

Company: San Diego Gas & Electric Company (U 902 M)
Proceeding: 2028 General Rate Case
Application: A.26-06-014/015
Exhibit: SDGE-06.1

REVISED PREPARED DIRECT TESTIMONY OF DEVIN K. ZORNIZER
(GAS MAJOR PROJECTS)

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**



September 2026

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SUMMARY

GAS MAJOR PROJECTS (in 2025\$)			
O&M	2025 Adjusted-Recorded (\$000)	Estimated TY2028 (\$000)	Change (\$000)
Non-Shared	30,786	37,895	7,109
Shared	0	0	0
Total O&M	30,786	37,895	7,109

GAS MAJOR PROJECTS (in 2025\$)							
Capital	2025 Adj Recorded (000s)	Est 2026 (000s)	Est 2027 (000s)	Est 2028 (000s)	Est 2029 (000s)	Est 2030 (000s)	Est 2031 (000s)
Total CAPITAL	62,473	38,912	41,419	142,134	57,887	52,037	44,004

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 Major Projects Test Year 2028 (TY2028) forecast of \$37,895,000 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 Major Projects capital expenditures in 2026, 2027, and 2028 of \$38,912,000, \$41,419,000, and \$142,134,000 respectively.
- The Gas Major Projects organization is dedicated to the safe, prudent, and cost-effective delivery of complex gas infrastructure programs and projects, ensuring compliance with state and federal regulations while maintaining best practices in major project execution.

1. TIMP Execution

- Authorize SDG&E's Test Year 2028 Transmission Integrity Management Program (TIMP), O&M forecast of \$34,638,000 and SDG&E's forecast for TIMP capital expenditures in 2026, 2027, and 2028 of \$25,873,000, \$25,859,000, and \$25,798,000, respectively, for TIMP work occurring within the 2028-2031 GRC cycle.

2. GSEP Execution

- Authorize SDG&E's forecast for Gas Safety Enhancement Plan (GSEP) Execution capital expenditures in 2026, 2027, and 2028 of \$9,627,000,

\$10,929,000, \$19,602,000, respectively, for pipeline and valve projects scheduled to be completed within the 2028-2031 GRC cycle.

3. Moreno Compressor Modernization

- Authorize \$87,020,000 for incremental capital costs over the authorized amount in D.24-12-074 that are necessary for completion of the Moreno Compressor Modernization (MCM) project.

4. Control Center Modernization Ongoing Programmatic Activities

- Authorize SDG&E's capital forecast for the continued execution of the Control Center Modernization (CCM) Ongoing Programmatic Activities in 2026, 2027, and 2028 of \$3,412,000, \$4,631,000, and \$4,566,000, respectively, for work occurring within the 2028-2031 GRC cycle.

5. High Pressure Distribution Assessments Execution

- Authorize SDG&E's Test Year 2028 High Pressure (HP) Distribution Assessments Execution, O&M forecast of \$3,257,000 and SDG&E's forecast for TIMP capital expenditures in 2026, 2027, and 2028 of \$0, \$0, and \$5,148,000, respectively, for HP Distribution project execution work occurring within the 2028-2031 GRC cycle.

6. Pipeline Safety Enhancement Plan

- Authorize recovery of \$663 million in Capital and \$21 million in O&M associated with 19 SDG&E Pipeline Safety Enhancement Plan (PSEP) Line 1600 reasonableness review projects that represent approximately 58 miles of transmission pipeline. The associated revenue requirement is approximately 173.5 million.¹
- Authorize recovery of \$1.4 million in Capital associated with one SDG&E PSEP Phase 1A reasonableness review project.²

¹ D.16-08-003 authorized SDG&E and SoCalGas to recover in rates, subject to refund, 50% of the revenue requirements associated with actual PSEP costs.

² D.16-08-003 authorized SDG&E and SoCalGas to recover in rates, subject to refund, 50% of the revenue requirements associated with actual PSEP costs.

**REVISED PREPARED DIRECT TESTIMONY OF DEVIN K. ZORNIZER
MAJOR GAS PROJECTS**

I. INTRODUCTION

A. Summary of Gas Major Projects Costs and Activities

My name is Devin Zornizer, Vice President of Infrastructure Project Delivery for Southern California Gas Company (SoCalGas). As the executive with oversight of this organization, I am accountable for the planning and execution of complex gas infrastructure projects for both SoCalGas and San Diego Gas and Electric Company (SDG&E), which are managed through a centralized department. This work directly supports the safe, reliable, and resilient operation of SDG&E's natural gas transmission, distribution, and storage systems by overseeing project development, coordinating multidiscipline teams, and meeting regulatory, operational, and safety requirements.

The purpose of my testimony is to present and support SDG&E's forecasted costs and activities for Gas Major Projects for Test Year (TY) 2028. These activities are essential for maintaining system safety and reliability, complying with state and federal regulations, and enabling operational efficiency and affordability.

Certain forecasted activities and estimated costs were presented previously in SoCalGas and SDG&E's 2025 RAMP Application (A.) 25-05-010/013 (consolidated) filed on May 15, 2025. Those activities and any changes that have occurred since the RAMP filing are detailed below.

**TABLE DZ-1
Gas Major Projects
Test Year 2028 Summary of O&M Costs**

Gas Major Projects In 2025\$ (000s)	2025 Adjusted- Recorded	TY2028 Estimated	Change
TIMP Execution	30,786	34,638	3,852
High Pressure Distribution Assessments Execution	0	3,257	3,257
Total Non-Shared Services	30,786	37,895	7,109
Total O&M	30,786	37,895	7,109

TABLE DZ-2
Gas Major Projects
Test Year 2028 Summary of Capital Costs

GAS MAJOR PROJECTS In 2025 \$ (000s)							
Categories of Management	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
A. TIMP Execution	15,466	25,873	25,859	25,798	25,837	25,848	25,864
B. Gas Safety Enhancement Programs Execution	44,144	9,627	10,929	19,602	23,176	17,300	9,229
C. Moreno Compressor Modernization	0	0	0	87,020	0	0	0
D. Control Center Modernization Ongoing Programmatic Activities	2,863	3,412	4,631	4,566	3,709	3,719	3,734
E. High Pressure Distribution Assessments Execution	0	0	0	5,148	5,165	5,170	5,177
Total	62,473	38,912	41,419	142,134	57,887	52,037	44,004

TABLE DZ-3
Pipeline Safety Enhancement Plan (PSEP)
Summary of PSEP Reasonableness Review Project Costs

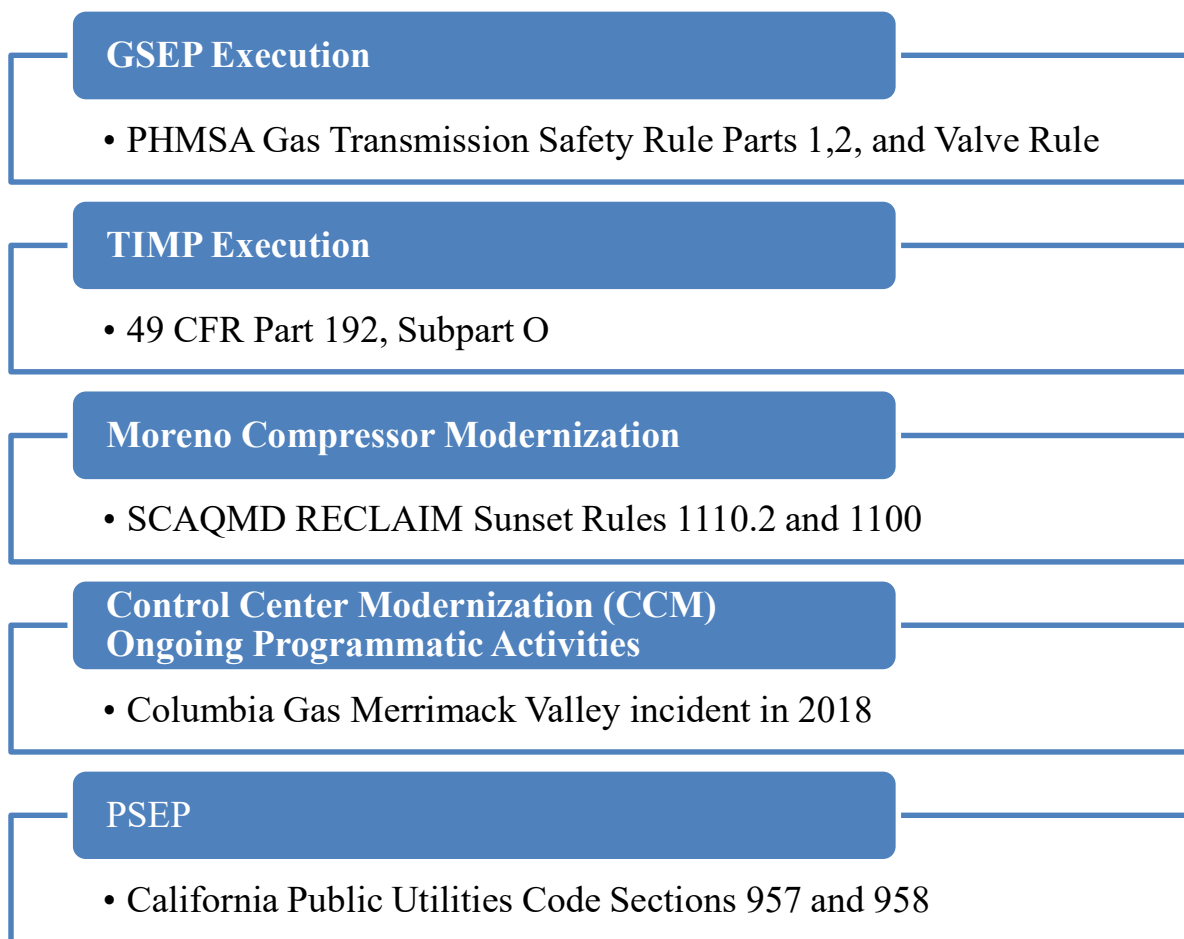
(\$000s)	Capital	O&M
Line 1600 Reasonableness Review	662,716	20,926
PSEP Reasonableness Review Project	1,400	0

B. Gas Major Projects Executes Predominantly Compliance and Safety Related Programs

Gas Major Projects is responsible for the prudent execution of complex gas infrastructure programs and projects, with a primary focus on safety and compliance-driven work aligned with applicable state and federal regulations. These efforts include pipeline safety enhancements and integrity management activities that support system reliability and public safety while satisfying regulatory obligations. Sponsored costs and activities under Gas Major Projects include the

Pipeline Safety Enhancement Plan (PSEP), Gas Safety Enhancement Programs (GSEP) Execution, Transmission Integrity Management Program (TIMP) Execution, Moreno Compressor Modernization (MCM), and Control Center Modernization (CCM) Ongoing Programmatic Activities. Figure DZ-1 identifies the applicable state and federal regulations associated with the programs under Gas Major Projects and the corresponding sponsored costs. The compliance-driven requirements for each program are further discussed below and in Appendix B.

Figure DZ-1
Gas Major Projects
State & Federal Regulations and Safety Programs



1. **GSEP Execution**

Following pipeline incidents in San Bruno, California and Marshall, Michigan, Congress enacted the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act), which established several mandates to improve pipeline safety. In response, the

1 Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an Advanced Notice
2 of Proposed Rulemaking (ANPRM) in 2011 titled “Safety of Gas Transmission and Gathering
3 Pipelines.” Given the breadth and complexity of issues raised, PHMSA announced in March
4 2018 that they would split the proposed regulations into three categories: Part 1, Part 2, and
5 Part 3.

6 Section 4 of the 2011 Pipeline Safety Act directed PHMSA to issue regulations, as
7 appropriate, requiring the installation of automatic or remote-controlled shut-off valves
8 (collectively, Rupture Mitigation Valves [RMV]), or equivalent technology, on newly
9 constructed, or replaced natural gas or hazardous liquid pipeline facilities. Beginning in
10 February 2020, PHMSA initiated the Valve Installation and Minimum Rupture Detection
11 Standards rulemaking. The final rule was published in the Federal Register on April 8, 2022,
12 with an effective date of October 5, 2022, and certain provisions became effective on April 10,
13 2023.

14 Published as the first of three parts of the Gas Transmission and Gathering Rulemaking,
15 the GTSR Part 1 amended sections of Title 49 CFR Parts 191 and 192. On October 1, 2019,
16 PHMSA issued the Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP
17 Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments final
18 rule, GTSR Part 1.³ The GTSR Part 1 imposes significant new safety and integrity requirements
19 to gas transmission pipelines under PHMSA’s jurisdiction. These changes became effective on
20 July 1, 2020, with certain compliance obligations commencing July 1, 2021 (*see* Section
21 V.B.1.a). To meet these requirements and compliance deadlines, SDG&E has implemented
22 actions including – but not limited to – the following:

- 23 • Where MAOP reconfirmation is required for pipeline segments outside the
24 scope of the authorized PSEP phases, implementing procedures to
25 reconfirm MAOP in accordance with 49 CFR § 192.624;
- 26 • Conducting assessments on segments outside of HCAs as required in 49
27 CFR § 192.710, which – consistent with the TIMP requirements, are
28 managed under the TIMP framework;

³ Pipeline Safety: Safety of Hazardous Liquid Pipelines, 84 Fed. Reg. 190,52260 (October 1, 2019),
available at: <https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20458.pdf>.

- Implementing procedures under 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 lack “traceable, verifiable, and complete” records, which are also managed under the TIMP.
- Additionally, PHMSA finalized the Valve Installation and Minimum Rupture Detection Standards rule on March 31, 2022, with final regulatory language published in the Federal Register on April 8, 2022.

TABLE DZ-4
Gas Transmission Gathering Rule (GTSR)
Scope and Progress

Pipeline Remediation, YE 2025	Test or Replace Miles		
	Total	Completed	
GTSR Part 1	46	29	63%

C. TIMP Execution

SDG&E’s TIMP Execution function serves as the operational implementation core of the TIMP. It is responsible for conducting ongoing in-line inspections and integrity assessments, and for remediating pipeline conditions in accordance with the requirements set forth in 49 CFR § 192, Subpart O – Gas Transmission Pipeline Integrity Management. Although Subpart O originally focused on baseline assessments for transmission pipelines located in HCAs, PHMSA expanded these requirements through 49 CFR § 192.710 to include assessments of transmission pipelines operated in moderate consequence areas (MCAs) and Class 3 and Class 4 locations. Additionally, to further enhance system safety and reliability, SDG&E evaluates and assesses non-HCA pipeline segments that are contiguous to or in proximity to HCA pipelines on a case-by-case basis.

D. Moreno Compressor Modernization

The Moreno Compressor Modernization (MCM) project is a multi-year effort that originated in response to comply with Air Quality Management District (AQMD) Mandates. MCM efforts were undertaken to comply with the South Coast Air Quality Management

District's (SCAQMD) sunset of its Regional Clean Air Initiatives Market (RECLAIM) program.⁴ SCAQMD initiated the RECLAIM sunset program to transition equipment at RECLAIM facilities to command-and-control regulations based on Best Available Retrofit Control Technology (BARCT) assessments. MCM, described in Section VI of this testimony, is designed to meet regulatory requirements under SCAQMD Rule 1110.2⁵ ("Emissions from Gaseous and Liquid Fueled Engines") and Rule 1100⁶ ("Implementation Schedule for Nox Facilities"). This project will reduce NOx emissions and support ozone attainment goals established by the California Air Resources Board (CARB) and the United States Environmental Protection Agency (EPA).

E. Control Center Modernization (CCM) Ongoing Programmatic Activities

The Distribution Regulator Stations (DRS) and High-Consequence Area (HCA) methane sensors constitute the remaining components of the Control Center Modernization (CCM) Ongoing Programmatic Activities.⁷ By deploying real-time monitoring and control capabilities at select distribution regulator stations, and improving leak detection along the transmission system through the installation of HCA methane sensors, these activities strengthen system safety by providing Gas Control with a more comprehensive, real-time view of the gas network and enabling faster detection of and response to abnormal operating conditions.

F. Pipeline Safety Enhancement Plan

On September 9, 2010, a 30-inch diameter natural gas transmission pipeline ruptured and caught fire in the city of San Bruno, California. In response, the Commission promulgated new regulations in Decision (D.)11-06-017 (later codified at California Public Utilities Code Sections 957 and 958), finding that "natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety," and ordering all California natural gas transmission pipeline operators "to prepare and file a comprehensive Implementation Plan to

⁴ Under RECLAIM program, rather than regulating each individual piece of equipment that emits air pollution, the SCAQMD regulated the total pollution at subject facilities by setting targets for annual facility-wide reductions of NOx emissions. Each facility participating in RECLAIM received RECLAIM trading credits and businesses that beat their reduction targets could trade their credits on the open market.

⁵ SCAQMD Rule 1110.2 Emissions from Gaseous- and Liquid-Fueled Engines, (Amended November 1, 2019).

⁶ SCAQMD Rule 1100 Implementation Schedule for NOx Facilities, (Adopted December 7, 2018, and Amended January 10, 2020).

⁷ Authorized in D.19-09-051 and D.24-12-074.

1 replace or pressure test all natural gas transmission pipeline in California that has not been tested
2 or for which reliable records are not available.” The Commission required that the plans provide
3 for testing or replacing all such pipelines “as soon as practicable.” On August 26, 2011,
4 SoCalGas and SDG&E filed their proposed PSEP.

5 The primary objectives of SDG&E’s PSEP are to: (1) enhance public safety; (2) comply
6 with Commission directives; (3) minimize customer impacts; and (4) maximize the cost
7 effectiveness of safety investments. As directed by the Commission, SoCalGas and SDG&E
8 PSEP includes a risk-based prioritization methodology that prioritizes pipelines located in more
9 densely populated areas over those in less populated areas. To implement this approach, PSEP is
10 organized into three distinct phases: Phase 1A, 1B, and 2A. The scope of each phase is described
11 in greater detail below.

12 In June 2014, the Commission issued D.14-06-007, approving SoCalGas and SDG&E’s
13 proposed PSEP and “adopt[ed] the concepts embodied in the Decision Tree,” “adopt[ed] the
14 intended scope of work as summarized by the Decision Tree,” and “adopt[ed] the Phase 1
15 analytical approach for Safety Enhancement [...] as embodied in the Decision Tree [...] and
16 related descriptive testimony.”⁸ In approving the plan, the Commission acknowledged the broad
17 scope of SoCalGas and SDG&E’s PSEP. Subsequently, in A.15-06-013, the assigned
18 Administrative Law Judge directed the parties to meet and confer on a procedural plan to
19 transition PSEP work into the GRC and to address PSEP costs anticipated prior to the next GRC
20 test year. In resolving the application, D.16-08-003 stipulated that all remaining Phase 1A
21 projects, as well as forecasted projects not included in the application, be addressed in the Test
22 Year 2019 GRC and subsequent GRCs.⁹

23 Upon completion of this General Rate Case (GRC), SDG&E will have finished
24 construction of all PSEP activities and presents the remaining associated costs for reasonableness
25 review.

⁸ D.14-06-007 at 59 (Ordering Paragraph (OP) 1).

⁹ SDG&E’s PSEP projects in this application are being covered through reasonableness review in compliance with D.14-06-007, D.20-02-024, and D.24-12-074.

G. Organization of Testimony

My testimony is organized as follows:

- **Introduction:** Provides an overview of this testimony, and the programs under Gas Major Projects that support safety, reliability, sustainability, and affordability.
- **Affordability & Efficiency:** Discusses how Gas Major Projects applies risk-based prioritization, integrated planning, and innovation to deliver energy infrastructure projects and programs that support the execution of a diverse range of construction projects efficiently and affordably.
- **Non-Shared O&M Costs:** Details forecasted costs and activities for the TIMP Execution and High Pressure Distribution Assessment Execution.
- **Capital Costs:** Outlines planned capital projects for TIMP Execution, GSEP Execution, Moreno Compressor Modernization, and Control Center Modernization Ongoing Programmatic Activities, explaining how these investments support long-term system safety, reliability and regulatory compliance.
- **Risk Assessment Mitigation Phase (RAMP) Integration:** Identifies activities that were included in SDG&E's RAMP filing and explains how risk mitigation strategies are incorporated into this GRC request.
- **Reasonableness Review:** Provides justification for the reasonableness of the requested costs associated with PSEP Line 1600 projects in alignment with the Commission directive to execute the Line 1600 Test or Replace Plan. Also includes justification for the reasonableness of the requested costs associated with one PSEP P1A project.

H. Support To and From Other Witnesses

My testimony references the testimony and workpapers of several other witnesses, either in support of their testimony or as support for mine.

- Exhibit (Ex.) SCG-02B/SDGE-02B– Risk Management - RDF Integration
- Ex. SDGE-04 – Gas Distribution
- Ex. SDGE-05 – Gas Transmission & Storage

- Ex. SDGE-03 – Gas Engineering & System Integrity
- Ex. SDGE-21 – Regulatory Accounts
- Ex. SDGE-14 – Information Technology
- Ex. SDGE-32 – Summary of Earnings

II. AFFORDABILITY & EFFICIENCY

SDG&E recognizes the Commission’s increasing emphasis on affordability, as shown throughout D.24-12-074. The forecasts presented in this testimony are consistent with the Commission’s affordability objectives and reinforce SDG&E’s ongoing commitment to providing safe, reliable, and affordable service to customers. Gas Major Projects (GMP) is responsible for delivering the Company’s complex pipeline and facility infrastructure projects, applying deep technical expertise and cross-disciplinary coordination to execute on compliance and safety driven programs safely and prudently while meeting regulatory and safety requirements. Advancing pipeline safety and system integrity through innovative, cost-effective engineering and design practices remains a priority.

GMP is focused on disciplined planning and coordination of large infrastructure programs to realize operational efficiencies and cost savings for customers. Specifically, GMP was established to centralize project and portfolio management expertise and apply a scalable, consistent framework grounded in industry best practices for infrastructure projects across the portfolio. Through a collaborative and agile culture anchored in safety, accountability, and integrity, GMP advances system safety, reliability, and decarbonization objectives through innovative infrastructure delivery. The following discusses key processes implemented by GMP to maximize efficiencies and customer value. Additionally, Table DZ-5 below briefly describes two SDG&E projects that exemplify these tenets of GMP’s execution approach, providing cost-saving benefits to ratepayers.

TABLE DZ-5

Selected Projects That Achieve Affordability and Efficiency Objectives

PROJECT	PROCESS	DESCRIPTION
GTSR Supply Line 49-11 Section 1 Hydrotest	Program and Project Coordination	Through collaboration between the GTSR and PIEx planning teams, it was determined that a planned hydrotest satisfies TIMP compliance requirements for this project. As a result, the hydrotest will remediate the applicable scope for both programs on this section of the pipeline, eliminating the need to incur additional costs and resource commitments associated with conducting a traditional In Line Inspection (ILI) or robotic ILI.
PSEP Line 49-339 Derate	Collaboration with Relevant Stakeholders	The PSEP team coordinated with Gas Transmission Planning (GTP) and Regional Engineering to evaluate Line 3010 and Supply Line 49-339. The teams confirmed that both lines could be derated and reclassified as DOT-distribution assets. This change was determined to have a negligible impact on both the Transmission and Distribution systems, thereby avoiding the need for pipeline replacement under the PSEP program.

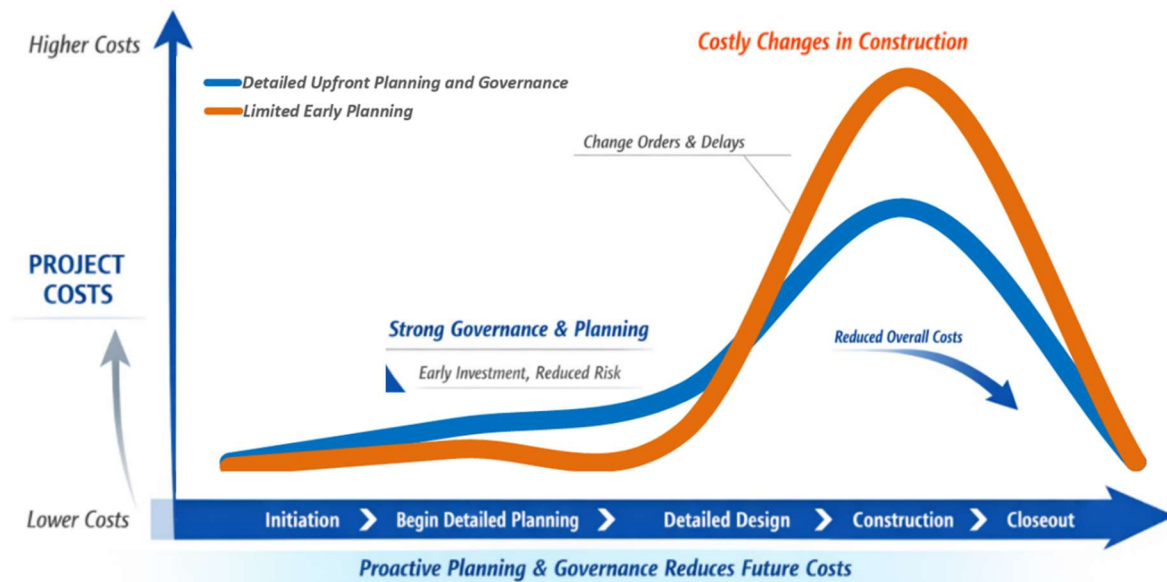
A. Centralized Organizational Governance

To achieve Gas Major Projects' objectives, the programs are governed through a Program Management Office (PMO), which brings together personnel with specialized technical, project management, and controls expertise. The PMO provides functional guidance on project design and execution to cost effectively meet regulatory requirements, apply industry best practices, and continuously incorporate process improvements. The PMO develops standards and procedures to promote consistency across projects and performs critical functions including organizational-level oversight, policy development, budgeting and portfolio management, and performance reporting to keep management informed of construction progress.

The PMO provides structured governance and oversight essential to planning and executing gas infrastructure projects with consistency, predictability, and efficiency. By establishing early-stage decision-making related to scope, design, constructability, and risk mitigation - when decisions have the greatest influence on long term cost outcomes, the PMO reduces costly redesigns and change events during construction. This disciplined approach supports cost control and affordability for customers. Together, GMP's governance structure, integrated planning approach, and PMO foundation create a disciplined delivery model that advances reliable infrastructure investment while aligning with the Commission's affordability

objectives. Figure DZ-2 illustrates how effective upfront planning and effective governance influence overall project cost outcomes.

Figure DZ-2
Proactive Planning and Governance Impacts



B. Project Delivery Model

GMP operates according to a Project Delivery Model (PDM), originally developed by SoCalGas and SDG&E for the PSEP program. The PDM provides an integrated framework for planning, managing, and executing a diverse portfolio of complex infrastructure projects. This model centralizes core functions, including scope development, engineering, environmental planning, project controls, procurement, and construction management into a coordinated structure that enhances transparency, consistency, and accountability across all phases of a project. By unifying these key components, the model enables efficient decision making, improves cost and schedule performance, and supports that projects are delivered safely, reliably, and in alignment with regulatory and operational requirements. This approach is particularly effective for an organization responsible for diverse and complex infrastructure portfolios as it supports standardized best practices while allowing flexibility to address project specific needs.

1. The Stage Gate Review Process Promotes Efficient Project Oversight and Execution

The PDM is supported by a Stage Gate Review Process that sequences and schedules project workflow deliverables. Through this process, the PMO monitors adherence to standards

and procedures, confirms proper authorization and documentation, and promotes consistent project execution. The Stage Gate Review Process detailed in the table below consists of five stages, each with defined objectives and leadership review at the end of the stage to confirm readiness to proceed.¹⁰

For Line 1600, many of the Stage 1 and Stage 2 activities were accomplished through the extensive process of reviewing and evaluating options for addressing PSEP requirements for Line 1600, which ultimately resulted in the approved Line 1600 plan. The approved Plan defined the scope of work to be completed, a high-level execution plan, baseline schedules and estimated costs.

