

Company: Southern California Gas Company (U 904 G)
Proceeding: 2028 General Rate Case
Application: A.26-06-____
Exhibit: SCG-05

(PUBLIC)

PREPARED DIRECT TESTIMONY OF GINA OROZCO

(GAS TRANSMISSION & STORAGE)

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



June 2026

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SUMMARY

GAS TRANSMISSION & STORAGE (In 2025 \$)			
Categories of Management	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
Total Non-Shared Services	100,109	111,265	11,156
Total Shared Services (Incurred)	15,041	17,808	2,767
Total O&M	115,150	129,073	13,923

GAS TRANSMISSION & STORAGE (In 2025 \$)							
Categories of Management	2025 Adjusted-Recorded (000s)	Est. 2026 (\$000)	Est. 2027 (\$000)	Est. 2028 (\$000)	Est. 2029 (\$000)	Est. 2030 (\$000)	Est. 2031 (\$000)
Non-Collectible (NC)	281,744	312,239	380,663	511,337	545,417	568,670	589,534
Collectible (CO)	30,112	3,874	3,870	3,869	3,868	3,867	3,868
Total Capital	311,856	316,113	384,533	515,206	549,285	572,537	593,402

Summary of Requests

- Southern California Gas Company (SoCalGas, SCG, or the Company) respectfully requests that the California Public Utilities Commission (CPUC or Commission) adopt its Test Year (TY) 2028 General Rate Case (GRC) forecasts for Gas Transmission and Storage (GT&S) operations and maintenance (O&M) and capital expenditures.
- For TY 2028, SoCalGas requests approval of \$129,073,000 (in 2025 dollars) for GT&S O&M expenses, consisting of \$111,265,000 for non-shared services and \$17,808,000 for shared services. In addition, SoCalGas requests that the Commission adopt its GT&S capital expenditure forecasts as reflected in Appendix C.
- The activities sponsored in this testimony, as summarized below, are required to operate and maintain SoCalGas’s gas transmission pipelines, compressor stations, and underground and aboveground storage facilities in compliance with applicable federal, state, and local laws, codes, and regulatory standards. This testimony explains how GT&S activities support the Commission’s objectives of

safety, reliability, affordability, and operational efficiency, and identifies the factors driving incremental changes since prior rate cases, including regulatory compliance mandates, risk mitigation requirements, safety enhancements, and system modernization needs.

- **Safety and Regulatory Compliance:** The requested funding supports mandatory compliance with requirements established by the Pipeline and Hazardous Materials Safety Administration (PHMSA), CPUC General Order (GO) 112 F, the California Air Resources Board (CARB), the California Geologic Energy Management Division (CalGEM), and other applicable federal and state authorities across transmission pipeline operations, compressor stations, underground storage, aboveground storage, and control room operations. Key safety and compliance activities include:
 - ***Transmission Pipeline System Safety and Integrity:*** These activities involve Gas Transmission (GT) pipeline, compression, regulation, and instrumentation operations and maintenance necessary to comply with federal and state safety standards, including 49 Code of Federal Regulations (CFR) Part 192 and CPUC GO 112 F. These activities include leak surveys, leak repairs, inspections, patrols, damage prevention programs, automated and remote-controlled valve operations, system upgrades, and methane monitoring.
 - ***Cathodic Protection (CP):*** These activities involve O&M activities that mitigate external corrosion risks to transmission pipelines, protecting employees, the public, the environment, and the long-term integrity of the pipeline system.
 - ***Gas Storage Integrity:*** These risk mitigation activities for underground gas storage wells include ongoing well integrity testing, pressure testing, and mechanical integrity assessments, in compliance with CalGEM and PHMSA regulations. The activities include the abandonment of wells that are no longer viable; drilling of replacement wells to maintain storage field deliverability; and the operation and maintenance of associated aboveground facilities supporting safe injection and withdrawal

operations. As part of this request, SoCalGas proposes to transition Storage Integrity Management Program (SIMP) execution costs from balanced account treatment to base operations.

- **Reliability and Resilience:** The requested funding also supports the continued reliable and resilient operation of the GT&S system through labor and non-labor resources needed to address aging infrastructure, maintain emergency response readiness, and modernize critical facilities. Key activities with anticipated incremental costs during the TY 2028 GRC period include:
 - ***Compressor Station Operations:*** These activities involve inspections, maintenance of emissions control equipment, continuous system monitoring, emergency response capability, and modernization of aging engines and auxiliary equipment to maintain system pressures and support overall transmission and storage reliability.
 - ***Right of Way and Vegetation Management:*** These increased O&M activities address managing encroachment, wildfire risk, land movement, and site access challenges across rural and expanding urban areas. These efforts also support permitting requirements and environmental compliance obligations.
 - ***Control Room and Supervisory Control and Data Acquisition (SCADA) Expansion:*** These activities involve additional staffing and system enhancements necessary to support the Control Center Modernization (CCM) initiative. By TY 2028, more than 3,350 additional assets will be integrated into the Control Room for monitoring, with an additional 831 assets deployed to Gas Control by 2031. These assets include Distribution Regulator Stations (DRS), Electronic Pressure Monitors (EPM), Optical Pipeline Monitoring (OPM) systems, and methane sensors. The expanded asset base enhances situational awareness, improves outage response capability, and strengthens operational safety.
- **Operational Modernization and Workforce Readiness:** SoCalGas’s request includes funding necessary to modernize GT&S operations and maintain a trained

workforce capable of managing an increasingly complex and digitally enabled system. Key modernization activities include:

- Deployment and maintenance of new monitoring and control technologies, including OPM systems, High Consequence Area (HCA) methane monitors, and DRS/EPM integration;
 - Workforce training and staffing to support expanded monitoring, control room operations, and new system wide digital capabilities; and
 - Specialized tools, control room information technology (IT) systems, operational technology (OT)/SCADA upgrades, and software needed to maintain compliance, improve operational efficiency, enhance system safety, and support reliable service.
- **Environmental Stewardship and Emissions Reduction:** The request supports compliance with CARB Leak Detection and Repair (LDAR) requirements and Environmental Protection Agency (EPA) Subpart W greenhouse gas reporting obligations. Activities include quarterly LDAR surveys, leak repairs, ambient and wellhead monitoring, extensive emissions data management, and annual reporting. These efforts advance California’s emissions reduction goals while supporting continued regulatory compliance for transmission and storage operations.
 - **Customer Support and Market Operations:** The requested funding also supports essential customer facing and market operations, including ENVOY® system enhancements, capacity products support, Gas Scheduling, GT&S strategy and system analytics, data subscriptions, Backbone Transportation Service (BTS) support, core transportation agent (CTA) administration, forecasting tools, and staffing required to meet customer needs and maintain transparent, reliable system operations.
 - **Franchise and Agency Driven Obligations:** Finally, the activities sponsored in this testimony respond to operations, maintenance, and construction requirements imposed by city, county, and state agencies under SoCalGas’s freeway and franchise agreements. These obligations are non-discretionary and necessary to maintain compliance while continuing safe and reliable system operations.

**PREPARED DIRECT TESTIMONY OF GINA OROZCO
(GAS TRANSMISSION & STORAGE)**

I. INTRODUCTION

A. Summary of Gas Transmission & Storage Costs and Activities

My testimony supports the Test Year (TY) 2028 forecasts for operations and maintenance (O&M) costs for both non-shared and shared services, and for capital costs associated with SoCalGas’s Gas Transmission and Storage (GT&S) system. Table GO-1 summarizes my sponsored costs.

Certain forecasted activities and estimated costs were presented previously in SoCalGas’s 2025 RAMP Application 25-05-010/013 (consolidated) filed on May 15, 2025. Those activities and any changes since the RAMP filing are detailed in Section VI.

**TABLE GO-1
Test Year 2028 Summary of Total Costs**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
Categories of Management	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
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Collectible (CO)	30,112	3,874	3,870	3,869	3,868	3,867	3,868
Total Capital	311,856	316,113	384,533	515,206	549,285	572,537	593,402

1 **1. Purpose and Scope of Testimony**

2 The purpose of my testimony is to demonstrate the reasonableness of SoCalGas’s GT&S
3 capital and O&M expense forecasts necessary to construct, operate, and maintain the GT&S
4 systems including Gas Control and System Planning. The forecast outlined in this testimony
5 aligns with SoCalGas’s overarching commitment to the core principles of delivering safe,
6 reliable, and affordable energy today and being ready for tomorrow.

7 Core operational activities supported by this forecast include pipeline patrols and leak
8 surveys; locate-and-mark and standby oversight; inspection, testing, calibration, and maintenance
9 of valves, measurement and regulation equipment; compressor station operations and emissions
10 monitoring; CP and corrosion mitigation; underground storage well integrity management and
11 pressure monitoring; aboveground storage inspection and testing; environmental monitoring and
12 reporting; and continuous gas control and SCADA system oversight. These activities are
13 foundational to safe operations and reliable gas service.

14 All costs in this testimony are shown in 2025 dollars, unless otherwise noted. In addition
15 to this testimony, please also refer to my workpapers (*See Exhibit (Ex.) SCG-05-WP (O&M) and*
16 *SCG-05-CWP (Capital)* for additional information about the activities described herein.

17 **2. Overview of the Gas Transmission and Storage System**

18 SoCalGas operates one of the nation’s largest integrated natural gas distribution,
19 transmission, and storage systems, supporting energy reliability for over 21 million people across
20 a 24,000 square mile service territory in Southern California.

21 The transmission system includes approximately 3,385 miles of high-pressure pipeline
22 that transports natural gas from interstate receipt points and local California production into the
23 distribution system and underground storage fields. SoCalGas’s transmission system receives
24 and delivers gas from the east and north to the load centers in the Los Angeles Basin, Imperial
25 Valley, San Joaquin Valley, north coastal areas, and San Diego County. These pipelines form the
26 backbone of the regional gas network and enable reliable delivery across Southern California. To
27 maintain system pressures and operational flexibility, SoCalGas operates seven active
28 compressor stations equipped with compressor engines, filtration and dehydration vessels,
29 cooling systems, and SCADA-enabled controls.

30 SoCalGas also operates four underground natural gas storage fields as an essential part of
31 its integrated transmission system: Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey.

1 These fields provide essential balancing capability, both daily and seasonal, and serve as
2 reliability assets during peak demand and system contingencies. These storage fields also
3 provide operational resiliency and flexibility for the Southern California energy grid.
4 Aboveground storage facilities and related infrastructure also support safe storage operations and
5 asset integrity.

6 Gas Control and SCADA Operations provide continuous centralized monitoring and
7 operational coordination across the GT&S system, offering 24/7 oversight of the transmission
8 system, including monitoring pressures, flows, and system conditions; remotely operating valves
9 and compressor stations; managing Operational Flow Orders (OFOs); and coordinating planned
10 and emergency outages.

11 In summary, GT&S assets form a complex, interconnected system that supports safe and
12 reliable natural gas delivery across Southern California to millions of customers. Its transmission
13 pipelines, compressor stations, storage fields, and monitoring systems operate under
14 comprehensive federal and state requirements designed to protect the public, SoCalGas's
15 employees, the environment, and critical energy infrastructure. Figure GO-1 provides an
16 overview of SoCalGas's gas transmission system.

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Figure GO-1
SoCalGas Gas Transmission and Storage System



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3. Regulatory Framework and Compliance Obligations

The transmission, compressor, storage, and monitoring activities described above operate within a comprehensive federal and state regulatory framework¹ that establishes mandatory safety, integrity management, environmental, and reporting requirements.

Compressor station operations comply with PHMSA regulations,² the CARB Oil & Gas Rule,³ and Transportation Security Administration (TSA)⁴ critical-infrastructure expectations.

¹ Regulatory bodies include: Pipeline and Hazardous Materials Safety Administration (PHMSA), CPUC, California Air Resources Board (CARB), and California Geologic Energy Management Division (CalGEM).

² 49 CFR Chapter I (PHMSA).

³ California Air Resources Board Oil and Gas Methane Regulations (Cal. Code Reg., Title 17, §§ 95665–95677).

⁴ Transportation Security Administration (TSA), Pipeline Security Guidelines (Critical Infrastructure Security Expectations).

1 Personnel at these sites perform equipment inspections, emissions monitoring, event-driven
2 assessments, repairs, system upgrades, and 24/7 emergency readiness.

3 Underground storage operations are governed by CalGEM Title 14 California Code of
4 Regulations (Cal. Code Reg. or CCR) §1726 et seq.,⁵ CalGEM Underground Injection Control
5 (UIC) requirements,⁶ California Public Utilities Commission (CPUC) General Order (GO) 112-
6 F,⁷ and PHMSA’s 49 CFR §192.12.⁸ Activities include well operation, mechanical-integrity
7 testing, pressure surveys, corrosion mitigation, gas quality monitoring, emergency preparedness,
8 and extensive data and records management.

9 Aboveground storage facilities must also comply with nationally recognized safety
10 standards, such as American Petroleum Institute (API) 510,⁹ API 570,¹⁰ API 653,¹¹ and National
11 Fire Protection Association (NFPA) 70B.¹² These standards establish inspection and
12 maintenance requirements for tanks, vessels, piping, and electrical equipment. SoCalGas
13 performs periodic inspections, testing, data collection, operator qualification, and equipment
14 repairs to maintain compliance and asset integrity.

15 Environmental compliance is another major component of system operations. SoCalGas
16 conducts methane LDAR activities under the CARB Oil & Gas Rule and performs
17 greenhouse-gas measurement and reporting under EPA’s Subpart W¹³ and CARB’s mandatory
18 reporting regulation. These regulations require routine inspection, monitoring, repair
19 documentation, and annual reporting of emissions data.

⁵ Cal. Code Reg., Title 14, § 1726 (Requirements for Underground Gas Storage Projects).

⁶ *Id.* §§ 1724.5–1724.13 (Underground Injection Control).

⁷ CPUC Design Standards - GO 112-F (Design, Construction, Testing, Maintenance, and Operation of Utility Gas Gathering, Transmission, and Distribution Piping System).

⁸ 49 CFR § 192.12, Underground natural gas storage facilities.

⁹ API Standard 510 – Pressure Vessel Inspection Code.

¹⁰ API Standard 570 – Piping Inspection Code.

¹¹ API Standard 653 – Tank Inspection, Repair, Alteration, and Reconstruction.

¹² NFPA 70B – Electrical Equipment Maintenance.

¹³ U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Rule – Subpart W (40 CFR § 98).

1 The forecasts presented in my testimony reflect the resources required to comply with
2 these obligations and to manage risk within a highly regulated, high-consequence operating
3 environment.

4 **4. Forecast Methodology**

5 The GT&S O&M forecast predominantly uses Base Year (BY) 2025, with targeted
6 incremental adjustments to reflect identifiable workload increases, staffing adjustments,
7 expanded monitoring, training, improved forecasting tools, system modernization efforts, and
8 compliance-driven requirements. The base year approach provides a reasonable representation of
9 steady-state operations under current regulatory requirements. Incremental increases are limited
10 to activities supported by documented safety, compliance, operational, or workload drivers.

11 Capital forecasts primarily rely on a zero-based methodology that reflects project timing,
12 regulatory mandates, asset condition, modernization initiatives, and system resiliency
13 requirements across the 2026–2028 forecast period. Historical averages are used for work that is
14 subject to external drivers or reflect inherently variable workloads. Using this approach, in
15 combination with category specific forecasting methods, results in capital estimates that are both
16 robust and appropriately supported throughout the forecast period.

17 Accordingly, the projected O&M and capital expenditures are prudent, necessary, and
18 fully justified. Subsequent sections provide detailed explanations of the drivers, methodologies,
19 and incremental changes associated with each forecast component.

20 **5. Key Operational and Compliance Drivers**

21 Primary upward adjustments in this area are driven by incremental safety and compliance
22 activities, evolving regulatory requirements, asset aging, and expanded monitoring capabilities.

23 Targeted incremental activities include:

- 24 • Enhanced Right-of-Way (ROW) maintenance to address encroachment,
25 land movement, vegetation overgrowth, and personnel access concerns;
- 26 • O&M of the growing inventory of automated and remote-controlled
27 valves;
- 28 • Improved personnel protective equipment, including flame-resistant (FR)
29 garments, standardized headgear, and ANSI-compliant safety vests;

- Technology enhancements supporting work management, data collection and methane monitoring;
- Expanded aboveground storage assets inspections and testing for over 4,000 components under applicable API and NFPA standards;
- Enhanced Gas Storage vegetation management and pipe coating activities supporting wildfire risk reduction and corrosion mitigation;
- Focused increases in Gas Control and SCADA Operations staffing and systems support associated with the CCM initiative, which integrates more than 3,350 new and existing field assets into centralized monitoring systems;
- Enhanced methane reduction activities in compliance with state and federal regulations;
- Enhanced personnel training; and
- Repair or replacement of pipeline, compressor and storage equipment and systems to address aging infrastructure, comply with environmental regulation requirements, improve safety, mitigate system risks, or expand system capacity.

B. Organization of Testimony

My testimony is organized as follows:

- **Introduction:** Provides an overview of this testimony and operations under GT&S that support safety, reliability, compliance, and affordability;
- **Affordability & Efficiency:** Discusses how GT&S organizations apply integrated planning, and innovation to deliver projects and programs efficiently and affordably;
- **Non-Shared O&M Cost:** Identifies activities, forecasted costs, and drivers of operations for GT&S operations, where the forecasted costs belong exclusively to SoCalGas;
- **Shared O&M Costs:** Identifies activities, forecasted costs, and drivers for shared service operations of SoCalGas and SDG&E;

- 1 • **Capital Costs:** Identifies capital investment activities, planned capital
2 forecasts and the drivers that necessitate these investments for the GT&S
3 system, where the forecasted costs belong exclusively to SoCalGas;
- 4 • **Risk Assessment Mitigation Phase (RAMP) Integration:** Identifies
5 activities that align with SoCalGas’s RAMP filing and explains how risk
6 mitigation strategies are incorporated into this GRC request;
- 7 • **Deferred Work:** Identifies work previously authorized in the 2024 GRC,
8 focused on safety and reliability, that was not performed and is being
9 requested again in the 2028 GRC;
- 10 • **Conclusion:** Summarizes the testimony and reinforces the importance of
11 these programs in meeting safety, reliability, and policy objectives while
12 maintaining affordability; and
- 13 • **Witness Qualifications** that set forth my qualifications as a witness.

14 **C. Support To and From Other Witnesses**

15 My testimony relies on and provides foundational operational support to several other
16 SoCalGas witness areas. The relationships summarized below reflect areas where GT&S
17 activities depend on forecasts, policies, or methodologies sponsored by other witnesses, as well
18 as areas where my testimony provides operational, cost, or system insights that support their
19 testimony.

20 **1. Risk-Based Decision-Making Framework (RDF) Integration (Ex. SCG-02B/SDGE-02B)**
21

22 This witness area provides the enterprise risk framework and the methodology used to
23 translate RAMP activities into GRC requests. My testimony incorporates these policies in its
24 RAMP mitigation tables and in the explanation of incremental activities tied to safety, reliability,
25 compliance, and climate risks. My testimony depends on this witness for RAMP methodology,
26 risk definitions, and compliance treatment of risk mitigations.

27 **2. Gas Engineering & System Integrity (GESI) (Ex. SCG-03)**

28 The GESI witness area sponsors the program management activities covered under the
29 Storage Integrity Management Program (SIMP), overarching integrity methodologies risk
30 assessments, and engineering standards used across transmission pipelines and storage wells. My
31 testimony sponsors SIMP Execution, including well integrity testing, mechanical integrity,

1 remediations, and compliance with CalGEM and PHMSA requirements. My testimony depends
2 on GESI for risk ranking, program design, and technical standards; and GESI depends on my
3 witness area for O&M and execution of capital workloads.

4 This witness area also identifies long-term climate hazards (*e.g.*, wildfire, heat, landslide,
5 and flooding) and adaptation priorities for the GT&S system. It also describes SoCalGas's
6 proactive Geohazard Management Program (GMP) that identifies and assesses potential risk to
7 gas infrastructure from geohazards. My GT&S forecasts include vegetation management, coating
8 work, and site access enhancements aligned with Climate Adaptation Vulnerability Assessment
9 (CAVA) hazard assessments. My testimony relies on CAVA for hazard identification, and
10 CAVA relies on GT&S operations for practical implementation and cost forecasting.

11 Furthermore, this witness area's testimony and my testimony reference common
12 mitigation measures presented in the 2025 RAMP Report.¹⁴ Specifically, both testimonies
13 reference risk controls C002 (Damage Prevention Activities) and C401 (SIMP), as identified in
14 the 2025 RAMP Report (Chapter SCG-Risk-1 Excavation Damage and Chapter SCG-Risk-4
15 Underground Gas Storage System, respectively).

16 3. Sustainability and Environmental (Ex. SCG-13)

17 This witness area sponsors interpretation of environmental and emissions regulations,
18 including CARB Oil & Gas Rule and EPA/CARB Subpart W reporting. The GT&S testimony
19 includes field labor, monitoring, repair, and data activities needed to comply with these rules at
20 compressor stations and storage fields. My witness area relies on the Sustainability and
21 Environmental witness area for regulatory interpretation and compliance frameworks, and
22 Sustainability and Environmental relies on my witness area for execution and resource needs.

23 4. Gas Major Projects (Ex. SCG-06)

24 This witness area sponsors large, discrete capital projects that interface with GT&S
25 operations (*e.g.*, system expansions, major facility upgrades). My testimony provides the
26 operational context and integration requirements, and Gas Major Projects provides design,
27 engineering, permitting, capital cost detail, and construction execution.

¹⁴ Application (A.) 25-05-010, SoCalGas 2025 Risk Assessment and Mitigation Phase Report (2025 RAMP Report) (May 15, 2025), available at: <https://www.socalgas.com/socalgas-2025-ramp-application>.

1 **5. Operations Support (Ex. SCG-12)**

2 This witness area sponsors costs for vehicles and facility upgrades. My testimony relies
3 on this witness area for the capital and O&M associated with vehicles used for patrol, leak
4 surveys, compressor operations, and storage field maintenance. My testimony identifies the
5 operational need, and Operations Support determines cost and lifecycle planning.

6 **6. Gas Distribution (GD) (Ex. SCG-04)**

7 This witness area’s testimony and my testimony reference common mitigation measures
8 presented in the 2025 RAMP Report. Specifically, both testimonies reference risk control C002
9 (Damage Prevention Activities), as identified in the 2025 RAMP Report (Chapter SCG-Risk-1
10 Excavation Damage).

11 **7. Compensation & Benefits (Ex. SCG-16/SDGE-20)**

12 This witness area’s testimony and my testimony reference adjustments in connection with
13 the compensation modernization initiative.

14 **II. AFFORDABILITY & EFFICIENCY**

15 GT&S enhances affordability and efficiency through optimized system operations,
16 preventative programs, disciplined project governance, customer support, targeted infrastructure
17 investments, and modernization of asset management systems as described below. Collectively,
18 these practices promote prudent use of resources, reduce lifecycle costs, and support the
19 provision of safe, reliable, and affordable service to customers.

20 **Operational Efficiencies and Preventative Programs:** GT&S achieves operational
21 efficiency through standardized, regulation-aligned work practices conducted in compliance with
22 49 CFR Part 192¹⁵ and CPUC GO 112 F.¹⁶ Pipeline patrols, leak surveys, damage prevention
23 activities, valve maintenance, and odorization are examples of activities proactively performed to
24 prevent failures. Compressor station inspections and emissions control activities similarly
25 comply with PHMSA, CARB, EPA, API and TSA requirements, helping to minimize unplanned
26 outages and costly emergency repairs.

¹⁵ 49 CFR § 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards).

¹⁶ GO 112-F (Design, Construction, Testing, Maintenance, and Operation of Utility Gas Gathering, Transmission, and Distribution Piping System).

1 Preventive programs such as Cathodic Protection reduce long-term costs by mitigating
2 corrosion-related leaks and pipeline failures. Efficiency is further supported through technology
3 enhancements that improve real-time asset data visibility, optimize field dispatches, and
4 strengthen compliance with PHMSA’s Control Room Management Regulation.¹⁷

5 **Project Delivery and Governance:** GT&S projects are delivered by the GT&S
6 Technical Services teams with governance support from the GT&S Project Management Office
7 (PMO). The PMO administers standardized project delivery and governance processes that
8 promote disciplined scoping, planning, execution, and lessons learned review. This framework
9 enables early, informed decision-making and reduces the risk of redesigns, change orders, and
10 construction phase uncertainties that can drive cost variability.

11 GT&S projects are implemented under the Project Delivery Model (PDM), maintained by
12 the PMO. The PDM includes a structured Stage Gate Review Process that sequences deliverables
13 and promotes consistent scoping, planning, and execution. Stage-specific deliverables support
14 adherence to standards, appropriate authorization of scope and funding, and disciplined oversight
15 in support of financial prudence. Each stage includes a leadership review to confirm objectives
16 and assess cost, schedule, and risk before proceeding. It also incorporates structured
17 collaboration with multiple company organizations, which identifies scope and schedule
18 synergies, minimizes operational, customer, and community impacts, and supports prudent
19 decision-making throughout the project lifecycle. When projects occur in the same geographic
20 area, teams coordinate activities to reduce redundant mobilizations, limit disruptions, and share
21 resources where feasible. Additional information on Stage Gate requirements is provided in the
22 testimony of Gas Major Projects (Ex. SCG-06).

23 **Gas Control:** Gas Control incorporates efficiency and affordability considerations into
24 daily operations by continuously analyzing the GT&S system in conjunction with forecasted
25 demand. These demand forecasts inform operational decisions, such as whether to start
26 compressor stations or shift storage fields between withdrawal and injection modes. Because
27 compressor stations and storage field equipment entail significant operating costs, Gas Control
28 actively evaluates system conditions to optimize facility operations. This approach reduces fuel

¹⁷ 49 CFR § 192.631 (Control Room Management).

1 consumption and operating expenses, supporting efficient system performance and customer
2 affordability.

3 **GT&S Strategy:** The GT&S Strategy maintains a strong focus on consumer affordability
4 when developing pricing guidelines for storage and California Energy Hub (CEH) products.
5 CEH offers flexible, transaction-based services that help customers, marketers, and system
6 operators optimize the use of SoCalGas's storage and transmission system.

7 Gas parking and loaning services promote affordability and efficiency by enabling
8 customers to balance supply and demand without costly market purchases, avoid imbalance
9 penalties, and make efficient use of existing infrastructure rather than requiring additional
10 pipeline or storage capacity. Under the G-PAL tariff, CEH offers interruptible gas parking and
11 loaning services. Gas parking allows customers to temporarily store gas when supply is high or
12 demand is low, while loaning provides temporary access to gas when market needs are elevated.

13 Storage services offered under the G-TBS tariff use transactional pricing, with
14 reservation charges negotiated based on market conditions and specific service requirements.
15 This pricing approach promotes affordability by allowing customers to pay only for the storage
16 flexibility they require, enabling prices to adjust with market conditions, and offering a more
17 cost-effective hedge against price volatility than fixed-cost structures.

