristic differences or welding defects and discontinuities without causing damage to the original part. Although not specifically identified on the decision tree, SoCal indicated that the specific NDE method(s) selected would be appropriate to detect manufacturing-related threats. For example: shear wave ultrasonics and/or phased array ultrasonic testing to detect long seam anomalies or heat affected zone anomalies such as hook cracking. NDE is a common method used for pipeline integrity assessments of certain threats as outlined within 49 CFR 192, Subpart O. NDE is different than pressure testing. NDE cannot assess the pipeline's strength in the same physical way as a pressure test. However, with data obtained from various NDE methods in conjunction with other known pipeline attributes, critical engineering analysis can be performed to assess the pipeline's estimated remaining life and predicted failure pressure.

SoCal has provided RCP with excerpts from their gas transmission integrity management program that outline their processes for pipeline integrity assessments using direct assessment (NDE) techniques. RCP presumes that these regulatory requirements and internal compliance programs would be used to assess the entirety of the segment if a Phase 2B segment was to qualify for the NDE option.

The data set that SoCal provided does not include information about whether any segments are located above ground, which is one of the primary factors that would allow a segment to have NDE as an option before removal from PSEP scope. Based on this, the affected mileage could not be determined for the NDE option. SoCal did indicate they do not believe there are any Phase 2B segments located above ground, which would eliminate NDE as an option for Phase 2B segment removal from PSEP scope. However, if there are segments that would qualify for this option, it is recommended that the specific NDE technologies be identified that are capable of detecting and characterizing unstable time dependent and time independent threats, including but not limited to stress corrosion cracking (SCC) and selective seam corrosion. The NDE methods deployed should assess the entirety of the segment with a statistically high confidence level. Interpretation and analysis of the data obtained from NDE is also critical and must be performed by a qualified individual(s) with experience in the specific NDE technologies deployed. An engineering analysis should be performed to determine the segment's estimated remaining life and predicted failure pressure in addition to whether the segment requires any remedial actions to be taken prior to being removed from PSEP scope.

Inline Inspection

Based on the data supplied by SoCal, there does not appear to be any Phase 2B mileage eligible for In Line Inspection (ILI). If a Phase 2B segment were to qualify for ILI, the decision tree indicates that Circumferential Magnetic Flux Leakage (CMFL) or Electro Magnetic Acoustic Transducer (EMAT) tools would be the two ILI technologies deployed.

- The CMFL tool is capable of detecting and sizing metal loss (internal or external). It can detect, but not necessarily determine the size of selective seam corrosion (external or internal), axially oriented crack-like manufacturing defects (e.g., hook cracks), dents, wrinkles, laminations and bends.
- The EMAT tool is capable of detecting and sizing axially oriented Stress Corrosion Cracking (SCC), cracks and hard spots. It can detect, but not necessarily determine the

size of external and internal corrosion, selective seam weld corrosion, axially oriented crack-like defects, and dents.

ILI is a common method used for pipeline integrity assessments of certain threats as outlined within 49 CFR 192, Subpart O. ILI cannot assess the pipeline's strength in the same physical way as a pressure test. However, the data obtained from various ILI technologies provides a more comprehensive profile of the pipeline's integrity status compared to a pressure test. Interpretation and analysis of the data obtained from ILI is also critical and must be performed by a qualified individual(s) with experience with the specific ILI technologies deployed. An engineering analysis should be performed to determine the segment's estimated remaining life and predicted failure pressure in addition to whether the segment requires any remedial actions to be taken prior to being removed from PSEP scope.

SoCal has provided RCP with excerpts from their gas transmission integrity management program that outline their processes for pipeline integrity assessments using ILI technologies. RCP presumes that these regulatory requirements and internal compliance programs would be followed if a Phase 2B segment was to qualify for the ILI option, prior to removal from PSEP scope.

TT0-6

For certain pipe segments that have pressure test records that do not necessarily meet modern pressure test requirements of 49 CFR 192 Subpart J, but meet the criteria outlined in a report sanctioned by the Department of Transportation Office of Pipeline Safety in 2004, the decision tree allows these segments to be removed from PSEP scope. The correct[4] test pressure ratio depicted in the TT0-6 report should be used to determine whether a segment meets the TT0-6 criteria. Based upon data provided by SoCal, 36 miles of Phase 2B pipeline would meet the criteria of the TT0-6 report and would be eligible for removal from PSEP scope.

For the segments that qualify for this option, it is recommended that these be assessed with ILI tools capable of detecting and sizing unstable time dependent and time independent threats and remediate any anomalies in accordance with SoCal's gas transmission integrity management plan before removal from the PSEP scope. If a segment is not ILI-capable, then the conservative option should be to pressure test or replace before removal from PSEP scope.

Conclusion

The alternative approaches depicted within the decision tree (i.e., NDE, ILI and documented spike test meeting TT0-6 criteria) are reasonable alternatives to testing or replacement of Phase 2B segments, given the pathways depicted in the decision tree, with clarifications and edits noted herein.