TABLE DZ-6
Stage Gate Descriptions and Objectives

STAGE	DESCRIPTION	OBJECTIVES
Stage 1 Initiation and Business Case	Project Sponsor: • develops initial business case and the preliminary cost and schedule based on established requirements, supported by the Project Team.	1. Initiate Project 2. Complete Feasibility Study 3. Develop Preliminary Cost and Schedule 4. Identify High Level Risk Assessment 5. Refine Scope 6. Develop Revenue Recovery Strategy 7. Conduct Stage Gate
Stage 2 Preliminary Design & Option Selection	Project Team: • analyzes proposed options and makes selection based on scope, cost, schedule and risk; • initiates design, long lead procurement and permitting activities are initiated; • baselines scope, cost, and schedule.	1. Project Site Assessment 2. Option Analysis and Selection 3. Project Execution Plan (PEP) 4. Preliminary Design 5. Baseline Cost and Schedule 6. Long Lead Procurement 7. Conduct Stage Gate
Stage 3 Detailed Design & Procurement	Project Team: • obtains funding approval, finalizes design of selected option, secures necessary permits, and completes procurement activities; • submits RFP and awards construction contract;	1. Obtain Budget Authorization 2. Detailed Design 3. Land Rights and Permit Acquisition 4. Update Risk Assessment 5. Final Design and Material Procurement 6. Update PEP 7. Construction Request for Proposal (RFP)

¹⁰ Evaluations are gate reviews or completion check lists. Certain stages are condensed or combined for valve and small pipeline projects.

STAGE	DESCRIPTION	OBJECTIVES
	• completes safety requirements.	8. Complete Safety Requirements 9. Re-baseline Cost and Schedule 10. Conduct Stage Gate
Stage 4 Construction	Project Team: • manages construction execution, monitoring scope, cost and schedule; • mobilizes the Contractor and confirms safety and quality standards are met; • submits Date of Operation (DOO) noted on the NOP upon construction completion and commissioning/startup achievement.	1. Implement Safety Requirements 2. Mobilize Construction Contractor 3. Monitor Scope, Cost, Schedule and Risk 4. Commissioning and System Start-Up 5. Submit Notice of Operation (NOP) 6. Develop Training Plan and Documentation 7. Demobilize Construction Contractor 8. Site Restoration and Inspections 9. Conduct Stage Gate
Stage 5 Closeout	Once the asset is in service, the Project Team: • finalizes project closeout activities; • advises relevant stakeholders, gathers, reconciles, and uploads documentation, and all project costs are recorded and finalized; • transmits interim and final project documentation to the asset owner.	1. Communicate Project Completion 2. Finalize Project Documentation 3. Material and Equipment Closeout 4. Technical and Document Closeout 5. Stakeholder Closeout 6. Financial and Commercial Closeout 7. Lessons Learned 8. Asset Document Turnover 9. Monitor Closeout Process 10. Project Closeout Meeting

2. The Project Review Process Prudently Includes Collaboration with Relevant Stakeholders

To minimize impacts to customers and communities, SDG&E evaluates how various project options may impact SDG&E's transmission system and the customers and communities it serves. Prudent decision making relies on close coordination between project teams and key internal stakeholders — including Region Operations, Gas Engineering, Gas Transmission Planning, Gas Control, Commercial Industrial Services, Regional Public Affairs — to appropriately route, design, and schedule pipeline and valve work in a manner that manages costs and accommodates system capacity constraints. These teams provide critical input on project-specific considerations, such as: (1) the feasibility of shut-ins and alternate feeds to regulator stations or customers, (2) anticipated customer and community impacts, (3) opportunities for cross-programmatic coordination, and (4) environmental requirements, rights-

of-way, and permitting needs. This information informs project scope development and constructability decisions.

C. Program and Project Coordination

Effective coordination across the programs under Gas Major Projects is essential to support safe, efficient, and affordable pipeline operations. Housing these programs within a single organizational structure enables consistent oversight, shared planning, and stronger collaboration, resulting in operational and cost efficiencies. When projects occur in the same geographic area or pipeline system, the programs coordinate execution to reduce redundant mobilization, minimize community, customer, and system impacts, and efficiently share field resources. This integrated approach allows PSEP, GTSR, and TIMP projects to be executed simultaneously, keeping clear accounting delineations for cost allocation, reducing outages, and supporting timely, cost-effective integrity remediation.

For example, by aligning schedules, scopes, and resource planning across these programs, SDG&E has the ability to coordinate a hydrostatic test project completion to address integrity needs identified through the TIMP process. This coordination allows TIMP to remediate active threats and other integrity concerns, during the same operational windows used for testing and validation activities. Integrating these efforts reduces the frequency of system outages, minimizes construction impacts on customers and communities, and supports the timely and cost-effective completion of identified integrity actions in support of system safety and risk management.

Coordinating GTSR hydrostatic testing and replacement projects with integrity threats identified through the TIMP, results in measurable cost savings by eliminating the need for separate TIMP Execution-specific integrity assessments. Based on representative project cost estimates, performing a single, integrated hydrostatic test that satisfies both GTSR and applicable TIMP requirements has avoided SDG&E's TIMP Execution-related costs for this GRC cycle by approximately \$47 million, compared to executing these activities independently. These efficiencies are contingent upon full funding of the GTSR program in this GRC. Absent such funding, the integrated savings described above would not be realized, and the proposed TIMP Execution program would require incremental funding, approximately equivalent to the identified savings to complete these activities independently and meet PHMSA-mandated assessment deadlines. Another way coordination of TIMP activities and hydrotest work provides

1 efficiency benefits is through improved hydrotest outcomes. When TIMP assessments identify
2 anomalies or other features requiring replacement within the extent of a planned hydrotest, the
3 TIMP work is completed first. Addressing known defects beforehand reduces the likelihood of
4 hydrotest failures, such as leaks or ruptures. As a result, SDG&E avoids the costs associated
5 with locating and remediating the source of potential test failures, and associated schedule
6 delays, thereby enhancing overall project efficiency and reliability.

7 **D. Scope Validation**

8 GTSR projects, which fall within the scope of federally mandated pipeline compliance
9 programs, undergo a rigorous scope validation process prior to execution. Project teams evaluate
10 records and internal data to validate project scope, mileage, and regulatory applicability (*e.g.*,
11 PHMSA and CPUC (or other mandated) regulations). This process may result in scope
12 refinements or reductions, through record reconciliation, MAOP changes, or line abandonment,¹¹
13 producing verifiable cost avoidance and direct ratepayer benefits.

14 **E. Prudent Procurement Practices**

15 GMP achieves additional cost savings for the benefit of customers through prudent
16 procurement practices that leverage competitive bidding, market based pricing, and existing
17 agreements. SDG&E strives to minimize project execution costs through cost-avoidance efforts
18 that focus on efficiencies identified in the engineering and design process through efficient
19 procurement practices, coordination and scheduling effectiveness, and construction execution.
20 The majority of agreements entered into for materials and services have been either
21 competitively bid or set at market-based rates stemming from previous competitive solicitations.
22 In other words, in addition to individual bidding events, as appropriate, SDG&E executes
23 agreements by leveraging terms and conditions and rates from existing agreements. When
24 acquiring material, material bids are designed to obtain multiple quotes for the best pricing
25 options, promote work with select firms for efficiency of process, and encourage the
26 development of local resources and sourcing.

27 **III. NON-SHARED O&M COSTS**

28 “Non-Shared Services” are activities performed by a utility solely for its own customers’
29 benefit. Although Corporate Center provides certain services to SDG&E and other subsidiaries,

¹¹ Lines are abandoned after a thorough review of the ability of adjoining lines to meet current and future load requirements and to verify there will be no customer impact or system constraints.

for purposes of this general rate case, SDG&E treats the costs for services received from Corporate Center as Non-Shared Services costs, consistent with the treatment of costs incurred from external vendors. Table DZ-7 summarizes the total forecasted non-shared O&M costs for the listed cost categories.

TABLE DZ-7
Non-Shared O&M Summary of Costs

Gas Major Projects (in 2025\$)	2025 Adjusted- Recorded	TY2028 Estimated	Change
A. TIMP Execution	30,786	34,638	3,852
B. High Pressure Distribution Assessments Execution	0	3,257	3,257
Total Non-Shared Services	30,786	37,895	7,109

A. TIMP Execution (NSS IMP002.000)

TABLE DZ-8
TIMP Execution Costs

A. TIMP Execution	2025 Adjusted- Recorded (000s)	TY2028 Est. (000s)	Change (000s)
1. TIMP Execution	30,786	34,638	3,852
Total	30,786	34,638	3,852

1. Description of Costs and Underlying Activities

The activities and costs associated with this cost category include labor and non-labor expenses for the execution of the TIMP Program. As described above and in the Gas Engineering and System Integrity (GESI) testimony (Ex. SDGE-03), SDG&E's TIMP was designed to comply with the requirements of Title 49 of the Code of Federal Regulations (CFR) – specifically Part 192, Subpart O – Gas Transmission Pipeline Integrity Management, and later 49 CFR § 192.710. The program encompasses activities such as threat identification, risk analysis, pipeline assessments, and other actions taken to address integrity concerns and reduce the risk of pipeline failure.

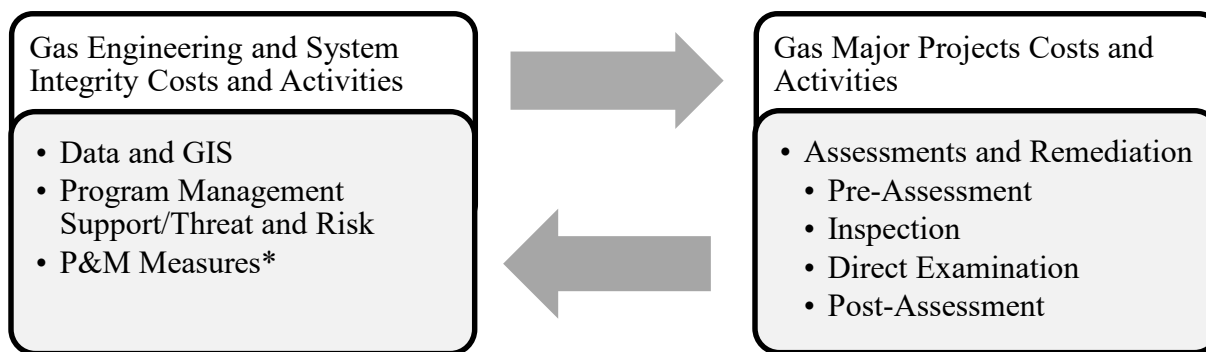
GMP, which includes engineers, project managers, technical advisors, project specialists, and other employees with varying levels of responsibility primarily provides oversight of execution for TIMP activities. SDG&E currently organizes TIMP activities and associated costs into four categories: 1) Assessments & Remediation, 2) Preventive & Mitigative (P&M)

Measures, 3) Data and GIS, and 4) Program Management Support/Threat & Risk. The forecasted TIMP labor and non-labor costs presented in this testimony and the associated workpapers support SDG&E's execution of the Assessments & Remediation and corrosion-related P&M Measures activities that are necessary for regulatory compliance, system safety, and system reliability. Forecasted TIMP labor and non-labor costs for the remaining categories (*e.g.*, Data and GIS) are presented in the GESI testimony (Ex. SDGE-03).

SDG&E executes its TIMP assessment projects primarily through Gas Major Projects to leverage the centralized expertise of its construction and project management professionals. Due to the organization's portfolio and role within the enterprise, its employees are well positioned to effectively plan and execute infrastructure projects across the enterprise. The figures below delineate the forecasted costs and activities across each witness area and provide additional detail regarding the scope of work included within Gas Major Projects.

Figure DZ-3

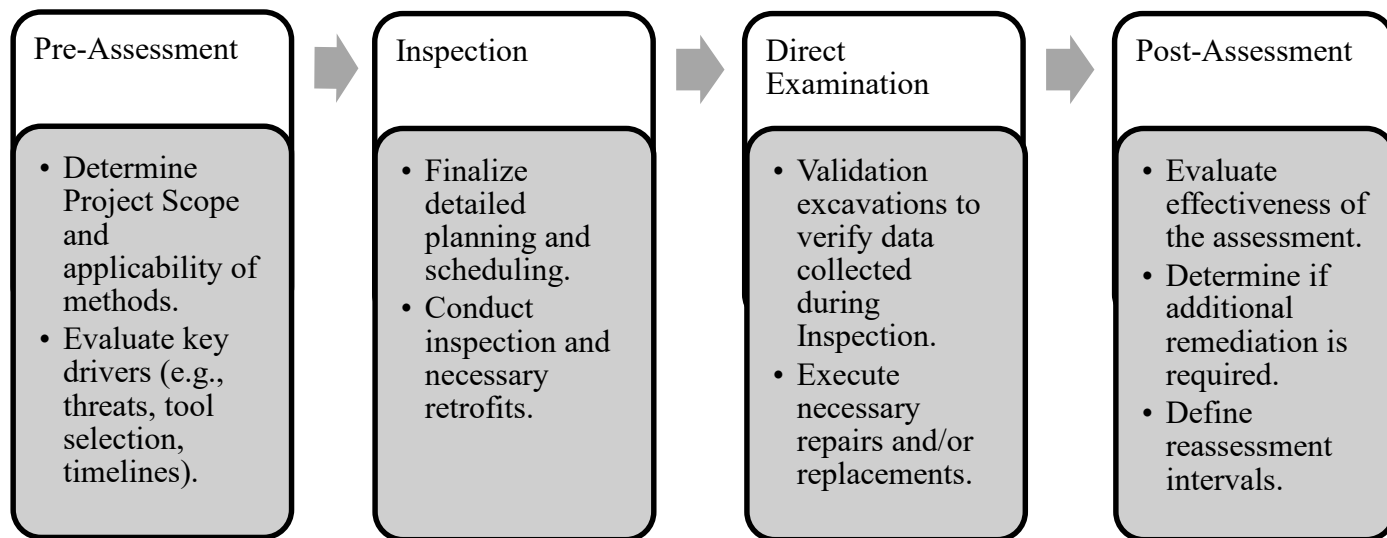
Delineation of TIMP Activities



*Corrosion Projects identified within P&M Measures are included in Gas Major Projects testimony.

Figure DZ-4

Gas Major Projects Four-Step TIMP Execution Process



The development and handoff of the annual TIMP Assessment Plan described in the GESI testimony (Ex. SDGE-03), reflects collaboration between employees within the Integrity Management (IM) Department and Gas Major Projects. TIMP assessments are planned and executed using a four-step Assessment and Remediation process consisting of: (1) Pre-Assessment; (2) Inspection; (3) Direct Examination; and (4) Post-Assessment.

a. Pre-Assessment

The first stage of the four-step Assessment and Remediation process is Pre-Assessment. During this phase, the Project Team reviews operational data, historical records, and prior assessment results to define project scope and determine the federally prescribed assessment method(s) applicable to each pipeline segment. Based on identified threats, SDG&E may be required to apply one or more assessment methods, including in-line inspection (ILI), various forms of pressure testing, direct examination, Guided Wave Ultrasonic Testing (GWUT), or direct assessments for corrosion and cracking. Assessment methods are typically fixed for the duration of a project unless new information emerges that requires a change in scope. Any such change must still be completed within the applicable regulatory timelines. While selection of assessment method(s) vary on a project-by-project basis, the assessment methods most commonly employed by SDG&E are described below:

- ILI: This method utilizes specialized tools, also referred to as “smart pigs”, that travel inside the pipeline to detect pipeline flaws and defects.

ILI tools are available in a variety of sizes and technologies, but their use requires that a pipeline be configured to accommodate tool passage. Because many pipeline segments were constructed before ILI technology existed, the use of this assessment method often requires pipeline modifications or retrofits 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. Through continued execution of TIMP activities and complying with state mandates,¹² SDG&E has increased the number of miles of pipeline capable of ILI inspection. Currently, approximately 78% of SDG&E's transmission system is considered "piggable." A key benefit of ILI tools is the volume and quality of pipeline data collected across the full length of a pipeline segment, which provides integrity information for both HCA and non-HCA segments and enhances SDG&E's ability to conduct risk assessments. Consistent with this approach, the executive summary of the GTSR Part 1 final rule recognizes that "improving ILI methods as an alternative to hydrostatic testing is better for risk evaluation and management of pipeline safety."¹³

- ECDA: The External Corrosion Direct Assessment (ECDA) process integrates operating data and above-ground surveys to identify and address locations where external corrosion activity has occurred, is occurring, or may occur.¹⁴ ECDA is labor-intensive and, depending on the location of the excavations, can result in higher costs, particularly if located in environmentally constrained or densely populated areas.

¹² Pub. Util. Code § 958: "At the completion of the implementation period, all California natural gas intrastate transmission line segments shall meet all of the following: [...] where warranted, be capable of accommodating in-line inspection devices."

¹³ Pipeline Safety: Safety of Hazardous Liquid Pipelines, 84 Fed. Reg. 190,52185 (October 1, 2019), available at: <https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20458.pdf>.

¹⁴ Described in ANSI/NACE SP0502-2010 as "a structured process that is intended to improve safety by assessing and reducing the impact of external corrosion on pipeline integrity."

- SCCDA: SDG&E applies Stress Corrosion Cracking Direct Assessment (SCCDA) when the use of a crack detection ILI tool capable of assessing stress corrosion cracking threats is not practicable. SCCDA relies on the results of indirect inspection tools used in ECDA (Close Interval Surveys (CIS), Direct Current Voltage Gradient (DCVG), and Alternating Current Voltage Gradient (ACVG)) along with soil resistivity measurements, operational history, and environmental conditions, to identify pipeline locations susceptible to SCC. Similar to ECDA, SCCDA is labor-intensive and can involve varying excavation costs depending on site conditions. During Pre-Assessment, projects are categorized as baseline assessments (for newly covered segments or segments not previously assessed), first-time assessments (when a new method is applied to a previously assessed segment), or reassessments required under federal regulations. During this step, SDG&E also identifies key project drivers, including pipeline threats, inspection tool selection, and compliance timelines – and coordinates with internal stakeholders to reduce operational impacts and optimize costs.

2. Inspection

The second step of the Assessment and Remediation process is Inspection. During this phase, SDG&E executes the selected assessment method(s) (*e.g.*, ILI, ECDA). Activities include finalizing detailed planning and scheduling, overseeing vendors and construction contractors, managing project costs, and documenting inspection activities and results.

3. Direct Examination

The third step in the process is Direct Examination. During Direct Examination, the pipeline is excavated to complete visual and non-destructive examination in order to validate inspection results and to perform necessary repairs and/or replacements. During this step, SDG&E completes repairs required to address anomalous conditions discovered during assessments, as described below:

a. Remediation¹⁵

Remediation activities conducted during the Direct Examination phase address

¹⁵ This activity also consists of capital activities described in workpapers. *See* Ex. SDGE-06-CWP Gas Major Projects.

1 anomalous conditions in accordance with PHMSA regulations.¹⁶ Anomalous conditions are
2 analyzed, classified, and prioritized by severity—immediate, scheduled, or monitored—
3 consistent with regulatory requirements.¹⁷ Immediate repair conditions require prompt action—
4 such as temporary pressure reduction, pipeline shutdown, or urgent repairs—and often
5 necessitate extended work hours by internal departments, city inspectors, contractors, and
6 construction personnel until the threat is mitigated. Scheduled and monitored conditions are
7 addressed in accordance with standard operating procedures and applicable regulations.¹⁸
8 Following validation through surface evaluations, appropriate post-assessment repairs or
9 reconditioning (such as welded steel sleeves, grinding, or pipe replacement) are performed to
10 enhance safety and prevent incidents. In some cases, initial findings may identify the need for
11 further remediation following Post-Assessment.

12 As ordered in D.24-12-074¹⁹, an independent study of SoCalGas’s TIMP and DIMP,
13 conducted by Structural Integrity Associates, Inc. (SI Associates) concluded that SoCalGas’s
14 TIMP is effective, in part, due to the identification and repair of a significant number of
15 immediate conditions.²⁰ These conditions require an expedited response given their associated
16 risk, and timely repair is critical to maintaining the safety and reliability of pipelines. The study
17 further noted that as a result of new regulations, there has been a notable increase in the
18 conditions in both HCAs and areas outside of HCAs that have required remediation. This is
19 further discussed below.

20 **4. Post-Assessment**

21 The final step of the four step Assessment and Remediation process is Post-Assessment.
22 During this step, SDG&E reviews data generated during Pre-Assessment, Inspection, and Direct
23 Examination to evaluate the effectiveness of the assessment, determine whether additional

¹⁶ Complies with 49 CFR §§ 192.933 and 192.714.

¹⁷ 49 CFR §§ 192.933 and 192.714, and American Society of Mechanical Engineers (ASME) B31.8s.

¹⁸ 49 CFR Part 192, Subpart O and § 192.714.

¹⁹ D.24-12-074 at 265 (“To facilitate the reallocation of additional activities proposed as FIMP, the Commission directs SoCalGas to have an independent study performed of the efficiency of SoCalGas’s TIMP and DIMP programs and related activities, including their management, to determine how best to improve their effectiveness, efficiency, and cost[.]”).

²⁰ See the SoCalGas GESI testimony, Ex. SCG-03, Appendix F (SI Associates Report: Aligning Safety, Compliance, and Cost-Effectiveness: A Comprehensive Review of SoCalGas’s TIMP and DIMP Programs, January 2026) at Section 5.6 (Repairs).

remediation is needed, and establish further reassessment intervals. Additional remediation may include expanded pipeline repairs or preventive and mitigative actions, such as installing permanent monitoring devices, upgrading cathodic protection, or adding valves. The P&M measures included in this testimony and supporting workpapers consist primarily of the maintenance or addition of rectifiers and anodes, monitoring probes, and additional surveys along the pipelines with similar material coating and environmental characteristics to manage corrosion risks. Ongoing programmatic improvements to P&M procedures are discussed in the Gas Engineering and System Integrity testimony (Ex. SDGE-03).

5. Description of RAMP Mitigations

This cost category consists entirely of non-shared O&M costs associated with the C171 risk control and mitigation presented in the 2025 RAMP Report and identified in the table below. All TIMP Execution activities are risk mitigation measures that address safety risks and were identified in the 2025 RAMP Report, SDGE-Risk 2 High Pressure Gas System, as described in the section above. Activities that are compliance-driven or mandated by the CPUC or other regulatory agencies are shown in bold. Appendix B to this testimony provides detailed information regarding applicable mandates for each control.

TABLE DZ-9
RAMP and GRC Risk Control/Mitigation Activities - O&M
In 2025 \$ (000s)

ID	Control/Mitigation Name	RAMP 2028 Estimate	GRC 2028 Forecast	Change
C171	Integrity Assessments & Remediation	28,505 ⁽²¹⁾	34,638	6,133

a. Description of Selection and Prioritization of RAMP Risk Mitigations

As described above, SDG&E's TIMP is designed to comply with the requirements of 49 CFR Part 192, Subpart O and 49 CFR § 192.710. Consistent with these regulations, SDG&E assesses higher-risk transmission pipelines²² for a range of threats, including internal and external

²¹ The total RAMP O&M forecast for C171 is \$29 million. The cost shown on the table represents the estimated RAMP O&M forecast allocated to this workpaper, proportional to the GRC O&M forecast, representing 98.2% of the total activity. The other portion of costs for C171 can be found in the GESI testimony (Ex. SDGE-03).

²² HCA, Class 3, Class 4, and piggable MCA pipeline segments as scoped by 49 CFR Part 192 Subpart O and 49 CFR § 192.710.

corrosion, stress corrosion cracking, manufacturing defects, construction and fabrication issues, weather-related and outside forces, incorrect operations, equipment failure, and third-party damage. SDG&E evaluates pipeline data, operating conditions, and other relevant information to determine the appropriate actions necessary to maintain system integrity and reliability. Regulatory mandates and guidance (*e.g.*, advisory bulletins), current pipeline data, historical activity levels, and system needs are key factors that inform the scope of this control.

SDG&E continues to execute its risk-informed TIMP activities to provide safe and reliable transmission service, support system integrity, and maintain regulatory compliance.

The Gas Engineering & System Integrity testimony (Ex. SDGE-03) includes a portion of C171 costs and activities for program management of the TIMP. These program management costs are separate and distinct from the project execution management costs and activities sponsored in the Gas Major Projects testimony.

6. Forecast Method

The forecast method used for TIMP Project Execution O&M is a recorded three-year average. As described in the Cost Drivers section below, TIMP regulations have evolved in recent years that have impacted TIMP Assessment and Remediation work and associated costs. The level of activity executed in 2023, 2024 and 2025 best represent the current organizational structure and the workload required to comply with federal requirements.

The changes in SDG&E's assessment methods (*e.g.*, new ILI tool runs, increase in SCCDA) and related validation and remediation activities in the forecast years, as compared to historical years prior to 2023, are subject to the same enhanced federal requirements that are expected to continue through at least this current assessment cycle. During this cycle, SDG&E will bring pipeline segments under the TIMP into compliance with updated requirements. The level of accuracy of project-specific forecasting decreases particularly as SDG&E forecasts further into future years. Based on its latest assessment plan, SDG&E is anticipating a level of activity through 2031 that is similar to that of 2023-2025 and expects that a three-year average will smooth the year-to-year variability that is inherent with TIMP work.

SDG&E made incremental adjustments to each forecast year to account for the increase in the volume of assessments projected for 2026-2031 relative to 2023-2025. To determine these adjustments, SDG&E evaluated the projected number of assessments in the forecast period and

1 applied average historical cost assumptions, recognizing the variability in scope and cost across
2 individual projects.

3 To determine assessment volumes for the forecast period, SDG&E applied distinct
4 planning approaches based on the relative level of information available. For 2026–2027,
5 SDG&E incorporated project quantities based on its most recent Assessment Plan, applicable
6 compliance requirements, and operational considerations. Because the Assessment Plan is
7 updated annually, SDG&E develops more detailed plans in the near term and recognizes
8 increased uncertainty beyond a two-year horizon. Accordingly, SDG&E developed the 2028–
9 2031 assessment volumes by reviewing projects completed during 2022–2025. A six-year
10 historical cycle was used instead of a seven-year cycle, to reflect known execution risks that can
11 affect compliance timing, such as tool availability and permitting constraints, as well as the
12 potential for shortened reassessment intervals or additional assessment requirements identified
13 upon completion of the ILI for pipelines subject to 49 CFR §192.939(a)(1)–(3). In some cases,
14 ILI results may identify stress corrosion cracking threats that may necessitate an unplanned
15 SCCDA. When this occurs, the SCCDA expands project scope and can extend execution
16 timelines, while remaining subject to the same regulatory compliance deadline as the associated
17 ILI, increasing scheduling variability and compliance risk. The 2028–2031 projections were
18 further normalized to account for this variability, recognizing that assessment execution may be
19 advanced or deferred to balance regulatory obligations with system and operational needs.

20 Overall, the TIMP O&M forecast reflects a reasonable and compliant pace of work to
21 maintain the safety and reliability of SDG&E’s transmission system and is based on information
22 available at the time the forecast was developed.

23 **7. Cost Drivers**

24 The primary cost drivers for this forecast consist of both labor and non-labor components.
25 Labor costs reflect the employees necessary to direct, oversee, execute, and ultimately manage
26 compliance and program requirements. Non-labor costs include contractor services, materials,
27 permitting, and other non-labor costs directly associated with execution of TIMP requirements.

28 A primary cost driver for TIMP Project Execution O&M is the number and type of
29 assessments that SDG&E is required to perform under PHMSA regulations. TIMP project
30 counts and project scopes vary from year to year due to several factors, including prescriptive

requirements for assessment methods and reassessment timing,²³ system reliability considerations (*e.g.*, seasonal demand and inventory), and opportunities for cost efficiencies (*e.g.*, shifting projects to leverage or integrate with other scopes of work).