18 CEH also enhances efficiency through transparent posting of hub market activity. As
19 required by Decision (D.) 07-12-019, CEH posts information such as net hub positions, net
20 parked and loaned volumes, withdrawal schedules for parked gas, and repayment schedules for
21 loaned gas within one business day. This transparency reduces uncertainty, improves planning
22 for operators and market participants, and helps avoid system constraints or market disruptions.

23 Additionally, CEH operates web-based auctions that allow storage customers to bid for
24 higher priority on interruptible injection or withdrawal rights for next-day operations. This
25 process allocates limited injection and withdrawal capacity to those who value it most, enhances
26 system efficiency and supports smoother daily operations while reducing operational constraints.

27 **Capacity Products Support:** Capacity Products Support maintains the SoCalGas
28 ENVOY® Electronic Bulletin Board (EBB), which enables end-use customers, shippers, and
29 energy marketers to schedule natural gas deliveries into the Southern California system.
30 ENVOY® provides a dashboard-style interface that allows users to submit real-time
31 nominations, buy and sell pipeline capacity, trade imbalance positions, monitor metered natural

1 gas usage, and manage their storage accounts. It also delivers up-to-the-minute operational
2 information, including system capacity, OFO status, maintenance activities, and storage
3 inventory levels. By consolidating these functions and providing transparent operational data in
4 real time, ENVOY® helps customers make more informed and cost-effective decisions, supports
5 efficient system balancing, and promotes affordability by reducing the need for last-minute
6 market purchases and avoiding imbalance-related penalties.

7 **Gas Storage Wells:** The Company's four gas storage fields enhance affordability by
8 reducing reliance on higher-cost interstate supplies during peak demand periods and by
9 supporting system balancing and gas supply for electric generation reliability.

10 Replacing older, lower-performing wells with new, higher-deliverability wells provides
11 long-term affordability and operational efficiency benefits. Between 2016 and 2025,
12 approximately 90 low-performing wells were abandoned due to SIMP findings, CalGEM
13 directives, and high operating costs. As wells are removed from service, the remaining wells
14 must operate at or near peak capacity, which increases wear, shortens their effective lifespan, and
15 accelerates maintenance cycles. High-rate flow can also deteriorate the well completion liners
16 and place additional stress on surface equipment.

17 The GS Wells capital request includes 11 replacement wells. These include injection,
18 withdrawal, water disposal, liquid removal, and observation wells. New wells reduce long-term
19 operating and maintenance costs by avoiding capital-intensive mitigation measures required for
20 aging wells and by improving reliability.

21 **Risk-Based Assessment Intervals for Gas Storage Wells-**Gas storage wells are subject
22 to biennial pressure testing and wall¹⁸thickness inspections unless otherwise approved by
23 CalGEM.-Based on detailed mechanical integrity analyses and risk assessments associated with
24 well interventions, SoCalGas has obtained CalGEM approval for extended inspection intervals of
25 up to seven years on a well specific basis since 2022.

26 Extended intervals improve the quality of inspection data by reducing measurement
27 noise, keep more wells in service to support reliability and deliverability, and reduce formation
28 damage associated with repeated well interventions. They also lower inspection costs,

¹⁸ Cal. Code Reg., Title 14, § 1726.6 (Mechanical Integrity Testing).

1 occupational risk, and emissions associated with rig operations and logistics, thereby reducing
2 ratepayer, environmental, and community impacts.

3 **Maximo Mobile Asset Management System:** Maximo Mobile is the Transmission
4 organization's core asset management platform, supporting maintenance, inspections,
5 compliance, and asset lifecycle management. Integrated with Cognos, Geographic Information
6 System (GIS), and MyTSR, Maximo enables paperless reporting and streamlined data collection.
7 Ongoing enhancements include the automation of aerial leak surveys, improved operational
8 technology asset tracking for TSA compliance, automated work orders, QR based mobile access,
9 and expanded system integrations. These enhancements improve data accuracy, strengthen
10 compliance, enable data informed risk management, and optimize operational costs.

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

12 "Non-Shared Services" are activities that are performed by a utility for the benefit of its
13 system and its customers. Table GO-2 summarizes the total non-shared O&M forecast by cost
14 category.

15 O&M activities are routinely performed on the GT&S system in response to federal and
16 state regulatory agency codes and standards,¹⁹ customer expectations, system conditions,
17 franchise obligations, and to sustain safe and reliable operation of the system. This work includes
18 leak surveys, leak repairs, patrols, valve inspections and repairs, corrosion control, damage
19 prevention, compressor station operations, equipment inspections and repairs, emissions control,
20 safety related inspections, well integrity testing, ambient monitoring, and ROW maintenance. In
21 addition, there is a variety of supporting activities necessary to complete this field O&M work.
22 Examples of support work include system status monitoring, compliance documentation,
23 engineering, planning, permitting, class location evaluations, emissions documentation,
24 regulatory reporting, governance and leadership. Investment in these activities supports
25 SoCalGas's commitment to mitigate risks associated with hazards to public and employee safety,
26 infrastructure integrity, system reliability, and affordability.

¹⁹ See, e.g., Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, 49 CFR § 192; Cal. Gov't Code § 4216, et seq.; GO 112-F; GO 58-A; CalGEM; CARB; EPA; API.

1 The level of funding requested in this testimony is consistent with continuing compliance
 2 with pipeline safety regulations and the continued safe and reliable operation of SoCalGas's
 3 GT&S system.

4 In preparing projections for the TY 2028 forecast, SoCalGas GT&S reviewed historical
 5 spending levels, including units of work, and developed an assessment of future needs and
 6 associated risks. This analysis entailed a review of the historical 2021 through 2025 spending
 7 and consideration of the underlying cost drivers. Depending on future expectations for the
 8 underlying cost drivers, a primary forecast methodology was selected. Based on this analysis,
 9 the selected baseline forecast method is BY 2025. In addition, incremental work above historical
 10 spending levels was identified to maintain the safe and reliable operation of the GT&S system
 11 and supporting work processes. An analytical calculation was then performed to determine the
 12 funding of these new or more-extensive work elements. The overall result is a forecast that has
 13 its foundation based on the historical representation, to which incremental expenses have been
 14 added.

15 In summary, GT&S requests the Commission adopt a TY 2028 forecast of O&M expense
 16 for non-shared services of \$111,265,000, as summarized in Table GO-2.

17 **TABLE GO-2**
 18 **Non-Shared O&M Summary of Costs**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
Categories of Management	2025 Adjusted - Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
A. GT&S VP & PMO (2GT003.000)	1,043	1,277	234
B. Storage Products & Balancing (2GT003.001)	353	382	29
C. GT Pipeline and Instrumentation Operations (2GT000.000)	19,084	21,546	2,462
D. GT Compressor Station Operations (2GT000.001)	12,969	14,430	1,461
E. GT Cathodic Protection (2GT000.002)	1,657	1,794	137
F. GT Technical Services (2GT000.003)	2,627	4,680	2,053
G. Aboveground Storage (2GT002.000)	4,592	5,862	1,270
H. Gas Storage Fields (2GT002.001)	32,393	34,419	2,026
I. Underground Storage (2GT001.000)	2,654	2,823	169

GAS TRANSMISSION & STORAGE (In 2025 \$)			
Categories of Management	2025 Adjusted - Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
J. Environmental Regulations (2GT002.002)	9,111	10,224	1,113
K. SIMP Execution (2GT001.001)	13,627	13,829	202
Total Non-Shared Services	100,109	111,265	11,156

1 The Commission should find this forecast reasonable and fully justified in that: (1) the
2 activities support continued delivery of safe and reliable service; (2) activities are consistent with
3 local, state, and federal regulations; (3) activities respond to operations, maintenance, and
4 construction needs; (4) the forecast amounts are reasonable in light of historical spending and
5 anticipated work increases; (5) the activities support SoCalGas’s commitment to mitigate risks
6 associated with hazards to public and employee safety, infrastructure integrity, and system
7 reliability; and (6) system operations have been optimized to enhance affordability and
8 efficiency.

9 **A. GT&S VP & PMO (2GT003.000)**

10 **TABLE GO-3**
11 **Non-Shared O&M – GT&S VP & PMO**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
A. GT&S VP & PMO	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. GT&S VP & PMO	1,043	1,277	234

12 **1. Description of Costs and Underlying Activities**

13 These costs cover labor and non-labor expenses for the Vice President of GT&S
14 Operations and the GT&S PMO.

15 The Vice President of GT&S Operations provides strategic leadership to the Gas
16 Transmission, Storage, GT&S PMO, and Gas Control & System Planning organizations,
17 overseeing the safe, reliable, and efficient operation of the Company’s natural gas transmission
18 pipeline and storage infrastructure. This role carries enterprise accountability for system
19 integrity, operational risk management, emergency preparedness, regulatory compliance, and
20 cost stewardship. The Vice President establishes operational strategy and a governance

1 framework necessary to manage GT&S assets in accordance with federal and state regulatory
2 requirements, align operational strategies with corporate objectives, and follow industry best
3 practices. This includes advancing risk-based asset management, modernizing infrastructure,
4 sustaining system resiliency, and maintaining operational readiness to protect public safety and
5 system reliability.

6 GT&S PMO functions as the formal governance and execution oversight body under the
7 direction of the Vice President of GT&S Operations. The PMO provides centralized governance
8 and portfolio oversight across programs and initiatives. It manages project lifecycle standards,
9 prioritization, and resource allocation while tracking cost, schedule, scope, and risk performance.
10 The PMO formalizes project stage approvals and decision documentation, elevates delivery risks
11 to Company leadership, and reinforces financial accountability through transparent reporting and
12 disciplined forecasting. Operating under the direction of the Vice President, the PMO translates
13 executive priorities into structured execution. Together, this framework establishes clear
14 accountability and coordinated oversight necessary to advance critical initiatives safely and in
15 compliance with regulatory requirements, while maintaining long-term system reliability and
16 minimizing operational and financial risk.

17 **2. Forecast Method**

18 The forecast for GT&S VP and PMO is anchored on a BY 2025 methodology, with
19 targeted adjustments applied to address known and anticipated cost pressures. These conditions
20 include workload, staffing levels, and execution requirements necessary to sustain the
21 governance and control model expected to remain in place through TY 2028. Accordingly, BY
22 2025, together with incremental adjustments, provides the most reasonable representation of
23 projected costs.

24 **3. Cost Drivers**

25 The primary cost drivers in the GT&S VP and PMO forecast stem from the ongoing
26 regulatory and operational governance associated with managing a large-scale natural GT&S
27 system, which requires sustained leadership and program management capabilities to meet
28 objectives.

29 Costs associated with the Vice President role are driven by regulatory requirements, risk-
30 based asset integrity obligations, emergency preparedness oversight, system resiliency planning,
31 and the increasing complexity of operational compliance standards. These responsibilities

1 require sustained executive leadership to manage system risk, direct and monitor corrective
 2 plans, and align operational strategies with corporate objectives and regulatory direction on
 3 safety, reliability, cost-effectiveness, and system modernization.

4 PMO-related costs are driven by the scale and complexity of the GT&S portfolio,
 5 including the number of concurrent initiatives, capital and operational prioritization
 6 requirements, cost and schedule performance monitoring, structured risk identification and
 7 escalation protocols, and documentation and reporting standards that support regulatory review
 8 and internal control transparency. As portfolio complexity and compliance expectations evolve,
 9 the level of governance, coordination, and financial oversight required to manage these activities
 10 correspondingly increases.

11 SoCalGas requests incremental funding in this work category to support enhanced
 12 technical training for field personnel. This incremental funding supports the need to update
 13 legacy training modules that no longer reflect current system configurations or regulatory
 14 expectations. This training will support employees that are new to roles due to workforce
 15 turnover in qualification standards related to equipment operation and the use of field
 16 measurement and analysis devices. This incremental cost is anticipated to be \$223,000 in TY
 17 2028, above BY 2025.

18 **B. Storage Products & Balancing (2GT003.001)**

19 **TABLE GO-4**
 20 **Non-Shared O&M – Storage Products & Balancing**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
B. Storage Products & Balancing	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Storage Products & Balancing	353	382	29

21 **1. Description of Costs and Underlying Activities**

22 These costs cover labor and non-labor activities for the Storage Products and Balancing
 23 team that support the operation of the CEH/Operational Hub, which provides unbundled natural
 24 gas storage and parking services, as outlined in SoCalGas Rate Schedules G-TBS and G-PAL.
 25 Staff responsibilities include:

26 **Storage Product Services:** These activities involve managing the sale of storage
 27 products and CEH/Operational Hub services through sales campaigns, open seasons, and

1 bilateral negotiations to meet customer needs and to maximize reliability and value for SoCalGas
2 ratepayers. These activities are required under SoCalGas Transportation Tariff Rule 30,²⁰ as well
3 as SoCalGas Rate Schedules G-TBS,²¹ and G-PAL.²² Additionally, staff serve as subject matter
4 experts regarding the natural gas market, actively participate in various regulatory proceedings,
5 and provide analytical and regulatory compliance support to many groups throughout SoCalGas.

6 **Southern System Minimum Flow Requirement Support:** At the request of Gas
7 Control operations, these activities involve procuring baseload gas supply through spot purchases
8 to achieve the Company's goals of maintaining system reliability by meeting the Southern
9 System minimum flow requirement, avoiding curtailments, and providing the best value to the
10 Company's customers per SoCalGas Rule 41.²³ Additionally, this group sells spot supplies of
11 gas to balance system supply with demand.

12 **2. Forecast Method**

13 The forecast method developed for Storage Products and Balancing is based on BY 2025,
14 with incremental adjustments applied to labor and non-labor costs. This method is appropriate
15 because in 2025, the Storage Products & Balancing work volume was adjusted, resulting in a
16 higher forecast estimate than the historical average. Thus, the base year provides the most current
17 staffing level needed to carry out the full scope of work activities. It is expected that staffing
18 expenses will remain consistent through 2028, thereby making 2025 costs representative of
19 expectations for TY 2028.

20 **3. Cost Drivers**

21 The primary cost drivers for Storage Products & Balancing activities are described in
22 Section III.B.1.

23 As for incremental cost drivers for Storage Products & Balancing activities, from BY
24 2025 to TY 2028, SoCalGas forecasts a \$24,000 increase primarily needed to maintain natural

²⁰ SoCalGas Rule No. 30 "Transportation of Customer-Owned Gas," September 1, 2023, *available at:*
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=129>.

²¹ SoCalGas Schedule G-TBS "Transaction Based Storage Service," September 1, 2023, *available at:*
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=72>.

²² SoCalGas Schedule G-PAL "Operational Hub Services," October 15, 2023, *available at:*
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=398>.

²³ SoCalGas Rule No. 41 "Utility System Operation," September 1, 2023, *available at:*
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=441>.

1 gas market subscriptions to the Intercontinental Exchange natural gas trading platform associated
 2 with existing workforce requirements to implement the activities described in Section III.B.1.
 3 These activities help the Company achieve its goal of delivering value to its customers.

4 **C. GT Pipeline and Instrumentation Operations (2GT000.000)**

5 **TABLE GO-5**
 6 **Non-Shared O&M - GT Pipeline and Instrumentation Operations**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
C. GT Pipeline and Instrumentation Operations	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. GT Pipeline and Instrumentation Operations	19,084	21,546	2,462

7 **1. Description of Costs and Underlying Activities**

8 These costs cover labor and non-labor expenses for the Gas Transmission (GT) Pipeline
 9 and Instrumentation Operations team that supports the safe, reliable, and efficient operation of
 10 the GT pipeline system and its associated facilities. Ten operating bases across a 24,000 square
 11 mile service area conduct routine maintenance activities, perform system inspections, and
 12 provide rapid emergency response during events such as earthquakes, wildfires, excavation
 13 damage, and other abnormal operating conditions that impact system stability or performance.

14 An underlying cost driver across all GT Pipeline and Instrumentation Operations
 15 activities is the aging profile of the transmission asset base. As transmission pipelines, valves,
 16 actuators, measurement stations, and associated instrumentation continue to age, additional
 17 patrol, inspection, repair, and monitoring activities are required to maintain safe operation in
 18 accordance with 49 CFR § 192, Subpart M (Maintenance).²⁴ In addition, federal PHMSA rules
 19 and CPUC requirements drive the modernization of pipeline valves, actuators, communications
 20 equipment, and other instrumentation. This equipment requires more frequent inspections,
 21 extended troubleshooting efforts, increased callouts, and expanded system data management.

22 GT Pipeline and Instrumentation Operations also manage gas quality standards to
 23 maintain system functionality and protect downstream customers. The organization supports
 24 environmental and regulatory compliance activities for both aboveground and underground
 25 infrastructure, including requirements related to air quality, hazardous materials, groundwater

²⁴ 49 CFR §§ 192.701-192.756.

1 protection, stormwater control, and waste management. Compliance with environmental
2 regulations involves managing air emissions, hazardous materials, waste disposal, stormwater
3 controls, and groundwater protection. Compliance may also require obtaining permits or
4 authorizations from local, state, and federal agencies (*e.g.*, Certified Unified Program Agencies
5 (CUPA) and air quality management districts). California's environmental requirements apply to
6 both aboveground and underground pipeline facilities and are layered on top of federal PHMSA
7 operational standards. GT Pipeline and Instrumentation Operations actively track changes to
8 federal, state, and local regulations and adjust operational practices as needed. These ongoing
9 efforts support SoCalGas's environmental commitments and contribute to California's
10 greenhouse gas reduction objectives.

11 Core activities for GT Pipeline and Instrumentation Operations include:

12 **Instrument Leak Survey & Pipeline Patrol:** Leak survey requirements are governed by
13 49 CFR §192.706–192.723 and CPUC GO 112-F, which define survey frequency based on class
14 location and pipeline attributes. Surveys of Class 1-3 locations are conducted semiannually, and
15 surveys of Class 4 locations and railroad crossings are performed quarterly. Operators use
16 calibrated leak detection instruments on foot, in vehicles, or via aerial patrol for remote terrain,
17 consistent with federal requirements for accessibility and survey reliability. Additional special-
18 purpose surveys are required before paving or street improvements, after significant operational
19 events, during pressure uprates, or whenever unusual operating conditions or external factors
20 justify increased survey frequency. Field reconnaissance and pipeline patrols are completed, in
21 identified moderate to high threat locations as needed to support the Geohazard Management
22 Program.²⁵

23 Routine patrol activities are required under 49 CFR §192.705²⁶ and CPUC GO 112-F to
24 identify conditions that may affect safe operation, including construction activity, evidence of
25 leaks, abnormal operating conditions, land movement, erosion, or security concerns. Patrol
26 frequency varies by class location, as defined in PHMSA rules. Under § 192.5 (Class

²⁵ For a description of the Company's Geohazard Management Program, *see* GESI testimony (Ex. SCG-03).

²⁶ 49 CFR § 192.705 (Transmission lines: Patrolling).

1 Locations)²⁷ and §192.611 (Class Location Change Requirements),²⁸ transmission pipelines
2 located in areas that have transitioned to higher population density, particularly Class 4 locations,
3 require increased patrol, inspection, and leak survey frequencies. These reclassified segments
4 require enhanced monitoring, documentation, and preventative measures, increasing operational
5 workload and cost. Patrol activities include ROW inspections; installation and verification of
6 high-pressure markers; inspection of bridges, spans, and overhead crossings; and documentation
7 of potential threats or encroachments. These activities support compliance by allowing early
8 detection of hazards that could affect pipeline integrity.

9 Standby services and emergency response staffing support events such as third-party
10 excavation damage, wildfires, earthquakes, flooding, and other natural disasters affecting
11 pipeline safety. PHMSA requires emergency plans and rapid response to emergencies under
12 §192.615 (Emergency Plans).²⁹ California's oversight structure (CPUC and California Office of
13 Emergency Services (CalOES) coordination requirements) further increases the scope of
14 operational readiness needed for transmission's emergency response. Qualified personnel are
15 required to monitor any excavation occurring within ten feet of a high-pressure transmission
16 pipeline (above 60 psig). This oversight helps reduce the risk of immediate or delayed pipeline
17 damage, ground movement, coating compromise, and integrity threats during third-party
18 activities.

19 Leak surveys and patrolling activities are necessary to maintain or improve the pipeline
20 system and extend the life of pipeline assets, by allowing early detection of hazards that could
21 affect pipeline integrity.

22 **Pipeline Maintenance:** Maintenance activities encompass the day-to-day operation of
23 pipeline facilities, valves, appurtenances, and associated infrastructure. This includes routine
24 maintenance, corrective work, documentation, and operational monitoring necessary to enable
25 safe operations and maintain compliance with PHMSA regulations and CPUC GO 112-F, as well
26 as the requirements outlined in 49 CFR Part 192, Subpart M.

²⁷ 49 CFR § 192.5 (Class Location).

²⁸ 49 CFR § 192.611 (Change in class location).

²⁹ 49 CFR § 192.615 (Emergency plans).

1 **Automated and Remote-Controlled Shut-Off Valves:** Included within this work
2 category are the O&M of automated and remote-controlled valves on the transmission system.
3 Automated control valves have been installed throughout the transmission system to enable the
4 prompt isolation of transmission pipelines during emergency situations. These valves serve as an
5 important risk-mitigation measure for pipeline ruptures and are therefore critical to the safe
6 operation and reliability of the transmission system.

7 In D.11-06-017, the Commission directed pipeline operators to address the installation of
8 “automated or remote-controlled shutoff valves.” In response to this directive, SoCalGas
9 submitted a Valve Enhancement Plan (VEP) as part of its Pipeline System Enhancement Plan
10 (PSEP). Further, Section 4 of the 2011 Pipeline Safety Act directed the PHMSA to issue
11 regulations requiring, as appropriate, the installation of automatic or remote-controlled shut-off
12 valves which resulted in the Valve Installation and Minimum Rupture Standards rulemaking
13 (Valve Rule). The final rule was fully effective in April 2023. Automatic Shutoff Valves (ASVs)
14 and Remote-Controlled Valves (RCVs) enhance system safety by augmenting existing valve
15 infrastructure to improve SoCalGas’s ability to promptly identify, isolate, and contain escaping
16 gas in the event of a pipeline rupture. Additional information on the Valve Rule, including its
17 expansion beyond the scope of the PSEP Valve Enhancement Plan can be found in the Gas
18 Major Projects Testimony (SCG-06).

19 **Measurement & Instrumentation Maintenance:** Measurement and Regulation (M&R)
20 facilities are maintained and inspected under 49 CFR §192, Subparts L³⁰ and M, as well as
21 CPUC GO 112-F, which sets inspection intervals and performance requirements. Activities
22 include inspection, maintenance, testing, and calibration of pressure limiting stations, relief
23 valves, control valves, valve actuators, valve controls, transmitters, producer stations, regulators,
24 associated instrumentation, and large customer meter set assemblies (MSA).

25 These components play a central role in maintaining pipeline pressures at or below the
26 Maximum Allowable Operating Pressure (MAOP) as required by PHMSA. MSAs undergo
27 routine maintenance to support metering accuracy and gas quality compliance.

³⁰ 49 CFR § 192, Subpart L (Operations).

1 **Odorization:** To support early leak detection and public safety, SoCalGas odorizes
2 natural gas within the Transmission system in compliance with 49 CFR §192.625,³¹ which
3 requires gas to contain a readily detectable odorant at concentrations allowing a person with a
4 normal sense of smell to recognize a leak at one-fifth of the lower explosive limit (LEL). This
5 federal requirement establishes performance-based criteria for proper odorization and applies to
6 all transmission pipelines where odorized gas is necessary for safety.

7 Odorant levels are routinely verified using odor-intensity tests and odorometers at key
8 monitoring points across the transmission network. The odor intensity testing involves testing
9 gas to verify that a recognizable amount of gas odor is detectable, testing for any harmful
10 components, and calibrating appropriate equipment intervals.

11 SoCalGas coordinates closely with approved odorant suppliers to maintain adequate
12 odorant inventory and delivery schedules, consistent with PHMSA's expectations for continuous
13 odorant availability under pipeline operating conditions. Odorant injection equipment and
14 storage facilities are monitored and maintained according to federal operational standards for
15 pipeline safety. Activities include delivering and safely storing odorants at SoCalGas receipt
16 points and monthly odor intensity testing on transmission pipelines. Odorant deliveries are
17 required throughout the year as the volume of odorants in the odorant tanks depletes at different
18 rates based on gas throughput.

19 These activities are necessary to support public safety and system reliability, as well as
20 meet regulatory requirements.

21 **Damage Prevention Activities:** Locate-and-Mark activities comply with Cal. Gov't
22 Code § 4216,³² which requires operators to identify and mark underground facilities before
23 excavation. This program is a key preventive measure to reduce the risk of third-party excavation
24 damage, one of the leading causes of pipeline incidents. Work includes locating and marking gas
25 transmission pipelines; direct job observations during excavation near SoCalGas facilities;
26 potholing and depth verification checks; marking electrical lines beyond the electric utility's
27 power drop pole; and identifying telecommunications, SCADA, and fiber lines located within or

³¹ 49 CFR § 192.625 (Odorization of gas).

³² Cal. Gov't Code § 4216 (Dig Safe Requirements).

1 near SoCalGas assets. These activities help reduce excavation-related risks and support
2 compliance with both state and federal damage prevention expectations (49 CFR §192.614).³³

3 **Pipeline Monitoring Technologies:** Pipeline Monitoring Technologies include both
4 Optical Pipeline Monitoring (OPM) and High Consequence Area (HCA) Methane Monitoring.
5 OPM technology uses specialized fiber-optic sensing cables to detect abnormal operating
6 conditions, such as leaks, ground subsidence, and third-party intrusion, across the transmission
7 system. Gas Transmission maintains OPM equipment, batteries, utility power, and other
8 materials necessary for safe and reliable operation. This equipment is necessary for the safety
9 and reliability of the transmission system.

10 HCA Methane Monitoring maintenance is performed to verify that fixed methane
11 detection units located in HCAs remain fully operational and capable of providing near real-time
12 indication of potential gas releases. These installations support federal pipeline safety
13 expectations under 49 CFR §192, Subpart O – Integrity Management, which requires operators
14 to consider additional preventive and mitigative measures for HCAs. CPUC GO 112-F
15 incorporates PHMSA requirements and reinforces the need for enhanced monitoring and
16 maintenance programs in areas where an incident could pose elevated public safety or
17 environmental consequences.

18 Methane monitoring systems are strategically deployed near high-occupancy structures,
19 areas with significant excavation challenges, and locations situated within approximately 220
20 yards of high-pressure, large-diameter transmission pipelines. These areas represent increased
21 risk profiles and require additional protective measures consistent with federal integrity
22 management principles.

23 Routine maintenance includes inspecting the physical installation, validating sensor
24 functionality, confirming communication links, cleaning equipment, and performing any
25 necessary repairs or component replacements. These activities help maintain a continuous
26 detection capability, enhance situational awareness for pipeline operators, and contribute to the
27 broader safety and reliability objectives of both PHMSA regulations and California state
28 oversight requirements.

³³ 49 CFR § 192.614 (Damage Prevention Program).