[4] (HTP/MOP) = -0.02136 (% SMYS at MOP) + 3.068, when SCC or selective seam corrosion are anticipated.

APPENDIX D

B. **R**SI Pipeline Solutions Comments In Response to RCP's Evaluation

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New Albany, OH 43054
mrosenfeld@rsi-ps.com, 740-398-9543

November 2, 2021

Mr. Travis Sera
Southern California Gas Company

Re: RSI comments in response to RCP review of Phase 2B hydrotest decision process

Dear Mr. Sera:

RSI Pipeline Solutions LLC developed a decision process for assessment method selection and pressure test level selection at the request of Southern California Gas Company (SoCal). The decision process addresses "Phase 2B" of SoCal's plan to comply with CPUC regulations and directive to SoCal to pressure test or replace natural gas transmission pipelines that were not, or could not be confirmed to have been, pressure tested according to the requirements of 49 CFR 192, §192.619(a). The CPUC requires independent engineering review for reasonableness of SoCal's proposed assessment plan. RCP, an industry consulting firm, performed that independent review of the RSI-developed process.

The RSI process reviewed by RCP had a revision date of April 17, 2021. RCP issued their review report on June 7, 2021. You have requested RSI's comments in response to RCP's review.

RCP evaluated the decision process by testing it against a dataset of pipeline segments supplied to them by SoCal. RCP also evaluated it against current regulations and generally accepted industry practices. RCP's review was generally favorable toward the Phase 2B test decision processes and made several additional recommendations or interpretive remarks. RSI does not generally disagree with most of RCP's evaluation findings or interpretation, but RSI provides clarification of the points listed below.

RCP report	RSI response
RCP's decision process outcomes by mileage did not match RSI's outcomes by mileage; RCP had several process outcomes with -0- mileage.	RSI is unable to confirm RCP's execution of the process. It is possible that RCP and RSI were working with differing dataset versions, or differing assumptions for a segment's ILI-feasibility or spike test objective. Differences in dataset values may influence outcomes.
Part 192 has eliminated the test to 1.1X MAOP for Class 1 for new construction and for MAOP verification. The test level selection process should be revised to remove the 1.1 test factor.	RSI agrees. RSI notes that the regulatory change occurred in October 2020 which was after the initial development of the decision process.

RCP report	RSI response
Stated that specific selection, reliability, and defect analysis aspects of the NDE process should be specified if the NDE path is followed.	Noted, but those details were outside the scope of the test selection process. Other SoCal procedures cover those matters.
Stated that NDE does not assess the pipeline strength as a pressure test does. A similar remark is made for ILI.	Pipe strength (e.g., SMYS) must already be known to qualify for Phase 2B. Thus, NDE or ILI to determine strength are unnecessary.
Stated that an engineering analyses of failure pressure and remaining life should be performed in conjunction with the ILI option.	Noted, but those analyses are outside the scope of the test selection process. SoCal has procedures to cover those activities.
Recommended that segments meeting the TTO-6 criteria also be assessed with ILI, or that those segments not capable of ILI be retested or replaced.	RSI recognizes the potential perception of non-compliance in that the known test was not in accordance with Subpart J, however, SoCal can justify the position that a test meeting TTO-6 was as or more effective a test of the integrity of the pipe than Subpart J and request a waiver, if necessary.
RCP cited and applied the TTO-6 spike test pressure equation recommended for stress-corrosion cracking (SCC) or selective seam corrosion (SSWC) to the decision process.	RSI recognizes that SCC or SSWC could be present on SoCal piping. However, in keeping with the purpose of the Phase 2B decision tree to address possible deficiencies in the commissioning pressure test, RSI used the spike test pressure equation recommended by TTO-6 for managing pipe manufacturing integrity threats. This could produce different outcomes for that part of the decision process.

This summarizes RSI's response to RCP's review of the Phase 2B assessment and pressure test level selection processes.

If you have questions or comments, please feel free to let me know.

Sincerely,

Michael J. Rosenfeld, PE
Chief Engineer

SDG&E 2024 GRC Testimony Revision Log –August 2022

Exhibit	Witness	Page	Line or Table	Revision Detail
SDG&E-09	*Amy Kitson, Travis Sera*	*AK TS-11*	*Table: KS-6*	*Changed the RSE value for SDG&E-3-New 04 to 37 from 43*
SDG&E-09	*Amy Kitson, Travis Sera*	*AK TS-13*	*Table: KS-7*	*Changed the RSE value for SDG&E-3-New 04 to 37 from 43*
SDG&E-09	*Amy Kitson, Travis Sera*	*AK TS-35*	*Table: KS-11*	*Changed the RSE value for SDG&E-3-New 04 to 37 from 43*
SDG&E-09	*Amy Kitson, Travis Sera*	*AK TS-54*	*Table: KS-17*	*Changed the RSE value for SDG&E-3-New 04 to 37 from 43*