Regulatory change has also been a significant cost driver in recent years. Beginning with the implementation of GTSR Part 1, effective July 1, 2020 and July 1, 2021, SDG&E updated its TIMP to comply with new federal requirements and guidance.²⁴ These materially increased TIMP activities and costs, as documented in the SoCalGas independent TIMP and DIMP efficiency study ordered by D.24-12-074.²⁵ In response to enhanced threat evaluation requirements, including those reflected in PHMSA advisory bulletins²⁶ and GTSR Part 1, SDG&E increased its use of advanced ILI technologies, such as Electromagnetic Acoustic Transducer (EMAT) tools and Circumferential Magnetic Flux Leakage (MFL-C) tools during the TY 2019 GRC period, resulting in higher O&M and capital expenditures.²⁷

GTSR Part 2, which became effective May 24, 2023, expanded remediation requirements for pipeline segments located both within²⁸ and outside²⁹ of HCAs. While certain elements of these requirements were not fully implemented until 2024 due to the enforcement discretion policy issued by PHMSA,³⁰ the impacts have been substantial.

²³ PHMSA prescribes a maximum seven-year interval (49 CFR § 192.939) and ten-year interval (49 CFR § 192.710) for reassessment of TIMP pipelines and includes provisions for more frequent reassessment depending on evaluations of pipeline data and findings.

²⁴ 49 CFR §§ 191 and 192.

²⁵ *See* Ex. SCG-03, Appendix F at Section 5.6 (Repairs).

²⁶ PHMSA issued an advisory bulletin in 2018 declaring the Stress Corrosion Cracking (SCC) threat to be considered “active” by default for all pipeline segments. Since the issuance of the bulletin, the number of pipeline segments considered susceptible to the SCC threat have increased as pipeline operators have discovered SCC on pipeline segments previously considered to be unsusceptible to the SCC threat. Pipeline Safety: Deactivation of Threats, 82 Fed. Reg. 50,14106 (March 16, 2017), available at: <https://www.govinfo.gov/content/pkg/FR-2017-03-16/pdf/2017-05262.pdf>.

²⁷ A.25-02-012, Application of SDG&E to Recover Costs Recorded to the Transmission Integrity Management Program Balancing Account (February 27, 2025).

²⁸ 49 CFR § 192.933.

²⁹ 49 CFR § 192.714.

³⁰ *Id.*

1 Consistent with the SI study for SoCalGas's TIMP, SDG&E anticipates that this level of
2 activity will continue several years into the future,³¹ though it is possible an increased level of
3 activity could persist through 2034 due to the ten-year maximum assessment/reassessment
4 cycle.³² These additional excavations and repairs directly increase the costs SDG&E incurs to
5 execute the TIMP.

6 In addition to the cost drivers already described, SDG&E's actual project costs are
7 variable due to many factors, including but not limited to the following:

8 - **Assessment method:**

9 **a. ILI Projects**

- 10 ○ Tool types – Certain tool types, such as EMAT, continue to be cost
11 drivers. Use of EMAT can increase project costs by up to \$1
12 million. Other newly utilized tool types could add a minimum of
13 approximately \$300 thousand per project.
- 14 ○ Number of tool runs – ILI projects may require multiple tool runs
15 for a variety of reasons. Pipelines with significant debris often
16 require several cleaning runs and, in some cases, onsite tool
17 recalibration or rebuilds. These circumstances increase costs
18 associated with company labor, contracted workforce, and other
19 services. In addition, ILI tool selection is driven by the potential
20 threats that must be assessed. In many cases, multiple types of ILI
21 tools — each designed to detect particular threats — are required
22 to collect the full range of data necessary to complete an
23 assessment. In some instances, data validation demonstrates that
24 collected data does not meet required quality standards,
25 necessitating tool re-runs and additional analysis, which can
26 further increase project duration and cost. These situations
27 typically arise from tool performance issues.

³¹ *Id.*

³² 49 CFR § 192.710.

- Temporary vs. permanent facilities – SDG&E generally prefers to install permanent facilities for pipelines subject to future reassessments. However, feasibility depends on site-specific factors including available space, easements, rights-of-ways (ROWs), and other factors. Where temporary facilities are required, additional costs associated with excavation, permitting, traffic control, and labor are expected. While costs associated with reassessments may be more predictable, increased variability is expected for baseline or first-time assessments.

b. ECDA and SCCDA Projects

- Length of the covered segment – Longer covered segments generally result in higher inspection costs.
- Number of excavations – The number of excavations required to complete an assessment depends on inspection results and can vary by location.
- Location of excavations – Some excavation sites can be difficult to access, and certain locations such as hillsides and water crossings are more susceptible to Stress Corrosion Cracking (SCC). Inspection results may therefore require SDG&E to perform complex and costly excavations in difficult-to-access locations.

Based on the most recent Assessment Plan and currently identified threats, SDG&E does not anticipate using pressure testing, spike hydrostatic pressure testing, ICDA, in-situ direct examination, GWUT, or other technologies during the 2026-2031 period. However, assessment methods may change based on pre-assessment analysis conducted for individual projects, and such changes could have significant cost implications.

- **Geographical factors:** Urban and suburban location challenges – Projects located in urban or suburban environments often involve restrictive permitting requirements, such as limited work hours or nighttime construction, extensive traffic control measures, and the presence of unknown substructures. These challenges affect project execution timelines and directly drive costs. In dense urban areas, projects may also impact large customers, such as electrical

1 generation plants. To minimize impacts, work may need to be scheduled during
2 nights or weekends, and conditions are subject to change.

- 3 - **Program Coordination:** SDG&E leverages other project scopes where possible
4 to address TIMP compliance requirements. For example, SDG&E has
5 strategically planned MAOP reconfirmation pressure testing under for projects
6 that must be assessed under the TIMP during the 2028 GRC cycle. Because a
7 pressure test performed for the purposes of reconfirming MAOP under 49 CFR §
8 192.624 would also fulfill the compliance requirement for the TIMP, the TIMP
9 forecast currently excludes that pipeline scope, resulting in an estimated cost
10 avoidance of \$47,000,000. However, if the MAOP reconfirmation funding
11 request is not authorized, SDG&E would necessarily incur those costs under the
12 TIMP and seek cost recovery through the TIMP Balancing Account (TIMPBA)
13 for costs not forecasted at the time of the TY2028 GRC.
- 14 - **Assessment findings:** The number of ILI tools or assessment method types,
15 which are driven by identified threats that must be evaluated, directly impact both
16 O&M and Capital activities under TIMP. As the quantity and complexity of data
17 collection increases (*e.g.*, more tool types to appropriately assess for threats) the
18 number of required excavations to validate findings also increases. This in turn
19 leads to identification of additional conditions discovered that require
20 remediation. SDG&E experienced this dynamic following GTSR Part 1, when
21 increased baseline and first-time ILI assessments resulted in a higher volume of
22 excavations and remediations to comply with new regulatory requirements.³³
- 23 - **Impact of evolving regulations:** As described in greater detail in Ex. SDGE-03,
24 GESI testimony, PHMSA published new rules updating the edition of ASME
25 B31.8S incorporated into federal regulations. These updates have affected
26 SDG&E's threat identification and risk assessment processes, which drive the
27 assessment, excavation, and remediation activities.³⁴ In addition, in 2024
28 PHMSA issued an advisory bulletin emphasizing the "importance of evaluating

³³ A.25-02-012, SDG&E Chapter II: Technical – Project Execution and Management, Ex. SDG&E-02 at 3-4.

³⁴ For additional background, refer to the GESI testimony, Ex. SDGE-03.

1 their pipeline facilities for the existence and potential threat of hard spots in the
2 pipe body.”³⁵ The pipeline industry is actively evaluating the ability of ILI and
3 in-the-ditch inspection tools to detect and characterize hard spots, as well as
4 developing criteria to determine when immediate action is warranted. SDG&E is
5 currently analyzing and integrating these evolving requirements and assessing
6 their impacts on TIMP assessments. To account for enhanced threat identification
7 and risk assessment, the TY2028 GRC TIMP Project Execution forecasts include
8 one additional excavation dig relative to historical averages.

9 - **Adoption of SI’s Independent Study Recommendations:** Additional factors
10 that may affect TIMP costs, though not currently reflected in Project Execution
11 forecasts, include implementation of applicable recommendations from SI
12 Associates’ independent study³⁶ evaluating the efficiency of SoCalGas’s TIMP
13 and DIMP. SoCalGas and SDG&E align policies and processes to enhance
14 consistency and efficiencies, so these recommendations will be implemented for
15 SDG&E’s TIMP, too. While some recommendations aim to improve cost
16 efficiencies, the timing, scope, and project-specific applicability of these
17 recommendations remain uncertain. For example, although the study found
18 SoCalGas’s SCC evaluation process to be sophisticated³⁷ and appropriate,³⁸ it
19 recommends continued enhancement of SCC risk assessment data to enable
20 SCCDA as a potential alternative to EMAT in some circumstances.³⁹ Because
21 assessment scopes are finalized during pre-assessment, the cost impacts of
22 ongoing SCC process improvements on future assessments and remediations
23 cannot yet be quantified.

³⁵ Pipeline Safety: Identification and Evaluation of Potential Hard Spots – In-Line Inspection Tools and Analysis, 89 Fed. Reg. 222,90827 (November 18, 2024), *available at*: <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2024-11/2024-26725.pdf>.

³⁶ See Ex. SCG-03, Appendix F.

³⁷ *Id.* at Section 5.8.2 (SCC Threat).

³⁸ *Id.*

³⁹ *Id.*

In summary, SDG&E’s TIMP –particularly project execution – is subject to inherent variability arising from the interaction of prescriptive regulatory requirements, site-specific field conditions, and continuing enhancements to federal integrity management practices and standards. The Commission has long recognized this variability and has consistently authorized balancing account mechanisms to “ensure that SDG&E has sufficient funds to carry out all the necessary TIMP-related work to ensure that its gas transmission system remains safe and reliable.”⁴⁰

The variability of TIMP Project Execution capital costs, which are incurred to comply with federal regulations, further necessitates continuation of SDG&E’s TIMP Balancing Account (TIMPBA), as discussed in greater detail in Exhibit SDGE-03 (Gas Engineering & System Integrity testimony) and Exhibit SDGE-21 (Regulatory Accounts testimony).

B. High Pressure Distribution Assessments Execution (NSS 1MP002.002)

TABLE DZ-10
Summary of High Pressure Distribution Assessments Execution Costs

GAS MAJOR PROJECTS (In 2025 \$)			
B. HP Distribution Assessments Execution	2025 Adjusted- Recorded (000s)	TY2028 Est. (000s)	Change (000s)
1. HP Distribution Assessments Execution	0	3,257	3,257
Total	0	3,257	3,257

1. Description of Costs and Underlying Activities

The activities and costs associated with this cost category include O&M labor and non-labor expenses required to complete integrity assessments on high priority, high-pressure (HP) distribution pipeline segments (specifically, segments that operate under 20% Specified Minimum Yield Strength (SMYS) and pressures exceeding 60 psig). Over time, and in an effort to increase the margin of safety on certain pipelines, SDG&E reduced operating pressures on several transmission assets to achieve stress levels below 20% SMYS, where rupture risk is significantly reduced. As a result of these pressure reductions, certain pipelines previously classified as transmission assets are now classified as distribution assets operating at the upper end of the distribution stress spectrum. Although these segments are governed under distribution

⁴⁰ D.13-05-010 at 387.

regulations, they operate at higher stress levels than typical distribution pipelines and, in some cases, may be subject to integrity threats more commonly associated with vintage transmission pipelines. In particular, these HP distribution segments may contain manufacturing-related defects, including pipe body anomalies, longitudinal pipe seam defects, and girth weld issues.

Drawing on an established history of in-line inspection (ILI) and defect detection practices under 49 CFR Part 192 Subpart O, SDG&E proposes to apply a TIMP-like approach to the condition assessment of these HP distribution segments. This approach is intended to more comprehensively understand the baseline condition of distribution pipelines that are both more susceptible to certain integrity threats and exposed to higher operating stress. Advanced TIMP methodologies, particularly advanced assessment techniques such as robotic ILI, have proven effective in transmission systems by enabling proactive identification of threats beyond historical leak performance. Applying these techniques to selected HP distribution segments allows SDG&E to more accurately estimate actual pipeline risk and supports data-driven decision-making for pipeline management and remediation activities.

a. Description of RAMP Mitigations

This cost category consists entirely of non-shared O&M costs associated with the M171 risk control/mitigation, which was not included in the 2025 RAMP Report and is newly proposed in the 2028 GRC. The M171 HP Distribution Assessment Execution activities identified in the section above are safety-driven risk mitigation measures associated with SDGE-Risk 2: High Pressure Gas system, identified in the 2025 RAMP Report. Activities that are compliance-driven or mandated by CPUC or other agencies are listed in bold. Appendix B to this testimony provides additional detail regarding applicable mandates for each control.

TABLE DZ-11
Southern California Gas Company
RAMP and GRC Risk Control/Mitigation Activities - O&M

Transmission Integrity management Program – TIMP (2MP002.00)				
ID	Control/Mitigation Name	2025 RAMP 2028 In 2024 \$ (000s)	2028 GRC 2028 In 2025 \$ (000s)	Change (000s)
M171	High Pressure Distribution Assessments	4,102	3,257	(845)

1 **b. Description of Selection and Prioritization of RAMP Risk**
2 **Mitigations**

3 SDG&E selected this mitigation as a targeted assessment activity focused on high
4 pressure distribution pipeline segments. In prioritizing this mitigation, SDG&E considered
5 factors such as pipeline age, stress level, and diameter. As described above, the proposed scope
6 is limited to a small number of pipelines that share characteristics with pipelines subject to
7 TIMP. The objective of this mitigation is to generate more comprehensive baseline condition
8 data for selected high pressure distribution segments exposed to higher stress levels. This
9 mitigation measure would enable SDG&E to improve threat identification and risk assessment
10 methodologies, such as those described in the GESI direct testimony (Ex. SDGE-03), that will
11 enhance risk mitigation activities and decision-making.

12 **2. Forecast Method**

13 Using existing DIMP pipeline analysis, SDG&E identified two candidate HP distribution
14 segments for robotic ILI assessment. This cost category is forecast using a zero-based method,
15 with project specific cost estimates developed for each segment. The estimates are informed by
16 historical cost data and execution experience from comparable ILI projects.

17 The Full Time Equivalent (FTE) forecast is based on an average FTE per dollar ratio
18 derived from historical average TIMP execution data (1MP002.000). Depending on company-
19 wide resource availability during this GRC cycle, the work may be performed using internal
20 labor, outside contractors, overtime, or a combination. The FTE forecast reflects average labor
21 hours required to complete the planned activities.

22 **3. Cost Drivers**

23 The cost drivers for HP distribution assessments include both labor and non-labor
24 components. Labor costs consist of the employees required to direct, oversee, and execute the
25 assessments on the HP distribution segments. Non-labor costs consist of contractors, materials,
26 permitting, and other expenses necessary to complete the assessments. The primary cost driver
27 is the number of assessments, along with segment-specific factors, such as pipeline configuration
28 and assessment complexity.

29 **IV. CAPITAL**

30 Capital costs for Gas Major Projects include expenditures for Gas Safety Enhancement
31 Programs (GSEP) Execution, Transmission Integrity Management Program (TIMP) Execution,
32 Moreno Compressor Modernization, and the Control Center Modernization (CCM). These

investments are necessary to meet regulatory requirements and support safety, reliability, and operational objectives. Table DZ-12 summarizes capital forecasts for 2026 through 2031. Project-specific in-service dates are provided in workpapers. Capital expenditures expected to be placed in-service between 2026, and Test Year 2028 are included in the Test Year 2028 revenue requirement (refer to Summary of Earnings testimony (Ex. SDGE-27)). Capital expenditures with post-test year in-service dates (*i.e.*, 2029-2031) are supported by the capital post-test year mechanism presented in the Post-Test Year Ratemaking testimony (Ex. SDGE-28).

TABLE DZ-12
Capital Expenditures Summary of Costs

GAS MAJOR PROJECTS (In 2025 \$)							
Categories of Management	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
A. TIMP Execution	15,466	25,873	25,859	25,798	25,837	25,848	25,864
B. Gas Safety Enhancement Programs Execution	44,144	9,627	10,929	19,602	23,176	17,300	9,229
C. Moreno Compressor Modernization	0	0	0	87,020	0	0	0
D. Control Center Modernization Ongoing Programmatic Activities	2,863	3,412	4,631	4,566	3,709	3,719	3,734
E. High Pressure Distribution Assessments Execution	0	0	0	5,148	5,165	5,170	5,177
Total	62,473	38,912	41,419	142,134	57,887	52,037	44,004

A. Transmission Integrity Management Program (TIMP) Execution (034680)

TABLE DZ-13
Capital Expenditures Summary of Costs

A. TIMP Execution	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. TIMP Execution	15,466	25,873	25,859	25,798	25,837	25,848	25,864
Total	15,466	25,873	25,859	25,798	25,837	25,848	25,864

1. Description and Background

The cost category for TIMP execution captures all capital costs associated with integrity assessments, retrofits, repairs, and replacements for pipelines classified as transmission under DOT regulations. The TIMP continually evaluates the transmission pipeline system and takes action 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.

Consistent with 49 CFR Part 192, Subpart O and 49 CFR § 192.710, SDG&E TIMP is a risk-based program designed to identify pipeline threats, assess pipeline condition, and implement remediation actions to reduce the likelihood of pipeline incidents and maintain system reliability. SDG&E continues to evaluate its system for ILI expansion where necessary.

ILI pipeline assessments are primarily O&M activities and are performed using specialized devices that internally traverse the pipeline to collect information that is used to assess the pipeline condition. However, some pipelines are not designed to accommodate these inspection tools, requiring retrofitting along the pipeline route (a predominantly capital activity). 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 direct examinations to both validate the inspection findings and determine necessary repairs, if needed. In certain cases, pipeline replacement is selected when it is more economically feasible and allows for future ILI assessments. ILI provides detailed condition data, particularly for time-dependent threats, and supports informed remediation decisions.

Following assessments, SDG&E implements appropriate remediation measures in compliance with 49 CFR Part 192, Subpart O and § 192.714. Remediation may include, but is not limited to, different combinations of cylindrical replacement of targeted pipe segments, recoating of pipe segments identified as having ineffective cathodic protection, installing new cathodic protection infrastructure such as rectifiers, and reducing the Maximum Operating Pressure (MOP).

1 **a. Description of RAMP Mitigations**

2 TIMP capital costs include risk control(s)/mitigation(s) measures addressing safety risks
3 that were identified in the 2025 RAMP Report addressing SDGE-Risk 2 High Pressure Gas
4 System. TIMP activities constitute required safety mitigations and are compliance driven, as
5 such costs are reviewed at the workpaper level to support timely completion as planned.
6 Activities that are compliance-driven or mandated by the CPUC or other regulatory agencies are
7 listed in bold. Appendix B provides details regarding applicable mandates for each control.

8 **TABLE DZ-14**
9 **RAMP and GRC Risk Control/Mitigation Activities – Capital (\$000s)**

ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (000s)
C171	Integrity Assessments & Remediation	71,020	103,347	32,327

10 **b. Description of Selection and Prioritization of RAMP Risk**
11 **Mitigations**

12 TIMP prioritization is guided by regulatory requirements,⁴¹ system risk, pipeline
13 condition data, and operational considerations. SDG&E assesses higher-risk transmission
14 pipelines⁴² for threats including corrosion, cracking, manufacturing and construction defects,
15 outside force damage, equipment failure, and operational corrections. SDG&E evaluates
16 pipeline data, operating conditions, and other necessary data to determine the appropriate actions
17 needed to maintain system integrity and reliability and reduce risk. Remediating identified
18 threats through replacement, repair, or other corrective actions reduces the likelihood and
19 consequences of pipeline failures and improves the overall safety, reliability, and integrity of the
20 system. Factors such as regulatory mandates and guidance (*e.g.*, advisory bulletins), current
21 pipeline data, historical activity levels, and system needs inform the scope of this control.

22 SDG&E continues its risk-informed TIMP activities to maintain compliance, support
23 system integrity, and provide safe and reliable transmission service. An independent efficiency
24 review by SI Associates observed that SDG&E’s TIMP reflects effective risk-based

⁴¹ Also refer to the GESI testimony, Ex. SDG&E-03.

⁴² HCA, Class 3, Class 4, and piggable MCA pipeline segments as scoped by 49 CFR Part 192 Subpart O and 49 CFR § 192.710.

prioritization, structured planning, and disciplined project execution, resulting in timely repairs, increasing ILI, and measurable public safety benefits.

Program management costs associated with C171 (Integrity Assessment and Remediation) are addressed separately in the Gas Engineering & System Integrity direct testimony (Ex. SDGE-03).

2. Forecast Method

The TIMP capital forecast is based on a recorded three-year average (2023-2025). This period best reflects the impact of enhanced federal requirements, including GTSR-related changes. Given the inherent variability of TIMP activities, driven by inspection findings and evolving conditions, this approach provides a reasonable estimate of expected costs while acknowledging forecasting limitations and supporting continued use of the TIMPBA.

3. Cost Drivers

Primary cost drivers for TIMP Execution include both labor and non-labor components estimating the number and type of required integrity assessments, capital retrofits needed to enable ILI, and repairs and pipeline replacements resulting from assessment findings. Labor consists of the employees required to direct, oversee, execute, and ultimately manage compliance and program requirements. Non-labor consists of contractors, materials, permitting, and other non-labor costs that are necessarily incurred in relation to those requirements.

Consistent with evolving federal regulations, SDG&E continues to evaluate and implement enhanced TIMP processes and tools to maintain the integrity of the gas transmission pipeline system. As previously described, federal compliance requirements have introduced changes to SDG&E's TIMP processes and activities and highlight the impacts that retrofitting, repair, and replacement activities have on SDG&E's overall TIMP capital costs.

When determined necessary through SDG&E's four-step assessment process, employing new ILI tools such as those capable of assessing cracks and crack-like features (*e.g.*, EMAT) 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. The increase in first-time ILI tool runs driven by enhanced federal requirements is expected to continue through at least this current assessment cycle, during which SDG&E will bring pipeline segments under the TIMP into compliance with updated

requirements. As previously described, assessment method and tool selection are determined during the Pre-Assessment phase of O&M activities.

Capital repairs and replacements are also driven by the O&M activities and findings, and the type and amount of work is dependent upon pipeline/project specific factors. When deploying new assessment methods (*e.g.*, SCCDA) and assessment tools (*e.g.*, MFL-C, EMAT), the increase in pipeline data for a pipeline project requires additional analysis which also leads to an increase in validation excavations to confirm the data on pipeline conditions.⁴³ Due to the overall increase in pipeline data and findings, SDG&E has seen an increase in conditions requiring repair, previously described above (Non-shared O&M Costs). As a result of the increase in assessment findings combined with the enhanced GTSR Part 2 repair requirements for areas outside of HCAs, the increase in remediation is expected to continue at least through this current assessment cycle, which the independent study on SDG&E's TIMP and DIMP efficiency projected to 2030 based on a seven year reassessment cycle,⁴⁴ though SDG&E anticipates that an increased level of activity through 2034 is plausible due to the ten-years maximum assessment/reassessment cycle of 49 CFR § 192.710.

Due to the variability and regulatory nature of SDG&E's TIMP Project Execution capital costs, SDG&E requests continuation of the TIMPBA, but modified to revert back to a two-way balancing account with 50 percent interim rate recovery for capital-related costs and O&M costs, as further discussed in the GESI testimony (Ex. SDGE-03).

B. Gas Safety Enhancement Programs (GSEP) Execution (235730, 245750)

TABLE DZ-15
Gas Safety Enhancement Program (GSEP) Execution Capital Costs

In 2025\$ (000s)	2025 Adjusted- Recorded	Est. 2026	Est. 2027	Est. 2028	Est. 2029	Est. 2030	Est. 2031
Gas Safety Enhancement Programs (GSEP) Execution	44,144	9,627	10,929	19,602	23,176	17,300	9,229
Total	44,144	9,627	10,929	19,602	23,176	17,300	9,229

⁴³ A.25-02-012, SDG&E Chapter II: Technical – Project Execution and Management, Ex. SDG&E-02 at 12-14.

⁴⁴ See Ex. SCG-03, Appendix F Section 5.6 (Repairs.)

1 **1. Description and Background**

2 These forecasted capital expenditures for GSEP support compliance with PHMSA’s
3 GTSR Part 1 and the Valve Installation and Minimum Rupture Detection Standards (Valve
4 Rule). Following the San Bruno and Marshall incidents, Congress enacted the 2011 Pipeline
5 Safety Act, prompting PHMSA to adopt strengthened federal gas transmission and gathering
6 requirements. GTSR Part 1, issued October 1, 2019, amended 49 CFR Parts 191 and 192,
7 establishing new mandates for MAOP reconfirmation, expanded non-HCA assessments, and
8 material verification, with compliance beginning July 1, 2021.⁴⁵ The Valve Rule, published
9 April 8, 2022, added new rupture-mitigation valve and rupture detection requirements for
10 applicable transmission pipelines.

11 SDG&E complies with these requirements by performing MAOP reconfirmation under
12 §192.624, non-HCA assessments under §192.710 through TIMP, and material verification under
13 §192.607 as applicable for assets lacking traceable, verifiable, and complete records.

14 The new and impending gas rules and regulations include the PHMSA GTSR Part 1 and
15 the Valve Rule. While the impacts of the GTSR Part 1 have been assessed and are continually
16 managed and validated by the Integrity Management department and supporting groups, there
17 are requirements stemming from the Valve Rule that will also result in incremental scope
18 impacting activities in this GRC period, which are further discussed below.

19 **a. GTSR Part 1 Replacements and Hydrotests**

20 GTSR Part 1 requires reconfirmation of MAOP for applicable transmission pipelines,
21 with 50 percent completion by July 3, 2028,⁴⁶ and 100 percent by July 2, 2035, or as otherwise
22 required.⁴⁷ Based on applicable federal requirements, SDG&E reviewed its transmission pipeline
23 segments to determine whether they are in the scope of the GTSR Part 1. SDG&E has already
24 met the initial 50% completion deadline through the execution of the 19 PSEP Line 1600

⁴⁵ Some requirements were effective July 1, 2020; *see* FAQ 1 of Frequently Asked Questions (FAQ) for the Final Rule titled “Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments,” published on October 1, 2019, *available at* <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-06/Batch-1-FAQs-PHMSA-2019-0225-9-15-20.pdf>.

⁴⁶ 49 CFR § 192.624(a).

⁴⁷ 100% 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.” 49 CFR § 192.624(b).

1 projects and is now focused on planning the remaining projects in coordination with TIMP
2 compliance deadlines. This integrated planning approach enables GTSR hydrostatic testing to
3 satisfy both MAOP reconfirmation and TIMP compliance requirements while achieving
4 meaningful cost savings through coordinated execution (see Section III.A.3, “Program
5 Coordination” for additional details).

6 Consistent with FERC accounting guidance issued June 23, 2020⁴⁸, costs incurred for
7 first-time pressure testing to meet new federal safety standards are capitalized.⁴⁹ The forecast is
8 based on an assumption that pipeline segments will generally be tested or replaced; however, 49
9 CFR § 192.624 permits operators to use any of six reconfirmation methods: pressure testing,
10 pressure reduction, engineering critical assessment (ECA), pipe replacement, pressure reduction
11 for pipeline segments with small potential impact radius (PIR), and alternative technology. Final
12 reconfirmation methods for pipeline segments may change subject to a segment- or project-
13 specific evaluation of factors including, but not limited to, safety; constructability; customer,
14 community, and environmental impacts; system reliability; and costs.

15 Detailed project information is provided in the supplemental workpapers (Ex. SDGE-06-
16 WP-S, Volume I) accompanied by a Summary of Standard Planning & Construction for
17 Replacement, Hydrotest, Valve, and Abandonment Projects.