The activities described above are essential for maintaining and enhancing the integrity, safety, and reliability of the gas transmission pipeline system, collectively supporting one or more RAMP mitigations.

Non-RAMP Costs: Necessary expenses associated with non-RAMP activities are included in the forecast for GT Pipeline and Instrumentation Operations. These costs may include, but are not limited to cleaning expenses, hazardous waste management, and office supplies.

a. Description of RAMP Mitigations

Within this cost category, there are non-shared O&M costs for risk controls C117 (Leak Survey & Patrol), C132 (Pipeline Maintenance), C155 (Measurement & Instrumentation Maintenance), C160 (Odorization), C002 (Damage Prevention Activities), and C010 (Pipeline Monitoring Technologies) that were presented in the 2025 RAMP Report and are listed in Table GO-6.

The activities described above support C117, C132, C155, C160, C002, and C010. These activities are essential for maintaining and enhancing the integrity, safety, and reliability of the gas transmission pipeline system.

Activities that are compliance-related or mandated by the CPUC or other agencies are listed in bold, and Appendix B attached to this testimony provides the compliance information regarding these mandates for each control.

**TABLE GO-6
RAMP and GRC Risk Control/Mitigation Activities – O&M**

GT Pipeline and Instrumentation Operations				
ID	Control/Mitigation Name	2025 RAMP 2028 Estimate In 2024 \$ (000s)	2028 GRC 2028 Forecast In 2025 \$ (000s)	Change (000s)
C117	Leak Survey & Patrol	848	2,571	1,723
C132	Pipeline Maintenance	5,239	11,055	5,816
C155	Measurement & Instrumentation Maintenance	3,418	5,569	2,151
C160	Odorization	487	383	(104)

GT Pipeline and Instrumentation Operations				
ID	Control/Mitigation Name	2025 RAMP 2028 Estimate In 2024 \$ (000s)	2028 GRC 2028 Forecast In 2025 \$ (000s)	Change (000s)
C002	Damage Prevention Activities	1,900 ³⁴	1,692	(208)
C010	Pipeline Monitoring Technologies	5,906	275	(5,631)
TOTAL		17,798	21,545	3,747

b. Description of Selection and Prioritization of RAMP Risk Mitigations

The RAMP risk mitigation efforts are associated with specific actions, such as programs, projects, processes, and utilization of technology and are designed to address a specific safety and/or reliability risk. The Company's selection and prioritization of these RAMP mitigation activities considered many factors when determining if these risk mitigation activities are an effective and worthwhile investment. The Enterprise Risk Management (ERM) process for identifying and assessing system risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

Risk controls C117, C132, C155, C160, C002, and C010 support risk reduction and strengthen the reliability and efficient operation of the transmission pipeline system and its associated facilities. 11 potential risk drivers are addressed by these activities that protect against equipment failure and reduce the risk of serious injuries, fatalities, infrastructure damage, and environmental impacts resulting from the failure of high-pressure gas pipeline. In prioritizing this proactive approach, SoCalGas seeks to reduce the likelihood of future risk events, and avoid significantly higher operational, customer and recovery impacts associated with responding to realized incidents.

The costs forecast for C117 (Leak Survey & Patrol), C160 (Odorization), and C002 (Damage Prevention Activities) were closely aligned to the RAMP forecasts. C132 (Pipeline Maintenance), C155 (Measurement and Instrumentation Maintenance), and C010 (Pipeline

³⁴ The total RAMP O&M forecast for C002 is \$31.6 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 6% of the total activity. The other portion of costs for C002 can be found in the GESI testimony (Ex. SCG-03) and Gas Distribution (Ex. SCG-04).

1 Monitoring Technologies) had variances from the RAMP filing. The difference between the
2 RAMP forecasts and the forecasts in this testimony can be partially attributed to RAMP using a
3 2024 forecast, while this testimony uses a BY 2025 forecast with incremental adjustments. In the
4 RAMP filing, incremental costs associated with Pipeline Maintenance for Vessel and Tank
5 Inspection work were underestimated, which has led to a cost variance in this control. In
6 addition, some costs that were identified as non-RAMP in the RAMP filing have been
7 categorized as “Pipeline Maintenance” in the GRC, which has also impacted the variance for this
8 control. Although the costs for the RAMP control, “Measurement and Instrumentation
9 Maintenance,” are at the high end of the five-year average spending level, the work in this
10 category often varies slightly from year to year. Analysis has determined that the 2025 activity
11 level best represents the baseline for the future level of activity projected for this control. For
12 “Pipeline Monitoring Technologies,” HCA Methane Monitoring installations used a lower to the
13 ground sensor that can be accessed for maintenance. In the RAMP filing, a sensor that was
14 higher from the ground was anticipated, which needed traffic control and a crane or bucket truck
15 for maintenance. This has led to lower maintenance costs, which has led to a variance. OPM
16 work has been delayed due to scheduling issues, which has caused an additional variance in the
17 RAMP filing. The underlying risk control strategies remain unchanged from the RAMP filing.

18 **2. Forecast Method**

19 The forecast method for GT Pipeline and Instrumentation Operations is based on BY
20 2025, with incremental adjustments applied to account for anticipated cost pressures. These
21 adjustments include incremental labor and non-labor costs necessary to sustain and enhance the
22 transmission pipeline system as described in the section below. Although a review of the five-
23 year historical average (2021-2025) results in a higher baseline for this work category, the BY
24 2025 method is appropriate as it reflects the most current full scope of activities driven by
25 regulatory requirements and asset conditions. The activities in this work category do not have
26 significant variability year-to-year and changes beyond the incremental requests to current
27 operations are not anticipated at this time.

28 **3. Cost Drivers**

29 The primary cost drivers for the GT Pipeline and Instrumentation Operations category,
30 grounded in obligations under 49 CFR §192 and GO CPUC 112-F, were described in the

1 Description of Costs and Underlying Activities. In addition to costs captured in BY 2025, the
2 following incremental costs are requested:

3 **Pipeline Maintenance:** Incremental funding is requested under Pipeline Maintenance to
4 support additional upkeep associated with the expanding inventory of automated and remote-
5 controlled shut-off valves. As discussed in Section III.C., Description of Costs and Underlying
6 Activities, the increased installation of these valves was driven by state (PSEP-VEP) and federal
7 (Valve Rule) regulatory requirements. As a result, since 2014, SoCalGas has installed 403
8 automated and remote-controlled shut-off valves on its transmission system. These complex
9 assets require increased troubleshooting time, more frequent operational callouts, and enhanced
10 data management. The incremental funding required for this activity is \$1,811,000 over the 2025
11 adjusted-recorded base for TY 2028, of which \$400,000 is associated with non-labor costs and
12 \$1,411,000 with labor. Additional information on the Valve Rule, including its expansion
13 beyond the scope of the PSEP Valve Enhancement Plan, can be found in the Gas Major Projects
14 Testimony (SCG-06).

15 In addition, incremental, non-labor funding of \$144,000 is requested under Pipeline
16 Maintenance in 2028 for the adoption of FR garments, standardized headgear, and ANSI-
17 compliant safety vests for employee safety, per the Injury Illness Prevention Program, Cal
18 Occupational Safety and Health Administration (OSHA), Title 8, Section 3203,³⁵ and Protection
19 From Flames and Electric Arcs, Cal OSHA, Title 8, Section 2940.11.³⁶ These uniforms are
20 necessary for employee safety, regulatory compliance, operational readiness, and clear
21 identification of authorized personnel.

22 **Pipeline Monitoring Technologies:** Under Pipeline Monitoring Technologies,
23 incremental OPM maintenance funding is requested to support activities such as handhole
24 inspections, cover replacement, battery and power system upkeep, and station maintenance. 53
25 handholes and seven (7) OPM Stations are expected to be in-service and require maintenance by
26 TY 2028. The incremental funding required for this activity is \$24,000 over the 2025 adjusted-
27 recorded base for TY 2028.

³⁵ Cal/OSHA, Injury and Illness Prevention Program (Cal. Code Reg., Title 8, § 3203)

³⁶ Cal/OSHA, Protection from Flames and Electric Arcs (Cal. Code Reg., Title 8, § 2940.11)

In addition, incremental funding is requested under Pipeline Monitoring Technologies for maintenance of additional methane monitoring equipment expected to be operational by 2028. Funding supports unplanned maintenance, alarm response, damage repair, supervision, and materials. 458 HCA Methane Monitoring sites are planned to be in service and require maintenance by TY 2028. The incremental funding required for this activity is \$245,000 over the 2025 adjusted-recorded base for TY 2028.

D. GT Compressor Station Operations (2GT000.001)

**TABLE GO-7
Non-Shared O&M - GT Compressor Station Operations**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
D. GT Compressor Station Operations	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. GT Compressor Station Operations	12,969	14,430	1,461

1. Description of Costs and Underlying Activities

GT Compressor Station Operations costs support the safe and reliable operation of SoCalGas’s seven active compressor stations and their related infrastructure. These facilities include compressor engines, ancillary mechanical and electrical equipment, monitoring and control systems, odorization equipment, filtration and dehydration vessels, cooling systems, and real-time telemetry/SCADA communications connected to Gas Control. This equipment is fundamental to maintaining system pressures, supporting continuous natural gas transmission, and upholding overall transmission system integrity, as required under 49 CFR Part 192 and CPUC GO 112-F.

An underlying cost driver for compressor station activities is aging infrastructure. Many compressor stations have been in service for several decades and require significant upgrades to maintain long-term reliability, operational resilience, and compliance with evolving safety and emissions standards. In addition to modernizing engines and control systems, older stations increasingly require investment in ancillary equipment such as enhanced monitoring and diagnostics, auxiliary power and lubrication systems, gas detection and ventilation equipment, and updated communications and automation infrastructure. These upgrades are necessary to meet current regulatory expectations, reduce equipment failures, improve system controllability,

1 and minimize unplanned outages, supporting continued safe and reliable operations of aging
2 compressor facilities that serve as critical transmission assets.

3 To comply with federal, state, and local regulations, GT Compressor Station Operations
4 implement formal operating procedures, preventive maintenance programs, monitoring activities,
5 and documentation practices. Key compliance-driven activities include:

6 **Regulatory Compliance:** GT Compressor Station Operations must comply with
7 numerous regulatory frameworks, including requirements under 49 CFR Part 192, the CARB Oil
8 & Gas Rules, LDAR obligations, and state environmental statutes. Compliance activities cover
9 air quality management, hazardous materials handling, groundwater protection, stormwater
10 programs, wastewater process controls, and waste management for both aboveground and
11 underground facilities.

12 **Operational Procedures:** Standardized operating, maintenance, and safety procedures
13 are developed and implemented for new, modified, and legacy station equipment. These
14 procedures address requirements under PHMSA’s O&M rules, including inspections, testing
15 intervals, operational checks, valve alignment, and response protocols. Procedure updates
16 support consistent operations and reflect evolving regulatory expectations and system conditions.

17 **Emissions Monitoring and Control:** Continuous emissions monitoring, testing, and
18 reporting are required to comply with state and federal air quality regulations and to support
19 California’s greenhouse gas reduction objectives. In 2028, the installation of three new Vapor
20 Capture Systems will require dedicated maintenance resources. Additionally, a system-wide rod
21 packing quality and maintenance plan is projected to reduce rod packing emissions across all
22 compressor stations. This plan will establish inspection intervals, maintenance schedules, and
23 performance criteria to support equipment reliability and safe operation of compressor engines.

24 **Inspection and Maintenance Activities:** Routine and event-driven inspections are
25 required under PHMSA’s maintenance regulations. These include scheduled inspections of
26 compressor engines, pressure control components, cooling and lubrication systems, filtration
27 vessels, sensors, electrical equipment, and control systems. Post-event inspections occur after
28 earthquakes, flooding events, wildfires, pipeline shut-ins, or other operational disturbances.
29 These assessments identify potential equipment impacts, validate safe operating conditions, and
30 reduce reliability risks.

1 Real-time telemetry, monitoring, and control systems are essential components of safe
2 and reliable inspection and maintenance activities under GT operations. These systems provide
3 continuous visibility into pressure, flow, equipment status, alarms, and station performance,
4 enabling operators to detect abnormal conditions early and take timely corrective action.

5 Advancements in sensor technology, automation, and communication networks are
6 essential to inspection and maintenance activities. They require updates to legacy hardware and
7 software to enable compatibility, cybersecurity resilience, and regulatory compliance. Over time,
8 components such as pressure and temperature transmitters, programmable logic controllers
9 (PLC), remote terminal units (RTU), communication modules, and SCADA interfaces
10 experience wear, obsolescence, or performance degradation. Regular replacement,
11 reprogramming, and testing are necessary to maintain data quality, minimize communication
12 failures, and allow the control systems to perform as intended during both normal operations and
13 emergency events.

14 Upgrades and maintenance activities include:

- 15 • Calibration and replacement of field instrumentation to enable accurate pressure,
16 flow, and temperature measurements that support operational decision making
17 and regulatory reporting;
- 18 • Modernization of PLCs, RTUs, and SCADA components to maintain functional
19 reliability, cybersecurity compliance, and integration with updated corporate and
20 field networks;
- 21 • Periodic software and firmware updates to address vulnerabilities, enhance
22 functionality, and maintain alignment with industry standards and vendor support;
- 23 • Testing and validation of alarm logic, interlocks, and automated shutdown
24 sequences to support equipment response during abnormal conditions, reducing
25 the likelihood of incidents or system upsets; and
- 26 • Upgrades to communication infrastructure, including radio, cellular, and fiber
27 systems, to improve data transmission reliability, reduce latency, and maintain
28 continuous situational awareness.

29 **System Integrity Management:** Compressor stations support system integrity by
30 adjusting operating parameters (pressure, flow, and temperatures) and by addressing gas quality
31 issues consistent with integrity management expectations under PHMSA's Subpart O. Station

1 personnel coordinate with Engineering and Gas Control to maintain stable system operations
2 during seasonal demand swings, maintenance work, or pipeline outages.

3 Post-event assessments represent a core regulatory expectation. Following natural
4 disasters, extreme weather, seismic activity, wildfires, flooding, power disruptions, or abnormal
5 operating conditions, compressor stations must be evaluated for structural impacts, equipment
6 damage, misalignments, control system abnormalities, and potential environmental or safety
7 hazards. Timely assessment and corrective action help prevent degraded components from
8 contributing to failures that could jeopardize public safety, system reliability, or regulatory
9 compliance. Event response processes reduce operational risk, prevent equipment degradation,
10 and help support uninterrupted gas delivery. These efforts strengthen safety performance,
11 support regulatory compliance, and support safe and efficient operation under both normal and
12 adverse conditions.

13 **Emergency Preparedness:** These activities support emergency response requirements
14 under 49 CFR §192.615, promote continuous situational awareness, reduce operational risk, and
15 strengthen system reliability. Strategically placing key personnel at key stations helps prevent
16 prolonged outages, supports adherence to mandated emergency response standards, and enhances
17 the utility's ability to operate critical compressor facilities safely and effectively under both
18 normal and adverse conditions.

19 Compressor stations maintain 24-hour on-call staffing and are ready to respond to
20 operational issues, alarms, equipment failures and unplanned outages, control system
21 malfunctions, abnormal operating conditions and other issues that require immediate
22 intervention. Faster response times reduce the likelihood of escalation, help maintain safe
23 operating pressures, and prevent extended service disruptions. This capability is especially
24 critical at compressor stations that serve as major transmission hubs, pressure-maintenance
25 points, or single-contingency locations, where delayed response could significantly impact
26 system performance.

27 In addition, onsite personnel support regulatory requirements for emergency preparedness
28 and operational readiness, including:

- 29 • Timely hazard recognition and mitigation, as required under emergency response
30 and incident management expectations;

- Execution of emergency shutdown (ESD) protocols, pressure adjustments, and operational isolation when abnormal conditions arise;
- Immediate coordination with Gas Control, field operations, and emergency responders during events such as equipment failures, pipeline operational issues, seismic activity, or severe weather impacts; and
- Documenting and reporting activities that demonstrate compliance with CPUC and PHMSA timelines for incident notification, post-event assessments, and corrective action.

Security Requirements (TSA Critical Infrastructure): Several compressor stations have been designated as TSA Critical Infrastructure, requiring enhanced physical security measures. Increased on-site security presence helps deter vandalism, theft, unauthorized entry, and tampering—activities that could compromise compressor engines, control systems, power infrastructure, or telecommunications equipment. Strengthening security supports system safety, protects key operational assets, and safeguards employees and the public. It also supports continuity of operations for critical infrastructure subject to both federal and state oversight. Personnel assigned to these locations play a key role in supporting physical security requirements by:

- Monitoring and supporting newly installed hardening measures, including upgraded fencing, access control points, and perimeter protections;
- Providing real-time situational awareness to detect and respond quickly to unauthorized activity or security anomalies; and
- Coordinating with Gas Control, Security Operations, and field responders to enable timely and effective response to potential threats.

Compressor Time Study: In the 2024 GRC Decision (D.24-12-074), the Commission directed SoCalGas to conduct a time study for Compressor Station Operations to document the time needed to perform employee tasks to support a reasonable level of staffing. SoCalGas hired a third party to conduct this study which initiated in December of 2025. The report is provided in Appendix D.

1 adjustments. The incremental adjustments that impacted the variance include Rod Packing
2 Maintenance, Vapor Capture System Maintenance, vessel and tank inspections not captured in
3 BY 2025 costs, and enhanced security at sites identified as TSA-critical. The underlying scope of
4 work and risk control strategy remain unchanged from the RAMP filing.

5 C142 activities are required under 49 CFR Part 192 and CPUC GO 112-F and support the
6 safe and reliable operation of SoCalGas's seven active compressor stations and their related
7 infrastructure.

8 **2. Forecast Method**

9 The forecast method for GT Compressor Station Operations is based on BY 2025, with
10 incremental adjustments to account for anticipated pressures. The incremental adjustments are
11 associated with emissions monitoring and control programs; cyclical inspection and maintenance
12 activities not reflected in the 2025 baseline; enhanced safety compliance measures; and increased
13 security staffing at TSA-designated critical facility compressor stations to maintain regulatory
14 compliance, system reliability, and infrastructure protection. These incremental activities are
15 described in the following section. A review of the five-year historical average (2021-2025)
16 indicates that work activities in this category exhibit minimal year-to-year variability and
17 changes beyond the requested incremental requests to current operations are not anticipated at
18 this time. Accordingly, the BY 2025 method is appropriate as it reflects the most recent full
19 scope of operations and maintenance activities driven by regulatory requirements and asset
20 conditions.

21 **3. Cost Drivers**

22 The primary cost drivers for GT Compressor Station Operations are regulatory
23 compliance, including 49 CFR § 192, CPUC GO 112-F, CARB Oil & Gas requirements, and
24 LDAR standards, which necessitate continuous monitoring, reporting, and operational
25 adjustments. Environmental compliance activities related to air quality, hazardous materials,
26 stormwater, and waste management further contribute to costs. Aging compressor station
27 infrastructure is also a key cost driver, as many facilities have been in service for several decades
28 and require increased maintenance, inspections, and modernization to sustain safe, reliable, and
29 compliant operations.

30 In addition to costs captured in BY 2025, the following incremental costs are requested:

1 **Emissions Monitoring and Control:** To meet the obligations under CARB, including
2 LDAR requirements, and California Senate Bill (SB) 1371,³⁷ SoCalGas must maintain and
3 operate emissions-related systems such as Compressor Rod Packing assemblies and Vapor
4 Capture Systems. These systems play a critical role in controlling methane and volatile organic
5 compound (VOC) emissions associated with compressor operation. Effective maintenance is
6 required to maintain emissions within permitted limits and supports compliance with regulatory
7 requirements for leak reduction, methane mitigation, and air quality performance.

8 Incremental funding is requested to support these activities. For the Compressor Rod
9 Packing Maintenance Program, a request of \$154,000 in 2028 is needed to perform scheduled
10 replacement and system optimization to enable continued emissions control effectiveness.
11 Additionally, annual funding of \$56,000, beginning in 2028, is required to maintain the Vapor
12 Capture Systems scheduled for installation in 2028 at three compressor stations. These vapor
13 capture units reduce fugitive emissions by capturing and routing vented gas back into the fuel or
14 process stream, thereby improving operational efficiency and supporting environmental
15 compliance.

16 Funding for these programs reduces the risk of noncompliance, avoids potential
17 regulatory enforcement actions for noncompliance, and supports the state's broader greenhouse
18 gas reduction goals through continued reductions in methane and other pollutant emissions.

19 **Inspection and Maintenance Activities:** Incremental costs of \$578,000 are requested
20 over the 2025 adjusted-recorded base for TY 2028 for mechanical inspections of vessels and
21 tanks subject to API 510 and API 653 compliance. This incremental increase represents the
22 activities that were not captured in BY 2025 due to the cyclical nature of this work. Transmission
23 Inspections include more than 1,000 vessels and tanks, each requiring inspection every five, ten,
24 15, or 20 years, per API 510 for vessels and API 653 for tanks. This incremental funding request
25 allows for the completion of tests at one to two stations per year through 2031.

26 Additionally, incremental non-labor funding of \$27,000 in 2028 is requested for the
27 adoption of new FR garments, standardized headgear, and ANSI-compliant safety vests for
28 employee safety per the Injury Illness Prevention Program, Cal OSHA, Title 8, Section 3203 and
29 Protection from Flames and Electric Arcs, Cal OSHA, Title 8, Section 2940.11. These uniforms

³⁷ SB 1371 (Durazo, 2026), available at: <https://legiscan.com/CA/text/SB1371/id/3417535>.

1 are necessary for employee safety, regulatory compliance, operational readiness, and clear
 2 identification of authorized personnel.

3 **Security Requirements (TSA-Designated Critical Infrastructure):** Compressor
 4 stations designated as TSA critical facilities require enhanced physical security and operational
 5 readiness measures to meet federal pipeline security guidelines and protect essential gas
 6 transmission infrastructure. As part of the hardening of these compressor stations, continuous
 7 onsite personnel presence is necessary to support security operations, monitor critical systems,
 8 and safeguard the facilities against external threats, attempted intrusion, or interference that
 9 could impact system safety and reliability.

10 Incremental funding for \$540,000 is requested to support this enhanced security plan for
 11 sites in 2028. As fencing and perimeter security upgrades are completed, additional staffing is
 12 required to monitor the proper functioning of these measures and to protect the stations
 13 throughout implementation and operation.

14 **E. GT Cathodic Protection (2GT000.002)**

15 **TABLE GO-9**
 16 **Non-Shared O&M – GT Cathodic Protection**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
E. GT Cathodic Protection	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. GT Cathodic Protection	1,657	1,794	137

17 **1. Description of Costs and Underlying Activities**

18 The GT Cathodic Protection (CP) plays a critical role in supporting SoCalGas’s
 19 commitment to safety and regulatory compliance through activities that mitigate external
 20 corrosion, a primary threat to pipeline integrity and safety. By applying a controlled electrical
 21 current, CP systems prevent steel corrosion in the underground environment, thereby extending
 22 asset life, reducing the risk of leaks or ruptures, and enhancing operational reliability, consistent
 23 with applicable federal regulations (49 CFR Parts 192.451-192.493).³⁸ Implementing effective
 24 CP maintains safety, environmental health, and the long-term performance of critical
 25 infrastructure.

³⁸ 49 CFR § 192, Subpart I (Requirements for Corrosion Control).

1 Two CP methods are employed to provide corrosion protection to underground steel
2 pipelines:

- 3 • **Galvanic Anode CP:** This system employs sacrificial anodes made of more
4 active metals, typically magnesium, that corrode preferentially, thereby
5 preventing pipeline degradation. The anodes are buried near the pipeline and
6 electrically connected, allowing protective current to flow without an external
7 power source. This method is well-suited for small to medium pipelines in low-
8 resistivity soils. This passive protection method supports pipeline integrity and
9 extends asset life.
- 10 • **Impressed Current CP:** This is an advanced corrosion control system that
11 protects underground steel pipelines by supplying a continuous direct current
12 (DC) from an external power source. It uses inert anodes connected to a DC
13 power supply (rectifier) to deliver protective current to the pipeline. This method
14 is highly effective for large pipeline networks or areas with high soil resistivity.
15 By actively maintaining the pipeline as the cathode, this cathodic protection
16 system supports the pipeline's long-term integrity and minimizes corrosion-
17 related failures.

18 CP activities support safe operation and compliance with 49 CFR Subpart I. Core tasks
19 include:

- 20 • **Annual Electrical Test Station (ETS) readings**
- 21 • **Bi-monthly electric current source inspections**
- 22 • **Annual rectifier maintenance**
- 23 • **Annual pipeline assessments (required at intervals ≤ 15 months)**
- 24 • **Rectifier inspections six times per year (required at intervals ≤ 2.5 months)**

25 This work includes voltage and amperage checks, equipment calibration, cleaning,
26 tightening connections, replacing tags, and troubleshooting deficiencies. Regular inspections
27 maintain system integrity, extend pipeline life, and mitigate corrosion risks. Additional work
28 includes replacing or upgrading CP components (bonds, test points, and insulators) and
29 addressing anode depletion, which accelerates under drought or in high-resistivity soils. Anode
30 life varies depending on soil type, weather conditions, pipeline length, and coating type.

a. Description of RAMP Mitigations

Within this cost category, there are non-shared O&M costs for risk control C108 (Cathodic Protection – Maintenance) that were presented in the 2025 RAMP Report and are listed in Table GO-10. The activities described above support C108.

Activities that are compliance or mandated by CPUC or other agencies are listed in bold, and Appendix B attached to this testimony provides the details regarding these mandates for each control.

**TABLE GO-10
RAMP and GRC Risk Control/Mitigation Activities – O&M**

GT Cathodic Protection				
ID	Control/Mitigation Name	2025 RAMP 2028 Estimate In 2024 \$ (000s)	2028 GRC 2028 Forecast In 2025 \$ (000s)	Change (000s)
C108	Cathodic Protection – Maintenance	3,078	1,793	(1,285)

b. Description of Selection and Prioritization of RAMP Risk Mitigations

The RAMP risk mitigation efforts are associated with specific actions, such as programs, projects, processes, and utilization of technology and are designed to address a specific safety and/or reliability risk. The Company’s selection and prioritization of these RAMP mitigation activities considered many factors when determining if these risk mitigation activities are an effective and worthwhile investment. The ERM process for identifying and assessing system risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

C108 addresses external corrosion, internal corrosion, manufacturing defects, and equipment failure, which are four of the potential drivers to the High-Pressure Gas System risk. If not addressed, the drivers could lead to a risk event with potential consequences for customers, including serious injuries or fatalities, operational and reliability impacts, and environmental impacts. In accordance with 49 CFR §§ 192.451-192.493, proactive inspections, assessments and other CP activities maintain the system safety and reliability by protecting against corrosion and reducing the likelihood of a potential leak or other risk event. In prioritizing this proactive approach, SoCalGas seeks to reduce the likelihood of future risk events, and avoid significantly higher operational, customer and recovery impacts associated with responding to realized incidents.