18 **b. Valve Rule**

19 The Valve Rule requires installation of rupture mitigation valves (RMV) on onshore gas
20 transmission pipelines that have nominal diameters greater than or equal to 6 inches in diameter
21 that are either newly constructed, or entirely replaced transmission pipeline segments.⁵⁰ PHMSA
22 also revised regulations regarding identification of potential ruptures, notifications to public
23 safety agencies, among other requirements. The final requirements address congressional
24 mandates, incorporate recommendations from the National Transportation Safety Board, and are
25 necessary to reduce the consequences of large-volume, uncontrolled releases of natural gas and

⁴⁸ FERC Accounting Guidance, Docket: AI20-3-000, *Accounting for Pipeline Testing Costs Incurred to Comply with New Federal Safety Standards* (June 23, 2020), available at: <https://www.ferc.gov/sites/default/files/2020-06/AI20-3-000.pdf>.

⁴⁹ *Id.* at 2.

⁵⁰ 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. Also specifies spacing intervals from eight to twenty miles based on class location per 87 Fed. Reg. 68,20983 (April 8, 2022).

hazardous liquid pipeline ruptures. The final rule was published in the Federal Register on April 8, 2022.⁵¹

The Valve Rule expands the scope beyond SDG&E's existing PSEP Valve Enhancement Plan (VEP) and results in additional capital investment during this GRC period. While both aim to accomplish the 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 in comparison to the VEP are summarized in Table DZ-16 below.

TABLE DZ-16
Valve Rule and PSEP VEP Comparison

	Valve Rule	PSEP VEP
Type of Project	New or Replacement	Replacement
OD Threshold	≥6 inches	≥12 inches
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

c. Description of RAMP Mitigations

This cost category includes capital costs for risk controls and mitigations identified in the 2025 RAMP Report, as summarized in Table DZ-17 below. GSEP is a safety-driven program that serves as key mitigations for one of SDG&E's highest priority safety risks, SDGE-Risk-2 High Pressure Gas System. All forecasted GSEP capital costs presented above are compliance-driven risk mitigation measures mandated by PHMSA and implemented to address pipeline safety risks, as further described in SoCalGas and SDG&E's 2025 RAMP Report.⁵² Activities that are compliance-driven or mandated by the CPUC or other regulatory agencies are listed in bold. Appendix B provides the applicable mandates for each control.

⁵¹ Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards, 87 Fed. Reg. 68,20940 (April 8, 2022), available at: <https://www.govinfo.gov/content/pkg/FR-2022-04-08/pdf/2022-07133.pdf>.

⁵² Refer to the RDF Integration testimony (Ex. SCG- 02B/SDG&E-02B) for more details regarding the SDG&E's 2025 RAMP Report.

TABLE DZ-17
RAMP and GRC Risk Control/Mitigation Activities – Capital

Gas Safety Enhancement Programs (GSEP)				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 <i>In 2024\$</i> (000s)	2028 GRC 2028-2031 <i>In 2025\$</i> (000s)	Change
C013	Gas Transmission Safety Rule – MAOP Reconfirmation	66,810	44,563	(22,247)
C118	Rupture Mitigation Valve Installation – Valve Rule	24,306	24,744	438
TOTAL		91,116	69,307	(21,809)

d. Description of Selection and Prioritization of RAMP Risk Mitigations

GSEP activities are driven by new federal gas transmission safety requirements. PHMSA’s GTSR Part 1 requires operators to reconfirm the MAOP for transmission pipeline segments under 49 C.F.R. § 192.624, with milestone deadlines in 2028 and 2035.

The relative risk of GTSR Part 1 Replacements and hydrotests is indistinguishable. Therefore, prioritization is based primarily on constructability, including engineering and design, system constraints, permitting status, land rights and access, and other considerations, to enable execution within available construction windows while minimizing system impacts and maintaining compliance while progressing to meet the 50% PHMSA compliance target. Prioritization also places an emphasis on addressing pipelines located in more populated areas.

GSEP execution is also driven by PHMSA’s Valve Rule, which requires additional rupture mitigation valve installations and related construction activities. Valve Rule activities are prioritized based on annual risk analysis to identify areas where RMV installations are appropriate.⁵³ The initial estimate is based on an initial implementation strategy that leverages established processes and resources from the PSEP VEP to promote efficient compliance.

2. Forecast Method

a. GTSR Part 1 Replacements and Hydrotests

The forecast for GTSR Part 1 activities is developed using a zero-based, project-specific methodology. This method reflects the size, scope, and complexity of executing GTSR projects. Class 3 project-specific cost estimates were developed for projects over \$10M, using preliminary

⁵³ 49 CFR § 192.935(a)(1).

engineering and project planning analyses. For projects that did not reach this threshold, a project-specific cost estimate was still developed. The forecast also includes a hydrotest failure allowance derived from forecasted pipeline test mileage and historical test failure rates. Project-level cost information and assumptions are provided in the supplemental workpapers (Ex. SDGE-06-WP-S, Volume I). SDG&E forecasted costs based on an anticipated level of executable spending from the portfolio of projects compiled with the goal to manage reconfirmation projects to an annual forecast that meets the 50% and 100% compliance milestone targets established by PHMSA while balancing SDG&E's obligation to maintain gas system capacity planning to support system reliability. Given system reliability requirements, certain projects requiring pipeline shut-ins may be delayed despite engineering readiness. This approach allows Gas Major Projects to advance alternate projects from the overall GTSR portfolio to maintain progress toward PHMSA's milestone deadlines while remaining within GRC-authorized spending levels.

b. Valve Rule

SDG&E has identified four valve installations to be completed during this GRC cycle. This cost category is forecast using a zero-based methodology, with the estimated cost per valve informed by historical cost data and execution experience from comparable projects, and reflecting the full scope of valve work including engineering and design, permitting, procurement, installation, integration with control and monitoring systems as applicable, testing, commissioning, and close-out.

3. Cost Drivers

a. GTSR Part 1 Replacements and Hydrotests

Primary cost drivers include both labor and non-labor components for compliance with PHMSA's GTSR Part 1 MAOP reconfirmation requirements, particularly for certain gas transmission segments located in more populated areas, such as Class 3 or Class 4 locations and HCAs. Performing hydrotests and replacements in these more densely populated areas introduces construction challenges that drive incremental cost due to constrained access, limited work windows, complex traffic control, enhanced safety requirements, and extensive coordination with local and state agencies.

Specifically, hydrotests in dense population areas face elevated construction complexity that may include sites such as schools and hospitals, which tighten work windows and restrict

1 access. Establishing and isolating test sections in congested rights-of-way often requires
2 significant traffic control, additional excavations at valves and pipeline connections, temporary
3 bypass and jumper configurations, and more complex shut-in system analysis to limit customer
4 impacts. Urban permitting and traffic control may include work-hour restrictions, encroachment
5 permits, lane closures, detours, and intensive coordination with cities, counties, state
6 transportation agencies, and other entities. Water handling in built-up areas (sourcing, staging,
7 containment/treatment, and permitted discharge) may require additional equipment, haul routes,
8 and staging constraints on tight sites. Finally, work in high trafficked areas typically requires
9 enhanced safety measures, extensive notifications, and potentially off-hour construction that may
10 increase staffing and duration.

11 Similar to hydrotesting activities, additional cost drivers include non-contiguous pipeline
12 replacements that may be located at discrete, geographically separated sites, requiring repeated
13 mobilization and demobilization of crews, equipment, and traffic control. Construction activities
14 frequently occur within congested rights-of-way and may necessitate localized excavations,
15 temporary pipeline shutdowns or bypass configurations, and detailed system isolation analysis to
16 minimize customer impacts. Urban permitting requirements can include work-hour restrictions,
17 encroachment permits, lane closures, and coordination with multiple local and state agencies,
18 which may extend project duration and increase costs. In addition, work in highly trafficked or
19 sensitive areas typically requires enhanced safety measures, stakeholder notifications, and
20 off-hour construction, further contributing to increased labor, traffic management, and overall
21 execution costs relative to contiguous pipeline replacements.

22 **b. Valve Rule**

23 Valve Rule costs are driven by the number and scope of RMV installations required to
24 comply with PHMSA's Valve Rule. Costs include both labor and non-labor components
25 necessary to support program execution and regulatory compliance. Labor costs reflect the
26 personnel required to plan, oversee, execute, and manage valve installations, including project
27 management, engineering, and construction management functions. Non-labor costs include
28 contractor services, materials and equipment, permitting, traffic control, and other supporting
29 costs incurred to implement these requirements.

C. Moreno Compressor Modernization (204760)

**TABLE DZ-18
Capital Expenditures Summary of Costs**

C. Moreno Compressor Station Modernization	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. Moreno Compressor Station Modernization	0	0	0	87,020	0	0	0
Total	0	0	0	87,020	0	0	0

1. Description and Background

The Moreno Compressor Modernization (MCM) Project is a compliance-driven effort required to address the sunset of South Coast AQMD RECLAIM program, and to comply with Rule 1110.2 and Rule 1100. In the TY 2024 GRC Decision, the Commission authorized costs up to \$409.7 million in direct 2021 dollars for the MCM project, which SDG&E may seek recovery for in a Tier 2 Advice letter once the project is completed and placed in service.⁵⁴ Within this GRC, SDG&E is not requesting a modification to the authorized amount but instead is requesting an additional \$87.0 million. After adjusting the originally authorized costs based on direct 2021 dollars to nominal dollars, the requested amount equates to a 15% increase on an inflation-adjusted basis.

The original forecast at the time of submission for the 2024 GRC was a Class 3 estimate, consistent with AACE International Recommended Practice No. 18R-97, which denotes an estimated final project cost between -20% or +30% from the current project cost. Since the approval of the 2024 GRC, the project design has matured to nearly 90% completion, providing a clearer understanding of the engineering scope, material quantities, construction requirements and vendor pricing. Some of the changes from initial assumptions resulted in additional staffing, extended schedule durations, and expanded project support. These combined factors, along with increased SoCal Edison system requirements and changes to California Building Codes have contributed to the updated project forecast and the resulting cost increase request. Additional details for the MCM project are provided in the Supplemental Workpaper section of (Ex. SDGE-06-CWP-S, Volume II).

⁵⁴ D.24-12-074 at 287-289.

1 **2. Forecast Method**

2 A zero-based forecast is used for MCM, relying on detailed project-specific estimates,
3 vendor pricing, and execution experience. This approach is appropriate for costs exceeding the
4 cost cap that cannot be supported by historical trends.

5 **3. Cost Drivers**

6 Primary cost drivers are non-labor and include additional activities and materials related
7 to updated compliance requirements following the 2024 GRC filing. These activity and
8 materials costs include: the integration of voltage stabilizing devices required to interconnect to
9 the Southern California Edison electric grid; incorporating additional third-party design and
10 engineering support in response to changes to the California Building Code (CBC), and the
11 International and California Fire Codes; significant quantity increases of steel, concrete, and
12 deep foundation piles in response to the CBC changes and a geotechnical report; and increased
13 environmental support due to new species protections under the California Endangered Species
14 Act. Labor costs are minimal and reflect project execution, coordination, compliance, and
15 closeout activities that are associated with the extended schedule of the project.

16 **D. Control Center Modernization (CCM) Ongoing Programmatic Activities**
17 **(215740, A04190)**

18 **TABLE DZ-19**
19 **Capital Expenditures Summary of Costs**

D. Control Center Modernization	2025 Adjusted- Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. Control Center Modernization Ongoing Programmatic Activities	2,863	3,412	4,631	4,566	3,709	3,719	3,734

20 **1. Description and Background**

21 The forecast for CCM Ongoing Programmatic Activities includes High-Consequence
22 Area (HCA) Methane Sensor installations and Distribution Regulator Stations (DRS)
23 enhancements. During this GRC cycle, SDG&E will begin deploying DRS enhancements and

1 continue installing HCA Methane Sensors as part of the CCM initiative originally authorized in
2 D.19-09-051⁵⁵ and D.24-12-074.⁵⁶

3 These activities enhance system safety and reliability by expanding visibility and control
4 capabilities across the gas network. Collectively, these investments strengthen operational
5 resiliency and situational awareness, through the ability to monitor and respond to abnormal
6 operating conditions in near-real time and support SDG&E's objectives to enhance public and
7 employee safety, system reliability, and operational effectiveness.

8 **a. CCM Distribution**

9 The DRS component of the program introduces real-time monitoring and remote-control
10 functionality at targeted regulator stations, which provides Gas Control with enhanced visibility
11 into the dynamic pressures and flows across the gas distribution system. By enabling Gas
12 Control to remotely operate and control DRS sites, Gas Control shifts from a monitor-and-
13 respond approach to a monitor, operate, and control approach, allowing for faster response times
14 and reducing reliance on manual field intervention. This change in approach places increased
15 emphasis on safety, system reliability, data analytics, remote operations, and proactive
16 maintenance. Overall, these enhancements reduce both the likelihood and potential
17 consequences of overpressure or under-pressure events. Additional details on scope and cost
18 estimates are provided in a supporting workpaper (*see* Ex. SDG&E-06-CWP, Volume III).

19 **b. CCM Transmission**

20 The CCM Transmission component includes the installation of HCA Methane Sensors,
21 which enables 24/7 control room monitoring personnel to accelerate the identification of,
22 response to, and remediation of potential leaks in high-risk locations along high-pressure
23 pipelines using advanced sensing technology. These sensors will help increase system
24 reliability, support sustainability efforts, and enhance the overall safety of our system.

25 During this GRC cycle, SoCalGas will transition the HCA Methane Sensor component to
26 Version 2 (V2) methane sensors, which will provide enhanced monitoring capabilities at a lower
27 capital and O&M cost than the Version 1 sensors. The V2 sensors reduce installation complexity
28 and lifecycle costs, enabling SoCalGas to improve safety while increasing cost-effectiveness and

⁵⁵ D.19-09-051 at 127-132.

⁵⁶ D.24-12-074 at 153-157, 200.

affordability for ratepayers. Although this transition to the V2 sensor extends the end date of deployment to 2031, the cost of the overall project has decreased. Additional details on scope and cost estimates are provided in a supporting workpaper (see SDG&E-06-CWP, Volume III).

c. Description of RAMP Mitigations

All CCM Ongoing Programmatic Activities in this cost category are designated as RAMP mitigations. The DRS work aligns with mitigation C124 (Regulator Station Installation, Replacement & Enhancement), and the HCA Methane Sensor work aligns with mitigation C010 (Pipeline Monitoring Technologies). These mitigations were prioritized based on safety, reliability, and cost-effectiveness considerations, as reflected in the Benefit-Cost Ratio (BCR) analysis. While certain BCR values are below one, these activities provide substantial public safety benefits by reducing the likelihood and severity of incidents that could impact customers and communities.

Within this cost category there are Capital costs for risk control(s)/mitigation(s) that were presented in the 2025 RAMP Report and are listed in the table below.

TABLE DZ-20
RAMP and GRC Risk Control/Mitigation Activities – Capital (\$000s)

ID	Control/Mitigation Name	2025 RAMP In 2024\$ 2028-2031 Estimate	2028 GRC In 2025\$ 2028-2031 Forecast	Change
C010	Pipeline Monitoring Technologies	2,536	894	-1,642
C124	Regulator Station Installation Replacement & Enhancement	8,839 ⁵⁷	14,834	5,995

d. Description of Selection and Prioritization of RAMP Risk Mitigations

RAMP risk mitigation activities consist of targeted programs, projects, processes, and technologies designed to address identified safety and/or reliability risks. Selection and prioritization considers many factors, including the Enterprise Risk Management (ERM) framework for identifying and assessing system risk as described in the RDF Integration

⁵⁷ The total RAMP Capital forecast (2028-2031) for C124 is \$17.784 million. The cost shown on the table represents the estimated RAMP Capital forecast allocated for this workpaper, proportional to the GRC Capital forecast, representing 49.7% of the total activity. The other portion of costs for C124 can be found in the Gas Distribution testimony (Ex. SDGE-04).

1 testimony (Ex. SCG-02B/SDGE-02B), safety impact, reliability benefits, technological maturity,
2 and cost-effectiveness.

3 **2. Forecast Method**

4 **a. CCM Distribution**

5 For CCM Distribution, DRS enhancement component, a zero-based forecast was applied
6 as historical spending does not accurately match the forecasted costs. Forecasted costs were
7 built from the ground up based on anticipated activities, including project management,
8 engineering, permitting, site acquisition, and configuration, rather than relying on historical
9 averages. An initial DRS project is expected to be completed by YE 2026.

10 **b. CCM Transmission**

11 For CCM Transmission, HCA Methane Sensor component, a zero-based forecast was
12 applied as SoCalGas will deploy a new generation of methane sensors with materially different
13 technology and cost profiles than those reflected in the 2024 GRC. The zero-based estimates are
14 based on vendor quotes, engineering analysis, and anticipated deployment volumes rather than
15 historical averages.

16 **3. Cost Drivers**

17 **a. CCM Distribution**

18 The underlying cost drivers are from project management, planning, designing,
19 engineering, permitting, construction and close out activities related to the enhancement of
20 DRSs. Supporting documentation is provided in the accompanying workpapers (Ex. SDG&E-
21 06-CWP-S, Volume III).

22 **b. CCM Transmission**

23 The primary cost drivers for the HCA methane sensor project are driven by the technical
24 complexity of integrating new field detection capabilities into an existing control center
25 environment. Labor costs reflect the project management, construction management, and
26 business readiness activities that company employees perform. Non-labor costs reflect:
27 contractor services for site design, installation, and commissioning; procurement of advanced
28 control and sensing equipment; and permitting and environmental compliance for field
29 installations. Supporting documentation is provided in the accompanying workpapers (Ex.
30 SDG&E-06-CWP-S, Volume III).

E. High Pressure Distribution Assessments Execution (A34680)

**TABLE DZ-21
Capital Expenditures Summary of Costs**

E. High Pressure Distribution Assessments Execution	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. High Pressure Distribution Assessments Execution	0	0	0	5,148	5,165	5,170	5,177
Total	0	0	0	5,148	5,165	5,170	5,177

1. Description and Background

The forecast for high pressure (HP) distribution assessment execution includes capital related costs necessary to complete integrity assessments on selected high priority, HP distribution pipeline segments. As part of prior safety initiatives, SDG&E reduced operating pressures on certain transmission pipelines to below 20% SMYS, significantly lowering rupture risk. As a result, some pipelines formerly classified as transmission assets are now regulated as distribution assets but continue to operate at higher pressures than typical distribution pipelines. Due to their operating history, age, and construction characteristics, these HP distribution segments may be exposed to threats more commonly associated with vintage transmission pipelines, including manufacturing-related defects in the pipe body, pipe seams, or girth welds. To proactively identify and evaluate these potential threats, SDG&E proposes targeted integrity assessments such as robotic ILI technology where practicable. Conducting TIMP-like assessments on these segments provides more detailed and actionable condition data than traditional distribution-only inspection methods, enhancing threat identification, risk modeling, and prioritization of mitigation activities.

ILI pipeline assessments are primarily O&M activities performed using specialized devices that travel internally through the pipeline to collect data used to assess pipeline condition. However, capital investments are required where pipeline retrofits are necessary to accommodate inspection tools. These retrofits may include installation of pressure control fittings to provide entry and exit points for robotic tools, valve replacements, or fitting modifications for adequate internal clearance. Once the retrofit is completed, the inspection tool

is run, followed by direct examinations to both validate the inspection findings and determine necessary repairs, if needed.

a. Description of RAMP Mitigations

This cost category consists entirely of capital costs associated with the M171 risk control/mitigation, which was not included in the 2025 RAMP Report and is newly proposed in the 2028 GRC. The M171 HP Distribution Assessment Execution activities identified in the section above are safety-driven risk mitigation measures associated with SDG&E-Risk 2: High Pressure Gas system, identified in the 2025 RAMP Report. Activities that are compliance-driven, or mandated by the CPUC or other regulatory agencies, are listed in bold. Appendix B provides details regarding applicable mandates for each control.

TABLE DZ-22
RAMP and GRC Risk Control/Mitigation Activities – Capital

Transmission Integrity Management Program - TIMP				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (000s)
M171	High Pressure Distribution Assessments	8,064	20,660	12,596

b. Description of Selection and Prioritization of RAMP Risk Mitigations

SDG&E selected this mitigation as a targeted assessment activity focused on high pressure distribution pipeline segments. In prioritizing this mitigation, SDG&E considered factors such as pipeline age, stress level, and diameter. As described above, the proposed scope is limited to a small number of pipelines that share characteristics with pipelines subject to TIMP. The objective of this mitigation is to generate more comprehensive baseline condition data for selected high pressure distribution segments exposed to higher stress levels. This mitigation measure should enable SoCalGas to improve threat identification and risk assessment methodologies, such as those described in the GESI testimony (Ex. SDGE-03), that will enhance risk mitigation activities and decision-making.

2. Forecast Method

The cost category uses a zero-based forecast informed by historical cost data and execution experience from comparable ILI projects. Construction cost estimates reflect previous work of similar scope in similar setting. HP distribution assessment costs are driven by variable

1 conditions (*e.g.*, pipeline data, findings, and conditions) that are typically not known until the
2 Pre-Assessment phase.

3 The FTE forecast is based on average FTE per dollar from TIMP historical data (P3120,
4 002760). Staffing may include internal labor, contractors, overtime, or a combination thereof.
5 The FTE estimate represents the average effort required to complete this activity. *See*
6 Ex. SDGE-06-CWP.

7 **3. Cost Drivers**

8 Primary capital cost drivers include the number of assessments and associated retrofits,
9 repairs, and replacements. Labor costs reflect personnel required to direct, oversee, and execute
10 assessments. Non-labor costs include contractors, materials, permitting, and other related
11 expenses.

12 **V. RISK ASSESSMENT AND MITIGATION PHASE INTEGRATION**

13 **A. GRC Risk Controls/Mitigations and Benefit Cost Ratios**

14 As previously discussed, certain costs supported in this testimony are for
15 Control/Mitigation activities described in SDG&E's 2025 RAMP Report⁵⁸ for activities designed
16 to reduce risk. Specifically, the controls and mitigations in this testimony were included in:
17 SDGE Risk-02 High Pressure Gas System and SDGE-03 Medium Pressure Gas System. As
18 further reference, a roadmap matching controls and mitigations to both the 2025 RAMP and the
19 TY2028 GRC testimony is appended to Ex. SCG-02B/SDGE-02B. Table DZ-23 below
20 summarizes the Control/Mitigation BCRs based on the costs forecasted⁵⁹ in this testimony and
21 estimated in the 2025 RAMP with the associated BCRs. Controls/Mitigations that are mandated
22 by CPUC or other agencies are listed in bold in the table below and are listed in Appendix B,
23 attached to this testimony, providing the details regarding the respective mandates for each
24 Control/Mitigation.

⁵⁸ A.25-05-013.

⁵⁹ Post-test year forecasts can be found in the detailed workpapers Ex. SDGE-28-WP and Ex. SDGE-28-CWP.

TABLE DZ-23
Comparison of RAMP and GRC Risk Control/Mitigation Benefit Cost Ratios

Gas Major Projects							
ID	Control/ Mitigation Name	2025 RAMP Direct, in 2024\$ 2028-2031			2028 GRC Direct, in 2025 \$ 2028-2031		
		BCR Societal	BCR Hybrid	BCR WACC	BCR Societal	BCR Hybrid	BCR WACC
C010	Pipeline Monitoring Technologies	1.09	0.80	0.67	4.82	3.04	2.58
C013	Gas Transmission Safety Rule - MAOP Reconfirmation	0.77	0.26	0.19	0.12	0.08	0.07
C118	Rupture Mitigation Valve Installation - Valve Rule	0.10	0.04	0.04	0.06	0.03	0.03
C124	Regulator Station Installation Replacement & Enhancement	0.12	0.05	0.05	0.07	0.03	0.02
C171	Integrity Assessments & Remediation	1.33	1.25	1.12	0.42	0.39	0.36
M171	High Pressure Distribution Assessments	0.07	0.06	0.06	0.05	0.05	0.04

Note: Controls/Mitigations shown in bold font are those that are mandated by state or federal regulations.

B. Justification For Proposed Mitigations With BCRs <1

The RDF prescribes a methodology for calculating Benefit Cost Ratios under three discount rates, as detailed in the table above. While certain mitigations have BCRs below one under RDF methodology, SoCalGas justifies their inclusion based on operational and regulatory compliance considerations. Detailed justifications are provided in the RDF Integration testimony (SCG-02B/SDGE-02B) and summarized in Table DZ-24, with supporting compliance drivers/mandates identified in Appendix B.

TABLE DZ-24
BCR <1 Justification

ID	Control/Mitigation Name	Justification
C013	Gas Transmission Safety Rule – MAOP Reconfirmation	This mitigation is required for compliance with the PHMSA-issued GTSR Part 1. Operators must reconfirm the MAOP of high-pressure pipelines in populated areas in accordance with 49 CFR §192.624(a).
C118	Rupture Mitigation Valve Installation – Valve Rule	This mitigation is required for compliance with the PHMSA-issued Valve Rule. Operators must perform a risk analysis of HCAs and determine where RMVs must be installed in accordance with 49 CFR §192.935(c).
C124	Regulator Station Installation Replacement & Enhancement	Continuation of activities authorized in the 2019 and 2024 GRCs to enhance the safety and reliability of the Gas Distribution system. This work aims to expand Gas Control’s ability to continuously monitor the system to enable faster identification of leaks and abnormal operating conditions so corrective actions can be taken as soon as practicable.
C171	Integrity Assessments & Remediation	SDG&E continues to implement the TIMP as mandated by 49 C.F.R. § Part 192, Subpart O and 49 C.F.R. § 192.710. TIMP addresses transmission pipeline failure risks through activities such as threat identification, assessment, remediation, and preventive and mitigative measures. Activities executed under the TIMP are necessary to maintain a compliant, safe, and reliable transmission pipeline system.
M171	High Pressure Distribution Assessments	This mitigation is a targeted assessment activity for high-pressure distribution pipeline segments based on factors such as pipeline age, stress level, diameter, and similarities to pipelines subject to TIMP. The mitigation is intended to generate baseline condition data for selected higher-stress segments and support improved integrity management decision-making. The BCR does not fully account for the foundational benefits that will result from integrating the collected data into integrity management planning, including improved understanding of these segments, enhanced risk modeling, and more targeted risk-informed investments.

C. Changes From 2025 RAMP Report

Since the filing of the 2025 RAMP Report in May 2025, certain circumstances have changed that affect the control/mitigation scope – including units, costs, and other factors underlying the forecasts presented in this GRC. In addition, updates to assumptions used to calculate the BCRs are described in the Risk Philosophy testimony (Ex. SCG/SDGE-02). The key changes are summarized below:

- C013 Gas System Gas Transmission Safety Rule - MAOP
Reconfirmation: Relative to the 2025 RAMP report, the TY2028 GRC forecast reflects lower units and costs due to updated scope validation and refinement of MAOP reconfirmation activities.
- C171 Integrity Assessments & Remediation: TIMP forecast updates are informed by the latest assessment plan information, evolving compliance requirements, and updated assumptions regarding planned integrity assessment and remediation activity. The number of forecasted projects and associated costs have been updated to reflect the latest projections.
- M171 High Pressure In Line Inspection: M171 is a newly forecasted mitigation relative to the 2025 RAMP report. It represents a targeted subset of A171 as previously described, with a narrower scope limited to select pipeline segments. The higher cost reflects updated estimates based on more detailed engineering evaluation and technology selection.
- C124 Regulator Station Installation Replacement & Enhancement: The TY2028 GRC forecast reflects higher costs than the 2025 RAMP report due to updates to the annual project execution pace. The 2025 RAMP projections were based on planning-level assumptions that anticipated a slower DRS enhancement rate, whereas the TY2028 GRC forecast reflects a revised installation profile informed by recent project execution and updated assumptions to better address reliability and safety.
- C010 Pipeline Monitoring Technologies: The TY2028 GRC forecast reflects schedule and cost changes relative to the 2025 RAMP report driven by the transition from V1 to V2 sensors. The 2025 RAMP report assumed a slower installation pace for the V1 sensors, however the

1 transition to V2 sensors, allows the schedule to reflect lower overall costs
2 and a condensed schedule duration due to the ease of constructability and
3 affordability of the new asset. As a result, the TY2028 GRC forecast
4 shows a shorter installation timeline with more refined cost assumptions
5 compared to the initial RAMP estimates.

6 The Commission's Safety Policy Division (SPD) issued their assessment report on
7 October 10, 2025 regarding the Companies' 2025 RAMP Reports. Parties subsequently served
8 opening and reply comments on November 17, 2025 and December 1, 2025 respectively.
9 Appendix B of the RDF Integration testimony (Ex. SCG-02B/SDG&E-02B) summarizes the
10 feedback received and the Companies' responses.

11 **D. CAVA Integration**

12 Pursuant to Commission decisions in the Climate Adaptation OIR (R.18-04-019),⁶⁰
13 SDG&E performed a Climate Adaptation Vulnerability Assessment (CAVA) focused on years
14 2030, 2050, and 2070, with the aim of identifying asset and operational vulnerabilities to climate
15 hazards across the SDG&E system. Some of the climate hazards that will have short- and long-
16 term ramifications in the Southern California region include extreme temperatures, wildfire,
17 inland flooding, coastal flooding and erosion, and landslides. Climate change is recognized as a
18 factor that can drive, trigger, or exacerbate multiple RAMP risks. Implementing climate change
19 adaptation measures and integrating climate vulnerability considerations into RAMP controls
20 and mitigations can enhance system infrastructure longevity and reduce the severity of long-term
21 negative climate impacts. The controls and mitigations described in further detail in this chapter,
22 as shown below, align with the goal of increasing SDG&E's physical and operational resilience
23 to the increasing frequency and intensity of climate hazards. Additional information on the
24 CAVA is provided in Ex. SDGE-09.

⁶⁰ D.19-10-054; D.20-08-046.

TABLE DZ-25
Controls and Mitigations that Align with Increasing Resilience to Climate Hazards

Potential Climate Hazard(s)	Relevant ID	Relevant Control / Mitigation	Risk Chapter
Inland Flooding; Landslides	C010	Pipeline Monitoring Technologies	High Pressure Gas System
Inland Flooding; Landslides	C013	Gas Transmission Safety Rule – MAOP Reconfirmation	
Inland Flooding; Landslides	C171	Integrity Assessments & Remediation	

VI. PSEP LINE 1600 REASONABLENESS REVIEW

A. Procedural History and Background

On September 9, 2010, a 30-inch diameter natural gas transmission pipeline ruptured and caught fire in the city of San Bruno, California. In response, on February 25, 2011, the Commission initiated Rulemaking (R.)11-02-019, “a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines.”⁶¹ In this Rulemaking, the Commission committed to enhance the safety of natural gas pipelines and concluded that “all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety.”⁶² Historic exemptions must come to an end with an orderly and cost-conscious implementation plan. To achieve this objective, the Commission ordered “all California natural gas transmission pipeline operators to prepare Implementation Plans to either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test.”⁶³ These plans were required to “provide for testing or replacing all such pipeline as soon as practicable” and were further required to comply with several specific directives by the Commission.⁶⁴

On August 26, 2011, all California transmission pipeline operators, including SoCalGas and SDG&E filed proposed plans to implement the Commission’s directives. The Utilities’ proposed plan, the PSEP, included a Decision Tree to guide whether specific pipeline segments

⁶¹ R.11-02-019, Order Instituting Rulemaking (February 24, 2011) at 1.

⁶² D.11-06-017 at 18.

⁶³ *Id.*

⁶⁴ *Id.*

1 should be pressure tested, replaced, or abandoned; a list of pipelines for which the Utilities had
2 not yet located pressure test records; a prioritization process to address pipelines in more
3 populated areas ahead of pipelines in less populated areas; a valve enhancement plan; a
4 technology plan; and preliminary cost forecasts. Line 1600 was included in the list of pipelines
5 to be addressed under PSEP.⁶⁵

6 On December 2, 2011, the Utilities amended their PSEP to include supplemental
7 testimony addressing ratemaking issues identified in a November 2, 2011 Amended Scoping
8 Memo and Ruling of the Assigned Commissioner.⁶⁶

9 **1. Commission Decision Approving SoCalGas and SDG&E's PSEP**

10 In June 2014, the Commission approved SoCalGas and SDG&E's proposed PSEP, but
11 did not pre-approve the costs to implement the plan. Specifically, the Commission "adopt[ed]
12 the concepts embodied in the Decision Tree," "adopt[ed] the intended scope of work as
13 summarized by the Decision Tree," and "adopt[ed] the Phase 1 analytical approach for Safety
14 Enhancement... as embodied in the Decision Tree...and related descriptive testimony."⁶⁷

15 Because SoCalGas and SDG&E's PSEP cost estimates were preliminary in nature, rather
16 than pre-approve cost recovery based on those preliminary cost forecasts, the Commission
17 adopted a process for reviewing PSEP implementation costs after-the-fact prior to authorizing
18 recovery of PSEP implementation costs in rates.⁶⁸

19 To enable after-the-fact review of PSEP costs prior to recovery in rates, the Commission
20 ordered SoCalGas and SDG&E to establish balancing accounts to record PSEP expenditures.
21 SoCalGas and SDG&E were ordered to "file an application with testimony and work papers to
22 demonstrate the reasonableness of the costs incurred which would justify rate recovery."⁶⁹

⁶⁵ D.18-06-028 at 8.

⁶⁶ R.11-02-019/A.11-11-002, Amended Testimony of SoCalGas and SDG&E in Support of Proposed Natural Gas Pipeline Safety Enhancement Plan (December 2, 2011) at 126-127, *available at*: <https://www.socalgas.com/regulatory/documents/r-11-02-019/Amended%20Testimony-12.2.11.pdf>.

⁶⁷ D.14-06-007 at 59 (OP 1).

⁶⁸ *Id.* at 59 (OP 2).

⁶⁹ *Id.* at 60 (OP 5).

1 There have been four closed proceedings and one pending proceeding that have been
2 filed in accordance with D.14-06-007.⁷⁰ These proceedings have guided the current, adopted
3 forecasting methodology, and the development and execution of the Line 1600 projects.

4 **2. Procedural History of Line 1600**

5 The Commission's decisions establish the requirements for bringing Line 1600 into
6 compliance with Public Utilities Code 958 and define the scope of cost review for that work. In
7 D.14-06-007, the Commission directed SoCalGas and SDG&E to address Line 1600's
8 replacement through a separate application, which led to the filing of A.15-09-013 for the
9 Pipeline Safety Reliability Project (PSRP). In D.18-06-028, the Commission denied the PSRP
10 and instead ordered the Utilities to submit a hydrostatic test or replacement plan for Line 1600 to
11 achieve compliance with § 958, providing detailed guidance on testing, replacement, and
12 rerouting options. The Utilities submitted the required Line 1600 Test or Replacement Plan, and
13 SED approved Design Alternative 1—replacement in High Consequence Areas and hydrostatic
14 testing in non-HCAs—on January 15, 2019.⁷¹ Subsequent decisions, including D.20-02-024,
15 addressed the provision of cost information, and D.24-01-007 closed A.15-09-013, determining
16 that the only remaining Line 1600 issues concern the reasonableness of costs incurred to
17 implement the SED-approved plan. Consistent with that directive, Line 1600 Pipeline Safety
18 Enhancement Plan costs are presented for Commission review in this General Rate Case.

19 Figure DZ-5 summarizes the key Commission decisions governing Line 1600 compliance
20 and cost review.

21 **Figure DZ-5**
22 **Line 1600 Procedural Background**



⁷⁰ Past proceedings include: A.14-12-016; A.16-09-005; A.18-11-010; A.17-03-021; A.17-10-008.

⁷¹ See Appendix C (SED Approval Letter).

1 In D.14-06-007, the Commission ruled that SoCalGas and SDG&E's proposal to address
2 Line 1600 by installing a new 36-inch high pressure gas transmission line (known as Line 3602)
3 should be addressed in a new application.⁷² As a result, following further engineering and
4 environmental review, the Utilities filed A.15-09-013 for a Certificate of Public Convenience
5 and Necessity (CPCN) to construct the PSRP. The PSRP proposed to bring Line 1600 into
6 compliance with Pub. Util. Code § 958 and D.11-06-017 by constructing a new 36-inch natural
7 gas transmission pipeline (Line 3602) to replace Line 1600's transmission capacity and enhance
8 reliability, and de-rate existing Line 1600 to distribution service.

9 As required by Commission Rules of Practice and Procedure 3.1 and 2.4, the Utilities
10 engaged in substantial engineering design work, environmental review (including consideration
11 of alternatives), and outreach to the public and stakeholders to prepare and file A.15-09-013 and
12 its Proponents' Environmental Assessment (PEA). Subsequently, the January 22, 2016 Joint
13 Assigned Commissioner and Administrative Law Judge's Ruling Requiring an Amended
14 Application and Seeking Protests, Responses, and Replies required the Utilities to submit
15 additional information, including a Cost-Effectiveness Analysis (CEA), that evaluated eleven
16 specified alternatives and updates to the PEA. In response, the Utilities filed an amendment to
17 Application 15-09-013 on March 21, 2016. Thereafter, among other things, the Utilities worked
18 with the Commission's Energy Division to conduct the significant environmental review
19 necessary to create an Environmental Impact Report, responded to intervenor discovery,
20 prepared testimony, participated in evidentiary hearings, and prepared numerous filings for the
21 Commission regarding the PSRP, alternatives to it, and bringing Line 1600 into compliance with
22 Pub. Util. Code § 958 and D.11-06-017. The information obtained during this process was
23 foundational and essential for developing the CPUC approved Line 1600 Plan and these costs
24 have been included in the Line 1600 projects.

25 In D.18-06-028, the Commission denied A.15-09-013, rejecting the Utilities' proposed
26 PSRP and its Line 1600 solution. Instead, the Commission ordered the Utilities to submit to
27 SED, within three months, a hydrostatic test or replacement plan for Line 1600. The
28 Commission provided detailed instruction for such a plan, including discussion of two options:
29 "1. Hydrotest the entire 49.7 miles of line and replace those segments that fail the test; and 2.

⁷² D.14-06-007 at 16-17.

1 Replace all pipeline segments in HCAs [High Consequence Areas] along Line 1600, thus
2 ensuring a new pipeline without vintage pipeline characteristics that are perceived to increase the
3 risk of Line 1600. Hydrotest in solely non-HCA segments would ensure less impact if there was
4 a failure during hydrotesting.”⁷³ The Utilities also were required to “identify proposed rerouting
5 of the line in specific segments and/or removal or moving of specific physical structures, known
6 at this time, due to safety compliance reasons.”⁷⁴

7 The Utilities utilized studies, engineering work and environmental review performed for
8 A.15-09-013, including analysis of the PSRP and alternative pipeline routing, to help design and
9 develop the alternatives presented to SED in the Line 1600 Test or Replacement Plan. The
10 availability of such information was essential for the Utilities to meet the three-month turnaround
11 time for submitting the required plan to SED.

12 In accordance with D.18-06-028, on September 26, 2018, the Utilities submitted to SED
13 the “Line 1600 Test or Replacement Plan” (Appendix E), which included four design alternatives
14 to pressure test or replace Line 1600 in compliance with Pub. Util. Code §§ 957 and 958.
15 SoCalGas and SDG&E proposed to implement Design Alternative 1 (Replace in HCAs, Test in
16 Non-HCAs). SED approved the Line 1600 Plan on January 15, 2019.

17 On May 31, 2019, Protect our Communities Foundation (POC), Sierra Club, Southern
18 California Generation Coalition (SCGC), and The Utility Reform Network (TURN) filed a
19 Petition for Modification (PFM) of D.18-06-028. D.20-02-024 approved the PFM in part,
20 ordering a review of a Class Three cost forecast for implementing Line 1600 Design Alternative

21 1. As stated in Ordering Paragraph 3:

22 “Within six months of the issuance of the Decision Approving Limited
23 Modifications To Decision 18-06-028, to supplement the above, it is
24 reasonable for Applicants to file cost information that includes, but is not
25 limited to: the Class Three cost forecast for all Line 1600 segments, cost
26 estimating methodology, proposed accounting treatment, contingency
27 factor assumptions, cost containment strategies, and proposed schedule for
28 applications for reasonableness review and cost recovery, supported by
29 direct testimony and work papers, of the work to implement the SED-

⁷³ D.18-06-028 at 92.

⁷⁴ *Id.*

1 approved hydrostatic test or replacement plan to the Commission to
2 review, with service to the parties in this proceeding.”⁷⁵

3 **3. Commission Directive to Transition Line 1600 Reasonableness Review**
4 **Costs into the GRC**

5 In D.24-01-007, issued on January 11, 2024, the Commission formally closed
6 A.15-09-013, determining that no further project-approval issues remained for adjudication in
7 that docket. The Commission found that the only outstanding matters associated with Line 1600
8 relate to the reasonableness of the costs incurred to execute the Line 1600 PSEP projects. The
9 Decision explicitly states that these remaining cost-related issues are “appropriate to be
10 considered in San Diego Gas & Electric Company and Southern California Gas Company’s
11 future General Rate Case.”⁷⁶

12 As a result of this determination, the Commission shifted all remaining Line 1600 review
13 from the Line 1600 proceeding into the GRC. This includes costs incurred under the Safety and
14 Enforcement Division-approved Design Alternative 1, which consists of replacing approximately
15 37 miles of Line 1600 in High Consequence Areas and hydrotesting an additional 13 miles in
16 non-HCA segments. This testimony therefore presents Line 1600 PSEP expenditures for
17 Commission review in this 2028 General Rate Case, consistent with the explicit direction
18 provided in D.24-01-007.

19 **B. Summary of L1600 Costs and Activities**

20 The activities and costs associated with PSEP Line 1600 Program executed in compliance
21 with D.11-06-017 and later codified in Pub. Util. Code §§ 957 and 958, which requires utilities
22 to pressure test or replace transmission pipelines that lack records meeting current standards.

23 The purpose of this section is to describe the prudent oversight, project execution, and
24 proactive cost management measures taken by SDG&E in the successful completion of the 19
25 independent PSEP projects (Line 1600 projects) identified in the September 26, 2018 Line 1600
26 Test or Replacement Plan approved by the Commission’s SED on January 15, 2019 (Line 1600
27 Plan or Plan), in compliance with Ordering Paragraph 4 of D. 20-02-024.⁷⁷ The CPUC approved
28 Plan specified that Line 1600 pipe located in more populated areas be replaced and Line 1600

⁷⁵ D.20-02-024 at 59 (OP 3).

⁷⁶ D.24-01-007 at Summary.

⁷⁷ A copy of the public version of the Line 1600 Plan is included as Appendix D.

1 pipe located in less populated areas undergo pressure testing. The approved Line 1600 Plan
2 identified the scope of work for the projects with some allowance for refinement during the
3 detailed design phase, the standards to which such work will be performed, and the schedule and
4 pace for performing such work. SDG&E executed the work consistent with the approved Plan
5 and the costs incurred were commensurate with this approved scope of work, standards, and
6 schedule.

7 In compliance with D.20-02-024, SDG&E filed Class 3 cost estimates for work
8 associated with the approved Line 1600 Plan as part of A.15-09-013 on August 12, 2020. In this
9 filing, SDG&E forecasted \$584 million in capital and \$56 million⁷⁸ in O&M costs on an
10 aggregate basis for the 19 Line 1600 PSEP individual projects identified in the Plan. SDG&E
11 has substantially completed construction work associated with the Line 1600 Plan and reports
12 capital costs totaling \$663 million and O&M costs totaling \$21 million⁷⁹ in O&M costs
13 associated with this work. Detailed workpapers included in the application describe project
14 descriptions and activities, some of the unanticipated challenges faced during detail design and
15 construction, a glossary of key terms, illustrative photographs, segment maps, and information
16 related to the major cost components of all 19 Line 1600 PSEP projects that comprise the Plan.

17 The costs in this chapter provide the basis for determining the revenue requirements
18 recorded in SDG&E's Safety Enhancement Capital Cost Balancing Accounts (SECCBAs) and
19 Safety Enhancement Expense Balancing Accounts (SEEBAs) that are associated with the
20 development and execution of the Line 1600 Plan.

21 As demonstrated in my testimony and workpapers, these PSEP costs were reasonably
22 incurred, and the associated revenue requirements are justified for rate recovery. As discussed in
23 detail in the testimony of Eric Dalton (Ex. SDGE-26), SDG&E is requesting amortization of
24 capital revenue requirement in the amount of an estimated \$173.5 million for SECCBA and
25 O&M revenue requirement of an estimated \$1.1 million for SEEBAs for Line 1600 as of

⁷⁸ These values include escalation, overheads, Allowance for Funds Used During Construction (AFUDC), and capitalized property tax (property tax incurred before each project is placed into service).

⁷⁹ These values include escalation, overheads, Allowance for Funds Used During Construction (AFUDC), capitalized property tax (property tax incurred before each project is placed into service), and an immaterial amount of forecasted trailing costs (approximately 0.2%) – actual amount to be finalized at the end of 2026.

December 31, 2027.^{80,81} This revenue requirement has been calculated as net of the amounts already recovered in rates via the 50% interim rate recovery mechanism the Commission adopted in D.16-08-003. While SDG&E requests findings that the underlying capital and O&M expenditures are just and reasonable, the recovery sought in rates during this GRC reflects the remaining unrecovered balances for these projects.

The project costs included in this chapter include direct and indirect⁸² costs incurred to execute each of the Line 1600 hydrotest and replacement. Project costs may include both capital and O&M expenditures, depending on the specifics of the project. For example, the majority of work associated with pressure testing is considered O&M. As part of the normal pressure testing process, however, a section of the existing pipeline is removed to accommodate the temporary tests that are used to conduct the pressure test. After the line is tested and the temporary test heads are removed, a new section of pipe is installed to “tie-in” the just-tested segment to the pipeline on either end of the segment. The tie-in pipe is new pipe and is capitalized in accordance with SDG&E’s accounting policy. Similarly, hydrotest projects may also include activities to replace features or sections of pipe in order to facilitate a successful Hydrotest, increase piggability for modern in-line-inspection tools, and mitigate safety concerns caused by wrinkle bends, dents, shallow pipe, corrosion, weld quality, cracking or laminations in the pipe. These costs are capitalized as well.

In my testimony and workpapers, I present the costs associated with developing and executing the Line 1600 Plan for reasonableness review and describe how:

- The procedural history and background of PSEP led to the successful completion of the Line 1600 Plan.

⁸⁰ SDG&E notes that SECCBA includes costs for an additional, non-Line 1600 project. Those costs are included in the SECCBA revenue requirement stated herein, but do not materially impact the revenue requirement.

⁸¹ The final revenue requirement will be updated to reflect the actual balance as of December 31, 2027, upon issuance of a final decision.

⁸² Certain company overhead costs are deemed incremental to PSEP and subject to recovery as they are associated with incremental PSEP activities. The applicable incremental overheads are included in the costs presented for review in this Application.

- The scope completed and costs incurred through execution of the Line 1600 are consistent with the forecast provided in the approved Line 1600 Test or Replacement Plan and Public Utilities Code 958.
- The Line 1600 Projects that make up the Plan were methodically and efficiently executed consistent with the approved Plan controlling costs while achieving PSEP objectives.
- The prudent execution of the Line 1600 Plan mitigated obstacles to maximize affordability through effective project and cost management

1. Cost Summary and Comparison

In evaluating the Line 1600 Plan, it is essential to examine the actual costs associated with the 19 projects outlined in the initial estimates. The costs summarized in Table 26 reflect a comprehensive assessment of capital and operational expenditures. By comparing the actual costs to the original and updated estimates presented below, we can ascertain the accuracy and reliability of the PSEP forecasting process.

As part of the initial estimating process, SDG&E developed forecasted costs for each of the 19 projects identified in the approved Line 1600 Test or Replacement Plan. As additional project-specific information became available, SDG&E updated these estimates and presented them in A.15-09-013, filed on August 12, 2020. Table DZ-26 below compares the actual costs incurred for each of the 19 individual Line 1600 projects, as described in my testimony, to the initial and updated cost estimates submitted in prior proceedings. This comparison not only illustrates the alignment between estimated and actual costs but also serves as a basis for demonstrating the prudent financial management of executing the Line 1600 Plan.

TABLE DZ-26
Comparison of Estimated Costs and Actuals (In \$000,000)

	Test or Replace Plan⁸³	2020 Cost Filing⁸⁴	Actuals⁸⁵
Capital	630	597	663
O&M	47	56	21
Total	677	653	684

The actual costs presented in the above table align with the initial estimates, within 5% of the 2020 cost filing, demonstrating a reasonable accuracy in the forecasting process and project execution. The actual cost variance for the Line 1600 program came well within the AACE Class 3 Total Installed Cost (TIC) accuracy range of +30% to -20%, adhering to the standard industry practices defined by the Association for the Advancement of Cost Engineering (AACE) International. This not only reflects effective financial planning but also instills confidence in SDG&E's project management, suggesting that the estimates were well-founded, and the projects were executed prudently per the Plan. Further, the alignment of actual costs with the class 3 estimates presented in the cost filing and the explanation in the workpapers of the unexpected challenges encountered on certain projects validates the appropriate use of contingency, which provided the necessary funding for unforeseen expenses and uncertainties that occurred during project planning and execution, further detailed in the Supplemental Workpapers (SDGE-06-WP-S, Volume IV). Given the prudent execution of these projects, and despite the disruption in the supply chain and workplace caused by COVID and the unanticipated challenging field conditions on certain projects, SDG&E was still able to safely complete the project work on schedule and manage total costs at a level well within the range of the aggregate of the Class 3 estimates. For these reasons, and as justified in this testimony and supporting workpapers, SDG&E should be granted full recovery of the revenue requirements requested in this GRC.

⁸³ Original Loaded & Escalated Costs from 2018 Class 4 Estimates, September 26, 2018 Line 1600 Test or Replacement Plan at p.62 (Includes escalation, overheads, excludes AFUDC and capitalized property tax).

⁸⁴ 2020 Cost Filing Total Estimated Capital and O&M Costs (Includes escalation, overheads, AFUDC, capitalized property tax, and removal costs that are not part of basis of calculating revenue requirement).

⁸⁵ Includes escalation, overheads, AFUDC, and capitalized property tax.

2. Summary of Project Costs

a. Pipeline Replacement Projects

TABLE DZ-27
Summary of Capital and O&M Costs (in Fully Loaded \$000s)

Project	Capital	O&M	Total
Midway Dr Replacement	35,306	0	35,306
Black Mountain Replacement	63,706	0	63,706
Serra Mesa Replacement	46,778	0	46,778
Kearny Mesa Replacement	29,638	0	29,638
Bear Valley Pkwy Replacement	41,038	80	41,118
Pomerado Rd North Replacement	74,609	0	74,609
Pomerado Rd South Replacement	61,268	0	61,268
Scripps Poway Pkwy Replacement	42,145	0	42,145
La Honda & Lincoln Replacement	39,801	0	39,801
Lilac Rd Replacement	87,939	0	87,939
Rainbow Replacement	50,062	0	50,062
MCAS North Replacement	17,225	0	17,225
MCAS Central Replacement	18,186	0	18,186
MCAS South Replacement	13,752	127	13,879
Total	621,451	207	621,658

b. Pipeline Pressure Test Projects

TABLE DZ-28
Summary of Capital and O&M Costs (in Fully Loaded \$000s)

Project	Capital	O&M	Total
Moosa Creek Hydrotest	6,344	2,412	8,756
Daley Ranch Hydrotest	8,686	2,531	11,217
Rice Canyon Hydrotest	10,621	5,363	15,984
Couser Canyon North Hydrotest	8,056	4,512	12,568
Couser Canyon South Hydrotest	7,853	5,690	13,543
Total	41,560	20,508	62,068

3. Project Cost Components

All costs associated with the Line 1600 PSEP Plan, are included within my testimony and supporting workpapers. Unless otherwise indicated, the cost forecast discussed in my testimony is fully loaded and escalated, including applicable company overheads, AFUDC and property tax incurred before the asset is placed into service (Capitalized Property Tax).⁸⁶

⁸⁶ Total indirect costs applied to capital projects consist of: Overheads, AFUDC, and Property Tax. AFUDC is the net cost for borrowed funds used for construction purposes plus a reasonable rate

1 For each project, SoCalGas and SDG&E prepared a Total Installed Cost (TIC) estimate
2 that reflects the anticipated un-escalated direct costs for that project as of the date of cost
3 estimate. These estimated costs include costs to complete activities associated with project
4 management, engineering, design and planning, environmental review, permitting, land and
5 right-of-way acquisition, material and equipment procurement, and construction.

6 The fully loaded project costs were determined by escalating the direct costs from the
7 TIC estimate, calculating associated indirect costs, and summing them to arrive at a fully loaded
8 and escalated total cost. For budgeting purposes, as reflected in the cost tables provided in the
9 supporting Workpapers, costs are separated into Direct Labor, Direct Non-Labor, Total Direct
10 Costs and Indirect Costs. Direct Labor represents salaries of Company (SoCalGas and SDG&E)
11 management and represented employees. Direct Non-Labor represents costs for activities and
12 services that support execution of a specific project, which include costs for contract labor,
13 purchased services, and materials required to complete a project. Indirect costs are determined
14 separately and represent costs for activities and services that are associated with direct costs—
15 such as payroll taxes, property taxes and pension costs that benefit a project but are not directly
16 charged to a project. Combined, direct and indirect costs constitute the “total cost.”

17 The Workpapers supporting my testimony present Direct Labor, Direct Non-Labor, Total
18 Direct Costs and Indirect Costs grouped into 12 general categories: Company Labor, Materials,
19 Mechanical Construction Contractor, Electrical Contractor, Construction Management &
20 Support, Environmental, Engineering & Design, Project Management & Services, ROW &
21 Permits, Overheads, AFUDC, Property Taxes. These activities are discussed in greater detail,
22 along with illustrative photographs depicting common construction activities, in the Summary of
23 Standard Planning and Construction Practices for Replacement, Hydrotest, Valve, and
24 Abandonment Projects (SDGE-06-WP-S, Volume VI). Project costs are either directly charged
25 to an individual project or are allocated on a pro rata basis across the 19 Line 1600 projects based
26 on the estimated cost to complete each individual project compared to the estimated total
27 aggregate cost to complete all 19 projects.

on other funds, such as equity. The calculation of AFUDC follows FERC Code of Federal Regulations found under item 17 of the Gas Plant Instruction of Part 201. Additionally, Resolution G-2739 grants SDG&E a modification to the FERC AFUDC formula. Capitalization of property tax for both SoCalGas and SDG&E was ordered by the CPUC in D.13-05-010.

1 In D.20-02-024, the Commission directed SoCalGas and SDG&E to prepare and file
2 Class Three estimates and associated supporting information for the PSEP Line 1600 Plan. A
3 minimum level of project engineering, design and planning work must be undertaken to develop
4 estimates of sufficient reliability to be categorized as Class Three level estimates under industry
5 standards. When these estimates were prepared over the first half of 2020, all 19 projects were at
6 least at an overall level of design development of approximately 30%, enabling SoCalGas and
7 SDG&E to prepare Class Three estimates for all 19 projects. The total project cost forecasts
8 presented in this testimony therefore reflect both the actual project development costs previously
9 incurred to engineer, design and plan the projects, along with estimated future costs to complete
10 and closeout the projects.