1 The difference between the RAMP forecast and the forecast in this testimony is due to
2 the RAMP using a 2024 forecast, while this testimony uses a BY 2025 forecast with incremental
3 adjustments. In the RAMP filing adjustments were made for Gas Safety Enhancement Programs
4 (GSEP) Balancing Account charges. This adjustment is no longer included in this activity, which
5 resulted in the variance from the RAMP filing shown in Table GO-10. The underlying scope of
6 work and risk control strategy remain unchanged from the RAMP filing.

7 **2. Forecast Method**

8 The forecast method for GT Cathodic Protection is based on BY 2025, with incremental
9 adjustments to account for AC monitoring activities scheduled to begin in 2028. These
10 incremental activities are described in detail in the following section. A review of the five-year
11 historical average (2021-2025) indicates that work activities in this category exhibit minimal
12 year-to-year variability and changes beyond the requested incremental requests to current
13 operations are not anticipated at this time. Accordingly, the BY 2025 method is appropriate as it
14 reflects the most recent full scope of operations and maintenance activities driven by regulatory
15 requirements and asset conditions.

16 **3. Cost Drivers**

17 The cost drivers behind the GT Cathodic Protection forecast are primarily driven by
18 regulatory compliance, system reliability, and safety requirements. These activities safeguard
19 pipeline integrity, minimize corrosion-related leaks, and protect safety.

20 In addition to activities included in Section III.E.1, incremental funding of \$115,000
21 annually is requested, beginning in 2028, to support Alternating Current (AC) interference
22 monitoring and mitigation near high-voltage electric transmission lines. Steel pipelines near
23 high-voltage AC electrical lines are susceptible to AC interference, which may increase the risk
24 of pipeline corrosion and safety risks to personnel, the public, and the environment. In
25 accordance with 49 CFR §192.473, new regulatory requirements effective in 2023 expanded
26 obligations for the identification, monitoring, and mitigation of AC interference on gas
27 transmission pipelines. These requirements have been programmatically developed by the
28 Transmission Integrity Management Program (TIMP) team and implemented by GT Cathodic
29 Protection. While AC interference had previously been monitored and mitigated primarily from a

1 safety perspective, the updated regulations³⁹ established defined thresholds for AC current
 2 density that must be evaluated and mitigated to prevent corrosion-related integrity risks. Through
 3 implementation of these requirements, SoCalGas will monitor and mitigate AC stray current to
 4 maintain the safety and integrity of its transmission pipeline system and support ongoing
 5 compliance with federal corrosion control standards. These measures address AC-induced
 6 corrosion and personnel safety hazards, necessitating the implementation of new equipment and
 7 O&M procedures.

8 **F. GT Technical Services (2GT000.003)**

9 **TABLE GO-11**
 10 **Non-Shared O&M – GT Technical Services**
 11

GAS TRANSMISSION & STORAGE (In 2025 \$)			
F. GT Technical Services	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. GT Technical Services	2,627	4,680	2,053

12 **1. Description of Costs and Underlying Activities**

13 The GT Technical Services costs support activities that provide the technical,
 14 engineering, and administrative capabilities required for the safe, compliant, and reliable
 15 operation of the gas transmission system. This organization delivers design engineering,
 16 instrumentation and control expertise, project planning, and environmental services, while also
 17 providing onsite technical support to GT Pipeline and Instrumentation Operations and GT
 18 Compression Station Operations for troubleshooting and field guidance. These functions are
 19 foundational to meeting CPUC and PHMSA expectations for system performance, asset
 20 integrity, and regulatory compliance.

21 GT Technical Services develops construction design requirements, prepares engineering
 22 drawings, and produces technical specifications needed for pipeline and compressor station
 23 projects. This includes cost estimating, feasibility evaluations, and selecting appropriate
 24 materials to meet safety and performance standards. The team also offers field engineering and

³⁹ These changes can be found in 49 CFR §192.473(C), available at: <https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-192/subpart-I/section-192.473>.

1 instrumentation and control (I&C) expertise, helping resolve operational and equipment issues
2 timely and effectively.

3 This group manages planning and scheduling activities to support the execution of
4 maintenance and capital work. Environmental reviews and documentation are prepared to meet
5 federal, state, and local permitting obligations. These activities support project approval,
6 environmental compliance, and safe access to transmission assets.

7 Core activities for GT Technical Services include:

8 **ROW Maintenance:** To protect transmission infrastructure and meet CPUC and
9 PHMSA safety requirements, the group coordinates activities that include vegetation
10 management, encroachment reviews, and land access maintenance. These efforts protect the
11 pipeline corridor from interference, facilitate inspection activities, and reduce the likelihood of
12 third-party impacts. ROW maintenance is required to address risk conditions and the increasing
13 likelihood of encroachments that can obstruct access needed for pipeline inspections, routine
14 operations, and emergency response. Maintaining clear and accessible ROWs supports safe and
15 reliable entry to remote and difficult-to-access areas, allowing personnel to perform ongoing
16 maintenance and promptly identify and mitigate potential hazards such as erosion, land
17 movement, vegetation overgrowth, and landslides that could compromise pipeline integrity or
18 delay response activities.

19 **Class Location Change:** GT Technical Services conduct and coordinate specialized
20 fieldwork, including strength testing, pressure validation, and assessments driven by class
21 location changes. These activities verify that transmission assets perform within required safety
22 margins and comply with federal integrity management rules. Class Location projects consist of
23 strength testing transmission pipeline segments operating out of class due to new developments
24 that increase population density in the area surrounding the pipeline. This activity supports the
25 safe operation of SoCalGas's pipelines by confirming that pipe segments meet the standards
26 prescribed by 49 CFR § 192.609⁴⁰ for new class locations.

27 **Permitting and Compliance:** GT Technical Services review construction plans from
28 utilities, developers, agencies, and contractors. By identifying conflicts with transmission assets

⁴⁰ 49 CFR § 192.609 (Change in class location: Required study).

1 and coordinating with external parties, GT Technical Services help avoid accidental damage,
2 which is a significant risk category monitored by regulators.

3 The permitting process for pipeline maintenance and construction work frequently
4 involves projects in overlapping jurisdictions, Tribal authorities, and multiple environmental
5 agencies, each requiring distinct reviews, documentation, and approval steps.

6 Construction activity near transmission pipelines requires compliance reviews and utility
7 plan checks. Coordinating with developers, local governments, and other utilities requires a
8 detailed examination of proposed projects to identify conflicts and evaluate construction risks to
9 verify that work near transmission assets meets safety and regulatory requirements. These plan
10 reviews play a critical role in reducing the likelihood of third-party damage and supporting the
11 safe execution of work across expanding urban and suburban development areas.

12 Regulatory agencies often require detailed assessments, such as biological resource
13 surveys, cultural resource studies, and complex environmental review (such as an Environmental
14 Impact Report (EIR)) under the California Environmental Quality Act (CEQA) and National
15 Environmental Policy Act (NEPA). These requirements impact project schedules and
16 administrative, consultant, and contractor costs. In many cases, work is limited to certain seasons
17 or cannot begin until seasonal surveys are completed, species-specific protections are addressed,
18 and mitigation plans are reviewed by the appropriate agencies. These reviews are rigorous and
19 time-consuming for developments near sensitive habitats and protected areas.

20 Work within national parks, federally managed lands, state conservation areas, or habitats
21 protected by federal and state wildlife agencies involves multiple layers of review,
22 environmental documentation, field surveys, and coordination with regulatory authorities.
23 Agencies such as the National Park Service, the Bureau of Land Management, and state and
24 federal wildlife agencies often require detailed permitting packages and extended approval
25 timelines, before field work can begin.

26 **Emergency Preparedness and Response:** GT Technical Services play a critical role in
27 emergency preparedness by supporting the Transmission Branch within the Incident Command
28 Structure (ICS). During major operational events or natural disasters, GT Technical Services
29 provide engineering analysis, mapping support, planning expertise, and field guidance in
30 coordination with the larger company response. This support strengthens the Company's ability

1 to respond quickly and safely during emergencies and aligns with state and federal emergency
2 response expectations.

3 GT Technical Services must activate quickly, supply accurate asset information, develop
4 operational strategies in real time, and coordinate technical evaluations of pipeline and
5 compressor station conditions during high-pressure situations. To remain fully capable of
6 supporting these responsibilities, the group must regularly update system mapping platforms,
7 refine engineering evaluation tools, and maintain clear communication pathways with field
8 operations, Gas Control, and emergency management partners.

9 Ongoing investment is required to keep personnel trained in ICS roles, regulatory
10 expectations, and advanced engineering analysis used during incident response. GT Technical
11 Services conduct regular exercises, scenario-based drills, system simulations, and cross-
12 functional coordination sessions to maintain a high level of operational readiness. These
13 activities support rapid mobilization and sound technical decisions during emergencies, helping
14 reduce system impacts and uphold regulatory expectations for timely, organized incident
15 responses.

16 In addition, GT Technical Services must maintain up-to-date documentation, mapping
17 datasets, equipment information, and response procedures so that accurate, actionable
18 information is available during an incident. This preparation requires sustained funding for
19 software systems, GIS updates, field data collection, and the staff time needed to manage
20 technical records that support emergency response.

21 **Material Procurement:** Many transmission projects require specialized materials and
22 certified components. GT Technical Services are responsible for the procurement of materials
23 necessary for construction, rehabilitation, and maintenance activities. Many projects rely on
24 components, custom-fabricated parts, or materials that must meet stringent engineering,
25 regulatory specifications, and have long lead times.

26 GT Technical Services play a critical role in supporting the safe operation of the gas
27 transmission system and meeting state and federal regulatory requirements. The associated costs
28 reflect the specialized expertise and ongoing activities required to maintain system reliability,
29 meet regulatory requirements, and support transmission operations across a wide range of
30 technical and compliance-driven needs.

1 base-year assumptions. RAMP is based on a 2024 forecast, while this GRC applies a BY 2025
2 forecast. Fewer Class Location Change (Hydrotest) projects were completed in 2025, which has
3 led to a variance from the RAMP filing. The underlying scope of work and risk control strategy
4 remain unchanged from the RAMP filing.

5 **2. Forecast Method**

6 The forecast for GT Technical Services is based on BY 2025, with incremental labor and
7 non-labor adjustments primarily driven by increased ROW activities, as described in the section
8 below. A review of historical costs indicates that, although a five-year historical average (2021-
9 2025) yields a significantly higher forecast, the use of BY 2025 for the baseline is appropriate
10 because it reflects current operating conditions, including existing workload, staffing levels, and
11 execution requirements necessary to sustain the current organizational structure, which is
12 expected to remain in place through TY 2028. Accordingly, BY 2025 adjusted for incremental
13 costs, provides the most reasonable representation of forecasted costs. This method captures the
14 full scope of activities driven by increased ROW maintenance associated with known conditions,
15 continued development near transmission corridors, and climate-related impacts, such as
16 increased erosion and subsidence, that necessitate maintenance beyond routine activities.

17 **3. Cost Drivers**

18 The primary cost drivers for the GT Technical Services category are described in the
19 “Description of Costs and Underlying Activities” section. In addition to costs captured in BY
20 2025, the following incremental costs are requested:

21 **ROW Maintenance:** Growth in residential, commercial, and industrial development
22 across previously undeveloped areas has had a substantial impact on the scope and complexity of
23 ROW maintenance. As development growth gets closer to transmission corridors, ROW
24 activities must address vegetation growth, fire risk, and the likelihood of encroachments that can
25 interfere with inspection access and operational activities. Patrol road upkeep requires repeated
26 grading, erosion repair, and other maintenance to maintain safe access for inspections, patrols,
27 and emergency response. Furthermore, many ROW segments are located in steep, rugged, or
28 environmentally sensitive terrain and can only be accessed with specialized contractors,
29 specialized equipment, and extended mobilization efforts. These areas often require additional
30 planning, longer travel times, and higher contractor costs due to limited accessibility and the
31 need to transport equipment capable of navigating difficult topography. Additionally, climate-

1 related impacts have caused increased erosion and subsidence in these segments that necessitate
2 maintenance beyond routine activities.

3 Incremental annual funding of \$2,035,000 in labor and non-labor costs in 2028 is
4 requested to address the increased workload associated with these ROW maintenance demands
5 beyond what is reflected in BY 2025. This work reflects the growing maintenance requirements
6 driven by development patterns, geographic challenges, and regulatory obligations.

7 **G. Aboveground Storage (2GT002.000)**

8 **TABLE GO-13**
9 **Non-Shared O&M – Aboveground Storage**

10

GAS TRANSMISSION & STORAGE (In 2025 \$)			
G. Aboveground Storage	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Aboveground Storage	4,592	5,862	1,270

11 **1. Description of Costs and Underlying Activities**

12 The Aboveground Storage costs encompass the leadership, management, planning,
13 inspection, assessment, and mitigation activities necessary to maintain the safe, reliable, and
14 efficient operation of aboveground infrastructure at natural gas storage fields. The scope of work
15 supported by these costs is essential to maintaining system integrity, meeting regulatory
16 requirements, and supporting continued storage field operations.

17 Leadership and management functions include directing O&M activities, monitoring
18 performance and regulatory compliance, identifying operational risks and improvements
19 opportunities, and allocating resources to support system reliability. These teams also provide
20 financial oversight in alignment with approved budgets and established operational priorities.

21 **Storage Facilities Management:** This group is responsible for managing, validating, and
22 maintaining operational and environmental data required for regulatory and audit purposes at gas
23 storage fields. This includes preparation of accurate, audit-ready datasets and documentation to
24 support annual CPUC audits, as well as internal company audits. The group tracks and reports
25 storage capacity and emissions data to comply with applicable environmental, safety, and
26 reporting requirements of the CPUC, CalGEM, U.S. Department of Transportation
27 (DOT)/PHMSA, South Coast Air Quality Management District (SCAQMD), Santa Barbara
28 County Air Pollution Control District (SBCAPCD), and CARB.

1 In addition, this group maintains and supports OT and monitoring systems used in the
2 storage fields. Activities include updating hardware and software, programming and automating
3 systems, and repairing and replacing technology to support reliable data collection and system
4 performance. These technologies enable storage field operators to monitor asset conditions and
5 make informed maintenance and repair decisions. The group also maintains and updates asset
6 management systems, such as Maximo, to generate reports and alerts identifying equipment and
7 assets requiring inspection, maintenance, or repair. These outputs are provided to storage field
8 personnel to support timely corrective actions.

9 **Storage Technical Services (STS):** This group provides project oversight, engineering
10 support, training, and management for maintenance and integrity activities at gas storage
11 facilities. The team oversees inspections across the gas storage system, including pressure vessel
12 and tank inspections, ultrasonic testing (UT), and electrical equipment testing. Additionally, STS
13 manages corrosion control programs to preserve the integrity of aboveground storage assets and
14 associated pipelines. Through these inspection, testing, and integrity management activities, STS
15 supports storage field operators in assessing asset conditions and maintaining continued safe and
16 reliable operation of storage facilities.

17 **a. Description of RAMP Mitigations**

18 Within this cost category, there are non-shared O&M costs for risk controls C014
19 (Storage HP Field Maintenance – Aboveground Facilities) and C016 (Storage HP Field
20 Maintenance – Aboveground Piping) that were presented in the 2025 RAMP Report and are
21 listed in Table GO-14. All cost forecasts included in this workpaper are associated with C014
22 and C016 and are required to meet safety, reliability, and regulatory requirements across a wide
23 range of federal, state, and local agencies, including PHMSA, OSHA, EPA, Federal Energy
24 Regulatory Commission (FERC), National Transportation Safety Board (NTSB), Federal
25 Emergency Management Agency (FEMA), CPUC, DOT, LA County, CARB, SCAQMD, the
26 NFPA, and CalGEM, as well as Cal. Code Reg., Title 14, § 1774.2.⁴¹ These risk controls reduce
27 the likelihood and consequences of equipment or piping failures at aboveground storage
28 facilities. Ongoing inspections, corrosion control, integrity testing, continuous operations, and
29 timely repairs help maintain asset condition and operational readiness, support reliable

⁴¹ Cal. Code Reg., Title 14, § 1774.2 (Pipeline Management Plans).

1 year-round gas delivery, and reduce the potential for unplanned outages or high-cost emergency
 2 events. Collectively, these activities enhance customer safety, protect affordability by avoiding
 3 reactive response costs, and strengthen overall system dependability.

4 Activities that are related to compliance or mandated by CPUC or other agencies are
 5 listed in bold, and Appendix B attached to this testimony provides the details regarding these
 6 mandates for each control.

7 **TABLE GO-14**
 8 **RAMP and GRC Risk Control/Mitigation Activities – O&M**
 9

Aboveground Storage				
ID	Control/Mitigation Name	2025 RAMP 2028 Estimate In 2024 \$ (000s)	2028 GRC 2028 Forecast In 2025 \$ (000s)	Change (000s)
C014	Storage HP Field Maintenance – Aboveground Facilities	4,778	4,262	(516)
C016	Storage HP Field Maintenance – Aboveground Piping	580	1,600	1,020
TOTAL		5,358	5,862	504

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

12 The RAMP risk mitigation efforts are associated with specific actions, such as programs,
 13 projects, processes, and utilization of technology and are designed to address a specific safety
 14 and/or reliability risk. The Company’s selection and prioritization of these RAMP mitigation
 15 activities considered many factors when determining if these risk mitigation activities are an
 16 effective and worthwhile investment. The ERM process for identifying and assessing system
 17 risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

18 The primary drivers are external and internal corrosion, weather and other outside forces,
 19 equipment and piping failures, incorrect or abnormal operations, third-party damage, and gaps in
 20 asset records. If not addressed, these conditions can lead to serious consequences such as injuries
 21 or fatalities, damage to nearby property and infrastructure, service outages and reliability
 22 shortfalls, litigation and fines, loss of public confidence, and environmental releases.

1 These mitigations were chosen because they directly target identified risk drivers by
2 lowering the probability of equipment or piping failures and limiting potential consequences
3 through staffing, inspections and monitoring, corrosion control, integrity testing, timely repairs,
4 accurate records, and compliance activities, reducing the risk of severe impacts to customers and
5 communities.

6 The primary difference between the RAMP forecast and the forecast in this testimony is
7 due to the RAMP using a 2024 forecast, while this testimony uses a BY 2025 forecast with
8 incremental adjustments. The incremental adjustments that impacted the variance include the
9 request for additional data management and regulatory reporting inspections and assessments
10 described in Section III.G.3.

11 **2. Forecast Method**

12 The forecast methodology for Aboveground Storage is BY 2025, with incremental
13 adjustments to support expanded data management and regulatory reporting functions, as well as
14 the inspection and assessment of storage pipelines, as described in the following section. A
15 review of historical costs indicates that, although application of a five-year historical average
16 (2021–2025) results in a higher forecast, the use of BY 2025 as the baseline is appropriate
17 because it reflects recent operating conditions. These conditions include current workload,
18 staffing levels, and execution requirements necessary to sustain the existing organizational
19 structure, which is anticipated to remain largely unchanged through TY 2028. Accordingly, BY
20 2025, adjusted for incremental costs, provides the most reasonable representation of forecasted
21 costs and captures the full scope of operations and maintenance activities.

22 **3. Cost Drivers**

23 The primary cost drivers behind the Aboveground Storage forecast include work
24 oversight and management activities necessary to support compliance with applicable regulatory
25 requirements. These activities are further described in Section III.G.1, “Description of Costs and
26 Underlying Activities,” and support compliance with requirements and standards established by
27 the CPUC and its Safety and Enforcement Division (SED), CARB, Cal. Code Reg., Title 14 §

1 1774.2⁴², Title 14 § 1774.1⁴³, 49 CFR § 192, DOT, CalGEM, NFPA 70B⁴⁴, API510⁴⁵, API570⁴⁶,
2 API 653⁴⁷, SCAQMD, and the SBCAPCD.

3 An incremental request of \$1,220,000 over the base year is requested for TY 2028 to
4 support inspections and data management activities necessary to sustain long-term operational
5 integrity and reliability of aboveground assets. These assets are susceptible to degradation
6 mechanisms such as internal and external corrosion that may not be evident without UT
7 inspections. Effective data management is essential to support inspection planning,
8 documentation, analysis of results, systematic tracking of findings and maintenance of records in
9 accordance with applicable API standards and CalGEM regulations, Cal. Code Reg., Title 14 §
10 1774.1 and § 1774.2. Specifically, API 510 establishes inspection practices for in-service
11 pressure vessels, API 570 establishes inspection requirements for piping systems to prevent leaks
12 and failures, and API 653 supports environmental protection objectives, including EPA Spill
13 Prevention, Control, and Countermeasure (SPCC)⁴⁸ 40 CFR § 112.7, requirements for
14 aboveground storage tank integrity. Pipeline inspection and testing is required to support Cal.
15 Code Reg., Title 14 §1774.1 that requires documentation of mechanical-integrity testing
16 frequencies, methods, and results, thereby requiring traceable inspection records.

17 In addition, as a prudent operator, SoCalGas conducts inspections that strengthens risk
18 identification, prioritization, and mitigation across a broad range of aboveground assets through
19 data-driven analysis, and inspections. The requested funding level supports the inspection,
20 assessment, data management, and reporting activities necessary to mitigate operational risks and
21 to enhance and sustain the safety and reliability of the Company's aboveground assets.

⁴² 14 CCR § 1774.2 (Pipeline Management Plans).

⁴³ 14 CCR § 1774.1 (Pipeline Inspection and Testing).

⁴⁴ NFPA 70B: Standard for Electrical Equipment Maintenance (2023 ed.)

⁴⁵ API 510: Pressure Vessel Inspection Code (2022 ed.).

⁴⁶ API 570: Piping Inspection Code (2022 ed.).

⁴⁷ API 653: Tank Inspection (2020 ed.).

⁴⁸ EPA, 40 CFR §112.7 (General Requirements for Spill Prevention, Control, and Countermeasure Plans).

1 **H. Gas Storage Fields (2GT002.001)**

2 **TABLE GO-15**
3 **Non-Shared O&M – Gas Storage Fields**
4

GAS TRANSMISSION & STORAGE (In 2025 \$)			
H. Gas Storage Fields	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Gas Storage Fields	32,393	34,419	2,026

5 **1. Description of Costs and Underlying Activities**

6 The Gas Storage Fields consist of the O&M activities necessary to operate and maintain
7 gas injection and withdrawal equipment and auxiliary systems required for safe and reliable
8 operation of the four storage fields operated by SoCalGas: Aliso Canyon, Honor Rancho, La
9 Goleta, and Playa del Rey.

10 These storage fields are an essential part of SoCalGas’s integrated storage, transmission,
11 and distribution system. As described in Section I.A.2 “Overview of the Gas Transmission and
12 Storage System,” this interconnected system is designed to receive natural gas from interstate
13 pipelines and local production sources and to enable deliveries to customers or into storage field
14 reservoirs, depending on system demands. These storage fields also provide operational
15 resiliency and flexibility for the Southern California energy grid. SoCalGas uses its storage
16 assets to efficiently meet gas balancing requirements. To satisfy these needs, individual storage
17 facilities supply or take natural gas, depending on withdrawal or injection requirements, as
18 managed by Gas Control. Fluctuating demands may require storage operations to perform gas
19 injection or withdrawal functions at any hour of the day, 365 days per year. Storage fields are
20 continually staffed with operating crews and on-call personnel to support these critical 24/7
21 operations.

22 SoCalGas’s natural gas transmission and distribution system was designed and has
23 developed based on the availability of strategically located storage resources and supply points.
24 SoCalGas’s transmission pipelines and integrated storage system cannot reliably function with
25 only pipeline supply as natural gas moves slowly, and receipt points are located far from major
26 load centers. Pipeline deliveries also occur at a constant hourly rate, while customer demand
27 fluctuates significantly throughout the day, especially for electric generation.

1 The situation is further complicated by the fact that California currently receives over
2 95% of its natural gas from out-of-state sources. With minimal instate production, SoCalGas
3 depends heavily on interstate deliveries, making local underground storage critical for
4 maintaining energy reliability. To support system reliability, the SoCalGas system relies on
5 underground storage to rapidly supply large volumes of natural gas over short periods in
6 response to conditions such as extreme weather, unforeseen pipeline maintenance, or temporary
7 reductions in interstate supplies. Facilitating these withdrawal demands places operational
8 demands on wells, pipelines, and other storage facilities, which in turn, necessitates continuous
9 maintenance and ongoing investment in these wells, pipelines, and facilities. In addition, the
10 storage fields provide significant flexibility and resilience and enable SoCalGas to operate and
11 maintain its transmission system safely and cost-effectively by providing a buffer against
12 transmission line outages, allowing pipelines to be taken out of service for maintenance and
13 repairs, and enabling pipeline pressure reductions to enhance the margin of safety. Historically,
14 maintaining sufficient gas in storage has helped prevent or mitigate the impact of high or volatile
15 gas commodity prices.

16 Sustaining this capability requires ongoing operations and continuous maintenance
17 activities for assets to remain safe, reliable, and capable of performing under both routine and
18 stressed operating conditions. Storage field O&M activities support system readiness, operational
19 flexibility, the ability to inject and withdraw natural gas, employee and public safety, regulatory
20 and environmental compliance, asset integrity, and long-term system reliability.

21 These activities include continuous oversight and operation of compressors, wells,
22 purification and dehydration systems, aboveground lateral pipe and surface facilities, auxiliary
23 equipment, and operating infrastructure that require a constant state of readiness. Field personnel
24 maintain system alignment, monitor equipment, manage inventories, and operate critical
25 infrastructure.

26 Preventive maintenance of main compressor units and compressor auxiliary equipment is
27 performed to sustain safe and reliable injection operations, reduce unplanned outages, and extend
28 equipment life. This work includes routine and critical inspections, troubleshooting of identified
29 issues, inspection and servicing, calibration and periodic condition assessments, repairs to worn
30 or damaged components, and general operating expenses including consumables such as engine
31 oil, lubricants, and spare parts. Maintenance activities also cover support systems such as

1 generators, air compressors, heat exchangers, and fire and gas detection systems that support the
2 compressors. These activities support asset integrity, operational continuity, and compliance by
3 keeping equipment functional, safe, and available when needed.

4 Well operational activities extend beyond periods of active injection or gas withdrawal,
5 and include ongoing monitoring and readiness functions, in accordance with 49 CFR §192.605.⁴⁹
6 Wells are maintained in a condition that allows safe and efficient operation when needed,
7 supporting field availability and long-term reservoir performance. Operational activities include
8 well opening and closing, monitoring during operations, continuous monitoring of wellhead
9 pressures, temperatures, integrity indicators, and response to alarms or abnormal conditions in
10 accordance with established procedures. Well inspection and maintenance activities include
11 routine wellsite inspections and monitoring to support regulatory compliance and equipment
12 integrity during both active and inactive periods, testing, calibration, and upkeep of wellsite
13 pressure monitoring equipment and methane detection systems in compliance with CARB Oil
14 and Gas Methane Regulations (Cal. Code Reg., Title 17, §§ 95665-95677).⁵⁰ Surface equipment,
15 subject to inspection and maintenance, includes gathering lines, vapor recovery units, process
16 equipment, tanks, wastewater systems, and disposal wells. Preventive and corrective
17 maintenance is performed in accordance with established operating and maintenance plans
18 developed pursuant to 49 CFR §192.605.