11 Significant project development activities related to achieving compliance with Pub. Util.
12 Code § 958 through testing and/or replacing Line 1600 were completed in order to develop an
13 accurate forecast. Project development activities include: evaluating engineering factors and
14 information related to the unique characteristics of Line 1600, including the condition of the
15 pipeline, integrity analysis and risks associated with A.O. Smith flash-welded pipe, operational
16 characteristics of the line, including supply to local distribution customers as well as its role
17 related to capacity and reliability of the transmission system; reviewing pipeline operation and
18 maintenance records; evaluating hydrotest feasibility; conducting line shutdown and system feed
19 analysis; evaluating test and replacement alternatives; evaluating routing; gathering and
20 evaluating environmental data; assessments of potential customer and community impacts,
21 including community and stakeholder input and communication regarding potential projects and
22 alternatives; performing constructability analysis of alternatives; engineering and survey
23 activities; cost estimating activities; cost effectiveness analysis; and regulatory support
24 activities.⁸⁷

25 At the time each estimate was performed, the estimate was based on information known
26 about the project at the time, along with assumptions about future work and project execution
27 activities. As the project execution activities continued, new information became available

⁸⁷ Project development work, and the resulting costs, performed to prepare and support A.15-09-013 enabled the Utilities to meet the three-month timeframe to submit the Line 1600 Test or Replacement Plan to SED in compliance with D.18-06-028. Such work provided foundational and directly applicable information that has been valuable, beneficial, and was utilized in the development and execution of the 19 projects that comprise the SED-approved Plan.

1 which caused some changes to the some of the projects compared to what was estimated and
2 impacted total project costs. Examples of issues that impacted projects were the discovery
3 during construction of unmapped foreign utilities, extensive unanticipated bedrock in the trench
4 alignment, and excessive groundwater encountered during construction. Each of the 19 Line
5 1600 projects has a detailed workpaper associated with it which includes an explanation of
6 variances that impacted project costs. The Commission may now review the total actual costs for
7 reasonableness as documented in this testimony and the (SDGE-06-WP-S, Volume IV).

8 **4. Accelerated and Incidental Mileage**

9 One component of the scope of Phase 1B in the SoCalGas and SDG&E Amended PSEP
10 Application included those pipeline segments that otherwise would be addressed in Phase 1A but
11 cannot be addressed in the near term due to the need to construct new infrastructure to maintain
12 service during pressure testing (*i.e.*, Line 1600). Phase 2 of the Pipeline Safety and Reliability
13 Project, also known as Line 1600 (A.15-09-013), addressed this aspect of Phase 1B, as defined in
14 the Amended PSEP Application.

15 The Commission directed the utilities to develop plans that “provide for testing or
16 replacing all [segments of natural gas pipelines which were not pressure tested or lack sufficient
17 details related to performance of any such test] as soon as practicable,”⁸⁸ and that address “all
18 natural gas transmission pipeline [...] even low priority segments,”⁸⁹ while also “[o]btaining the
19 greatest amount of safety value, *i.e.*, reducing safety risk, for ratepayer expenditures.”⁹⁰ The
20 inclusion of accelerated and incidental miles, defined below, is driven by efforts to achieve these
21 goals while also adhering to the objective of minimizing customer impacts.

22 Accelerated miles are miles that otherwise would be addressed in a later phase of PSEP
23 under the Decision Tree prioritization process but are being advanced to realize operating and
24 cost efficiencies. The Line 1600 Plan approved by the CPUC SED addressed the entirety of Line
25 1600 including accelerating the testing or replacing of segments of L1600 Phase 2A pipe. For
26 the projects included in this filing, there are 16.18 miles of Phase 2A accelerated pipe that were
27 addressed as part of the Plan.

⁸⁸ D.11-06-017 at 19.

⁸⁹ *Id.* at 20.

⁹⁰ *Id.* at 22.

Incidental miles are those which are not scheduled to be addressed in PSEP, but are included where it is determined that addressing them improves cost and program efficiency, addresses implementation constraints, or facilitates continuity of testing. Incidental miles are included (1) to minimize customer impacts, (2) in response to operational constraints, or (3) because of the cost and operational efficiencies gained by incorporating them into the project scope rather than executing a project circumventing them.

5. Disallowed Costs

a. Post-1955 PSEP Costs

D.14-06-007 (as modified by D.15-12-020) disallowed costs associated with pressure testing pipeline segments installed after January 1, 1956 where pressure test records are not available that provide the minimum information to demonstrate compliance with the then-applicable industry or regulatory strength testing and record keeping requirements. In the case where the pipe segment is replaced, an amount equal to the average cost of pressure testing is disallowed.

One replacement segment within one PSEP Line 1600 project was subject to this cost disallowance under D.14-06-007 (as modified by D.15-12-020). Specifically, the Black Mountain Replacement project included 26 feet of pipe manufactured after 1955 for which SoCalGas and SDG&E do not have documentation of a post-construction pressure test. This project was subject to a disallowance in the amount of \$6,279, representing the system average cost of pressure testing the 26-foot segment of pipe. At project completion, this disallowed cost was excluded from the PSEP balancing account and adjusted to reflect the actual amount of disallowed costs.

TABLE DZ-29
Disallowed Post-55 PSEP Forecasted Costs

Project	Capital
L1600-P1B-BLACK MTN	\$6,279
Total	\$6,279

b. Undepreciated Book Value for Post-1955 Replacement or Abandonment Projects Without Sufficient Record of a Pressure Test

The Commission also disallowed costs associated with any remaining undepreciated book value of post-1955 pipe without sufficient record of a pressure test. The 26-foot section

1 associated with the disallowance in Section A above is fully depreciated; therefore, there is no
2 associated undepreciated book value to disallow.

3 **c. PSEP Executive Incentive Compensation**

4 In compliance with the Commission's directive in D.14-06-007, the Utilities have not
5 included any executive incentive compensation costs in the PSEP Line 1600 projects.

6 **C. Project Scoping and Execution of the Line 1600 Test or Replace Plan**

7 **1. Scope**

8 Through the approved Line 1600 Plan, SDG&E replaced approximately 37 miles of
9 existing Line 1600 located in HCAs and through secured federal lands, and pressure tested
10 approximately 13 miles of existing Line 1600 located in non-HCAs. The approved scope of work
11 was divided into 19 projects, each of which can be constructed separately, to enable the Utilities
12 to minimize customer and community impacts and meet the Commission's directive to execute
13 PSEP as soon as practicable.⁹¹ The initial focus was on the replacement projects within the HCAs
14 which is consistent with the Commission's directive.

15 The Plan identifies the work required to complete the replacement and testing of Line
16 1600 while maintaining gas supply to the current customer base. The following sections provide
17 a summary of PSEP project management and cost controls as well as describe key elements of
18 the Line 1600 Plan that support the reasonableness of the costs incurred and compliance with
19 internal and external standards.

20 Line 1600 and PSEP are founded upon four overarching objectives. First, PSEP is
21 designed to enhance the safety of SoCalGas and SDG&E's integrated natural gas transmission
22 system. The purpose and objectives of PSEP, which stem from the Commission's directive to all
23 California pipeline operators in D.11-06-017 to prepare plans to pressure test or replace all
24 transmission pipelines that do not have documentation of a pressure test, or where the pressure
25 test does not meet certain regulatory standards, as soon as practicable, and to consider retrofitting
26 pipelines to allow for inline inspections and enhanced shutoff valves as part of those plans.

27 Second, SDG&E strives to fully comply with the directives of the Commission.
28 Accordingly, the PSEP establishes a process for meeting the safety enhancement directives set
29 forth by the Commission in D.11-06-017. Third, the PSEP is designed to minimize customer

⁹¹ D.11-06-017 at 19.

1 and community impacts. SDG&E has a long history of providing reliable service to customers
2 and recognizes that customers depend on service reliability for residential heating and essential
3 appliances, as well as for the reliable operation of California’s electrical grid, fuel production,
4 and other commercial and industrial uses that support California’s economy.

5 Fourth, through prudent and thoughtful execution of the PSEP, SDG&E strives to
6 maximize the cost effectiveness of infrastructure investments for the benefit of customers.
7 Having been in the business of providing reliable natural gas service for over 100 years, SDG&E
8 recognizes the need to carefully invest in its system in a manner that complements previous
9 investments in its system, avoids short-sighted or reactive actions that could result in
10 unnecessary or duplicative expenditures, and enhances the long-term safety and reliability of the
11 gas system.

12 **2. Reasonable Manager Standard**

13 To comply with the Commission’s directive in D.24-12-074, SDG&E intends to
14 demonstrate that the PSEP costs presented for review were incurred reasonably, through the
15 application of the “reasonable manager standard.” The reasonable manager standard was
16 initially articulated in D.90-09-088, which set the basic standards of reasonableness review: “The
17 act of the utility should comport with what a reasonable manager of sufficient education,
18 training, experience and skills using the tools and knowledge at his disposal would do when
19 faced with a need to make a decision and act. The action taken should logically be expected, at
20 the time the decision is made, to accomplish the desired result at the lowest reasonable cost
21 consistent with good utility practices.”⁹² Similarly, in D.05-01-054, the Commission recognized
22 that “[t]here’s a range of outcomes that defines reasonableness, and it’s based on what the
23 manager knew or should have known at the time that the decision was made.”⁹³

24 SDG&E has implemented PSEP according to the reasonable manager standard since its
25 inception which the Commission has recognized in prior PSEP Reasonableness Reviews that
26 have been deemed reasonable. SDG&E continues to look for ways to improve the cost
27 effectiveness of PSEP in support of the Commission’s affordability objectives. In D.14-06-007,
28 which originally adopted the proposed PSEP analytical approach/decision tree and established

⁹² D.90-09-088 at 171 (Finding of Fact (FOF) 14).

⁹³ D.05-01-054 at 14.

balancing accounts to record costs for Phase 1 projects, the Commission further commented on the standard of review that would be undertaken consistent with its earlier rulings on the reasonable manager standard: “When SDG&E and SoCalGas file applications to demonstrate the reasonableness of Safety Enhancement they will bear the burden of proof that the companies used industry best practices and that their actions were prudent. This is not a ‘perfection’ standard: it is a standard of care that demonstrates all actions were well planned, properly supervised and all necessary records are retained.”⁹⁴ D.14-06-007 builds upon a similar statement in D.90-09-088 where the Commission found that “the reasonable and prudent act is not limited to the optimum act, but includes a spectrum of possible acts consistent with the utility system need, the interest of the ratepayers, and the requirements of governmental agencies of competent jurisdiction.”⁹⁵ The Commission’s use of the terms “perfection standard” and “optimum act” is important to consider in light of the uniqueness and complexity of the PSEP projects presented herein, which were subject to various outcomes during their respective project life cycles that influenced costs. In each situation, SDG&E properly exercised its engineering and execution experience to achieve the most reasonable, cost-effective outcomes for ratepayers.

3. Descriptions of Each Pressure Test or Replacement Project

The approved Line 1600 Plan is comprised of 19 projects. The projects have been numbered from north to south and also given names to identify the geographic location and to identify whether the project is a replacement or a hydrotest project. As SoCalGas and SDG&E transitioned from high level planning to detailed design, engineering and planning, some refinements were necessary to address engineering, permitting, community or cost considerations which are detailed in the supporting workpapers. Information on these project refinements were communicated to the CPUC’s SED in conjunction with their oversight role and a copy of the final change log is provided as Appendix E. Overall, the 19 projects remained highly consistent with the information conveyed in the approved Line 1600 Plan. Only minor project refinements have been required, primarily related to project endpoints or minor route adjustments to improve constructability.

⁹⁴ D.14-06-007 at 36.

⁹⁵ D.90-09-088 at 171 (FOF 14).

Table DZ-30 below presents the projects in chronological order based on in service dates. Key factors for each project are identified in Table DZ-30 below. Unique factors associated with each project can influence hydrotest break points, section boundaries, schedule, and other key project attributes. For more detailed information, please refer to the workpapers for each project included with this filing (Ex. SDGE-06-WP-S, Volume IV).

TABLE DZ-30
Descriptions of Each Project and In-Service Dates – Planned and Actual

Project Name	Est. Miles	Act. Miles	Est In-Service Date	Act In-Service Date
Midway Dr Replacement	2.45	3.07	Q4 2020	Q4 2020
Black Mountain Replacement	4.13	4.19	Q4 2020	Q1 2021
Serra Mesa Replacement	4.23	4.34	Q4 2020	Q4 2020
Kearny Mesa Replacement	1.50	2.25	Q4 2020	Q4 2020
Bear Valley Pkwy Replacement	3.57	3.59	Q1 2021	Q3 2021
Pomerado Rd North Replacement	5.84	6.10	Q4 2021	Q2 2022
Pomerado Rd South Replacement	3.14	3.05	Q4 2021	Q2 2022
Scripps Poway Pkwy Replacement	3.64	3.69	Q1 2022	Q2 2022
La Honda & Lincoln Replacement	1.56	1.64	Q2 2022	Q3 2022
Rainbow Replacement	3.69	3.75	Q3 2022	Q4 2022
Lilac Rd Replacement	5.96	6.00	Q1 2023	Q4 2023
Moosa Creek Hydrotest	0.98	1.02	Q2 2023	Q2 2023
Daley Ranch Hydrotest	3.25	3.14	Q2 2023	Q2 2023
MCAS North Replacement	1.07	1.13	Q2 2023	Q3 2023
MCAS Central Replacement	1.21	1.45	Q3 2023	Q3 2023
MCAS South Replacement	0.91	0.90	Q3 2023	Q4 2023
Rice Canyon Hydrotest	3.22	3.36	Q1 2024	Q2 2024
Couser Canyon North Hydrotest	2.60	2.69	Q2 2024	Q2 2024
Couser Canyon South Hydrotest	2.53	2.56	Q2 2024	Q2 2024
Mileage Totals	55.48	57.92		

4. Project Schedule/Prioritization

The approved Line 1600 Plan comprised of 19 projects that were completed independently to efficiently address affordability, safety, operational, community, environmental, constructability, and cost considerations associated with each distinct portion of Line 1600. As previously mentioned and discussed in the approved Line 1600 Plan, the scope of

1 work consisted of 14 replacement projects and five hydrotest projects. The total length of new
2 16-inch diameter pipe that was installed was approximately 45.7 miles, and the total length of
3 existing Line 1600 that was hydrotested was approximately 12.2 miles. Maps showing details of
4 the individual projects are presented in the workpapers (Ex. SDGE-06-WP-S, Volume IV).

5 The 19 Line 1600 projects were completed as planned. As discussed in the approved
6 Plan, they were prioritized and scheduled to achieve the greatest safety enhancement benefits
7 first, focusing on the HCAs, and to complete all of the projects as soon as practicable. In
8 addition to safety, other factors were considered while scheduling the projects, including
9 customer benefits and impacts, operational limitations, potential permit lead time, land rights
10 lead time, and outreach activities.

11 Generally, projects from the City of Escondido south to the terminus of Line 1600 at
12 Mission Gate Station were prioritized first, as this corridor represented the highest concentration
13 of population immediately adjacent to existing Line 1600 and therefore stood to achieve the
14 greatest relative safety benefit. Additionally, the majority of the route for replacement pipeline
15 fell within existing streets, which was anticipated to minimize permitting time due to existing
16 franchise rights and achieved the avoidance of environmentally sensitive areas.

17 The following considerations were also taken into account when determining the
18 preliminary Line 1600 schedules: the ability to deliver gas to customers and potential permitting
19 lead times. Additionally, during summer months, sections of Line 1600 north of where it meets
20 Line 1601 in Escondido could not be isolated without consideration of impacts, such as
21 curtailments, due to high peak loads on peaker plants in the area; supply delivered at the Otay
22 Mesa receipt point could not affirmatively mitigate this concern during summer periods due to
23 pipeline capacity limitations. Therefore, because the hydrotest projects were located north of
24 Escondido, managing the impacts of capacity limitations on the system was a main driver in the
25 detailed scheduling of the hydrotest projects, and some schedule adjustments were required.
26 These schedule adjustments did not significantly impact the overall Line 1600 implementation
27 schedule as originally proposed in the Line 1600 Plan.

28 Next, several projects were located within jurisdictions that required long-lead permits or
29 land acquisitions. For scheduling purposes, some projects required early effort to begin a
30 potentially lengthy permit and/or land rights acquisition process. Given this potential, these
31 projects were scheduled to be constructed in the latter years of the proposed timeline. For

example, there were potential long-lead land acquisitions needed for local municipality-owned, State-owned lands such as Caltrans, and Federal-owned lands such as Marine Corps Air Station Miramar. Given the number, scope, and complexity of the Line 1600 projects, SDG&E assumed extensive community and customer outreach activities would be necessary to achieve the schedule and timeline set forth in the approved Line 1600 Test or Replacement Plan.

While some individual project schedules did shift slightly due to permitting durations, operational constraints, construction related challenges and other logistical factors, Line 1600 ultimately met its overall schedule targets. This was achieved through strong project management practices, proactive coordination with agencies and stakeholders, adaptive planning, and sustained efforts by the multidisciplinary teams involved. These collective actions allowed the Line 1600 work to remain on track and fulfill the timeline objectives established in the filing.

D. Line 1600 Was Prudently Executed to Maximize Affordability Through Effective Project and Cost Management

The Line 1600 Projects that make up the Plan were methodically and efficiently executed consistent with the approved Plan, and costs were effectively controlled while achieving PSEP objectives. The following section will describe how SDG&E mitigated issues to maximize efficiencies and affordability and complete construction as soon as practicable consistent with the longstanding overarching objectives of PSEP. Line 1600 followed the program governance, cost controls, and project management principles discussed above in Section II – Affordability & Efficiency, and also employed the following prudent project management practices that have long been hallmarks of SDG&E’s successful PSEP program.

1. Strategic Management of Project Constraints and Dependencies

Line 1600 projects were complex and required thoughtful orchestration. Many internal and external factors needed to align to begin construction. SDG&E’s execution and management teams balanced competing risks when authorizing a project team to mobilize for construction, since many of the factors that determine when SDG&E can begin construction are not in the direct control of SDG&E. Most can be anticipated and planned for to a certain degree, and those that cannot are mitigated as they occur. Restrictions on when construction can begin were determined and adhered to. For example: cities imposed project moratoriums during heavy traffic periods or their own renovation work; the Line 1600 team had to work in concert with a large customer’s planned outage or low usage period; Gas Control imposed restrictions on when the pipeline can be taken out of service; and seasonal pressure requirements on the system had to

1 be managed. In addition, permits, land rights, specialty equipment, and materials had to be
2 procured. The availability of construction contractors, inspectors, construction oversight
3 personnel, and regional operations personnel were acquired and managed. As a result, project
4 teams were often engaged in extensive efforts to navigate these needs and constraints in a timely
5 manner.

6 **2. Permitting and Temporary Land Right Acquisition**

7 With respect to utility construction projects, and more specifically, pipeline projects,
8 there is a significant difference between projects that are completely or mostly performed on
9 private land (“behind the fence”) and those that are “linear projects,” *i.e.*, located in public
10 rights-of-way. Line 1600 comprises linear projects located in franchised rights-of-way (*i.e.*,
11 streets) and also those located on private and federal land. Some individual Line 1600 projects
12 required multiple additional permits ranging from those required by environmental agencies
13 (*e.g.*, water, wildlife, cultural, etc.), and/or agencies with impacted land rights, such as Caltrans.
14 Some of these permits/agreements had long lead times and led to restricted project schedules. In
15 total, SDG&E obtained over 300 environmental and municipal permits, and over 250 land use
16 agreements for the projects included for review in this Application.

17 **3. Material Availability**

18 Given the unprecedented level of pipeline work, not only at SDG&E but at other
19 California utilities, material availability impacted the Line 1600 cost and schedule. Line 1600
20 also had to overcome the health and safety restrictions and supply chain disruptions caused by
21 COVID-19 which impacted SDG&E’s ability to obtain materials. SDG&E purchased, when
22 appropriate, bulk quantities of commonly used pipe fittings and pipe to have adequate material
23 available for projects. Bulk purchases result in better pricing as opposed to purchasing material
24 on a project-specific basis. Certain materials were not purchased “off the shelf” and were made-
25 to-order or modified to fit conditions. Examples are valves with extensions, vaults to house
26 equipment underground, and instrument cabinets. Material-related delays had to be managed in
27 the implementation of the Line 1600 projects.

28 **4. Unforeseen Factors Encountered During Construction**

29 Despite due diligence in the planning and engineering design phase, unforeseen factors
30 encountered during construction increased the complexity of certain projects and caused projects
31 to take longer than planned. Some unknown conditions can only be identified after construction

1 begins and the pipe is exposed, such as actual pipe condition, unknown substructures, and/or
2 unfavorable soil conditions, such as granite and other types of bedrock in the trench line or
3 groundwater filling the trench. Unforeseen factors encountered during construction are
4 particularly common for older developed areas, such as the dense urban locations of Line 1600
5 projects, because requirements for substructure recording were not as stringent historically as
6 they are today. Unidentified substructures required pipeline routing changes that impact
7 engineering and construction schedules and costs. Unanticipated soil conditions may require a
8 change in excavation or shoring methods and can also negatively impact construction
9 productivity and increase costs. Finally, coordination with other utilities can sometimes delay
10 project schedules. As discussed in workpapers, many of the Line 1600 projects were impacted by
11 extensive unanticipated rock and granite, excessive ground water, and also unknown foreign
12 utilities in the trench line.

13 **5. Sequencing Line 1600 Projects to Maximize Efficiency and** 14 **Productivity**

15 SDG&E strategically scheduled Line 1600 projects to keep company and contractor
16 workforces productive, thereby maximizing the cost-effectiveness of the overall effort for Line
17 1600. Construction start dates were tentatively slated months in advance to maintain a steady
18 flow of work to the construction teams. The various functional groups that support execution of
19 a project were consulted prior to these dates being proposed. The expected construction
20 completion dates of projects were monitored closely so that new projects were able to start soon
21 afterwards. The Line 1600 Plan gave careful consideration to sequencing and scheduling and
22 through diligent management and execution, the work was essentially completed as planned.

23 **6. Proactive Community Outreach Efforts to Minimize Community and** 24 **Customer Impacts**

25 The L1600 Plan consists of projects that are located in more densely populated areas. As
26 such, proactive community outreach efforts—to inform customers, elected officials and
27 government entities about the projects taking place in their communities—were an integral part
28 of SDG&E's prudent execution of Line 1600 to minimize community and customer impacts,
29 manage costs and implement PSEP as soon as practicable. Numerous meetings were held with
30 elected officials and municipal agencies to provide advance notice and ongoing updates
31 regarding PSEP projects. SDG&E also established a PSEP webpage, which provides
32 information about construction activities and project status to give customers and stakeholders

1 easier access to information. Additionally, SDG&E established a 24/7 phone hotline for
2 customers to call for information or voice concerns and requests for SDG&E follow up.

3 The Community Outreach team worked closely with external stakeholders early in the
4 planning stages to identify and help remove potential obstacles and roadblocks that could affect
5 Line 1600 project execution and maintain a positive customer experience by mitigating the
6 effects of construction with targeted communications and efforts to fully inform external
7 stakeholders prior to construction activity. Additionally, Community Outreach maintains good
8 relationships with external stakeholders including community-based organizations,
9 Homeowners' Associations, Chambers of Commerce, Associations, and local media to reach
10 sensitive communities and customers. These various outreach efforts were instrumental in
11 avoiding project delays and, in some instances, resulted in less onerous permitting conditions
12 being imposed on PSEP projects, helping to minimize costs and benefit customers.

13 **7. SDG&E's Procurement Efforts Reduced Costs for the Benefit of** 14 **Customers**

15 SDG&E implemented prudent procurement practices for Line 1600, consistent with the
16 approach laid out in Section II.3. above, including the use of the Performance Partnership
17 Program as well as the traditional competitive bidding process for construction contracts. A cost
18 savings practice unique to PSEP that was used for several Line 1600 projects is the Performance
19 Partnership Program. This program allows "Performance Partners" to enter into competitive
20 bidding for batches of projects as opposed to one at a time. This provides numerous benefits for
21 customers: providing competitive market prices, avoiding administrative costs for successive
22 individual bids, engaging construction contractors in longer-term agreements for numerous
23 projects (which lowers costs by hiring a sustained workforce with less downtime and allowing
24 contractors to work with the same internal engineering teams for a more collaborative effort),⁹⁶
25 and providing contractors an incentive to competitively bid for the work and agree to additional
26 cost-control mechanisms (since the winning bidder is awarded more than just one project).
27 Under the Performance Partnership Program, each project constructed by a Performance Partner
28 is subject to a target price risk/reward mechanism. This mechanism is based on establishing a

⁹⁶ These efforts also mitigate the risk of insufficient trade labor and supervisory resources (leading to direct cost savings through efficient dispersal and logistics of regional work) and better enable construction personnel to provide valuable engineering and design recommendations.

target price agreed to by SDG&E and the Performance Partner. The target price provides the Performance Partner with a cost incentive to efficiently perform the project because it stands to share both reduced and excess costs. The Performance Partner is not, however, entitled to any profits when costs exceed 20% of the target price. The Performance Partner Program methodology was utilized on several of the initial Line 1600 projects as it provided benefits associated with strong collaboration between SDG&E and the contractors to implement efficient, innovative and flexible approaches to solving technical and construction coordination challenges associated with the replacement projects that were located highly urbanized areas.

By virtue of this sharing mechanism, SDG&E realizes cost savings, for the benefit of customers, that would not exist under traditional competitively bid contracts. For the pipeline projects included for cost recovery in this filing that were awarded to a construction contractor under the Performance Partnership Program, as shown in Table DZ-31, approximately \$6.97 million in cost avoidance was realized when taking into account the difference between the negotiated target price and the final actual cost to SDG&E.

TABLE DZ-31

Line 1600 Performance Partner Cost Avoidance Summary

Project Name	Cost Without Performance Partner Program (\$ millions)	Cost Under Performance Partner Program (\$ millions)	Cost Avoidance (\$ millions)	Result
Bear Valley	\$23.0	\$22.7	\$0.35	Reward
The final total cost exceeded the Final Target Price for the following projects, the amount of the risk payment paid by the construction Contractor representing their share of the overage is shown as a cost avoidance for SDG&E (and ratepayers).				
Midway			\$0.13	Risk
Black Mountain			\$1.81	Risk
Pomerado South			\$2.60	Risk
Kearny Mesa			\$0.78	Risk
Serra Mesa L1600			\$1.30	Risk
Total			\$6.97	

Traditional competitive bidding was used for Line 1600 on projects later in the schedule, many of which were located in more rural areas. Traditional competitive bidding is suitable for projects where the design is well-defined, the approach to construction is anticipated to be straightforward, the schedule has time for a lengthier procurement process, the Company's

1 construction management team is very familiar with the work to be performed, and there is an
2 eager pool of experienced contractors competing for the work. Under these circumstances, this
3 traditional process is known to result in competitive pricing due to multiple contractors
4 aggressively competing for the work.

5 **8. Through Cost Tracking, Controls, and Management Practices,**
6 **SDG&E Prudently Manages PSEP Project Costs**

7 As part of the cost management effort, SDG&E tracked and categorized the Line 1600
8 costs that were incurred. Generally, project-specific costs were charged to their respective
9 project accounts. Costs that could not be attributed to a specific Line 1600 project are charged to
10 a non-project specific account, based on the related activity and support function. Through cost-
11 tracking and categorization, SDG&E documented that costs are appropriately categorized and
12 that the recorded costs were incurred to directly contribute to Line 1600 implementation and
13 execution.

14 SDG&E tracks costs by Work Order Authorizations (WOA). The general function of a
15 WOA is to track costs associated with planning and execution of a specific project. To properly
16 track costs to the appropriate category and project, projects and cost categories are assigned
17 unique internal order numbers that are used to track costs associated with that project or activity
18 to a WOA. Additionally, SDG&E implemented procedures to verify the accuracy of costs such
19 as verifying that the correct labor hours for the project, billed labor rates, and any additional
20 expenses are within the terms of the contract.

21 **E. PSEP LINE 1600 Executed Per Plan, On Schedule and for Reasonable Costs**
22 **in Line with Class 3 Estimates**

23 In summary, the approved Line 1600 Plan identified the scope of work for the projects
24 with some allowance for refinement during the detailed design phase, the standards to which
25 such work will be performed, and the schedule and pace for performing such work. SDG&E
26 executed the work consistent with the approved Plan and the costs incurred were based upon this
27 approved scope of work, standards, and schedule.