19 Purification systems, including dehydration and gas treatment facilities, are operated,
20 maintained and monitored to preserve gas quality, protect downstream equipment, and prevent
21 degradation during both flowing and non-flowing conditions. Operations include management of
22 Tri-ethylene glycol (TEG) dehydration systems, odorization equipment, and filtration systems
23 for consistent performance and compliance with gas quality specifications. Maintenance
24 activities include routine and critical inspections, filter changeouts, thermal fluid maintenance,
25 inspection and tuning of treatment equipment, and servicing of vapor-side components. Flare
26 stacks and associated vapor control systems are maintained to be compliant with environmental
27 regulatory bodies such as SCAQMD.

⁴⁹ 49 CFR § 192.605 (Procedural manual for operations, maintenance, and emergencies).

⁵⁰ California Air Resources Board Oil and Gas Methane Regulations (Cal. Code Reg., Title 17, §§ 95665-95677).

1 Activities associated with pipelines, headers, valves, flow control equipment,
2 compressors, and other surface assets include valve operations to control flow paths during
3 injection and withdrawal, support operational readiness, provide equipment isolation, and
4 coordinate maintenance activities.

5 In addition to these assets, other O&M costs are incurred to support storage field
6 operations. These activities include operational oversight and maintenance of electrical systems,
7 including repairs performed in accordance with NFPA 70B and GO 128;⁵¹ maintenance of utility
8 lines in compliance with GO 95; and road maintenance to support safe site access. Additional
9 supporting costs include scaffolding required for the operation and maintenance of field assets,
10 county and state regulatory fees, environmental compliance fees, trash and waste services,
11 permitting fees, and software and licensing costs necessary to support operational, maintenance,
12 and compliance functions.

13 **a. Description of RAMP Mitigations**

14 Within this cost category, there are non-shared O&M costs for risk controls C014
15 (Storage HP Field Maintenance – Aboveground Facilities) and C016 (Storage HP Field
16 Maintenance – Aboveground Piping) that were presented in the 2025 RAMP Report and are
17 listed in Table GO-16. The RAMP activities and costs identified within this workpaper for C014
18 and C016 are described in Sections III.H.1 and III.G.1.

19 Activities that are related to compliance or mandated by CPUC or other agencies are
20 listed in bold, and Appendix B attached to this testimony provides the details regarding these
21 mandates for each control.

⁵¹ GO 128 (Rules for Construction of Underground Electric Supply and Communication Systems).

TABLE GO-16
RAMP and GRC Risk Control/Mitigation Activities – O&M

Gas Storage Fields				
ID	Control/Mitigation Name	2025 RAMP 2028 Estimate In 2024 \$ (000s)	2028 GRC 2028 Forecast In 2025 \$ (000s)	Change (000s)
C014	Storage HP Field Maintenance – Aboveground Facilities	28,069	31,356	3,287
C016	Storage HP Field Maintenance – Aboveground Piping	3,406	3,063	(344)
TOTAL		31,475	34,419	2,943

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

The RAMP risk mitigation efforts are associated with specific actions, such as programs, projects, processes, and utilization of technology and are designed to address a specific safety and/or reliability risk. The Company’s selection and prioritization of these RAMP mitigation activities considered many factors when determining if these risk mitigation activities are an effective and worthwhile investment. The ERM process for identifying and assessing system risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

All cost forecasts included in this workpaper are associated with C014 and C016 and are required to meet safety, reliability, and regulatory requirements across a wide range of federal, state, and local agencies, including PHMSA, OSHA, EPA, FERC, NTSB, FEMA, CPUC, DOT, LA County, CARB, SCAQMD, the NFPA, and CalGEM, as well as Cal. Code Reg., Title 14, § 1774.2. These risk controls reduce the likelihood and consequences of equipment or piping failures at aboveground storage facilities. Ongoing inspections, corrosion control, integrity testing, continuous operations, and timely repairs help maintain asset condition and operational readiness, support reliable year-round gas delivery, and reduce the potential for unplanned outages or high-cost emergency events. Collectively, these activities enhance customer safety, protect affordability by avoiding reactive response costs, and strengthen overall system dependability.

The difference between the RAMP forecast and the forecast in this testimony is due to the RAMP using a 2024 forecast, while this testimony uses a BY 2025 forecast with incremental

1 adjustments. The underlying scope of work and risk control strategy remain unchanged from the
2 RAMP filing.

3 **2. Forecast Method**

4 The forecast method for Gas Storage Fields is based on BY 2025, with incremental
5 adjustments to support enhanced electrical inspections and repairs, seismic mitigation activities,
6 wildfire risk management and vegetation control, pipeline coating in fire-prone areas, and the
7 adoption of FR personal protective equipment as described in the following section. A review of
8 historical costs indicates that, although application of a five-year historical average (2021–2025)
9 results in a higher forecast, the use of BY 2025 provides the most recent baseline conditions.
10 Accordingly, the BY 2025 base year, adjusted for incremental costs, provides the most
11 reasonable representation of forecasted costs and captures the full scope of operational and
12 maintenance activities for aboveground storage, driven by regulatory requirements and asset
13 conditions.

14 **3. Cost Drivers**

15 The cost drivers underlying the Gas Storage Fields forecasts are primarily associated with
16 safety, risk management, and compliance with local, state, and federal regulations. These
17 requirements include those established by CalGEM, PHMSA, and other federal, state, and local
18 agencies, as well as local fire and safety codes, local air districts standards such as SCAQMD
19 and SBCAPD, and OSHA regulations.

20 The incremental cost to the base year forecast for TY 2028 is \$2,026,000, which includes
21 the following:

22 An incremental amount of \$1,007,000 is requested for additional infrared inspections;
23 electrical testing and repairs performed in accordance with NFPA 70B to identify electrical
24 degradation and potential equipment failures; and seismic repairs based on the California's
25 Accidental Release Prevention (CalARP) Seismic Guidance. The CalARP Seismic Guidance
26 provides a systematic framework for identifying and addressing seismic vulnerabilities affecting
27 facility piping, structures, buildings, utilities, and related systems. The resulting inventory of
28 repairs is necessary to reduce the risk of releases of regulated hazardous substances during or
29 following a seismic event. As a prudent operator, SoCalGas is increasing the level of work
30 associated with these activities to mitigate the risk of failures related to aging infrastructure that
31 could affect safety and system reliability.

1 An incremental amount of \$650,000 is requested to support additional wildfire
 2 management activities, including vegetation removal for wildfire risk reduction and pipeline
 3 coating in wildfire-prone areas. SoCalGas’s four storage fields extend across more than 4,000
 4 acres, and require ongoing vegetation management to mitigate wildfire risk and support fire
 5 prevention efforts. Year-round vegetation management compliance is required, due to the
 6 proximity of Very High Fire Hazard Severity Zone (VHFHSZ) in accordance with the Fire Code
 7 (L.A.M.C. § 57.322). Required activities include the removal of native brush, weeds, grass, trees
 8 and other hazardous vegetation within 200 feet of structures and buildings and within ten feet of
 9 combustible fence or roadways used for vehicular travel. In addition, pipe coating is required
 10 throughout these areas to maintain pipeline integrity and reduce corrosion and heat-related
 11 damage in fire-prone environments. As a prudent operator, SoCalGas is increasing the level of
 12 work associated with these activities to mitigate the risk of wildfire that could affect safety,
 13 system integrity, and supply reliability.

14 An incremental amount of \$93,000 is requested to support the adoption of FR garments,
 15 standardized headgear, and ANSI-compliant safety vests for employee safety per the Injury
 16 Illness Prevention Program, Cal OSHA, Title 8, Section 3203 and Protection From Flames and
 17 Electric Arcs, Cal OSHA, Title 8, Section 2940.11. These uniforms are necessary for employee
 18 safety, regulatory compliance, operational readiness, and clear identification of authorized
 19 personnel.

20 An adjustment of \$276,000 reflects changes in connection with the compensation
 21 modernization initiative. Please refer to the Compensation and Benefits testimony (Ex. SCG-
 22 16/SDGE-20).

23 **I. Underground Storage (2GT001.000)**

24 **TABLE GO-17**
 25 **Non-Shared O&M – Underground Storage**
 26

GAS TRANSMISSION & STORAGE (In 2025 \$)			
I. Underground Storage	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Underground Storage	2,654	2,823	169

1 **1. Description of Costs and Underlying Activities**

2 The Underground Storage costs include labor and non-labor expenses that support the
3 four storage fields operated by SoCalGas – Aliso Canyon, Honor Rancho, La Goleta, and Playa
4 del Rey.

5 Underground Gas Storage includes both operations and technical support groups that
6 provide services essential to the O&M of these critical gas delivery assets, supporting safety,
7 integrity, and reliability of gas storage wells. While each storage field has unique operating
8 conditions and characteristics, there are common support activities performed regularly that
9 account for the bulk of the routine expenses presented in this testimony.

10 Primary regulations governing underground storage O&M activities include CalGEM
11 requirements for California Underground Gas Storage Projects (Title 14, C.C.R. §1726 et seq.)
12 and PHMSA Underground Natural Gas Storage regulations (Title 49, CFR §192.12⁵²). These
13 regulations include requirements and standards such as well construction, mechanical integrity
14 testing, risk management, emergency response plans, data management, monitoring and
15 inspecting, wellhead and valve maintenance, and well decommissioning. Additionally, in July
16 2025, these regulations were expanded to include requirements such as the submission of a well-
17 by-well annual chemical inventory and consideration of additional risk mitigation strategies.
18 These regulations establish requirements for downhole facilities, including wells, wellbore
19 tubing, and casing.

20 Activities under this section are primarily driven by the regulations and requirements
21 mentioned above and are as follows:

- 22 • **Management, Supervision, Training, and Engineering:** These activities cover
23 the administrative salaries and engineering activities associated with the operation
24 of the underground storage fields. This includes funding for studies related to
25 reservoir operations and wells, necessary to maintain the integrity of the storage
26 system. Leadership, safety, technical training, operator qualification, and quality
27 assurance functions are other critical components of this grouping.
- 28 • **Wells:** Activities under this category include routine operations of storage
29 reservoirs, such as well operation, well testing, pressure surveys, and wellhead

⁵² 49 CFR § 192.12 (Underground Natural Gas Storage Facilities).

1 and downhole activities, including subsurface leakage surveys on injection and
2 withdrawal facilities. O&M activities also include lubricating valves, cleaning
3 lines, injecting corrosion inhibitors, monitoring pressure, and maintaining alarms
4 and gauges.

- 5 • **Data and Records Management:** These activities involve maintaining data and
6 records related to storage assets and operations. Typical tasks include authorizing
7 work orders; conducting surveys; documenting wells, pipelines, topography,
8 roads, rights-of-way, and infrastructure; verifying boundaries; and creating and
9 maintaining maps for underground zones and rights. Additionally, activities
10 include supporting internal and external audits, responding to data requests, and
11 addressing fees to government agencies to operate storage fields.

12 Additional activities include preparing for emergencies, managing chemicals and
13 consumables, and implementing systems for compliance tracking.

14 a. **Description of RAMP Mitigations**

15 Within this cost category, there are non-shared O&M costs for risk control C408 (Storage
16 Field Maintenance – Underground Components) that were presented in the 2025 RAMP Report
17 and are listed in Table GO-18. The RAMP activities and costs identified within this workpaper
18 for C408 are described above. All cost forecasts included in this workpaper are associated with
19 C408 and are required to meet safety, reliability, and regulatory requirements across a wide
20 range of federal, state, and local agencies, including CalGEM, PHMSA, CARB as well as
21 CPUC. These risk controls reduce the likelihood and consequences of equipment or well failures
22 at underground storage facilities. Ongoing inspections, corrosion control, integrity testing,
23 continuous operations, and timely repairs help maintain asset condition and operational
24 readiness, support reliable year-round gas delivery, and reduce the potential for unplanned
25 outages or high-cost emergency events. Collectively, these activities enhance customer safety,
26 protect affordability by avoiding relative response costs, and strengthen overall system
27 dependability.

28 Activities that are compliance or mandated by CPUC or other agencies are listed in
29 bold, and Appendix B attached to this testimony provides the details regarding these mandates
30 for each control.

TABLE GO-18
RAMP and GRC Risk Control/Mitigation Activities – O&M

Underground Storage				
ID	Control/Mitigation Name	2025 RAMP 2028 Estimate In 2024 \$ (000s)	2028 GRC 2028 Forecast In 2025 \$ (000s)	Change (000s)
C408	Storage Field Maintenance – Underground Components	3,857	2,823	(1,034)

b. Description of Selection and Prioritization of RAMP Risk Mitigations

The RAMP risk mitigation efforts are associated with specific actions, such as programs, projects, processes, and utilization of technology and are designed to address a specific safety and/or reliability risk. The Company’s selection and prioritization of these RAMP mitigation activities considered many factors when determining if these risk mitigation activities are an effective and worthwhile investment. The ERM process for identifying and assessing system risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

The primary drivers are external and internal corrosion, weather, and outside forces. If not addressed, these conditions can lead to serious consequences such as injuries or fatalities, damage to nearby property and infrastructure, service outages, reliability shortfalls, and environmental releases.

These mitigations were chosen because they directly target identified risk drivers by lowering the probability of gas well failures through integrity assessments, corrosion control, timely repairs and compliance activities, reducing the risk of severe impacts on customers and surrounding communities.

The difference between the RAMP forecast and the forecast in this testimony is due to the RAMP using a 2024 forecast, while this testimony uses a BY 2025 forecast with incremental adjustments.

2. Forecast Method

The forecast method for Underground Storage is BY 2025, with incremental adjustments to support increased costs for mechanical integrity testing. A review of historical costs indicates

1 that, although application of a five-year historical average (2021–2025) results in a higher
 2 forecast, the use of BY 2025 is appropriate because it provides the most recent baseline capturing
 3 the full scope of operational and maintenance activities for underground storage, driven by
 4 regulatory requirements and asset conditions.

5 **3. Cost Drivers**

6 Primary drivers for activities behind Underground Storage are safety, risk management,
 7 and compliance with state and federal regulations. The following regulations establish standards
 8 for Storage well operations:

- 9 • CalGEM Cal. Code Reg., Title 14, § 1726, *et seq.* and CalGEM Cal. Code Reg.,
 10 Title 14, §1724.5, *et seq.* – Underground Injection Control (UIC) U.S.
 11 Department of Transportation
- 12 • PHMSA Revised Federal Pipeline Safety Regulations, 49 CFR §192.12:
- 13 • CARB Oil and Gas Rule— Cal. Code Reg., Title 17, § 95665, *et seq.*

14 An incremental amount of \$162,000 is being requested in the TY 2028 forecast to cover
 15 increased costs related to CalGEM-mandated mechanical integrity testing. These cost increases
 16 are driven by vendor logging rate escalations ranging from 3% to 15% over recent years,
 17 reflecting the adoption of advanced technologies and methodologies.

18 **J. Environmental Regulations (2GT002.002)**

19 **TABLE GO-19**
 20 **Non-Shared O&M – Environmental Regulations**
 21

GAS TRANSMISSION & STORAGE (In 2025 \$)			
J. Environmental Regulations	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Environmental Regulations	9,111	10,224	1,113

22 **1. Description of Costs and Underlying Activities**

23 The labor and non-labor costs associated with Environmental Regulations relate to
 24 compliance activities for (1) the Greenhouse Gas Emission Standards for Crude Oil and Natural
 25 Gas Facilities (CARB Oil and Gas Rule), and (2) Greenhouse Gas Reporting under EPA Subpart
 26 W.

1 **The CARB Oil and Gas Rule, Title 17, CCR, Division 3, Chapter 1, Subchapter 10,**
2 **Article 4, Sub Article 13:** This regulation is designed to identify and reduce methane emissions
3 by requiring routine inspections, monitoring, and timely repair of leaks at storage and
4 transmission compressor stations. To comply with this regulation, SoCalGas incurs costs
5 associated with quarterly methane leak surveys and repair activities (LDAR); enhanced ambient
6 and wellhead monitoring with the use of automated instruments; and the development of
7 procedures to record and report a well blowout event at storage fields, as required in Sections
8 95669 and 95668(h) of the CARB Oil and Gas Rule.

9 Quarterly LDAR requirements increase labor needs because storage fields and
10 compressor stations span large footprints that require multiple full-coverage leak surveys each
11 year. These surveys must be performed by technicians trained to operate sensitive equipment,
12 such as optical gas-imaging cameras and high-precision methane-detection devices. In addition
13 to leak detection, CARB rules require ambient air monitoring and wellhead monitoring at
14 underground natural gas storage facilities. These activities involve deploying monitors,
15 collecting and validating data, responding to anomalies, and documenting results, all of which
16 increase field labor, contractor usage, equipment costs, and the administrative workload.

17 Each LDAR-identified leak increases resource demand. Repairs often require specialized
18 parts, materials, and additional technician hours, particularly when equipment must be isolated,
19 depressurized, disassembled, or taken out of service for repair. Follow-up validation and
20 documentation create further administrative and compliance efforts. LDAR programs also
21 generate large volumes of data that must be recorded, quality-checked, stored, and reported
22 annually. These reporting tasks increase internal labor needs for compliance management,
23 quality assurance, and data retention.

24 **Subpart W:** This regulation refers to the federal GHG reporting requirements for
25 petroleum and natural gas systems under EPA’s Greenhouse Gas Reporting Program (GHGRP),
26 while CARB’s Mandatory Greenhouse Gas Reporting Regulation (MRR) establishes state
27 reporting requirements. To comply with the federal and state Subpart W Greenhouse Gas
28 Reporting requirements, SoCalGas incurs ongoing labor and non-labor costs to support mandated
29 compliance activities. These rules mandate detailed, quantifiable measurement of methane and
30 other greenhouse gas emissions from transmission and storage facilities. Unlike traditional
31 emissions reporting, which often rely on emissions factors, Subpart W requires

1 equipment-specific measurements and direct quantification to a level of precision that
2 significantly increases workload and resource requirements. The federal regulations are codified
3 in Title 40, CFR, Part 98, Subpart W, while the state regulations are codified in Title 17, CCR,
4 Division 3, Chapter 1, Subchapter 10, Article 2, Subarticle 5.

5 Subpart W measurement activities involve procedures that are required to be performed
6 by certified contractors or specialized vendors with equipment capable of collecting high-fidelity
7 emissions data. Field work often includes controlled measurement activities, gas sampling,
8 vent-rate calculations, and equipment inspections that must be repeated annually or as operating
9 conditions change.

10 Subpart W also imposes extensive documentation, verification, and reporting
11 requirements. Internal teams must track, analyze, and validate field-collected data; maintain
12 records of measurement methods; prepare documentation for audits; and submit annual reports
13 that meet federal quality-control standards. These requirements add significant administrative
14 labor for data management, engineering review, emissions-inventory development, and
15 regulatory documentation.

16 **2. Forecast Method**

17 The forecast method for Environmental Regulations is based on BY 2025 with
18 incremental adjustments to support environmental regulation compliance. A review of historical
19 costs indicates that, although application of a five-year historical average (2021–2025) results in
20 a higher forecast, the use of BY 2025 is appropriate because it provides the most recent baseline
21 reflecting the current scope of environmental regulation related activities, with incremental
22 adjustments to support the activities needed to comply with the CARB Oil and Gas Rule.

23 **3. Cost Drivers**

24 Compliance with the CARB Oil and Gas Rule and Subpart W requirements represents a
25 substantial ongoing cost driver for the GT&S system. These requirements necessitate a
26 combination of field activities, specialized equipment, contractor support, monitoring, and
27 administrative oversight to comply with state and federal methane-reduction regulations.

28 An incremental request of \$1,080,000 over the base year is proposed for TY 2028 to
29 address the more stringent LDAR leak detection threshold, which has been reduced from 1,000
30 parts per million by volume (ppmv) to 500 ppmv. The lower leak detection threshold is expected
31 to increase the number of detected leak indications, which will require additional investigation

1 and repair, thereby increasing LDAR-related maintenance activities, staffing needs, and
 2 associated compliance costs. This incremental cost is based on the U.S. EPA’s December 2023
 3 Emissions Guidelines and the anticipated adoption by CARB to amend the Oil and Methane
 4 Regulations.

5 Furthermore, SoCalGas requests to transition the costs of LDAR- and Subpart W-related
 6 leak survey activities described above from the New Environmental Regulations Balancing
 7 Account (NERBA) treatment into base business starting in 2028, as described in the
 8 Sustainability and Environmental Testimony (Ex. SCG-13).

9 **K. SIMP Execution (2GT001.001)**

10 **TABLE GO-20**
 11 **Non-Shared O&M – SIMP Execution**
 12

GAS TRANSMISSION & STORAGE (In 2025 \$)			
K. SIMP Execution	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. SIMP Execution ⁵³	13,627	13,829	202

13 **1. Description of Costs and Underlying Activities**

14 SoCalGas originally modeled the Storage Integrity Management Program (SIMP) after
 15 the elements of the federally-mandated Distribution and Transmission Integrity Management
 16 Programs (DIMP and TIMP) and the requirements of API Recommended Practice (RP) 1171-
 17 Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer
 18 Reservoirs.⁵⁴

19 The SIMP is a comprehensive program designed to improve the safety of SoCalGas’s
 20 underground storage facilities through integrity management practices, thereby strengthening the
 21 reliability of Southern California’s natural gas infrastructure. SoCalGas’s underground storage
 22 system is increasingly critical to sustaining both electric and gas reliability and a strong SIMP
 23 reduces the potential impact of supply constraints. The SIMP applies a structured approach that
 24 leverages advanced inspection technologies and risk-informed measures to address gas storage
 25 reservoir and well integrity concerns. SoCalGas’s storage fields are subject to rigorous

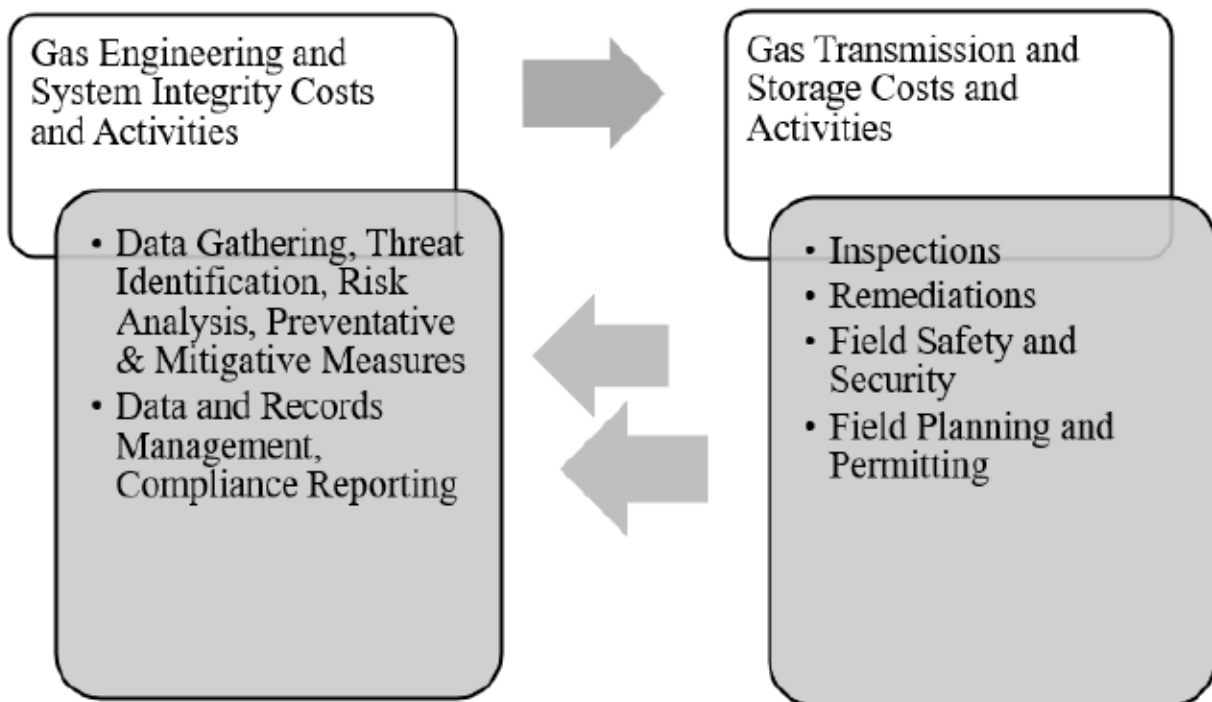
⁵³ Only SIMP execution costs are shown in this table.

⁵⁴ API Recommended Practice 1171 (API RP 1171)

1 monitoring, inspection, and safety requirements. The funding level requested for the SIMP is
2 intended to support continued compliance with current regulatory requirements, which include
3 CalGEM and PHMSA regulations.

4 SoCalGas manages SIMP programmatic activities through the GESI organization, while
5 SIMP execution activities are carried out by teams embedded within the GT&S organization.
6 Costs associated with SIMP programmatic activities are presented in the GESI Testimony (Ex.
7 SCG-03). This organizational structure promotes coordination between program oversight and
8 field execution by separate but aligned teams, leveraging operational expertise integral to
9 GT&S's core functions. Figure GO-2 delineates the forecasted costs by witness area.

10
11 **Figure GO-2**
12 **SIMP Delineation By Witness Area**
13



15 My testimony includes the costs for SIMP execution activities, which are described in the
16 following categories:

- 17 • **Inspections:** SoCalGas performs mechanical integrity inspections on gas storage
18 wells, including wellheads and completion assemblies, to assess the pressure-
19 containing capability of the well, detect possible leaks, and identify metal loss

1 features in tubing and casing. These regular inspections enhance safety by
2 reducing the risk of well failure during operations.

- 3 ○ Inspection logs, including wall thickness and cement evaluation
4 inspections (Magnetic Flux Leakage (MFL) and UT), are currently
5 required for each gas storage well at a two-year recurring frequency unless
6 otherwise approved by CalGEM. Pressure integrity testing (1.15 x MAOP)
7 is currently required for each gas storage well at a two-year recurring
8 frequency unless otherwise approved by CalGEM. The associated
9 pressure-testing cost is directly tied to capital-integrity assessments.
- 10 ○ Standard Annular Pressure Test (SAPT) is a pressure integrity test on the
11 wellbore and completion components to a target pressure based on
12 operating conditions of the well and reservoir.
 - 13 ▪ Final completion SAPT is performed post-integrity assessment.
14 This associated SAPT cost is directly tied to capital integrity
15 assessments.
 - 16 ▪ Reassessment SAPT is performed at the midpoint of an integrity
17 assessment interval extension approved by CalGEM. CalGEM
18 extension approvals are conditional on a mid-point satisfactory
19 SAPT.
- 20 ○ Noise and Temperature Surveys are also conducted in accordance with
21 CalGEM regulations.⁵⁵ These surveys are performed to confirm the
22 integrity of the wellbore and completion components, while the well is in
23 operation and connected to the gas system.
- 24 ● **Field Security:** SoCalGas implements comprehensive wellsite security and safety
25 protocols to mitigate operational hazards and risks. These measures cover facility,
26 employee, contractor, and public safety. Access to storage wells is restricted
27 during drilling, workover, operation, assessment, and abandonment activities.
28 Security provisions include patrols, surveillance cameras, and lighting.
29 Additionally, field security inspections are conducted before, during, and after

⁵⁵ 14 CCR §1726.6

1 work to maintain site safety and security. These practices align with API 1171
2 standards.

- 3 • **Field Planning and Management:** The activity pertains to the overall
4 responsibility for managing field activities for all integrity assessments and
5 remediations, well, wellhead, and reservoir. This also includes supervising and
6 witnessing inspection activities; training; coordinating with contracts,
7 environmental, and regulatory agencies; preparing field inventory verification
8 reports; reservoir containment assurance; permitting; resource management;
9 communication; field safety management; risk management; and land use
10 monitoring.

11 On July 1, 2025, CalGEM implemented new regulations, under SB 463 (Chemical
12 Inventory and Root Cause Analysis Regulations), mandating enhanced chemical inventory
13 tracking and root cause analysis protocols for underground gas storage operations. The new
14 regulations require operators of gas storage wells to provide a chemical inventory of constituents
15 in the materials that may be emitted in the event of a reportable leak. As a result, well chemical
16 data is being continuously collected by field personnel for reporting. Additionally, flow testing is
17 conducted at gas storage wells to generate Inflow Performance Relationships (IPR) for inclusion
18 in well-specific well control plans.

19 As explained in the GESI Testimony (Ex. SCG-03), in this GRC, SoCalGas requests the
20 closure of the SIMP one-way balancing account (SIMPBA) and the transition of SIMP costs into
21 base business operations.

22 a. Description of RAMP Mitigations

23 Within this cost category, there are non-shared O&M costs for risk control C401 (SIMP)
24 that were presented in the 2025 RAMP Report and are listed in Table GO-21. All O&M SIMP
25 activities described in the section above serve as risk control measures for the risks identified in
26 the 2025 RAMP Report. These activities support the safety, integrity, and reliability of the
27 underground gas storage system and are primarily driven by CalGEM requirements outlined in
28 the California Underground Gas Storage regulations (14 CCR §1726) and the PHMSA
29 Underground Natural Gas Storage regulations (49 CFR §192.12).

1 Activities that are compliance or mandated by CPUC or other agencies are listed in
 2 bold, and Appendix B attached to this testimony provides the details regarding these mandates
 3 for each control.

4 **TABLE GO-21**
 5 **RAMP and GRC Risk Control/Mitigation Activities – O&M**
 6

SIMP Execution				
ID	Control/Mitigation Name	2025 RAMP 2028 Estimate In 2024 \$ (000s)	2028 GRC 2028 Forecast In 2025 \$ (000s)	Change (000s)
C401	Storage Integrity Management Program (SIMP)	11,090 ⁵⁶	13,829 ⁵⁷	2,739

7 **b. Description of Selection and Prioritization of RAMP**
 8 **Risk Mitigations**

9 The RAMP risk mitigation efforts are associated with specific actions, such as programs,
 10 projects, processes, and utilization of technology and are designed to address a specific safety
 11 and/or reliability risk. The Company’s selection and prioritization of these RAMP mitigation
 12 activities considered many factors when determining if these risk mitigation activities are an
 13 effective and worthwhile investment. The ERM process for identifying and assessing system
 14 risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

15 This mitigation was selected as a control for the Underground Storage Risk, which
 16 includes the risk of failure of an underground gas storage well that results in serious injuries,
 17 fatalities, and/or damage to the infrastructure. As described in the SoCalGas 2025 RAMP report,
 18 there are ten potential drivers/triggers of this risk. SIMP addresses all ten of these drivers, which
 19 are external corrosion; internal corrosion; manufacturing defects; construction and fabrication;
 20 weather-related and outside forces such as earthquake, erosion, and other natural disasters;
 21 incorrect operations (including well interventions); equipment failure; third-party damage
 22 (excluding excavation damage); incorrect/inadequate asset records; and execution constraints.

⁵⁶ The total RAMP O&M forecast for C401 is \$19.8 million for 2028. The cost shown on the table represents the RAMP O&M forecast allocated to this workpaper, representing 56% of the total activity. The other portion of costs for C401 can be found in the GESI Testimony (Ex. SCG-03).

⁵⁷ SIMP execution costs included in this testimony.

1 The 2025 RAMP Report also identifies seven potential consequences associated with
2 Underground Gas Storage Risk, all of which are addressed by SIMP, including serious injuries or
3 fatalities; property damage; operational and reliability impacts; adverse litigations; penalties and
4 fines; erosion of public confidence; and environmental impacts.

5 Underground gas storage assets are essential components of California's reliable energy
6 delivery infrastructure. Accordingly, SIMP activities and measures are designed to enhance the
7 safety and reliability of the natural gas infrastructure, mitigate associated risks, and comply with
8 state and federal regulations.

9 The difference between the RAMP forecast and the forecast in this testimony is primarily
10 attributed to the difference in the number of inspections assumed in the 2025 RAMP forecast
11 compared to those reflected in the TY 2028 forecast. The variance in inspection volume is
12 largely due to extensions received from CalGEM.

13 2. Forecast Method

14 The forecast method for O&M SIMP Execution is based on BY 2025, with incremental
15 adjustments to support additional well inspections driven by the timing of CalGEM-mandated
16 inspection intervals, as described in the following section. This methodology establishes a
17 baseline grounded in the most recent actual expenditures, which best reflect future expectations
18 and provide a reliable basis for projecting O&M costs throughout the GRC period. BY 2025
19 represents the most recent historical cost baseline that incorporates increased inspection and
20 SAPT costs, as well as expanded data and reporting requirements required by CalGEM. SIMP
21 Execution O&M costs consist of three primary components, as described in Section III.K.1. Of
22 these components, well inspections vary year to year, while the remaining categories (N/T
23 surveys, field security, and field planning and management) remain relatively constant from
24 2025 through 2031. Year-to-year variability in the well inspection costs is driven by timing of
25 reassessments mandated by CalGEM.

26 3. Cost Drivers

27 The cost drivers behind the O&M SIMP Execution forecasts are safety, risk management,
28 and compliance with state and federal regulations. The primary drivers are the CalGEM
29 Underground Gas Storage regulations (14 CCR §1726) and the PHMSA Underground Natural
30 Gas Storage regulations (49 CFR §192.12). CalGEM UIC requirements, along with other federal,
31 state, public and local agency considerations, also influence these costs. Additional changes to

1 regulatory requirements, assessment cycles, and the Oil and Gas industry market, including
 2 resources, materials, and service company availability, may affect actual costs incurred.

3 Incremental funding of \$173,000 over the base year is requested to support additional
 4 well inspections that are driven by mandated well inspection intervals and extensions approved
 5 by CalGEM. SoCalGas began receiving CalGEM approved inspection interval extensions in
 6 2022, with extensions granted on a well-by-well basis for periods of up to seven years. As these
 7 extensions expire, wells are reaching their revised inspection deadlines and require reassessment,
 8 including the associated O&M inspection component. As a result, the number of required
 9 inspections will begin to increase in 2027 and rise throughout the TY 2028 GRC period.

10 **IV. SHARED O&M COSTS**

11 Shared Services are activities performed on behalf of both SoCalGas and SDG&E. These
 12 activities are necessary to provide customers with safe, reliable, and affordable service. The
 13 utility providing Shared Services allocates and bills incurred costs to the utility receiving those
 14 services. SDG&E's Gas Transmission Operations are managed and supported, in part, by
 15 SoCalGas personnel.

16 Table GO-22 summarizes the total shared O&M forecasts for the listed cost categories.

17
 18 **TABLE GO-22**
 19 **Shared O&M Summary of Costs**
 20

GAS TRANSMISSION & STORAGE (In 2025 \$)			
Categories of Management	2025 Adjusted - Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
A. GT&S Strategy (2200-0330.000)	900	815	(85)
B. Capacity Products Support (2200-0328.000)	978	1,213	235
C. Gas Scheduling (2200-2158.000)	930	1,004	74
D. Gas Transmission Planning (2200-2329.000)	1,090	1,116	26
E. Gas Control (2200-2289.000)	5,493	6,329	837
F. Gas Control SCADA Operation (2200-0329.000)	1,914	2,323	409
G. Gas Ops Control Center Information Technology (2200-0017.000)	690	1,374	684

GAS TRANSMISSION & STORAGE (In 2025 \$)			
Categories of Management	2025 Adjusted - Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
H. GT Operations Leadership & Oversight – USS (2200-0253.000)	2,107	2,682	575
I. Field Operations Manager (FOM) Pipeline East (2200-0265.000)	144	146	2
J. Gas Transmission FOM Victorville Compressor Operations - USS (2200-2173.000)	796	807	11
Total Shared Services (Incurred)	15,041	17,808	2,767

1 The shared services represented in this section support GT&S functions that encompass a
2 broad range of activities essential to the operation of the SoCalGas and SDG&E gas transmission
3 systems. These integrated functions include system strategy, gas market and product support,
4 daily gas scheduling, long-term system planning, centralized Gas Control operations, SCADA
5 system management, operational technology (OT) support, leadership and compliance oversight,
6 as well as field operations functions that support transmission pipelines, seven SoCalGas
7 compressor stations and the SDG&E’s Moreno Compressor Station.

8 In preparing projections for the TY 2028 forecast, SoCalGas GT&S reviewed historical
9 spending levels, including units of work, and developed an assessment of future needs and
10 associated risks. This analysis entailed a review of the historical 2021 through 2025 spending
11 and consideration of the underlying cost drivers. Depending on future expectations for the
12 underlying cost drivers, a primary forecast methodology was selected. Based on this analysis,
13 the selected baseline forecast method is the base year 2025. In addition, incremental work above
14 levels of historical spending was identified to maintain the safe and reliable operation of the
15 transmission system and its supporting work processes. An analytical calculation was then
16 performed to determine the funding of these new or more-extensive work elements. The overall
17 result is a forecast that has its foundation based on the historical representation, to which
18 incremental expenses have been added.

19 The resulting costs are reasonable and fully justified, as the associated activities are
20 necessary to support compliance and maintain system safety, reliability and affordability.

I am sponsoring the forecasts on a total incurred basis, as well as the shared services allocation percentages related to those costs. Those percentages are presented in my shared services workpapers, along with a description explaining the activities being allocated. See Ex. SCG-05-WP. The dollar amounts allocated to affiliates are presented in SoCalGas’s Shared Services testimony (Ex. SCG-22/SDGE-27).

A. GT&S Strategy (2200-0330)

**TABLE GO-23
Shared O&M – GT&S Strategy**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
A. GT&S Strategy	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. GT&S Strategy	900	815	(85)

1. Description of Costs and Underlying Activities

The costs covered under the GT&S Strategy category include labor and non-labor activities required under SoCalGas Transportation Tariff Rule 30⁵⁸ and SoCalGas Rate Schedules G-BTS,⁵⁹ G-OSD,⁶⁰ and G-PAL.⁶¹ The GT&S Strategy team supports the activities that evaluate general market conditions to determine the value of major transmission products such as Backbone Transportation Service (BTS) and Off-System Delivery. The GT&S Strategy costs are in support of the System Operator/Gas Control & System Planning. The GT&S Strategy team monitors and analyzes market and pricing information, recommends changes to capacity and storage market activities in response to market developments, develops pricing guidelines for storage and CEH products, and monitors the financial performance of CEH product offerings, while maintaining a focus on consumer affordability. Additionally, they serve as subject-matter experts providing analytical and operational support in various proceedings for

⁵⁸ SoCalGas Rule No. 30 “Transportation of Customer-Owned Gas,” September 1, 2023, available at: <https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=129>

⁵⁹ SoCalGas Schedule G-BTS, “Backbone Transportation Service,” August 20, 2021, available at: <https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=465>

⁶⁰ SoCalGas Schedule G-OSD, “Off System Delivery Service,” October 1, 2012, available at: <https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=310>

⁶¹ SoCalGas Schedule G-PAL “Operational Hub Services,” October 15, 2023, available at: <https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=398>

1 other departments within SoCalGas and SDG&E, such as Regulatory, Regulatory Accounting,
2 and Rates & Demand Analysis.

3 System gas flow throughput is allocated 89.57% to SoCalGas and 10.43% to SDG&E.
4 However, for this category, SDG&E’s share is reduced by 50% because half of the department’s
5 time is dedicated to supporting Storage Products & Balancing (entirely SoCalGas), while the
6 remaining half supports gas transportation activities. Therefore, the allocations for this effort are
7 94.78% for SoCalGas and 5.22% for SDG&E.

8 **2. Forecast Method**

9 The forecast method developed for GT&S Strategy is based on BY 2025, with
10 adjustments for reduced labor requirements and an increase in subscription costs. The base year
11 method is most appropriate because in 2025, the GT&S Strategy work volume was adjusted to
12 support the Storage Products & Balancing group, as well as promote process efficiencies,
13 resulting in a lower forecast estimate. Thus, the base year, plus necessary adjustments to
14 maintain the staffing level needed to carry out existing work requirements, provide the most
15 accurate representation of anticipated costs for TY 2028.

16 **3. Cost Drivers**

17 The primary cost drivers for GT&S Strategy activities are described in Section IV.A.1.
18 An overall decrease of \$95,000 from the base year is forecasted for GT&S Strategy. This net
19 decrease is driven by a reduction of \$108,000 in labor requirements in this area and an
20 incremental increase of \$13,000 in non-labor expenses attributed to maintaining natural gas
21 market data subscriptions and forecasting software, which support the existing workforce in
22 executing the activities described in Section IV.A.1.

23 **B. Capacity Products Support (2200-0328)**

24 **TABLE GO-24**
25 **Shared O&M – Capacity Products Support**

26

GAS TRANSMISSION & STORAGE (In 2025 \$)			
B. Capacity Products Support	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Capacity Products Support	977	1,213	236

27

1 **1. Description of Costs and Underlying Activities**

2 These costs include labor and non-labor expenses for the Capacity Products Support
3 team, which provides direct customer service for activities that support and enhance the delivery
4 of gas transportation services. Expenses are allocated 89.57% to SoCalGas and 10.43% to
5 SDG&E based on annual gas throughput. Key responsibilities include:

6 **SoCalGas ENVOY®:** Developing and maintaining SoCalGas ENVOY®, an internet-
7 based gas transportation management system that allows end-use customers, shippers, and
8 energy marketers to schedule gas deliveries into Southern California, helping customers manage
9 their natural gas supplies and make decisions on natural gas services for their business needs.

10 These activities are required under SoCalGas Transportation Tariff Rule 33.⁶²

11 **Energy Market Services:** Administering both the BTS and Core Aggregation
12 Transportation (CAT) services, and providing back-office support for the CEH, all of which are
13 required for SoCalGas and SDG&E to implement gas transportation service on its system in
14 compliance with SoCalGas Transportation Tariff Rule 30⁶³ and Rule 32,⁶⁴ and SoCalGas Rate
15 Schedules G-BTS⁶⁵ and G-PAL.⁶⁶ This group also manages and supports relationships with gas
16 marketers, suppliers, and upstream pipeline business relationships. Lastly, the group participates
17 in North American Energy Standards Board (NAESB) committee activities on behalf of
18 SoCalGas and SDG&E to support industry standard development, monitoring regulatory matters
19 under the jurisdiction of FERC related to upstream pipelines serving the SoCalGas and SDG&E
20 systems, and supporting implementation of modification to policies and procedures for
21 scheduling and nominations on the SoCalGas and SDG&E systems.

⁶² SoCalGas Rule No. 33 “Electronic Bulletin Board (EBB),” March 10, 2021, available at:
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=132>.

⁶³ SoCalGas Rule No. 30 “Transportation of Customer-Owned Gas,” September 1, 2023, available at:
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=129>

⁶⁴ SoCalGas Rule No. 32 “Core Aggregation Transportation,” April 25, 2018, available at:
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=131>.

⁶⁵ SoCalGas Schedule G-BTS, “Backbone Transportation Service,” August 20, 2021, available at:
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=465>

⁶⁶ SoCalGas Schedule G-PAL “Operational Hub Services,” October 15, 2023, available at:
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=398>

2. Forecast Method

The forecast method for Capacity Products Support is based on BY 2025. This method is appropriate because 2025 provides the most current staffing level needed to carry out the full scope of work activities, which do not have a lot of variability from year-to-year. Thus, significant changes to current operational needs are not anticipated at this time. It should be noted that the equivalent of one vacant position was backfilled late in the BY 2025, resulting in lower recorded costs than would have been the case under full staffing. The department is projected to be fully staffed in 2026. Therefore, the base year, plus necessary incremental adjustments to maintain the staffing level needed to carry out existing workforce requirements, provide the most accurate representation of anticipated costs for the GRC forecast period.

3. Cost Drivers

The primary cost drivers for Capacity Products Support activities are described in Section IV.B.1.

An incremental increase of \$219,000 over the base year is requested for TY 2028, associated with the hiring of one employee in late 2025 to backfill a vacancy necessary to carry out existing work requirements, as described in Section IV.B.1, and for materials and services needed to maintain SoCalGas ENVOY.®

C. Gas Scheduling (2200-2158)

**TABLE GO-25
Shared O&M – Gas Scheduling**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
C. Gas Scheduling	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Gas Scheduling	930	1,004	74

1. Description of Costs and Underlying Activities

These costs cover labor and non-labor activities for the Gas Scheduling team, which supports a 365-day-per-year operation that manages daily scheduling of nominations and allocations for gas transportation services, storage injections, and withdrawals for all gas quantities transported on the SoCalGas and SDG&E systems. Expenses are allocated 89.57% to SoCalGas and 10.43% to SDG&E based on annual gas throughput. Key activities include:

1 **Scheduling Nominations and Allocations:** This activity involves managing
2 transportation nominations for on-system and off-system deliveries based on capacity rights,
3 confirming nominations to interstate and intrastate suppliers, implementing OFO rules when
4 required to balance system capacity with demand, reporting scheduling quantities to customers,
5 tracking storage accounts, tracking and clearing shipper imbalances, and administering the
6 imbalance trading process all of which promotes system reliability. These activities are required
7 under SoCalGas Transportation Tariff Rule 30.⁶⁷

8 **SoCalGas ENVOY® Posts:** This activity involves managing postings to SoCalGas
9 ENVOY® transmission and storage system conditions, including critical and non-critical
10 notices, and hourly and daily operational capacity information. This enables SoCalGas to
11 communicate transparently and consistently with the gas marketplace and is required under
12 SoCalGas Tariff Rule 33.⁶⁸

13 **2. Forecast Method**

14 The forecast method for Gas Scheduling is based on BY 2025. This method is
15 appropriate because 2025 provides the most current staffing level needed to carry out the full
16 scope of work activities, which do not have a lot of variability from year-to-year. Thus,
17 significant changes to current operational needs are not anticipated at this time. It should be
18 noted that one vacant position was backfilled late in the base year, resulting in temporarily lower
19 recorded costs than had the department been fully staffed in 2025. The department is projected to
20 be fully staffed in 2026. Therefore, the base year plus necessary incremental adjustments to
21 maintain the staffing level needed to carry out existing workforce requirements provide the most
22 accurate representation of anticipated costs for the GRC forecast period.

23 **3. Cost Drivers**

24 The primary cost drivers for Gas Scheduling activities are described in Section IV.C.1.
25 An incremental increase of \$59,000 over the base year is requested for TY 2028, associated with
26 the hiring of one employee in late 2025 to backfill a vacancy and achieve full staffing. This is
27 necessary to carry out existing work requirements and align the forecast with the full execution

⁶⁷ SoCalGas Rule No. 30 “Transportation of Customer-Owned Gas,” September 1, 2023, available at: <https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=129>

⁶⁸ SoCalGas Rule No. 33 “Electronic Bulletin Board (EBB),” March 10, 2021, available at: <https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=132>.

of duties described in Section IV.C.1.

D. Gas Transmission Planning (2200-2329)

**TABLE GO-26
Shared O&M – Gas Transmission Planning**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
D. Gas Transmission Planning	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Gas Transmission Planning	1,089	1,116	27

1. Description of Costs and Underlying Activities

These costs cover labor and non-labor activities for the Gas Transmission Planning team that support the long-term planning and design of the SoCalGas and SDG&E gas transmission systems. Expenses are allocated 66.67% to SoCalGas and 33.33% to SDG&E based on estimated work splits between the two utilities. Key activities include:

Transmission System Capacity Analysis: This activity involves using hydraulic analytical tools to continually assess the transmission system’s ability to meet CPUC-mandated design standards, fulfill existing service obligations, and prepare for future demand by serving new customer needs and accessing new gas supply sources. This includes working closely with departments responsible for maintaining the safety and integrity of the gas transmission system by assessing the potential operational and customer service impacts of maintenance activities on the gas transmission system.

Transmission System Design: This activity involves developing analyses and reports, such as Seasonal Technical Assessments, to evaluate the transmission system’s ability to meet Commission-mandated standards for customer service and reliability, maintain reliability during major system outages, and provide recommendations to support system resiliency. These activities are necessary to support safety, maintain system reliability, and comply with regulatory requirements, including those prescribed by CPUC GO 112-F⁶⁹ and PHMSA Rule 49 CFR §192, Subpart C – Pipe Design. Such activities include calculating the Maximum Operating Pressure

⁶⁹ General Order No. 112-F, “State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering Transmission, and Distribution Piping Systems,” June 25, 2015, available at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K327/163327660.PDF>.

1 for a pipeline segment as a function of its pipeline strength and the terrain it crosses, identifying
2 pressure targets along a pipeline for pressure uprating and restoration procedures, and
3 establishing the operational parameters necessary for pipeline, valve station, and compressor
4 station design. The group also represents planning and operations in regulatory matters involving
5 the gas transmission system's design, operation, and future capabilities.

6 **2. Forecast Method**

7 The forecast method for Gas Transmission Planning is based on BY 2025, with
8 incremental adjustments for increased licensing and training costs. This method is appropriate
9 because 2025 provides the most current staffing level needed to carry out the full scope of work
10 activities, which do not have a lot of variability from year-to-year. Thus, significant changes to
11 current operational needs, beyond the identified incremental adjustments, are not anticipated at
12 this time.

13 **3. Cost Drivers**

14 The primary cost drivers for Gas Transmission Planning activities are described in
15 Section IV.D.1. This funding enables Gas Transmission Planning to assess the current gas
16 transmission system and plan for future development, supporting the Company's compliance
17 with CPUC requirements and directives. This level of funding also reflects the resources required
18 to evaluate operational and planning challenges associated with gas transmission maintenance
19 projects and other compliance-driven maintenance activities. Furthermore, this forecast provides
20 funding for the labor costs associated with leadership, management, and supervision necessary to
21 support the workforce requirements as described in Section IV.D.1.

22 An incremental increase of \$10,000 over the base year is requested for TY 2028 for
23 additional non-labor expenses necessary to procure licenses for hydraulic analytical tools, pay
24 professional engineering license fees, and provide professional engineering testing and training.

1 **Control Room Management:** Developing and adhering to a control room management
2 plan to comply with PHMSA Rule 49 CFR §192.631 §192.805 address alarm management,
3 system change management, fatigue mitigation, system operating experience, and personnel
4 training requirements. Alarm management involves reviewing safety-related alarm operations
5 and implementing methods to verify controllers have sufficient time to analyze and respond to
6 incoming alarms. Fatigue management involves implementing methods to mitigate the risks
7 associated with controller fatigue, which could impair their ability to perform their roles and
8 responsibilities. Analysis of fatigue management practices, shift lengths, and schedule rotations
9 is required to verify that controllers receive adequate rest. Lastly, training is required for system
10 gas controllers and lead system gas controllers to recognize fatigue-related effects and apply
11 appropriate mitigation strategies.

12 **Integration of CCM Assets:** Gas Control manages and operates both the SoCalGas and
13 SDG&E gas transmission pipeline networks. The CCM project has expanded Gas Control
14 responsibilities by providing visibility into the gas distribution system and operational control
15 over select distribution regulator stations. Additionally, the CCM project increased the
16 digitalization of the transmission system by deploying new field assets, such as OPM stations
17 and HCA methane sensors. The installation of these new field assets, along with enhancements
18 to existing field assets on both distribution and transmission pipelines, has increased Gas
19 Control’s workload, responsibilities, and personnel requirements.

20 The CCM project has driven the creation or change of new and existing business
21 processes to integrate data from over 3,350 additional field assets that will be monitored by the
22 Gas Control organization by 2028, with an additional 831 assets deployed to Gas Control by
23 2031. As a result, additional personnel are required to support:

- 24 • Monitoring of the OPM and HCA methane sensors on the transmission system;
- 25 • Monitoring and control of DRS sites on the distribution system;
- 26 • Routing and monitoring of distribution system Electronic Pressure Monitors
27 (EPM);
- 28 • Alarm response and incident management for planned and unplanned activities
29 associated with the newly deployed distribution and transmission field assets;
- 30 • Expanded distribution outage management, coordination, and engineering
31 support;

- Coordination with Distribution Field Operations, Dispatch, Transmission, and Emergency Management and Preparedness organizations; and
- Data analysis through new situational awareness platforms introduced via CCM technologies.

Table GO-28 presents a summary of the new field asset installations planned as part of the CCM Project.

TABLE GO-28
CCM Field Assets Active in Gas Control (By Year)

CCM Field Assets Active in Gas Control				
<i>Projections are cumulative</i>				
Asset Type	2025	2026	2027	2028
DRS	27	43	59	72
HCA Methane	92	192	317	628
EPM	0	1300	2650	2650
OPM	2	6	9	9
Total	121	1541	3035	3,359

These new CCM project processes and resources will support expanded 24/7 workload management and improve Gas Control’s ability to respond to abnormal operating conditions by enhancing communication and response times. Through new data analytics tools, Gas Control personnel will be able to leverage real-time and near-real-time data from these field assets. These tools will enable Gas Control to assess system health more effectively, proactively identify areas of concern, and take preventative maintenance measures.

a. Description of RAMP Mitigations

Within this cost category, there are shared services O&M costs for risk control C109 (Control Room Monitoring Operation and Fatigue Management) that were presented in the 2025 RAMP Report and are listed in Table GO-29. The RAMP activity identified within this workpaper is described in Section IV.E.1. It includes 24/7 remote monitoring and control of the transmission pipeline system in a real-time control room environment, enabling controllers to acknowledge, react, and respond to normal and abnormal operating conditions; serving as a communication center between departments conducting maintenance on the transmission system; and implementing fatigue management practices to reduce risks associated with controller fatigue that could impair their ability to carry out their roles and responsibilities. All the RAMP costs associated with C109 are included in this category. The difference between the RAMP

1 forecast and the forecast in this testimony is due to the RAMP using a 2024 forecast, while this
 2 testimony uses a BY 2025 forecast with incremental adjustments. It is also due to the underlying
 3 scope of work increasing to integrate new CCM assets into control room operations. The latter
 4 includes the additional resources required for operators to monitor these sites and respond to
 5 abnormal operating conditions when they occur. While there is an adjustment to the forecast
 6 estimate, the risk control strategy remains unchanged. This RAMP mitigation is necessary to
 7 comply with 49 CFR §192.631, §192.605, §192.615, and §192.636.