28 Regarding costs, as required by the CPUC, SDG&E filed Class 3 cost estimates for the
29 work associated with the approved Line 1600 Plan on August 12, 2020. In this filing, SDG&E

forecasted \$584 million in capital and \$56 million⁹⁷ in O&M costs on an aggregate basis for the 19 Line 1600 PSEP individual projects identified in the Plan. SDG&E has substantially completed construction work associated with the Line 1600 Plan and reports capital costs totaling \$663 million and O&M costs totaling \$21 million⁹⁸ in O&M costs associated with this work. The actual costs were recorded in the PSEP SEEBA and SECBA accounts with final cost recovery to be approved through a reasonableness review as part of this filing. Total costs are within 7% of the sum of the Class 3 estimates, which is well within the +20%/-30% accuracy range of the Class 3 estimates. This result is indicative of SDG&E's and SoCalGas's prudent management and execution of the Line 1600 work.

Given the prudent execution of these projects, despite the disruption in the supply chain and workplace caused by COVID-19 and the unanticipated challenging field conditions on certain projects, SDG&E was still able to safely complete the project work on schedule and manage total costs at a level well within the range of the aggregate of the Class 3 estimates. For these reasons, and as justified in this testimony and supporting workpapers, SDG&E should be granted full recovery of the requested revenue requirement.

VII. PIPELINE SAFETY ENHANCEMENT PLAN REASONABLENESS REVIEW

The purpose of this section is to present for reasonableness review the activities associated with the final SDG&E PSEP project – Supply Line 49-17 Phase 1A Replacement,⁹⁹ which was completed in December 2024. This project was completed in alignment with the prudent oversight, project execution, and proactive PSEP cost management measures discussed in prior sections of this testimony. The project costs included in this section include costs incurred in direct support of the project, and indirect costs.

TABLE DZ-32
Project Summary Information

Project	Location	Mileage	Capital (Direct 000's)
SL49-17 Phase 1A	San Diego	0.004	1,401

⁹⁷ These values include escalation, overheads, AFUDC, and capitalized property tax (property tax incurred before each project is placed into service).

⁹⁸ These values include escalation, overheads, AFUDC, capitalized property tax (property tax incurred before each project is placed into service), and an immaterial amount of forecasted trailing costs to be trued up at the end of the year, 2026.

⁹⁹ This project is separate from the Line 1600 bundle of projects presented in the preceding section.

1 Supply Line 49-17 is a Department of Transportation (DOT) defined-transmission line
2 with a predominantly 16-inch diameter that runs approximately 13.176 miles in the City of San
3 Diego, near residential and commercial areas. The pipeline is routed across Class 3 and 4
4 locations. The Supply Line 49-17 Phase 1A Replacement Project consists of the replacement of
5 0.004 miles of this pipeline. The project was particularly challenging from a technical
6 perspective since the section of pipeline being replaced was associated with a facility where
7 multiple pipelines intersect, limiting workspace and operating flexibility. Consistent with one of
8 the overarching objectives of PSEP to maximize the cost effectiveness of safety enhancement
9 investments, SDG&E effectively planned, designed, and completed construction activities for
10 this project, resulting in project costs that were approximately 19% lower than estimated. The
11 completion of this project resulted in successful completion of the remaining PSEP scope in
12 SDG&E's service territory. See additional details related to the execution of the project and
13 associated engineering, construction, and cost management activities in the supplemental
14 workpaper provided in Ex. SDGE-06-WP-S (Volume V).

15 The implementation of this project enhanced the safety of SDG&E's natural gas
16 transmission system, complied with Commission and statutory directives, minimized impacts to
17 customers and communities, and avoided and reduced costs for the benefit of customers.
18 SDG&E acted as a reasonable manager of PSEP by carefully considering information that was
19 known at the time decisions were made, exercised experienced and professional judgment in its
20 decision-making, and therefore should be granted full recovery of the costs requested.

21 **VIII. CONCLUSION**

22 In summary, GMP is responsible for the prudent execution of complex gas infrastructure
23 and pipeline safety programs that are predominantly driven by state and federal safety and
24 compliance requirements. These programs, including PSEP, GSEP Execution, TIMP Execution,
25 and Moreno Compressor Modernization, and Control Center Modernization Ongoing
26 Programmatic activities, are designed to reduce risk, enhance public and workforce safety, and
27 improve system integrity and reliability. Many of these investments are direct responses to
28 regulatory mandates issued following major pipeline incidents and reflect Commission and
29 PHMSA directives to bring legacy pipeline facilities into compliance with modern safety
30 standards.

1 While compliance and safety are the primary drivers of these programs, GMP executes
2 this work with a strong focus on affordability and operational efficiency. GMP applies risk-
3 based prioritization, integrated planning, and disciplined project governance to sequence and
4 coordinate work in a manner that minimizes customer and community impacts while optimizing
5 costs. Centralized program management, standardized delivery processes, cross program
6 coordination, and prudent procurement practices enable GMP to reduce redundant mobilization,
7 minimize outages, and capture efficiencies across programs. Through these approaches, GMP
8 advances regulatory compliance and system safety objectives while exercising careful
9 stewardship of customer dollars consistent with the Commission's emphasis on affordability and
10 prudent infrastructure investment.

11 This concludes my prepared direct testimony.

1 **IX. WITNESS QUALIFICATIONS**

2 My name is Devin K. Zornizer. I work in Los Angeles, California. I am employed by
3 SoCalGas as Vice President of Infrastructure Project Delivery with responsibility for SoCalGas
4 and SDG&E's Gas Major Projects execution where I am responsible for executive leadership
5 and oversight of infrastructure programs, major project delivery, and operational support
6 functions.. My career experience includes work in engineering design, field operations, and
7 project execution, providing a comprehensive understanding of infrastructure assets across their
8 full life cycle. I have over 25 years of professional experience in engineering, project
9 management, and operations. Throughout my career, I have held positions of increasing
10 responsibility involving the planning, design, construction, and operation of critical energy and
11 infrastructure systems. My experience includes direct oversight of pipeline and compressor
12 station operations, 24-hour control room operations, engineering, safety, and operational
13 functions to support safe, reliable system performance. I hold a Bachelor of Science degree in
14 Civil Engineering from California State Polytechnic University, Pomona. I am a Registered
15 Professional Engineer in the State of California (RCE 67723). My education, professional
16 licensure, and extensive industry experience have provided me with substantial technical,
17 operational, and leadership qualifications relevant to the matters addressed in this proceeding. I
18 have previously testified before the Commission.

APPENDIX A
Glossary of Terms

Appendix A

Glossary of Terms

ACRONYM	DEFINITION
AACEi	Advancement of Advance of Cost Engineering International
AC	Aliso Canyon
ACVG	Alternating Current Voltage Gradient
AFUDC	Allowance for Funds Used During Construction
ANPRM	Advanced Notice of Proposed Rulemaking
ANSI	American National Standards Institute
AQMD	Air Quality Management District
ASME	American Society of Mechanical Engineers
BARCT	Best Available Retrofit Control Technology
BCR	Benefit-Cost Ratio
CARB	California Air Resources Board
CAVA	Climate Adaptation Vulnerability Assessment
CCM	Control Center Modernization
CFR	Code of Federal Regulations
CIS	Close Interval Surveys
CNG	Compressed Natural Gas
CPUC	California Public Utilities Commission
CWIP	Construction Work in Progress
D	Decision
DCVG	Direct Current Voltage Gradient
DOO	Date of Operation
DOT	Department of Transportation
DRS	Distribution Regulator Stations
ECA	Engineering Critical Assessment
ECDA	External Corrosion Direct Assessment
EMAT	Electromagnetic Acoustic Transducer
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ERM	Enterprise Risk Management
FERC	Federal Energy Regulatory Commission
FTE	Full Time Equivalent
GC	Gas Capture
GESI	Gas Engineering and System Integrity
GIS	Geographic Information System
GMA	General Administration Costs

ACRONYM	DEFINITION
GMP	Gas Major Projects
GRC	General Rate Case
GSEP	Gas Safety Enhancement Programs
GTP	Gas Transmission Planning
GWUT	Guided Wave Ultrasonic Testing
HCA	High Consequence Area
HDD	Horizontal Directional Drilling
HP	High Pressure
HRCM	Honor Rancho Compressor Modernization
Hydrotests	hydrostatic testing
ILI	In Line Inspection
KPI	Key Performance Indicators
LNG	Liquified Natural Gas
MAOP	Maximum Allowable Operating Pressure
MCA	Moderate Consequence Area
MFL-C	Circumferential Magnetic Flux Leakage
MOP	Maximum Operating Pressure
MSCF	Million Standard Cubic Feet
NACE	National Association of Corrosion Engineers
NOP	Notice of Operation
NSR	New Source Review
O&M	Operations and Maintenance
P&M	Preventive & Mitigative
PDM	Project Delivery Model
PDR	Playa Del Rey
PEP	Project Execution Plan
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIEx	Pipeline Integrity Execution
PIR	Potential Impact Radius
PMO	Project (or) Program Management Office
PSEP	Pipeline Safety Enhancement Plan
RAMP	Risk Assessment Mitigation Phase
RDF	Risk-Based Decision-Making Framework
RECLAIM	Regional Clean Air Incentives Market
RFP	Request for Proposal
RMV	Rupture Mitigation Valves
ROW	Right-of-Way
SCAQMD	South Coast Air Quality Management District

ACRONYM	DEFINITION
SCC	Stress Corrosion Cracking
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SCG	Southern California Gas Company
SDGE	San Diego Gas and Electric
SECCBA	Safety Enhancement Capital Cost Balancing Account
SED	Safety and Enforcement Division
SEEBBA	Safety Enhancement Expense Balancing Account
SI Associates	Structural Integrity Associates, Inc.
SL	Supply Line
SMYS	Specified Minimum Yield Strength
SPD	Safety Policy Division
SVP	Senior Vice President
SVP	Senior Vice President/Chief Infrastructure Officer
TIC	Total Installed Cost
TIMP	Transmission Integrity Management Program
TIMPBA	TIMP Balancing Account
TY	Test Year
V2	Version 2
Valve Rule	Valve Installation and Minimum Rupture Detection Standards
VEP	PSEP Valve Enhancement Plan
WOA	Work Order Authorization
YE	Year End

APPENDIX B

Controls And Mitigations Compliance Driver Roadmap

APPENDIX B

GAS MAJOR PROJECTS

CONTROLS AND MITIGATIONS COMPLIANCE DRIVER ROADMAP

The table below indicates the compliance drivers that underpin activity identified in testimony.

RAMP Control/ Mitigation ID	Activity / Control/Mitigation Name	Compliance Driver
C013	Gas Transmission Safety Rule – MAOP Reconfirmation	49 CFR § 192.624
C118	Rupture Mitigation Valve Installation – Valve Rule	PHMSA “Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards” final rule (49 CFR Parts 192 and 195)
C171	Integrity Assessments & Remediation	49 CFR Part 192, Subpart O 49 CFR § 192.710

APPENDIX C

Line 1600 Plan – SED Approval Letter

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298



January 15, 2019

Roger Schwecke, Senior Vice President
Gas Operations and System Integrity
Southern California Gas Company
555 West 5th Street, GT21C3
Los Angeles, CA 90013

Safety and Enforcement Division's (SED) Response to San Diego Gas and Electric Company's (SDG&E) and Southern California Gas Company's (SoCalGas) Submission of Line 1600 Hydrostatic Test or Replacement Plan in Fulfillment of Pipeline Safety Enhancement Plan (PSEP) for Review and Approval

Dear Mr. Schwecke:

Background

California Public Utilities Commission (Commission) Decision (D.) 18-06-028, Ordering Paragraph (OP) #7 states: "No later than three months from the date of the issuance of this decision, consistent with General Order 112-F Reference, Title 49 Code of Federal Regulations, Part 192—Subpart J and the National Transportation Safety Board recommendations, Pub. Util. Code § 958 and Decision 11-06-017, San Diego Gas & Electric Company and Southern California Gas Company shall submit to Safety and Enforcement Division a hydrostatic test or replacement plan pertaining to the existing 49.7 miles of Line 1600 in its present corridor." Further, D.18-06-028 Conclusion of Law (COL) #14 states: "The Commission's requirement to have a hydrotest plan for Line 1600 is a necessary measure for compliance with Pub. Util. Code § 958." D.18-06-028 Finding of Fact (FOF) #72 states that "the unknowns of test and/or replace plans such as actual costs and ROW issues, should be addressed in the existing Commission PSEP and companion GRC processes."

D.18-06-028 also authorizes SED to "oversee the Applicants' compliance with Pub. Util. Code § 958 and PSEP consistent with directives in prior decisions and OP 15 in this decision. Any costs associated with PSEP work are proposed and managed through PSEP and rate case proceedings according to already existing CPUC institutionalized processes." (D.18-06-028, at 107.)

SDG&E and SoCalGas' Plan

Pursuant to D.18-06-028, OP #7, San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) timely submitted the proposed hydrostatic test or replacement plan pertaining to the existing 49.7 miles of Line 1600 to Safety and Enforcement Division (SED) on September 26, 2018.

SDG&E and SoCalGas indicated that the report analyzed and discussed four design alternatives for the hydrostatic testing and/or replacement plan for Line 1600. SDG&E and SoCalGas reported that they approached the four design alternatives with the following objectives: (1) to enhance public safety; (2) apply risk assessment and management principles; (3) comply with the Commission's Directives, Decisions and the Public Utilities Code section 958; (4) maximize the cost effectiveness of safety investments; and (5) minimize customer impacts.

SDG&E and SoCalGas evaluated and submitted the following four design alternatives and proposed one of the design alternatives for SED's review and approval:

- (1) Replacing 37 miles of Line 1600 pipeline in High Consequence Areas (HCAs) and hydrotesting approximately 13 miles of Line 1600 pipeline in non-HCAs (Replace in HCA/Test in Non-HCA alternative);
- (2) Hydrostatic strength testing (hydrotest or test) of the entire length of Line 1600 (Full Hydrotest alternative);
- (3) Full replacement of Line 1600, routing in nearby streets in the north (Full Replacement in Nearby Streets alternative); and
- (4) Full replacement of Line 1600, routing along Highway 395 in the north (Full Replacement Along Highway 395 alternative).

SDG&E and SoCalGas identified known specific segments of the Line 1600 pipeline that required rerouting due to safety and serviceability reasons and shared that information with SED. SED conducted a joint field inspection of the identified sites with SDG&E personnel and its contractor to evaluate the existing safety conditions, constructability and serviceability of Line 1600. After the field inspections, SED agreed with SDG&E's and SoCalGas' proposed reroute of many segments of Line 1600 due to safety and serviceability reasons.

SDG&E and SoCalGas reported that after careful evaluation of the four design alternatives, it selected to execute design alternative #1. SED observed in the SoCal Gas /SDG&E analysis that design alternatives #3 and #4 were scored as having the maximum safety margin and reliability. SED inquired the rationale for choosing the design alternative #1. SDG&E and SoCalGas indicated that it chose design alternative #1 after considering the Commission's directives in D.18-06-028.

SED's Approval

SED has reviewed and analyzed the hydrostatic test or replacement plan that SDG&E and SoCalGas submitted, including its proposal to execute the design alternative #1. SED approves the SDG&E and SoCalGas' proposed PSEP replacement of 37 miles of Line 1600 pipeline in High Consequence Areas (HCAs) and hydrotesting approximately 13 miles of the remainder of Line 1600 pipeline in non-HCAs (Replace in HCA/Test in Non-HCA alternative). SED requests to be apprised of any changes in the proposed plan, along with the Management of Change record. SED directs that SDG&E and SoCalGas submit to SED all the required PSEP

construction notifications, scope of work, engineering design data, welding and fabrication information no less than 60 days prior to construction, for SED's safety assurance review and inspections. In addition, SED requests that SDG&E and SoCalGas maintain and submit to SED periodically, a comprehensive management of change records that captures changes, particularly in design, materials and processes. SED further request that appropriate local public officials be notified in accordance with law.

If you have any questions, please contact Matthewson Epuna at (213) 576-7014 or by e-mail at Matthewson.Epuna@cpuc.ca.gov.

Sincerely,



Lee Palmer
Deputy Director - Safety and Enforcement Division
California Public Utilities Commission

Cc:

Elizaveta Malashenko, Deputy Executive Director, CPUC
Kenneth Bruno, Program Manager – GSRB/SED
Matthewson Epuna, Program and Project Supervisor, GSRB/SED
Edward Moldavsky, Staff Counsel
Edward Randolph, Director, Energy Division
Durga Shrestha, Senior Utilities Engineer Specialist GSRB/SED
Shirley Arazi, SoCalGas – Regulatory Affairs

APPENDIX D

Line 1600 Test or Replacement Plan

San Diego Gas Electric Company
Capital Expenditures
(In Thousands of 2025 \$)

Gas Major Projects	2026	2027	2028	2029	2030	2031
Total Capital	38,912	41,419	142,134	57,887	52,037	44,004
2026 - 2028 Capital Request	38,697	38,489	137,640	-	-	-
Post-Test Year Capital Forecast	215	2,930	4,494	57,887	52,037	44,004

San Diego Gas Electric Company
Capital Expenditures
(In Thousands of 2025 \$)

Gas Major Projects 2026 - 2028 Capital Request						
Category	Workpaper Sub	Workpaper Description	In-Service Date	2026	2027	2028
TIMP Execution	034680.001	TIMP Execution	Routine	25,873	25,859	25,798
TIMP Execution Total				25,873	25,859	25,798
Gas Safety Enhancement Plan Execution	235730.001	GTSR Part 1 Replacements and Hydrotests	Routine	7,570	397	-
	235730.002	GTSR Part 1 Replacements and Hydrotests	9/30/2027	823	5,820	-
	235730.003	GTSR Part 1 Replacements and Hydrotests	6/30/2028	606	1,038	4,240
	235730.004	GTSR Part 1 Replacements and Hydrotests	9/30/2028	413	744	4,547
	24575A.001	Valve Rule	Routine	-	-	6,321
Gas Safety Enhancement Plan Execution Total				9,412	7,999	15,108
Moreno Compressor Modernization	20476A.001	20476A - Moreno Compressor Modernization	8/31/2028	-	-	87,020
Moreno Compressor Modernization Total				-	-	87,020
Control Center Modernization Ongoing Programmatic Activities	215740.001	CCM Distribution	Routine	2,494	3,730	3,672
	A04190.001	CCM Transmission	Routine	918	901	894
Control Center Modernization Ongoing Programmatic Activities Total				3,412	4,631	4,566
High Pressure Distribution Assessments	A34680.001	HP Distribution Assessments Execution	Routine	-	-	5,148
High Pressure Distribution Assessments Total				-	-	5,148
Grand Total				38,697	38,489	137,640

San Diego Gas Electric Company
Capital Expenditures
(In Thousands of 2025 \$)

Gas Major Projects									
Post-Test Year Capital Forecast									
Category	Workpaper Sub	Workpaper Description	In-Service Date	2026	2027	2028	2029	2030	2031
TIMP Execution	034680.001	TIMP Execution	Routine	-	-	-	25,837	25,848	25,864
TIMP Execution Total				-	-	-	25,837	25,848	25,864
Gas Safety Enhancement Plan Execution	235730.001	GTSR Part 1 Replacements and Hydrotests	Routine	-	-	-	73	1,353	2,430
	235730.005	GTSR Part 1 Replacements and Hydrotests	3/31/2029	215	763	2,602	2,340	-	-
	235730.006	GTSR Part 1 Replacements and Hydrotests	3/31/2029	-	605	717	4,239	-	-
	235730.007	GTSR Part 1 Replacements and Hydrotests	9/30/2029	-	797	806	8,785	-	-
	235730.008	GTSR Part 1 Replacements and Hydrotests	9/30/2030	-	765	369	1,401	10,661	-
	24575A.001	Valve Rule	Routine	-	-	-	6,338	5,286	6,799
Gas Safety Enhancement Plan Execution Total				215	2,930	4,494	23,176	17,300	9,229
Control Center Modernization Ongoing Programmatic Activities	215740.001	CCM Distribution	Routine	-	-	-	3,709	3,719	3,734
	A04190.001	CCM Transmission	Routine	-	-	-	-	-	-
Control Center Modernization Ongoing Programmatic Activities Total				-	-	-	3,709	3,719	3,734
High Pressure Distribution Assessments	A34680.001	HP Distribution Assessments Execution	Routine	-	-	-	5,165	5,170	5,177
High Pressure Distribution Assessments Total				-	-	-	5,165	5,170	5,177
Grand Total				215	2,930	4,494	57,887	52,037	44,004

APPENDIX E

Line 1600 Test or Replacement Plan Change Log

As of 6/30/24

L1600 Test or Replacement Plan Change Log										
Count	Year	Quarter	PROJECT LINE	SECTION	CHANGE CATEGORY	Stage	Change No.	CHANGE DESCRIPTION	COMMENTS	SOURCE DOCUMENT
1	2019	Q4	L1600-P1B-Midway	9	Design	1	1	The total project mileage increased from 2.25 to 2.96 miles due to 2 changes: 1) Extending the replacement section on L1600-P1B-Midway south to the existing MLV- 1605. This design change facilitates the isolation of future replacement sections south of MLV- 1605 on L1600. The added scope on L1600-P1B-Midway reduces the mileage for L1600-P1B-Bear Valley Pkwy by 0.15 miles. 2) The project team will include approximately 0.59 miles (Sta.1316+04 - Sta.1346+98) of existing pipe installed in 2015 to be hydrotested along with the replacement sections. This change reduces the need for multiple hydrotests on replacement sections and minimizes community impacts by only performing one mainline hydrotest instead of two.		Project Scope Change Form #01, TvR Decision Tree, Stage Gate #01 (Approved)
2	2019	Q4	L1600-P1B-Midway	9	Design	2	2	In Stage 1, the utilization of the Escondido Creek Crossing was still under review, however in Stage 2, potholing efforts and GPR revealed that the existing bridge cell could not be used due to insufficient depth and seismic analysis results. The project will cross the Escondido Creek by installing a pipe span.		Stage Gate #02 (Approved)
3	2019	Q4	L1600-P1B-Midway	9	Design	3	3	Addition of a bridled tap off Line 1600 to SL 49-313 to increase the reliability of the single feed regulator station which changes end stationing from 1353+79.75 to 1354+03.17. Also, mileage updates in HPPD increased the total project mileage to 3.1458 miles.		Project Scope Change Form #04, Stage Gate #03 (Approved)
4	2019	Q4	L1600-P1B-Bear Valley Pkwy	10	Design	1	1	The replacement section for L1600-P1B-Midway was extended approximately 0.15 miles south to the existing MLV-1605. The 0.15 miles were originally included within L1600-P1B-Bear Valley. This change in replacement mileage facilitates the isolation of future replacement sections south of MLV- 1605 on L1600. As a result of the change, the total mileage for L1600-P1B-Bear Valley was decreased from 5.032 to 3.551.		Project Scope Change Form #01, Stage Gate #01 (Approved)
5	2019	Q4	L1600-P1B-Bear Valley Pkwy	10	Design	2	2	The replacement section for L1600-P1B-Midway was extended approximately 0.15 miles south to the existing MLV-1605. The 0.15 miles were originally included within L1600-P1B-Bear Valley. This change in replacement mileage facilitates the isolation of future replacement sections south of MLV- 1605 on L1600. As a result of the change, the total mileage for L1600-P1B-Bear Valley was decreased from 5.032 to 3.551.		Project Scope Change Form #01, Stage Gate #01 (Approved)
6	2019	Q4	L1600-P1B-Scripps Poway Pkwy	13	Design	1	1	A change in tie-in location between L1600-P1B-Black Mtn and L1600-P1B-Scripps Poway Pkwy increases Section 13's total mileage from 2.977 to 3.519. The tie-in relocation minimizes the construction time in condensed intersections and commercial business areas near Mercy Rd & I-15 freeway.		Project Scope Change Form #01, TvR Decision Tree, Stage Gate #01 (Approved)
7	2019	Q4	L1600-P1B-Black Mtn	14	Design	1	1	Mileage decreased from 4.530 Total miles to 4.100 due to change in tie-in locations which minimizes the construction time in condensed intersections and commercial business areas near Mercy Rd & I-15 freeway. It also reduces the need to odorize a 0.4 mile stub. The new tie-in location will be near Mercy Rd & Branicole Ln. Approximately 0.4 miles will be added to Scripps Poway Pkwy Replacement Project as a result.		Project Scope Change Form #01, Stage Gate #01 (Approved)
8	2019	Q4	L1600-P1B-Black Mtn	14	Material	2	2	Installation of 1900' of 4" psig main pipe to tie into Vulcan Materials in order to maintain feed		
9	2019	Q4	L1600-P1B-Kearny Mesa	18	Design	1	1	To reduce potential complications, L1600-P1B-Kearny Mesa necessitated a re-route through Ruffin Road to the north end of Section 19-Serra Mesa. A cost analysis that was performed deemed this option as the most cost efficient. The re-route increased project mileage by approximately 2800 ft (~0.531 miles) for constructability reasons. Additionally for constructability, the northern tie-in point was also moved ~585 ft further north to create ample workspace for a planned double stopple bypass to maintain feed to Solar Turbines. As a result of the re-route and change in tie-in location, the project's total mileage (including offset) increases from 1.413 miles to 2.028 miles.		Project Scope Change Form #01 TvR Decision Tree Stage Gate #01 (Approved)
10	2019	Q4	L1600-P1B-Kearny Mesa	18	Design	2	2	Serra Mesa necessitated the relocation of MLV 1612 to provide additional space for the MLV installation. The shift occurred within the same private property and increases the total footage for Serra Mesa by roughly 400'. This design change resulted in a ~400' scope reduction for Kearny Mesa. The 30% pipeline design and the 30% valve design were updated to reflect the ~400' shift. With the updated MLV location, the total mileage for Kearny Mesa was decreased from ~2.02 miles to 1.50 miles.		Project Scope Change Form #02, TvR Decision Tree Stage Gate #02 (Approved)