8 Activities that are compliance or mandated by CPUC or other agencies are listed in bold,
 9 and Appendix B attached to this testimony provides the details regarding these mandates for each
 10 control.

11 **TABLE GO-29**
 12 **RAMP and GRC Risk Control/Mitigation Activities – Shared Services O&M**
 13

Gas Control				
ID	Control/Mitigation Name	2025 RAMP 2028 Estimate In 2024 \$ (000s)	2028 GRC 2028 Forecast In 2025 \$ (000s)	Change (000s)
C109	Control Room Monitoring Operation and Fatigue Management	3,472	6,329	2,857

14 **b. Description of Selection and Prioritization of RAMP Risk**
 15 **Mitigations**

16 The RAMP risk mitigation efforts are associated with specific actions, such as programs,
 17 projects, processes, and utilization of technology and are designed to address a specific safety
 18 and/or reliability risk. The Company's selection and prioritization of these RAMP mitigation
 19 activities considered many factors when determining if these risk mitigation activities are an
 20 effective and worthwhile investment. The ERM process for identifying and assessing system
 21 risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

22 This mitigation is selected as a risk control for the High-Pressure Gas System Risk,
 23 which is defined as the risk of failure of a high-pressure gas pipeline resulting in serious injuries,
 24 fatalities, and/or damage to infrastructure. As outlined in the 2025 RAMP Report, there are four
 25 potential drivers of this risk which are addressed by C109. Those are weather-related and outside
 26 forces (e.g., landslide, earthquake, other natural disasters), incorrect operations, equipment

1 failure, and third-party damage (excluding excavation damage). Having a control room with 24/7
2 real-time operational monitoring and control responsibilities enables the Company to quickly
3 identify high-pressure gas pipeline failures caused by these drivers. For example, in the event of
4 a pipeline rupture, the control room may receive various real-time notifications through the
5 SCADA system including pressure rate of drop alarms, low-pressure alarms, and telemetry
6 issues caused by communication failure, all of which help controllers identify the rupture event.
7 The control room may also receive notifications of pipeline failures from external sources calling
8 the Company's emergency phone number listed on pipeline markers. Beyond identifying rupture
9 events, a control room with 24/7 real-time operational monitoring and control capabilities
10 reduces the likelihood of high-pressure gas pipeline failures by enabling controllers to promptly
11 identify abnormal operating conditions (*e.g.*, overpressures, equipment failures, gas leaks) and
12 take corrective action before such conditions escalate into emergencies. Such actions include
13 remotely adjusting valves and compressor stations to adjust gas flows and reduce gas pressure in
14 an affected area, and dispatching field personnel to investigate and remediate identified issues.

15 Additionally, per the 2025 RAMP Report, there are four potential consequences of a
16 High-Pressure System Risk which are addressed by C109. Those are serious injuries or fatalities,
17 property damage, operational and reliability impacts, and environmental impacts. Real-time
18 operational monitoring and control capabilities within a control room enable SoCalGas and
19 SDG&E to respond rapidly to high-pressure gas pipeline failures, including remotely isolating
20 affected segments and dispatching field personnel for remediation, thereby promoting public
21 safety, minimizing environmental impacts, and maintaining system reliability through effective
22 contingency planning for system upsets. Thus, even though the benefit-cost ratio (BCR) for this
23 mitigation is below 1, investing in a control room to mitigate a High-Pressure System Risk is
24 necessary, given the extreme disruption to operations and public safety this risk would cause.

25 2. Forecast Method

26 The forecast method for Gas Control is based on BY 2025 as the foundational cost level,
27 with incremental adjustments to account for new CCM assets that will be monitored by the
28 control room. This approach is appropriate because historical costs prior to 2025 do not
29 accurately reflect future staffing and operating requirements. Due to CCM projects, Gas
30 Control's workload and responsibilities increased, requiring an increased workforce in control
31 room, outage management, engineering, and training support. Staffing increases to support the

1 full scope of current work activities were largely completed by 2025. Therefore, BY 2025
 2 represents a stable and representative operational baseline, and the incremental cost components
 3 associated with continued CCM initiatives in 2027 and 2028 provide a reasonable indicator of
 4 future requirements.

5 **3. Cost Drivers**

6 The primary cost drivers for Gas Control activities are described in Section IV.E.1.
 7 SoCalGas is requesting an incremental increase of \$746,000 over the adjusted-recorded base
 8 year for the integration of CCM assets, which will include the deployment and data integration
 9 from over 3,350 new and existing field assets into the Gas Control Room by the end of 2028.
 10 The addition of these assets will require expanded resources to provide 24/7 monitoring, alarm
 11 response, and management of planned and unplanned events. To support this expanded
 12 operational footprint, the incremental labor funding required for this activity increases by
 13 \$736,000, which supports an additional 5.4 FTEs. These additional FTEs will primarily be
 14 allocated to the system controller and lead system controller classifications. In addition, non-
 15 labor incremental funding required for this activity increases by \$10,000, which is driven
 16 primarily by materials and services needed to support the additional personnel in the control
 17 room, such as office supplies, phone usage, and travel expenses to the department’s backup
 18 control room.

19 **F. Gas Control SCADA Operation (2200-0329)**

20 **TABLE GO-30**
 21 **Shared O&M – Gas Control SCADA Operation**
 22

GAS TRANSMISSION & STORAGE (In 2025 \$)			
F. Gas Control SCADA Operation	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Gas Control SCADA Operation	1,914	2,323	409

23 **1. Description of Costs and Underlying Activities**

24 These costs cover labor and non-labor activities for the Gas Control SCADA Operations
 25 team that supports the planning, operation, and maintenance of the SCADA system. Expenses
 26 are allocated 89.57% to SoCalGas and 10.43% to SDG&E based on annual gas throughput. Key
 27 activities include:

1 **SCADA System Maintenance and Support:** Developing and maintaining the SCADA
2 system that enables remote monitoring and operation of valves, compressors, pressure regulation
3 equipment, and gas flow throughout the system are necessary for controllers to safely and
4 effectively operate the transmission pipeline system, as required under PHMSA Rules 49 CFR
5 §192.605, §192.615, and §192.636, and state regulation CPUC GO 112-F. This also includes
6 developing and maintaining secure SCADA access controls to comply with cybersecurity
7 regulations, such as TSA Security Directive (SD) 2021-02E.⁷¹

8 Non-labor cost drivers include SCADA vendor support; ongoing expenses to maintain
9 servers and workstations that support the SCADA system and pipeline simulator; and
10 telecommunications costs for the Very Small Aperture Terminal (VSAT) and cellular
11 communications used to interface with field devices.

12 **Control Room Management:** This activity involves adhering to a control room
13 management plan to comply with PHMSA Rule 49 CFR § 192.631, including developing
14 SCADA displays consistent with API RP 1165, conducting point-to-point verifications to
15 validate that information presented in the control room is accurate, and testing the effectiveness
16 of backup SCADA systems in emergency situations.

17 **a. Description of RAMP Mitigations**

18 Within this cost category, there are shared services O&M costs for risk control C105
19 (SCADA Operations) that were presented in the 2025 RAMP Report and are listed in Table GO-
20 31. The RAMP activity identified within this workpaper is described in Section IV.F.1. It
21 includes managing the SCADA system used by the control room for remote monitoring, control,
22 and real-time operations of the gas transmission system. All the RAMP costs associated with
23 C105 are included in this category. The difference between the RAMP forecast and the forecast
24 in this testimony is due to the RAMP using a 2024 forecast, while this testimony uses a BY 2025
25 forecast. It is also due to an increase in the scope of work to integrate new CCM assets into the
26 SCADA system and the additional resources required to maintain these assets. While there is an
27 adjustment to the forecast estimate, the risk control strategy remains unchanged. This RAMP
28 mitigation is necessary to comply with 49 CFR §192.631.

⁷¹ SD-Pipeline-2021-02E, “Pipeline Cybersecurity Mitigation Actions, Contingency Planning, and Testing,” July 24, 2024, available at: <https://www.tsa.gov/sites/default/files/tsa-security-directive-pipeline-2021-02e-and-memo-508c.pdf>

1 Activities that are compliance or mandated by CPUC or other agencies are listed in bold,
 2 and Appendix B attached to this testimony provides the details regarding these mandates for each
 3 control.

4 **TABLE GO-31**
 5 **RAMP and GRC Risk Control/Mitigation Activities – Shared Services O&M**

Gas Control SCADA Operations				
ID	Control/Mitigation Name	2025 RAMP 2028 Estimate In 2024 \$ (000s)	2028 GRC 2028 Forecast In 2025 \$ (000s)	Change (000s)
C105	SCADA Operations	1,735	2,323	588

6 **b. Description of Selection and Prioritization of RAMP Risk**
 7 **Mitigations**

8 The RAMP risk mitigation efforts are associated with specific actions, such as programs,
 9 projects, processes, and utilization of technology and are designed to address a specific safety
 10 and/or reliability risk. The Company’s selection and prioritization of these RAMP mitigation
 11 activities considered many factors when determining if these risk mitigation activities are an
 12 effective and worthwhile investment. The ERM process for identifying and assessing system
 13 risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

14 This mitigation is selected as a risk control for the High-Pressure Gas System Risk,
 15 which is defined as the risk of failure of a high-pressure gas pipeline that results in serious
 16 injuries, fatalities, and/or damage to infrastructure. As outlined in the SoCalGas 2025 RAMP
 17 Report, some of the potential drivers of this risk include weather related and outside forces (*e.g.*,
 18 landslide, earthquake, other natural disasters), incorrect operations, and equipment failure, all of
 19 which are addressed by C105. Having a 24/7 control room with SCADA system functionality
 20 enables the Company to quickly identify high-pressure gas pipeline failures caused by these
 21 drivers. For example, in the event of a pipeline rupture, the control room may receive various
 22 real-time notifications through the SCADA system, including pressure rate of drop alarms, low
 23 pressure alarms, and telemetry issues caused by communication failure, all of which help
 24 controllers identify the rupture event. Additionally, a control room equipped with SCADA
 25 system functionality reduces the likelihood of a high-pressure gas pipeline failure by enabling
 26 controllers to identify abnormal operating conditions (*e.g.*, over-pressures, equipment failures,
 27 natural gas leaks) and to respond promptly through use of the SCADA system (*e.g.*, remote

1 manipulation of valves and compressor stations) before such conditions escalate into emergency
2 situations.

3 Additionally, per the 2025 RAMP Report, there are four potential consequences of a
4 high-pressure system risk which are addressed by C105. Those are serious injuries or fatalities,
5 property damage, operational and reliability impacts, and environmental impacts. A 24/7 control
6 room with SCADA system functionality enables SoCalGas and SDG&E to respond rapidly to
7 high-pressure gas pipeline failures, including remotely isolating affected segments, thereby
8 promoting public safety, minimizing environmental impacts, and maintaining system reliability
9 through effective contingency planning for system upsets. In the absence of a reliable SCADA
10 system that provides accurate and timely information (*e.g.*, equipment status, valve position,
11 pressure readings, and flow measurements at supplier receipt points), as well as appropriate
12 system configuration to enable remote operation of pipeline equipment, the control room's
13 ability to perform its operational roles and responsibilities would be significantly impaired. This
14 impairment would increase the likelihood and potential severity of a high-pressure system risks
15 to operations and public safety.

16 2. **Forecast Method**

17 The forecast methodology for Gas Control SCADA Operation is based on BY 2025 as
18 the foundational cost level, with incremental adjustments applied to account for anticipated cost
19 pressures. This approach is appropriate because Gas Control SCADA Operation's workload and
20 responsibilities increased due to CCM projects. Therefore, BY 2025 represents a stable and
21 representative operational baseline, and the incremental costs associated with continued CCM
22 initiatives in 2027 and 2028, together with SCADA hardware investments, provide a reasonable
23 basis for projecting future requirements.

24 3. **Cost Drivers**

25 The primary cost drivers for the Gas Control SCADA Operation activities are described
26 in Section IV.F.1.

27 An incremental increase of \$384,000 over the adjusted-recorded base year is requested
28 for TY 2025. This request includes a \$630,000 increase for incremental labor resources required
29 to effectively operate the SCADA system, support Control Room functions, and integrate new
30 CCM assets into the SCADA system. Additional resources are necessary to support the
31 deployment and integration of over 3,350 new and existing CCM assets into the SCADA system

1 by 2028. As the EPM installation projects are scheduled to conclude in 2027, and the HCA
 2 methane installation and DRS site upgrades are scheduled to continue through 2031, the costs
 3 associated with maintaining communications for these assets will transition to Gas Control
 4 SCADA Operations. This transition results in a corresponding increase in SCADA labor costs.
 5 Partially offsetting this increase, SoCalGas forecasts a \$246,000 decrease in non-labor costs,
 6 reflecting expected lower SCADA vendor support costs compared to BY 2025.

7 **G. Gas Ops Control Center Information Technology (2200-0017)**

8 **TABLE GO-32**
 9 **Shared O&M – Gas Ops Control Center Information Technology**

GAS TRANSMISSION & STORAGE (IN 2025 \$)			
G. Gas Ops Control Center Information Technology	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Gas Ops Control Center Information Technology	690	1,374	684

11 **1. Description of Costs and Underlying Activities**

12 These costs cover labor and non-labor activities for the Gas Ops Control Center
 13 Information Technology (IT) team that supports the resources required to maintain and update
 14 various Gas Control IT assets. Expenses are allocated 89.57% to SoCalGas and 10.43% to
 15 SDG&E based on annual gas throughput. Key activities include:

16 **Control Room Applications:** These activities involve maintaining and updating Gas
 17 Control’s electronic logging system (ELS), control room scheduling application, outage
 18 management platforms, alarm management tool, advanced forecasting tool, Gas Control data
 19 delivery middleware, Gas Control’s data historian (*i.e.*, AVEVA PI), and configuration of the
 20 control room audio-visual (AV) system. These expenditures also include application subscription
 21 costs and Amazon Web Services (AWS) Cloud Services. The tools supported by this group
 22 enhance safety by maintaining software applications required to monitor and respond to field
 23 incidents in the control room. Maintaining these software applications also improves situational
 24 awareness in the control room, thereby facilitating faster response and communication times for
 25 both planned and unplanned field work. This group also strengthens reliability through more
 26 accurate system demand forecasting.

1 **Data Management and Governance:** The development and implementation of data
2 governance processes help manage and secure Gas Control field data assets. This includes
3 maintaining secure cellular data connections required for the collection of field asset data,
4 including CCM assets; reliably transmitting that data to Gas Control; and coordinating with
5 SoCalGas’s IT organization to align cybersecurity policies and procedures with new
6 CCM-integrated field asset and control room technologies. These data management and
7 governance activities enhance system reliability through data integration and cross-system data
8 quality monitoring, and enable Gas Control to prepare for additional CCM asset monitoring.

9 **2. Forecast Method**

10 The forecast methodology for Gas Ops Control Center IT is based on BY 2025 as the
11 foundational cost level, with incremental adjustments to account for cost pressures described in
12 the cost driver section below. The base year methodology is appropriate because historical costs
13 prior to 2025 do not accurately represent future staffing and operating requirements. A
14 significant portion of this group previously worked on the development of Gas Control support
15 applications under the CCM Projects. While the development of these applications was largely
16 completed by 2025, these applications require ongoing operational support, as well as periodic
17 upgrades, enhancements, and technology refreshes throughout the forecast period. Accordingly,
18 the recorded BY 2025 costs provide a reasonable basis for building the TY 2028 forecast.⁷²

19 **3. Cost Drivers**

20 The primary cost drivers for Gas Operations Control Center Information Technology
21 activities are both completed and ongoing CCM projects, which require implementation and
22 ongoing support of CCM IT enhancements.

23 An incremental increase of \$684,000 over the adjusted-recorded base is requested for TY
24 2028. This increase includes \$489,000 in incremental labor costs and \$195,000 in incremental
25 non-labor costs to support the transition from capital project execution to ongoing operational
26 support, as CCM projects are completed during the forecast period. For example, while EPM
27 asset installation is scheduled to conclude in 2027 and HCA methane sensor installation will
28 continue through 2031, the ongoing costs to maintain these assets—including managing data

⁷² The increase in FTEs needed to perform O&M activities in this area is offset by a reduction in the CCM capital project work, as discussed in the SoCalGas Major Projects testimony (Ex. SCG-06).

1 pathways from field sensors to the data historian (AVEVA PI) and SCADA system, and
 2 maintaining data governance activities within Gas Control’s ELS, AVEVA PI, and GIS—will
 3 transition to the Gas Operations Control Center Information Technology function.

4 **H. GT Operations Leadership & Oversight – USS (2200-0253)**

5 **TABLE GO-33**
 6 **Shared O&M – GT Operations Leadership & Oversight**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
H. GT Operations Leadership & Oversight	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. GT Operations Leadership & Oversight	2,107	2,682	575

7 **1. Description of Costs and Underlying Activities**

8 The Gas Transmission Operations Leadership and Oversight costs support the Director of
 9 Gas Transmission Operations, an administrative associate, and the Governance and Compliance
 10 organization. These functions provide the leadership, regulatory coordination, and administrative
 11 structure required for SoCalGas and SDG&E to operate their transmission systems in alignment
 12 with federal and state requirements. The Director of Gas Transmission Operations provides
 13 overall leadership for the organization’s day-to-day activities, long-term operational strategy, and
 14 system performance management. Responsibilities include directing O&M programs, overseeing
 15 regulatory compliance activities, supporting work planning and prioritization, and guiding
 16 financial oversight to maintain alignment with approved budgets. The Director is also
 17 responsible for monitoring operational performance metrics, identifying areas for improvement,
 18 and guiding resource deployment to support system reliability and safety objectives. These
 19 functions are supported by an administrative associate who manages scheduling, correspondence,
 20 document preparation, and a broad range of administrative tasks, allowing operational and
 21 compliance staff to focus on technical and regulatory work.

22 Cost allocation between the utilities reflects the shared operational responsibilities.
 23 Expenses associated with this category are allocated 89.57% to SoCalGas and 10.43% to
 24 SDG&E, based on annual gas throughput levels. This allocation represents the relative share of
 25 transmission assets and operational work performed in each service territory.

1 The Governance and Compliance team plays a central role in supporting business
2 governance and regulatory obligations across Gas Transmission for both SoCalGas and SDG&E.
3 This team monitors compliance performance across a wide range of regulatory areas, tracks and
4 reports leaks, repairs, and manages compliance-related work orders within the enterprise asset
5 management system. These tasks require regular audits of system data, coordination with field
6 operations, and preparation of documentation for regulatory reporting and internal oversight.

7 In addition, the Governance and Compliance organization maintains and updates the
8 enterprise asset management software used to schedule, document, and track maintenance across
9 all transmission assets. This includes managing workflows, updating data structures, reviewing
10 maintenance records, and supporting system enhancements that improve data accuracy and
11 operational effectiveness. The team is responsible for managing all Gas Transmission policies,
12 coordinating policy updates, and verifying that documentation reflects current regulatory
13 requirements and internal standards. The group also oversees adherence to applicable state and
14 federal requirements, including regulations under 49 CFR §192, CPUC GO 112-F, and regional
15 air quality management district rules. Meeting these requirements involves continuous
16 coordination with internal stakeholders, preparing regulatory filings, reviewing compliance
17 evidence, participating in audits, and engaging with oversight agencies.

18 Overall, the GT Operations Leadership and Oversight function provides the leadership
19 structure, governance framework, and compliance infrastructure required for Gas Transmission
20 to meet regulatory expectations, support safe operating practices, and maintain consistent
21 performance across SoCalGas and SDG&E service territories. The associated costs reflect
22 ongoing staffing, administrative support, compliance management, policy updates, data system
23 maintenance, and regulatory coordination necessary to operate a complex, highly regulated gas
24 transmission system.

25 **2. Forecast Method**

26 The forecast methodology for GT Operations Leadership and Oversight is based on BY
27 2025 as the foundational cost level, with incremental adjustments applied to account for
28 anticipated cost pressures. These adjustments include incremental labor and non-labor costs
29 necessary to maintain critical software and hardware. This methodology is appropriate because
30 these costs are not expected to fluctuate significantly from year to year. Therefore, the most

1 recent year of recorded costs, with incremental adjustments, provides an accurate representation
 2 of current operational needs and serves as a reasonable basis for the TY 2028 forecast.

3 **3. Cost Drivers**

4 The GT Operations Leadership & Oversight forecast is primarily driven by the need to
 5 support ongoing regulatory compliance, maintain transmission system reliability, and sustain the
 6 software and hardware platforms required to support transmission system operations across
 7 SoCalGas and SDG&E. These systems are foundational to safe, reliable, and compliant
 8 transmission operations.

9 An incremental non-labor costs of \$554,000 over the base year is requested in TY 2028
 10 to support the maintenance of critical software and hardware used for transmission asset
 11 management and OT systems. This software and hardware were placed into service as part of a
 12 capital upgrade project. However, incremental funding is required to support their ongoing O&M
 13 efforts. The requested funding supports field OT asset configuration in Maximo, asset updates at
 14 the Blythe compressor station, enhancements to Maximo Mobile, and required updates to iFix
 15 software. In addition, funding supports the onboarding and integration of the Maximo Mobile
 16 and ePCMR applications across the Transmission and Storage organizations. Ongoing
 17 maintenance and support of these technologies are critical to effective field work execution,
 18 compliance documentation, asset tracking, and data integrity.

19 **I. Field Operations Manager (FOM) Pipeline East (2200-0265)**

20 **TABLE GO-34**
 21 **Shared O&M – Field Operations Manager (FOM) Pipeline East**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
I. Field Operations Manager (FOM) Pipeline East	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Field Operations Manager (FOM) Pipeline East	144	146	2

22 **1. Description of Costs and Underlying Activities**

23 The Field Operations Manager (FOM) Pipeline East costs support the leadership,
 24 operational management, and regulatory responsibilities required to operate and maintain Gas
 25 Transmission assets across SoCalGas’s East Region and the cathodic protection of SDG&E’s
 26 transmission system. This function provides the management structure and oversight needed to

1 guide field personnel, coordinate construction and maintenance activities, manage staffing and
2 workload distribution, and support reporting and compliance obligations across two utility
3 jurisdictions.

4 Cost allocation between the utilities reflects the shared operational responsibilities.
5 Expenses associated with this category are allocated 89.57% to SoCalGas and 10.43% to
6 SDG&E, based on annual gas throughput levels. This allocation represents the relative share of
7 transmission assets and operational work performed in each service territory.

8 FOM Pipeline East provides day-to-day operational leadership for the transmission
9 pipeline system in SoCalGas's East Region and for cathodic protection maintenance for
10 SDG&E's 185 miles of transmission pipelines. Responsibilities include workforce planning,
11 oversight of maintenance and construction schedules, development of operational work plans,
12 and financial management of O&M activities. The role also involves performance monitoring,
13 operational reporting, and coordination with Gas Control, Engineering, Environmental Services,
14 and Governance and Compliance teams to support safe and effective field execution.

15 This cost category also supports activities related to regulatory compliance, including
16 oversight of maintenance cycles, participation in inspections and audits, review of field
17 documentation, and support for programs required under federal and state regulations such as
18 CFR Part 192 and CPUC GO 112-F. The FOM Pipeline East organization plays a critical role in
19 tracking operational performance, managing field readiness, supporting incident response, and
20 coordinating corrective actions when required.

21 2. Forecast Method

22 The forecast methodology for FOM Pipeline East is based on BY 2025. While a review
23 of the five-year historical average (2021–2025) results in a higher baseline for this work
24 category, SoCalGas determined that BY 2025 more accurately reflects the ongoing operational
25 oversight and regulatory responsibilities driving these costs. As a result, the adjusted-recorded
26 expenditure from BY 2025 provides the most reasonable and reliable basis for forecasting future
27 requirements over the GRC period.

28 3. Cost Drivers

29 The underlying cost drivers for FOM Pipeline East relate to labor required to support the
30 existing workforce responsible for day-to-day operational duties, maintenance activities, field
31 oversight, and administrative coordination. These personnel activities form the backbone of

1 routine transmission operations and demand stable funding to maintain effective workflow
 2 management and operational continuity. The activities supported by this category remain
 3 essential to ongoing operations, compliance obligations, and risk management needs across the
 4 gas transmission system. A small incremental adjustment in TY 2028 reflects changes in
 5 connection with the compensation modernization initiative. Please refer to the Compensation
 6 and Benefits testimony (Ex. SCG-16/SDGE-20).

7 **J. Gas Transmission FOM Victorville Compressor Operations – USS (2200-**
 8 **2173)**

9 **TABLE GO-35**
 10 **Shared O&M – Gas Transmission FOM Victorville Compressor Operations**

GAS TRANSMISSION & STORAGE (In 2025 \$)			
J. Gas Transmission FOM Victorville Compressor Operations	2025 Adjusted-Recorded (000s)	TY 2028 Est. (000s)	Change (000s)
1. Gas Transmission FOM Victorville Compressor Operations	796	807	11

11 **1. Description of Costs and Underlying Activities**

12 The Gas Transmission FOM for Victorville Compressor Operations costs support the
 13 operational leadership and oversight necessary to manage SoCalGas’s seven compressor stations
 14 and SDG&E’s Moreno Compressor Station. This work category provides the management
 15 structure, technical coordination, and compliance activities required to operate these facilities
 16 safely and reliably, in alignment with federal and state regulatory expectations.

17 Since this work supports both SoCalGas and SDG&E compressor assets, costs are
 18 allocated between the two utilities based on annual gas throughput. Under this shared services
 19 model, 93% of expenses are allocated to SoCalGas and 7% to SDG&E. This allocation reflects
 20 the relative share of transmission volumes and station usage across the two service territories.
 21 Coordinating activities across both utilities adds complexity to planning, reporting, and
 22 operational decision-making, as processes must align with each utility’s governance structure
 23 and regulatory oversight.

24 The FOM organization is responsible for a broad range of activities that guide day-to-day
 25 compressor station operations and long-term maintenance planning. Core responsibilities include
 26 oversight of O&M work, development and monitoring of performance indicators, review of

1 financial performance, and preparation of operational and compliance reporting. The managerial
2 structure supporting these responsibilities includes the FOM, the Station Operations Manager, an
3 Engineering Team Lead, and dedicated administrative staff. Together, this team provides
4 technical leadership, workflow management, and administrative coordination across all ten
5 compressor station facilities.