L1600 Test or Replacement Plan Change Log

Count	Year	Quarter	PROJECT LINE	SECTION	CHANGE CATEGORY	Stage	Change No.	CHANGE DESCRIPTION	COMMENTS	SOURCE DOCUMENT
11	2019	Q4	L1600-P1B-Serra Mesa	19	Design	2	1	Serra Mesa necessitated the relocation of MLV 1612 to provide additional space for the MLV installation. The shift occurred within the same private property and increases the total footage for Serra Mesa by roughly 400'. The 30% pipeline design and the 30% valve design were updated to reflect the ~400' shift. Despite the increase in mileage for Serra Mesa, the total mileage (including offset) was decreased from 4.270 to 4.228 due to refined 30% drawing sets that provided more accurate stationing. This design change resulted in scope reduction for Kearny Mesa.		Project Scope Change Form #02, TvR Decision Tree, Stage Gate #02 (Approved)
12	2020	Q1	L1600-P1B-Black Mtn	14	Design	3	3	Minor change in tie in point results in project mileage update: Tie-in stationing points updated to ENGSTA 2015+56.97 and to ENGSTA 2204+39.91 per the Black Mountain IFC drawing package. The change was driven by refinement of the design. Total mileage replaced is now 3.576 miles with 4.100 miles of new pipeline to be installed.		Stage Gate #03, Project Scope Change Form #03 (Approved)
13	2020	Q1	L1600-P1B-MCAS North	15	Design	1	1	Minor change in tie in point results in project mileage update: The MCAS North scope originally included the replacement of approximately 1.17 miles of total pipe (Eng Sta 2197+40.00) to Eng Sta 2259+20.13). With updates to the tie-in location (Eng Sta 2204+39.91) for Section 14 Black Mountain indicated on 90% drawing sets, the total mileage for MCAS North was also updated. The total mileage for MCAS North now features 1.038 total miles of pipe necessitating remediation.		Project Scope Change Form #01, TvR Decision Tree, Stage Gate #01 (Approved)
14	2020	Q1	L1600-P1B-MCAS Central	16	Design	1	1	Minor change in tie in point and slight re-alignment results in project mileage update: A ~463.07' segment of the pipe originally planned within MCAS South scope has been redesigned and included into MCAS Central (PS AHD 2346+91.46 - PS AHD 2351+58.53). This change increases system reliability and capacity while decreasing customer impact during the L-1600 isolation by reducing the number of hydrotests and tie-ins that are required. The project also added ~0.449 miles (~2370 feet) of incidental pipe (PS AHD 2323+20.68 - PS AHD 2346+91.46) to achieve the single hydrotest. The stationing for the proposed tie-in points and new alignment are based on the most recently revised MCAS North (Section 15) and Central IFR 30 drawing packages and HPPD data dated 02/24/2020.		Project Scope Change Form #01, TvR Decision Tree, Stage Gate #01 (Approved)
15	2020	Q1	L1600-P1B-MCAS South	17	Design	1	1	Minor change in tie in point and slight re-alignment results in project mileage update: A ~463.07' segment of pipe originally planned within MCAS South scope has been redesigned and included into MCAS Central scope (PS AHD 2346+91.46 - PS AHD 2351+58.53). The portion of pipe being deferred is situated between SR 163 and KVPLS Replacement. This design change was necessary because the isolation plan for the north segment of KVPLS differs from isolation plan for the south segment of KVPLS. It minimizes customer impacts and increases system reliability by reducing the number of hydrotests and tie-ins that are needed on the project section. Stationing for proposed tie-in points and new alignment (due to potential environmental impacts) based on the most recently revised alignment (KMZ) and HPPD data dated 03/02/2020.		Project Scope Change Form #01, TvR Decision Tree, Stage Gate #01 (Approved)
16	2020	Q1 ¹	L1600-P1B-Kearny Mesa	18	Design	3	3	The MLV is part of the L1600 Serra Mesa project and is the terminal point at which Kearny Mesa project begins. Location of MLV is at 4200 Ruffin Rd. The previous diameter for this bridled tap was 8", per Gas Transmission Capacity Planning. However, an opportunity to accelerate Kearny Mesa NOP independent of Serra Mesa NOP was identified with use of the planned bridled pipeline as a temporary bypass. Gas Transmission Capacity Planning indicated that the 8" pipeline would need to be increased to 10" (see emails). Therefore, the diameter is being changed for the ~3,050' line and the bridled MLV in order to provide flexibility to accelerate NOP Kearny Mesa before Serra Mesa. See details in emails below. NOTE: There are currently 3 options to NOP for both projects: 1) NOP Serra Mesa 1st (using 10" bypass at Mission Gate Station), per the proposed schedule in L1600 Test or Replacement Plan 2018, 2) NOP Kearny Mesa 1st (using 10" bypass at Solar Turbines), and 3) NOP both projects together. This scope change form only grants the flexibility of option 2. Execution of option 2 is contingent on permitting and easement acceleration as well.		Project Scope Change Form #04, TvR Decision Tree, Stage Gate #03 (Approved)
17	2020	Q1 ¹	L1600-P1B-Kearny Mesa	18	Design	3	4	Removing robo-pig capability from the 10" Solar line scope. Components to be removed from the scope are 8'x8' vault with 10" PCF and 8'x8' vault with robo charging station. Pipeline Integrity group requested for TDW's to be used. 10" TDW fitting currently doesn't have stock code approved and standard (G7002) does not allow for 10" TDW's (only 16" and over). At 512 MAOP, the 10" line will be at 14.5% SMYS (<20% SMYS).		Project Scope Change Form #03, TvR Decision Tree, Stage Gate #03 (Approved)

L1600 Test or Replacement Plan Change Log

Count	Year	Quarter	PROJECT LINE	SECTION	CHANGE CATEGORY	Stage	Change No.	CHANGE DESCRIPTION	COMMENTS	SOURCE DOCUMENT
18	2020	Q2	L1600-P1B-Pomerado South	12	Design	1	1	The initial filing did not have detailed stationing data from HPPD nor finalized tie-in points. Stationing updates and tie-in changes have altered the overall mileage of this section. Minor changes in the project alignment have been made to more effectively manage tie-in locations for the Pomerado South Project. Per the latest 30% IFR Drawing Package dated 11/19/2019, total replacement length has increased from 3.047 miles to 3.14 miles (ENG STA 0+00 - ENG STA 165+58).		Project Scope Change Form #01, TvR Decision Tree, Stage Gate #01 (Approved)
19	2020	Q2	L1600-P1B-Pomerado North	11	Design	1	1	Updates in HPPD results in overall mileage update for the project: In February 2020 the HPPD entry (WOA G1200-49) changed beginning engineering stationing from 1564+24.38 (Oct 2018) to 1565+81.70 (Feb 2020). This changed the existing pipe replacement length from 5.33 miles to 5.30 miles. This change also increased the CAT 4 Criteria from 4.28 to 4.31. The overall project mileage changed to 5.84 miles.		Project Scope Change Form #02, TvR Decision Tree, Stage Gate #01 (Approved)
20	2020	Q2	L1600-P1B-Kearny Mesa	18	Design	3	5	Refining the design between 30% and IFC cause increasing the new installed mileage by 103.42'. This change was caused by moving the north tie-in point at Waxie Way, within the same private property (APN 369-082-28-00), in order to provide better constructability.		Project Scope Change Form #05, TvR Decision Tree, Stage Gate #03(Approved)
21	2020	Q2	L1600-P1B-Serra Mesa	19	Design	3	2	The 90% drawings were issued, and the lateral replacements were included in segment explanation form to capture this detail. This was previously not done at Stage 2 because the 30% drawings do not include this level of detail for laterals. Note, the mileage breakdown above (including offset of 2.27 miles) is only for L-1600, for lateral breakdown detail, please see 90% Segment Explanation Form.		Project Scope Change Form #05, TvR Decision Tree, Stage Gate #03 (Approved)
22	2020	Q2	L1600-P1B-Scripps Poway Pkwy	13	Design	1	2	A portion of the original Scripps-Poway scope has been moved to the updated Black Mountain scope. The original scope in 2018 and 2019 (based on 9-26-18 Test or Replacement Plan and October 2019 Retroactive Segment Explanation Form) had the end tie-in for Scripps Poway at Eng. Sta. 2019+00, which due to Black Mountain (adjacent project) scope refinement was changed to Eng. Sta. 2015+56.97 (loss of ~343.03' of existing pipe). However, ~0.7 miles of new 16" pipe installment was shifted from Black Mountain to Scripps Poway (Oct. 2019 Segment Explanation Form shows 3.0 miles of new pipe for Scripps). This change was done to remove the need to install and odorize a long stub of 16" pipe along Mercy Road, mitigate permit delays on Black Mountain, and lessen construction impacts on Black Mountain. In addition, this scope change form updates stationing for proposed tie-in points and new alignment based on the most recently revised alignment (30% Drawings) and HPPD data dated 04/13/2020.		Project Scope Change Form #02, TvR Decision Tree, Stage Gate #01 (Approved)
23	2020	Q3	L1600-P1B-Bear Valley Pkwy	10	Design	3	3	Minor changes to the total installation of new pipe for L1600-P1B-Bear Valley Pkwy replacement occurred between the 60% IFR package to IFC package. The new installation length is 3.603 miles, up from 3.55 miles. Change driver included route adjustment requested by the City of Escondido to accommodate future development and slight changes to the tie-in location on the north end of the route.		Project Scope Change Form #03, TvR Decision Tree,1) SD21_045_PD_3_IFC REV 0 2) SD21_138_PD_3_SEGMENT
24	2020	Q3	L1600-P1B-Bear Valley Pkwy	10	Schedule	3	4	To avoid the risk of work stoppage or demobilization driven by the discovery of nesting bird within the San Dieguito River Park segment of the Bear Valley Pkwy project, the project team accelerated the construction start to Q4 2020 instead of Q1 2021 to complete work within the San Dieguito River Park outside of bird nesting season which ranges from February 15 through August 31. The remaining replacement segment of Bear Valley Pkwy is primarily located within an urban area where sensitive species are not anticipated and migratory and nesting birds are expected to be tolerant of construction noise.		SD21_237_PD_3_DETAILED ENVIRONMENTAL REVIEW
25	2020	Q4	L1600-P1B-Serra Mesa	19	Design	4	3	To meet the planned shut-in window for a large commercial customer, SDG&E revised the Serra Mesa project plan to odorize the pipe before tie-in. By odorizing the pipe before tie-in and adjusting the tie-in method from a “cold” tie-in to a “hot” tie-in, SDG&E reduced the project tie-in duration. SDG&E installed an additional 16” valve at the Mission Gate Station to safely complete the hot tie-in operation.		RFC-02 Mission Gate Station 16-in Valve
26	2020	Q4	L1600-P1B-Serra Mesa	19	Design	4	4	The Serra Mesa and Kearny Mesa project tie-ins were initially planned to be staggered. SDG&E coordinated the Serra Mesa and Kearny Mesa project tie-ins to increase project efficiencies and reduce overall costs. As a result, removal of an existing 8” bypass and installation of a new 16” pressure control fitting on the existing 16” line was no longer required.		RFC-03 Solar Turbine 8IN By-Pass Removal
27	2020	Q4	L1600-P1B-Kearny Mesa	18	Design	4	6	Initially, the Serra Mesa and Kearny Mesa project tie-ins were planned to be staggered. SDG&E coordinated the Serra Mesa and Kearny Mesa project tie-ins to occur concurrently to increase project efficiencies and reduce overall costs. As a result, the installation of a temporary 8” bypass was no longer required.		RFC-03 Elimination of Solar Turbines Temporary 8-in Bypass

L1600 Test or Replacement Plan Change Log

Count	Year	Quarter	PROJECT LINE	SECTION	CHANGE CATEGORY	Stage	Change No.	CHANGE DESCRIPTION	COMMENTS	SOURCE DOCUMENT
28	2020	Q4	L1600-P1B-Kearny Mesa	18	Design	4	7	A temporary double stopple bypass was planned for installation at Waxie to maintain reliable service to a large customer during tie-in operations. SDG&E revised the project schedule to coordinate construction activities with a planned customer outage. As a result of this coordination, the temporary installation of the double stopple bypass was no longer required. Instead, SDG&E installed a single pressure control fitting and a 16” valve to facilitate tie-in operations.		RFC-04 Cancel of Double Stopple & Install PCF & 16 in Valve
29	2020	Q4	L1600-P1B-Black Mtn	14	Design	4	4	Due to system constraints driven by other compliance work on the transmission system scheduled to take place during the winter season, coupled with the proposed tie-in of the Black Mountain project, SDG&E determined it would not be prudent to remove Line 1600 for a period of 2 weeks during a period of potential high demand. As an alternative, to preserve reliability of service to customers while completing this safety enhancement work, SDG&E revised the work plan to energize the new pipeline via a tee, thereby reducing the projected outage window of Line 1600. SDG&E installed the tee at the tie-in at Mercy Rd.		RFC-10 North Tie-in Changes
30	2020	Q4	L1600-P1B-Black Mtn	14	Design	4	5	The original design included a hammer bore under a 72” storm drain. However, during drilling operations a hard material was encountered, most likely granite, underneath the storm drain. Due to the hard material, SDG&E revised the design to install the replacement pipe over the storm drain, which required relocation of an 8” water line.		RFC-9 Crossing over storm drain RFI-15 relocate 8" water line
31	2021	Q1	L1600-P1B-Pomerado South	12	Design	3	2	After conducting potholing on a series of three, 12' x 5' storm drains near Pomerado Road and Robison Rd (HS 82+00), it was discovered that the pipeline could not be installed over the storm drains. Additional geotechnical work was performed and it was determined a cased bore would be the most feasible installation to cross underneath the storm drains. The cased bore will be approximately 120'.		SD20_058_PD_2_PIPELINE GATE 2 PRESENTATION
32	2021	Q1	L1600-P1B-Pomerado South	12	Design	3	3	Design reduction of approximately 547 LF (STA 0+00 – STA 5+47) of 16” new pipeline installation from Pomerado South scope. The reduced scope will be added to the Pomerado North scope. The reduction of scope allows for the transition between Pomerado North and Pomerado South to be south of Ted Williams Parkway. The street width at this location increases by an additional bike lane and parking lane. This additional space will be used for hydrostatic water tank staging for both the Pomerado North and Pomerado South test segments.		SD20_014_PD_2_POMERADO SOUTH PROJECT NOTICE FORM
33	2021	Q1	L1600-P1B-Pomerado North	11	Design	3	2	547 LF of pipeline replacement, which was originally part of the Pomerado South project scope, has been added to the Pomerado North project. The increase in mileage allows an easier facilitation for hydrotesting; extending the project to the south enables the team to utilize the hydrotest yard on the southwest corner of the Pomerado and Ted Williams intersection.		90% Detailed Design Drawings
34	2021	Q1	L1600-P1B-Scripps Poway Pkwy	13	Design	3	3	After conducting an AC Interference Analysis on Line 1600 it was determined the Scripps Poway Parkway section will be subject to AC Interference from nearby electric transmission lines. An AC Mitigation Plan was created which involves installing zinc ribbon along portions of the Scripps Poway Parkway alignment to protect the 16" line from AC induced corrosion and to mitigate potential safety concerns associated with induced AC voltage. This new scope of work will be executed as part of the Scripps Poway Pkwy replacement project.		Scripps Poway_014 - Project_Notice_AC Mitigation
35	2021	Q2	L1600-P1B-La Honda & Lincoln	8	Design	3	1	During easement negotiations the private property owner requested that the alignment shift north within an existing access roadway to avoid potential long-term impacts to their planned development. This shift to the north tie-in location resulted in an additional 167 LF of pipe installation. In addition, shifting the northern tie-in location will avoid conflicts with additional utility installations and future heavy construction equipment/paving.		SD26_043_PD_3_LA HONDA IFR90 MAINLINE
36	2021	Q2	L1600-P1B-scripps Poway Pkwy	13	Design	3	4	During the planning of the hydrotest, it was determined that moving the east tie-in location from the proposed intersection would help in reducing traffic impacts, provide a safer working location and allow for additional workspace during the hydrotest. This change to the tie-in location resulted in a reduction of pipe installation of approx. 92 feet. The 92 feet will be added to the Pomerado South Section 12 project.		Scripps Poway_014 - Project_Notice_16-Inch Convenience Valve Shift
37	2021	Q2	L1600-P1B-Pomerado South	12	Design	3	4	During the planning of the hydrotest portion of the Scripps Poway Section 13 project, it was determined that moving the east tie-in location from the proposed intersection would help in reducing traffic impacts, provide a safer working location and allow for additional workspace during the hydrotest. Approx. 92 feet of pipe will be added to the Section 12 project from the Section 13 project to accommodate this change.		Scripps Poway_014 - Project_Notice_16-Inch Convenience Valve Shift
38	2021	Q3	L1600-P1B-Rainbow	1	Design	2	1	The design length of the replacement section will be reduced slightly at the north end. The tie-in point will be changed approximately 75 feet south of the original location as shown on the 30% "Issued for Review" package, dated 11/27/2019. The reduction in scope is a result of coordination with another project planned unrelated to the PSEP Line 1600 Test or Replace Plan.		SD32_014_PD_2_RAINBOW REPLACEMENT PROJECT NOTICE FORM

L1600 Test or Replacement Plan Change Log

Count	Year	Quarter	PROJECT LINE	SECTION	CHANGE CATEGORY	Stage	Change No.	CHANGE DESCRIPTION	COMMENTS	SOURCE DOCUMENT
39	2021	Q3	L1600-P1B-Pomerado South	12	Design	4	5	During construction, a previously unknown traffic signal conduit was discovered in the middle of the proposed trench line at HS 107+00 to HS 109+00. Additionally, a previously unknown existing fiber optic package was found in the proposed trenchline between HS 105+00 and HS 112+00. To avoid these two discovered conflicts, the gas line was slightly re-aligned between HS 102+27 to HS 113+78. The new route is more direct and will reduce total installed pipe by approximately 30 feet.		Pomerado South_RFI01_Reroute1 -4_R01
40	2022	Q1	L1600-P1B-Daley Ranch	7	Design	2	1	Rescoping two locations on the Daley Ranch Hydrotest project. The Ranger Station has been identified as an HCA Class 3, therefore, will be a replacement section and removed from the hydrostatic test. Approximately 1,013 feet of 16-inch pipe will be replaced from STA 1052+91.55 to STA 1063+04.71 at the Ranger Station. The southern end of the project has been reduced by approximately 1000 ft due to land and easement acquisition constraints for the La Honda project, which moved the tie-in location further north. The southern end will connect to La Honda project at STA 1117+02.69, instead of the old stationing at STA 1131+16.40. In order to accomodate Gas Control's request for an outage, the Moosa and Daley hydrotest projects are being combined as one hydrotest, isolation scheduled for March 15 - April 15. Updated IMRF report (December 2022) has added an additional 4 cut outs required in addition to the original 14 cutouts from the original scope.		SD24_PD_1_014_Project Notice & SD24_PD_058_STAGE GATE 1 PRESENTATION & MEETING MINUTES
41	2022	Q1	L1600-P1B-Bear Valley Pkwy	10	Design	4	4	During Stage 3, the Bear Valley replacement scope consisted of replacing approximately 18,459 feet (3.50 miles) of existing L-1600 with 19,024 feet (3.60 miles) of new 16" pipe, replacing approximately 56 feet (~0.01 miles) of existing regulator station inlet piping with approximately 252 feet (~0.05 miles) of new small diameter pipe (4" and 2") pipe. The actual 16" pipe installed was 18,766.69 feet (3.55 miles). This resulted in a decrease of approximately 257 feet of 16 inch pipe installed vs what was planned at the end of Stage 3, prior to construction kickoff. The lateral mileage (4" and 2") actually installed was approximately 185 ft which was a decrease of approximately 67 feet from what was planned. The change in mileage was due to location of existing substructures encountered in the field, minor alignment shifts to gain efficiencies during construction, and minor elevation changes of the pipeline route installed.		SD21_PD_4_014_Project Notice
42	2022	Q2	L1600-P1B-COUSER CYN NORTH	3	Design	1	1	Minor adjustment in stationing. Tie-in stationing was updated to reflect changes in the HPPD (High Pressure Pipeline Database). The 2018 baseline mileage report for Line 1600 utilized 2018 HPPD data. The project now relies on 2022 HPPD data, which has caused a shift in stationing. The south tie-in stationing was updated from 355+03.00 to 353+49.86. The north tie-in stationing changed from 490+57.38 to 492+69.43. These adjustments in stationing, increased mileage slightly from 2.56 to 2.63 miles.		SD23_PD_1_014_Project Notice
43	2022	Q2	L1600-P1B-Rice Canyon Hydrotest	2	Design	1	1	Minor adjustment to project end point. During Stage 1, Rice Canyon Hydrotest decreased from 3.28 miles to 3.24 miles. The reason for the mileage decrease was driven by shifting the southernly tie-in location of the northerly adjacent replacement segment.		SD33_058_PD_1_STAGE GATE 1 PRESENTATION AND MEETING MINUTES
44	2022	Q3	L1600-P1B-Lilac Road	5	Schedule	3	1	Schedule delay to construction kickoff due to anticipated delay in receipt of Caltrans permit from August 1, 2022 to November 14, 2022.		Lilac September Detailed Schedule SD27_136_PD_0_SCHEDULE SEP 2022
45	2022	Q4	L1600-P1B-Moosa Creek Hydrotest	6	Design	3	1	The scope of work for a 444 foot section of pipe (PS 947+10.97 to PS 951+54.64) was changed from hydrotesting the 1949 vintage pipe to replacing that small section with new pipe in order to mitigate shallow pipe which was identified within this high risk zone where agricultural activities are taking place. The replacement segment will be installed at an increased depth of cover to improve the safety of the pipeline.		SD30_PD_3_014_Project Notice
46	2023	Q2	L1600-P1B-Couser Cyn South	4	Schedule	3	1	Schedule advancement of construction kickoff date to accomodate Gas Control's request for isolation during shoulder season, minimizing overall impact to electric generators during seasons of high demand. Schedule of construction kickoff advanced from March 4, 2024 to January 29, 2024 with an isolation window scheduled for the month of April 2024.		SD17_058_PD_2_STAGE GATE 2 PRESENTATION AND MEETING MINUTES
47	2023	Q2	L1600-P1B-Couser Cyn North	3	Schedule	3	1	Schedule delay of construction kickoff date to accomodate Gas Control's request for isolation during shoulder season, minimizing overall impact to electric generators during seasons of high demand. Construction kickoff delayed from December 8, 2023 to January 29, 2024 with an isolation window scheduled for the month of April 2024.		SD23_058_PD_2_STAGE GATE 2 PRESENTATION

L1600 Test or Replacement Plan Change Log										
Count	Year	Quarter	PROJECT LINE	SECTION	CHANGE CATEGORY	Stage	Change No.	CHANGE DESCRIPTION	COMMENTS	SOURCE DOCUMENT
48	2023	Q2	L1600-P1B-Rice Canyon Hydrotest	2	Schedule	3	1	Schedule delay of construction kickoff date in order to accomodate Gas Control's request for isolation during shoulder season instead of high EG demand time. Construction kickoff delayed from September 23, 2023 to February 12, 2024 with an isolation window scheduled for the month of May 2024.		SD33_058_PD_2_STAGE GATE 2 PRESENTATION
49	2023	Q3	L1600-P1B-Couser Cyn North	3	Design	3	2	Rescoping a relatively short pipeline segment on the Couser North hydrotest to a replacement (re-route). An In-Line-Inspection by Pipeline Integrity identified a critical anomaly (crack-like) located underneath a pond on private land. Pipeline Integrity's assessment predicted a low failure pressure of 1260 PSI for this critical anomaly. The predicted failure pressure makes it challenging to hydrotest at the desired test pressures for the original proposed scope. The fact that this anomaly is in a location that is underwater provides unique environmental and construction challenges when it comes to remediating the anomaly to improve pipeline safety. Draining the pond would alter the course of aquatic features under the jurisdiction of the USACE, SWRCB, and CDFW. As a result, the project team conducted a cost-benefit analysis, which resulted in a 1,400-ft re-route as being the optimal option. Not only was this option the lowest cost, it also improves safety, future accessibility for O&M operations, emergency response, and mitigates the overall environmental impact of the project.		
50	2024	Q1	L1600-P1B-Couser Cyn North L1600-P1B-Couser Cyn South	3 & 4	Design	3	2	The Couser Canyon North and Couser Canyon South hydrotest projects will be combined into a single hydrotest for a total of 5.16 miles and share the pre-approved April 2024 Gas Control outage window.		

1 Not included in 2020 Q1 SED Quarterly Report

APPENDIX F

(Revised) RAMP to GRC Integration

Area: GAS MAJOR PROJECTS

Witness: Devin K. Zornizer

GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
034680.001	TIMP Execution	1CR02 C171	SDG&E-Risk-2 High Pressure Gas System Integrity Assessments & Remediation	No feasible units	15,467	25,873	25,859	25,798	25,837	25,848	25,864	0	0	0	0	0	0	0
215740.001	CCM Distribution	1CR03 C124	SDG&E-Risk-3 Medium Pressure Gas System Regulator Station Installation Replacement & Enhancement	Projects	1,949	2,494	3,730	3,672	3,709	3,719	3,734	0	1	3	3	3	3	3
235730.001	GTSR Replacements and Hydrotests	1CR02 C013	SDG&E-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmation	Miles	44,144	7,570	397	0	73	1,353	2,430	6	0	0	0	0	0	0
235730.002	GTSL49-24-Hydrotest	1CR02 C013	SDG&E-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmation	Miles	0	823	5,820	0	0	0	0	0	0	2	0	0	0	0

Note: Totals may include rounding differences. Total amounts preceded by a double asterisk (**) are in millions (\$MM). Unit values preceded by a single asterisk (*) are displayed in thousands (000s).

Area: GAS MAJOR PROJECTS

Witness: Devin K. Zornizer

GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
235730.003	GTSR-SL49- 18-Sec 1 North	1CR02 C013	SDG&E-Risk- 2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	606	1,038	4,240	0	0	0	0	0	0	2	0	0	0
235730.004	GTSR-SL49- 18-Sec 2 Central	1CR02 C013	SDG&E-Risk- 2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	413	744	4,547	0	0	0	0	0	0	3	0	0	0
235730.005	GTSR-SL49- 18-Sec 3 South	1CR02 C013	SDG&E-Risk- 2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	215	763	2,602	2,340	0	0	0	0	0	0	3	0	0
235730.006	GTSR-SL49- 16-HYDROT EST-NORTH	1CR02 C013	SDG&E-Risk- 2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmatio n	Miles	0	0	605	717	4,239	0	0	0	0	0	0	1	0	0

Note: Totals may include rounding differences. Total amounts preceded by a double asterisk (**) are in millions (\$MM). Unit values preceded by a single asterisk (*) are displayed in thousands (000s).

Area: GAS MAJOR PROJECTS

Witness: Devin K. Zornizer

GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
235730.007	GTSR-SL49-16-HYDROT EST-SOUTH	1CR02 C013	SDG&E-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmation	Miles	0	0	797	806	8,785	0	0	0	0	0	0	5	0	0
235730.008	GTSR-SL49-16-RPL Section 1	1CR02 C013	SDG&E-Risk-2 High Pressure Gas System Gas Transmission Safety Rule - MAOP Reconfirmation	Miles	0	0	765	369	1,401	10,661	0	0	0	0	0	0	1	0
24575A.001	Valve Rule	1CR02 C118	SDG&E-Risk-2 High Pressure Gas System Rupture Mitigation Valve Installation - Valve Rule	Valves	0	0	0	6,321	6,338	5,286	6,799	0	0	0	1	1	1	1
A04190.001	CCM Transmission	1CR02 C010	SDG&E-Risk-2 High Pressure Gas System Pipeline Monitoring Technologies	Installations	915	918	901	894	0	0	0	19	50	50	52	0	0	0

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SDG&E/GAS MAJOR PROJECTS/Exh No:SDGE-06-CWP.1/Witness: D. Zornizer

Area: GAS MAJOR PROJECTS
Witness: Devin K. Zornizer

GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
A34680.001	HP Distribution Assessment s Execution	1CR02 M171	SDG&E-Risk- 2 High Pressure Gas System DIMP - High Pressure Pipeline In-Line Inspections	No feasible units	0	0	0	5,148	5,165	5,170	5,177	0	0	0	0	0	0	0

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Area: GAS MAJOR PROJECTS

Witness: Devin K. Zornizer

GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
1MP002.000	TIMP Execution	1OR02 C171	SDG&E-Risk- 2 High Pressure Gas System Integrity Assessment s & Remediation	Miles of Pipe	30,786	21,761	25,609	34,638	34,638	34,638	34,638	36	35	63	28	28	28	28
1MP002.002	HP Distribution Assessment s Execution	1OR02 M171	SDG&E-Risk- 2 High Pressure Gas System DIMP - High Pressure Pipeline In-Line Inspections	Miles of Pipe	0	0	0	3,257	3,257	3,257	3,257	0	0	0	1	1	1	1

Note: Totals may include rounding differences. Total amounts preceded by a double asterisk (**) are in millions (\$MM). Unit values preceded by a single asterisk (*) are displayed in thousands (000s).



**SDG&E 2028 General Rate Case
Exhibit SDG&E-06.1 – Gas Major Projects
Revision Log - September 30, 2026**

PAGE	LINE / TABLE REFERENCE	REVISION DETAIL
Page vi	First Bullet Under 6.	Revised O&M costs lower: “Authorize recovery of \$663 million in Capital and \$26 21 million in O&M”.
Page 62	Line 12	Revised O&M costs lower: “ \$26 21 million”
Page 66	DZ-27	Revised O&M costs: “ 0 127 ”
Page 66	DZ-28	Revised O&M costs lower.
Page 82	Line 4	Revised O&M costs lower: “ \$26 21 million”