6 A significant portion of this cost category supports regulatory compliance activities
7 related to compressor station operations. These activities include reviewing and updating
8 operational procedures to reflect current regulatory requirements, supporting internal audits and
9 inspections, preparing documentation for federal and state reporting, and coordinating corrective
10 actions for operational findings. Compliance work also includes monitoring maintenance cycles,
11 evaluating equipment performance, and supporting programs required under 49 CFR Part 192,
12 CPUC GO 112-F and regional air quality rules applicable to compressor station operations.

13 Technical work performed under this cost category includes design reviews, updates to
14 operational and maintenance procedures, and engineering evaluations supporting station
15 equipment upgrades or configuration changes. The team conducts baseline inspections of
16 electrical systems, rotating equipment, and auxiliary station components to identify emerging
17 issues that may affect reliability or drive future maintenance needs. These baseline assessments
18 help determine whether station assets require repair, replacement, or further engineering review.
19 They also contribute to long-term planning for capital and O&M investments.

20 The Victorville FOM team coordinates with other internal departments, including
21 Engineering, Gas Control, Environmental Services, and Governance and Compliance. This
22 coordination supports the planning and execution of major maintenance activities, compressor
23 overhauls, emissions-related work, and operational changes that affect system capacity or
24 performance. Administrative personnel assist with scheduling, documentation, training
25 coordination, and preparation of reports that support operational tracking and regulatory
26 documentation.

27 Overall, the Victorville Compressor Operations FOM provides leadership, technical
28 judgment, staffing coordination, regulatory support, and administrative infrastructure to operate
29 eight compressor stations across two utilities. These activities support reliable operations,
30 regulatory compliance, and effective maintenance planning for critical transmission facilities.

1 **2. Forecast Method**

2 The forecast methodology for Gas Transmission FOM Victorville Compressor
3 Operations is based on BY 2025. BY 2025 reflects the most current staffing level required to
4 perform the full scope of work activities for this category. Furthermore, this level of activity is
5 expected to remain stable over the GRC period. BY 2025 recorded expenditures represent the
6 most reasonable and reliable basis for forecasting future funding requirements.

7 **3. Cost Drivers**

8 The underlying cost drivers for Gas Transmission FOM Victorville Compressor
9 Operations include labor for the specialized workforce responsible for the operation,
10 maintenance, and regulatory activities associated with compressor stations. These facilities
11 depend on skilled personnel trained to operate complex mechanical, electrical, and control
12 system equipment. Maintaining a stable workforce enables the organization to support day-to-
13 day operations, respond to equipment issues, and carry out routine maintenance, keeping
14 compressor stations operating safely and effectively.

15 Foundational activities and costs associated with this work category are expected to
16 remain at the base year level. A small incremental adjustment in TY 2028 reflects changes in
17 connection with the compensation modernization initiative. Please refer to the Compensation
18 and Benefits testimony (Ex. SCG-16/SDGE-20).

19 **V. CAPITAL**

20 Capital expenditures within SoCalGas’s GT&S organization are necessary to maintain
21 system safety, reliability, and compliance with federal and state regulations, while maintaining
22 affordability for ratepayers. These investments support a broad set of activities that sustain the
23 critical GT&S operations, address conditions identified through inspections and integrity
24 assessments and respond to external mandates and environmental conditions.

25 For GT operations, capital work includes the replacement of aging transmission pipeline
26 segments; leak repair work; installation, upgrades, and remediation of cathodic protection
27 systems; and construction of transmission pipeline replacements driven by public infrastructure
28 improvements, including street and highway widening projects. These investments also support
29 climate- and geohazard-related mitigation projects, including activities that address erosion,
30 subsidence, slope movement, and loss of cover, as well as construction practices required to
31 comply with methane reduction requirements. Additional capital expenditures are required to

1 maintain and upgrade compressor stations, measurement and regulation stations, and security
2 systems at critical facilities to support safe pressure control, emissions and air quality
3 compliance, effective system monitoring, and protection against unauthorized access. These
4 investments also support the modernization of OT and information systems, including SCADA
5 upgrades, control room software improvements, and cybersecurity enhancements required under
6 federal directives.

7 For gas storage operations, capital work includes well replacements, well abandonments,
8 well workovers, and upgrades to storage compressors to maintain injection and withdrawal
9 capabilities, comply with CalGEM requirements, and replace aging subsurface and surface
10 equipment necessary for safe storage operations.

11 The forecasts presented in this testimony rely primarily on a zero-based methodology,
12 driven by defined project scopes, regulatory obligations, engineering assessments, and known
13 asset conditions. A five-year historical average is used for cost categories that are externally
14 driven or are highly variable workloads such as pipeline relocations, leak repairs, and new
15 transmission pipeline additions. Together, these methods provide a reasonable and
16 well-supported basis for estimating capital requirements across the forecast period. As these
17 activities are essential for mitigating safety risks, maintaining the integrity of the GT&S system,
18 and meeting mandatory regulatory obligations, the associated capital costs are reasonable and
19 fully justified.

20 A key cost driver across GT&S capital projects is the need for specialized engineering,
21 construction, and inspection expertise required to design, install, and place facilities into service,
22 in accordance with applicable safety and regulatory standards. Many projects require skilled
23 labor trained in open-cut construction, precision welding, non-destructive examination,
24 hydrostatic testing, inspection, and commissioning activities. The availability and cost of this
25 specialized workforce are influenced by market conditions, regional labor rates, and competition
26 for qualified contractors, particularly during periods when multiple large-scale infrastructure
27 projects across the state are underway and competing for the same limited resources.

28 Material and equipment costs also materially influence overall project forecasts. GT&S
29 projects require steel pipe, fittings, valves, coatings, instrumentation, and specialized
30 construction equipment that must meet stringent engineering, performance, and safety
31 specifications. Pricing for these materials is subject to market volatility driven by manufacturing

1 capacity, raw material pricing, transportation costs, and supply-chain constraints. In addition,
 2 delays in procurement or material availability can extend project schedules, increase construction
 3 duration, and result in higher total project costs. Together, labor and material requirements
 4 reflect the technical complexity and safety-critical nature of GT&S infrastructure and are
 5 significant drivers of capital cost variability across the forecast period.

6 The following sections describe the capital investment categories that comprise the
 7 GT&S capital request.

8 Table GO-36 summarizes the total capital forecasts for 2026-2031. The particular in-
 9 service date for the capital expenditures that underly these forecasts is provided in workpapers.
 10 Appendix C to this testimony provides a table that illustrates the capital expenditures that are
 11 estimated to have in-service dates between 2026 and TY 2028. Capital expenditures that are in-
 12 service between 2026-2028 will contribute to the TY 2028 revenue requirement request
 13 presented in the Summary of Earnings testimony (Ex. SCG-27). Capital expenditures with in-
 14 service dates in the post-test years (*i.e.*, 2029-2031) are also included in Appendix C. The post-
 15 test year revenue requirement request is included in the Post-Test Year Ratemaking testimony
 16 (Ex. SCG-28).

17 **TABLE GO-36**
 18 **Capital Expenditures Summary of Costs**

GAS TRANSMISSION & STORAGE (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. GT Pipelines New Additions	510	1,348	1,346	1,345	1,345	1,345	1,345
B. GT Pipelines Replacements	47,642	34,314	53,216	75,694	90,284	90,283	90,280
C. GT Leak Repair	16,521	16,212	16,198	16,190	16,188	16,188	16,187
D. GT Pipeline Relocation – Freeway	2,503	2,122	2,121	2,120	2,120	2,120	2,120
E. GT Pipeline Relocation – Franchise/Private/ROW	5,837	8,104	8,098	8,095	8,094	8,093	8,093

GAS TRANSMISSION & STORAGE (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)
F. GT Compressor Stations	22,542	8,424	21,632	26,261	8,924	8,924	8,923
G. GT Cathodic Protection	19,933	11,338	8,752	8,220	21,329	21,328	21,328
H. GT Measurement & Regulation Stations	21,091	5,561	33,999	53,234	63,310	63,309	63,307
I. GT Security & Auxiliary Equipment	2,276	11,313	16,247	17,933	19,066	19,066	19,065
J. GT Technology & Software	11,963	5,370	5,529	2,871	2,542	2,421	3,724
K. GS Compressor Stations	9,874	15,853	5,847	14,255	13,643	29,616	52,054
L. GS Wells	37,563	43,775	50,319	70,420	77,457	85,199	93,716
M. GS Pipelines	34,346	27,774	28,482	25,908	42,183	52,732	54,287
N. GS Purification Equipment	6,554	16,964	12,054	15,606	19,289	23,892	17,813
O. GS Auxiliary Equipment	34,438	49,646	59,251	86,000	80,748	64,816	64,658
P. SIMP Execution	36,307	56,282	59,730	89,342	81,051	81,493	74,790
Q. GT Buildings & Improvements	64	1,304	1,303	1,303	1,303	1,303	1,303
R. GT Capital Tools	1,665	221	221	221	221	221	221
S. GS Capital Tools	227	188	188	188	188	188	188
Total	311,856	316,113	384,533	515,206	549,285	572,537	593,402
Non-Collectible (NC)	281,744	312,239	380,663	511,337	545,417	568,670	589,534
Collectible (CO)	30,112	3,874	3,870	3,869	3,868	3,867	3,868

1 **A. GT Pipelines New Additions (003010.000)**

2 **TABLE GO-37**
 3 **Capital Expenditures – GT Pipelines New Additions**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
A. GT Pipelines New Additions	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GT Pipelines New Additions (Collectible)	485	1,281	1,279	1,278	1,278	1,278	1,278
2. GT Pipelines New Additions (Non-Collectible)	25	67	67	67	67	67	67
Total	510	1,348	1,346	1,345	1,345	1,345	1,345

4 **1. Description**

5 The forecasted capital expenditures for GT Pipelines New Additions are primarily
 6 developed in response to customer requests for new or expanded natural gas service. As new
 7 residential, commercial, and industrial developments emerge, additional transmission
 8 infrastructure may be required to maintain adequate supply to existing customers, while
 9 providing requested service to growing areas. These capital projects strengthen the backbone of
 10 the transmission system and improve system resiliency, capacity, and operational reliability
 11 across the service territory. Additional detailed information supporting this expenditure is
 12 provided in my capital workpapers. *See* SCG-05-CWP, WP #003010. Costs in this category
 13 encompass full lifecycle activities required to plan, design, and construct new transmission
 14 facilities. Activities include route evaluation, engineering design, permitting, environmental
 15 review, and coordination with state and local agencies. The work also involves material
 16 procurement, contractor mobilization, pipeline construction, installation of fittings and valves,
 17 commissioning of pressure regulating stations, and completion of service lines. As part of
 18 construction, mitigation measures must be implemented to address environmental, cultural, and
 19 community impacts, as well as requirements related to traffic control, right-of-way restoration,
 20 and post-construction inspections.

21 Project size and complexity can vary widely. Some new additions involve short pipeline
 22 extensions measuring only a few feet, while others require installing several miles of

1 transmission line. Projects often present logistical and engineering challenges, particularly those
2 located on steep terrain, with limited access, or in environmentally sensitive areas. Weather
3 conditions, seasonal construction windows, and remote locations can further complicate
4 construction sequences and cost management.

5 Overall, the work funded in this forecast supports customer requests for access to the gas
6 transmission system. It contributes to long-term system resilience, provides capacity to meet
7 customer demand, and supports the safe and reliable delivery of natural gas.

8 **2. Forecast Method**

9 The forecast methodology developed for GT Pipelines New Additions uses a five-year
10 average based on historical data from 2021 through 2025. Activities within this cost element are
11 primarily driven by external customer requests, resulting in workload variability from year to
12 year. This approach is appropriate as it captures historical spending patterns while accounting for
13 fluctuations in project timing and scope.

14 **3. Cost Drivers**

15 The underlying cost drivers for GT Pipelines New Additions reflect the customer-driven
16 needs that underpin transmission system expansion projects. One of the primary drivers is
17 customer and load growth. As communities expand and new residential, commercial, or
18 industrial developments are proposed, SoCalGas receives requests for new service connections
19 or additional system capacity. These requests require expansion of pipeline infrastructure to
20 provide adequate supply to growing service areas and to support new construction that requires
21 natural gas for heating, process loads, or other end uses. This customer-driven growth remains a
22 core factor in the need for new transmission pipeline additions.

23 Together, customer demand, project complexity, regulatory compliance requirements,
24 labor and material needs, and emissions reduction obligations drive the capital expenditures
25 associated with GT Pipelines New Additions. These factors reflect the broader operational
26 environment in which transmission system expansion is planned, designed, and constructed.

1 **B. GT Pipeline Replacements (003020.000)**

2 **TABLE GO-38**

3 **Capital Expenditures – GT Pipeline Replacements**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
B. GT Pipeline Replacements	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GT Pipeline Replacements	47,642	34,314	53,216	75,694	90,284	90,283	90,280

4 **1. Description**

5 The forecasted capital expenditures for GT Pipeline Replacements are required to support
 6 the safety and integrity of the transmission system by replacing natural GT pipeline segments
 7 that exhibit deteriorated conditions, are subject to external forces that compromise pipeline
 8 stability, or require modification to meet regulatory obligations. Additional detailed information
 9 supporting this expenditure is provided in my capital workpapers. *See* SCG-05-CWP, WP
 10 #003020.

11 A factor of GT Pipeline Replacements is the transmission pipeline conditions. SoCalGas
 12 operates transmission pipelines up to 36 inches in diameter across a large and diverse service
 13 area extending from the Colorado River in the east to the Pacific Coast in the west, and from
 14 Tulare County in the north to the San Diego County line in the south. The condition of these
 15 assets is routinely evaluated through patrols, in-line inspections, and external assessments. When
 16 corrosion or physical damage is identified, personnel conduct detailed evaluations to determine
 17 whether repair or replacement is required to mitigate risk and meet applicable safety
 18 requirements.

19 Projects within GT Pipeline Replacements may also include pipeline replacements to
 20 address external damage, loss of soil cover due to erosion or agricultural activities, municipal or
 21 right-of-way constraints, and geohazards⁷³ such as slope movement, subsidence, or

⁷³ SoCalGas’s Geohazard Management Program (GMP) is a proactive program that identifies and assesses potential risk to gas infrastructure from geohazards within the SoCalGas and SDG&E service territories. The evaluation process includes (among other activities) desktop analysis to determine areas of potential impact; field reconnaissance and site-specific advanced analysis if further data is needed; assessing risk for site-specific locations and assets; and recommended mitigation or

1 | landslides, -changes in class location resulting from new development. Changes in class location
2 | must be addressed within a 24 month period to maintain compliance with federal pipeline safety
3 | regulations. These projects are undertaken to reduce the potential for pipeline damage, maintain
4 | required access for inspection and maintenance, and support continued safe and compliant
5 | operation of the transmission system. Shallow or exposed pipeline conditions can arise from
6 | erosion, land movement, watercourse migration, or agricultural activities. Projects addressing
7 | these issues typically include adding protective cover or installing concrete revetment mats.
8 | These measures reduce exposure-related risks such as corrosion, third-party interference, and
9 | further instability, thereby maintaining system safety and reliability.

10 | Activities in this category must also comply with environmental requirements for
11 | methane reduction and gas capture established under SB 1371. These projects often require
12 | additional fittings, temporary gas handling equipment, increased contractor support, and complex
13 | construction sequencing, to minimize emissions during replacement activities. These measures
14 | add material, labor, and engineering costs beyond the baseline construction scope.

15 | Project complexity and location also influence costs. Urban projects typically involve
16 | higher costs due to extensive permitting requirements, traffic control planning, road restoration
17 | obligations, coordination with municipalities, and the presence of other utilities within congested
18 | underground corridors. In contrast, rural or remote projects may require specialized construction
19 | equipment, extended crew mobilization, and additional logistical planning because access roads
20 | may be limited or nonexistent. Weather conditions, environmental sensitivities, and rugged
21 | terrain often add to construction challenges and affect the duration and cost of work.

22 | As part of GT Pipeline Replacement activities, pipeline recoating is conducted to address
23 | coating degradation. Although CP systems protect pipelines from corrosion, high-quality coating
24 | remains the primary defense against corrosive soil environments. When coating systems degrade
25 | due to age, soil stress, or construction disturbance, the burden on CP systems increases,
26 | potentially reducing their effectiveness. Replacing a deteriorated coating restores the pipeline's
27 | protective barrier, reduces the current required to maintain effective cathodic protection, and
28 | enhances the overall efficiency and reliability of the corrosion protection system.

monitoring. As part of geohazard management, SoCalGas implemented updated design and construction parameters for new pipeline installations in areas identified as geohazard-prone. See the testimony of GESI (Ex. SCG-03) for more information about the GMP.

1 Regulatory and environmental requirements represent another significant cost driver for
2 the construction of new pipelines. Pipeline construction projects must comply with a broad range
3 of state and federal regulations, which may require environmental permitting, biological surveys,
4 cultural resource assessments, environmental mitigation measures, and ongoing communication
5 with regulatory agencies. These activities impact planning timelines, administrative workloads,
6 and the total cost of project execution.

7 Labor and contractor services also contribute substantially to project costs. Transmission
8 pipeline installation requires skilled labor trained in open-cut construction, welding,
9 hydrotesting, inspection, and commissioning activities. Market conditions, contractor
10 availability, and regional labor rates all influence cost variability. This is particularly relevant in
11 years where multiple infrastructure projects across the state compete for the same specialized
12 resources.

13 Material and equipment costs also play a central role in driving the overall forecast. Steel
14 pipe, fittings, valves, coatings, and specialized machinery must meet specific engineering and
15 safety requirements, and prices for these materials fluctuate based on market dynamics,
16 manufacturing capacity, transportation factors, and supply chain constraints. Delays in material
17 availability may lengthen project timelines and increase total expenditure.

18 **a. Description of RAMP Mitigations**

19 Within this cost category, there are capital costs for risk controls C125 (Pipeline
20 Relocations/Replacement) and C126 (Shallow/Exposed Pipe Remediations) that were presented
21 in the 2025 RAMP Report and are listed in Table GO-39. The activities described above support
22 C125 and C126.

23 Activities that are related to compliance or mandated by CPUC or other agencies are
24 listed in bold, and Appendix B attached to this testimony provides the details regarding these
25 mandates for each control.

TABLE GO-39
RAMP and GRC Risk Control/Mitigation Activities – Capital

GT Pipeline Replacements				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (\$000s)
C125	Pipeline Relocations/ Replacements	106,944	123,861	16,917
C126	Shallow/Exposed Pipe Remediation	62,940	222,680	159,740
TOTAL		169,884	346,541	176,657

b. Description of Selection and Prioritization of RAMP Risk Mitigations

The RAMP risk mitigation efforts are associated with specific actions, such as programs, projects, processes, and utilization of technology and are designed to address a specific safety and/or reliability risk. The Company's selection and prioritization of these RAMP mitigation activities considered many factors when determining if these risk mitigation activities are an effective and worthwhile investment. The ERM process for identifying and assessing system risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

C125 and C126 address manufacturing defects, construction and fabrication issues, weather-related or external forces, third-party damage, and incorrect or inadequate asset records, which are five of the potential drivers to the High-Pressure Gas System risk. If not addressed, these drivers could lead to a risk event with operational, reliability, and environmental potential consequences. In prioritizing this proactive approach, SoCalGas seeks to reduce the likelihood of future risk events, and avoid significantly higher operational, customer, and recovery impacts associated with responding to realized incidents.

The difference in the RAMP forecast for this category results from the use of differing base-year assumptions. RAMP is based on a 2024 forecast, while this GRC applies a zero-based forecast. At the time of the RAMP filing, specific projects were not yet identified, and therefore a zero based forecast was not developed. For the GRC, the forecast is based on known and defined projects that support transmission system operations and reliability. The underlying scope of work and risk control strategy remain unchanged from the RAMP filing.

1 **2. Forecast Method**

2 The forecast method developed for GT Pipeline Replacements is zero-based. SoCalGas
3 evaluated historical expenditures from 2021 through 2025 and considered available information
4 on planned future projects. A zero-based approach was selected as the most appropriate
5 forecasting method based on the projects currently identified, while recognizing that additional
6 activities may emerge over the forecast period. For 2030 and 2031, specific projects are included
7 where a defined need has been identified. However, given that many future activities remain
8 undefined over this longer planning horizon, forecasted expenditures for those years are aligned
9 to the 2029 forecast level. This approach provides the best estimate of anticipated workload by
10 directly aligning expenditures with documented pipeline conditions, applicable regulatory
11 requirements, and supporting engineering assessments. *See* supplemental workpaper, Ex. SCG-
12 05-CWP, WP #003020, for additional details.

13 **3. Cost Drivers**

14 The underlying cost drivers for GT Pipeline Replacements arise from several operational,
15 environmental, and market-based factors directly affecting the scope, schedule, and cost of
16 individual projects. Key cost drivers for projects forecast in this category include safety and
17 reliability risk mitigation, construction complexity, project location, contractor availability,
18 environmental permitting and compliance requirements, and material availability and costs.

19 More than 180 projects have been identified within this cost category for the 2026-2029
20 period. As described in the “Forecast Method” above, for 2030 and 2031, forecasted
21 expenditures are aligned to the 2029 forecast level. Project size and complexity can vary widely,
22 ranging in size and magnitude from a few feet to several miles of replacement. The projects
23 described below are representative of activities included in this cost category:

24 **L1011 & L8109 Crossover Tap Valve Replacement:** This project addresses a safety
25 and operational issue involving two underground natural gas pipelines in the Ventura Hills area.
26 A valve that is intended to fully separate the two pipelines did not function properly, which
27 allowed natural gas to flow into a pipeline that had been shut down during an emergency caused
28 by a mudslide. Gas entering a pipeline that is supposed to be shut off creates a safety risk during
29 emergency response and maintenance activities. The proposed work removes and replaces the
30 faulty valve so the pipelines can be fully and reliably separated when required. This action
31 prevents unintended gas flow during outages, reduces safety risk during emergencies, and

1 supports safe and reliable system operation when pipelines are taken out of service for
2 maintenance or emergency conditions.

3 **L1003 MP 22.32 Carpinteria Creek Exposure Project:** This project is required to
4 address safety and reliability concerns caused by severe storms and flooding. Erosion at the
5 Carpinteria Creek crossing exposed a section of an underground natural gas pipeline, leaving it
6 vulnerable to damage. When a pipeline is exposed, it is at greater risk from future storms, debris,
7 or additional erosion, which could affect safe operation. To maintain service while eliminating
8 this risk, a temporary smaller-diameter pipeline will be installed along an existing highway
9 bridge. At the same time, a new permanent pipeline segment will be constructed beneath the
10 bridge, where it will be protected from future flooding and erosion. Once the new pipeline is in
11 place, the exposed section will be permanently taken out of service. This approach removes the
12 pipeline from a high-risk environment, restores structural protection, and supports the continued
13 safe and reliable operation of the natural gas system in compliance with safety requirements.

14 **L-235 Replace Main Line Valve 2:** This project is needed to address ongoing natural
15 gas leaks from a large shut-off valve on a major underground pipeline. The valve has been
16 inspected regularly, and leaks have repeatedly been detected over many years. Because the leaks
17 are caused by defects in the valve itself, they cannot be permanently repaired. The proposed
18 solution is to remove the faulty valve and replace it with a new one. Replacing the valve
19 eliminates the source of the gas leakage, prevents continued release of natural gas, and restores
20 the pipeline's ability to operate safely and reliably. This work supports public safety, protects the
21 integrity of the system, and meets applicable safety and regulatory requirements.

22 Collectively, the capital requirements for GT Pipeline Replacements reflect the
23 operational, regulatory, and market realities under which SoCalGas must execute these projects.

C. GT Leak Repair (B03020.000)

TABLE GO-40
Capital Expenditures – GT Leak Repair

GAS TRANSMISSION & STORAGE (In 2025 \$)							
C. GT Leak Repair	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GT Leak Repair	16,521	16,212	16,198	16,190	16,188	16,188	16,187

1. Description

The forecasted capital expenditures for GT Leak Repair are required to support the safety and integrity of the transmission system by repairing leaks to meet regulatory obligations governed by CPUC GO 112-F. Additional detailed information supporting these expenditures is provided in my capital workpapers. *See* SCG-05-CWP, WP #B0302. The condition of transmission pipelines is routinely evaluated through patrols, leak surveys, in-line inspections, and external assessments. When leakage is detected, personnel conduct detailed evaluations to determine whether repair or replacement is required to mitigate risk and meet applicable safety requirements.

Transmission leak repairs are critical to the overall safety, reliability, and integrity of the natural gas system because unmitigated leaks can escalate into higher-risk conditions that threaten public safety, system operability, and environmental protection. Transmission pipelines operate at high pressures and serve as the backbone of the delivery system, supplying gas to large geographic areas and downstream distribution networks. Prompt identification and repair of leaks reduce the likelihood of gas accumulation, ignition hazards, service interruptions, and potential infrastructure damage, while also limiting methane emissions and environmental impacts.

Leaks are systematically prioritized based on criteria established in CPUC GO 112-F, which classifies leaks according to their severity, location, and potential consequence. Higher-priority leaks, such as those that pose immediate safety risks to people, property, or critical facilities (Code 1), are addressed immediately, while lower-risk leaks are scheduled for timely repair commensurate with their threat level. This risk-based prioritization framework enables SoCalGas to allocate resources efficiently, address the most consequential conditions

1 first, and maintain compliance with regulatory requirements, while supporting safe and reliable
2 transmission system operations.

3 Leak repair activities involve the planning, design, engineering, procurement, permitting,
4 installation, construction, and closeout processes necessary to remediate leaks on transmission
5 pipelines and associated appurtenances. Leak classification and required response timeframes are
6 governed by CPUC GO 112-F. Leak repair work is a critical component of SoCalGas's pipeline
7 safety program.

8 **a. Description of RAMP Mitigations**

9 Within this cost category, there are capital costs for risk control C113 (Leak Repair) that
10 were presented in the 2025 RAMP Report and are listed in Table GO-41. The activities described
11 above support C113.

12 Activities that are compliance or mandated by CPUC or other agencies are listed in bold,
13 and Appendix B attached to this testimony provides the details regarding these mandates for each
14 control.

15 **TABLE GO-41**
16 **RAMP and GRC Risk Control/Mitigation Activities – Capital**
17

GT Leak Repair				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (\$000s)
C113	Leak Repair	74,864	64,753	(10,111)

18 **b. Description of Selection and Prioritization of RAMP Risk**
19 **Mitigations**

20 The RAMP risk mitigation efforts are associated with specific actions, such as programs,
21 projects, processes, and utilization of technology and are designed to address a specific safety
22 and/or reliability risk. The Company's selection and prioritization of these RAMP mitigation
23 activities considered many factors when determining if these risk mitigation activities are an
24 effective and worthwhile investment. The ERM process for identifying and assessing system
25 risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

26 C113 addresses weather-related/external forces and third-party damage, which are two of
27 the potential drivers to the High-Pressure Gas System risk. If not addressed, these drivers could

1 lead to a risk event resulting in serious injuries, fatalities, infrastructure damage and
2 environmental consequences. The activities in C113 address the regulatory obligations governed
3 by CPUC GO 112-F. By prioritizing this proactive approach, SoCalGas aims to reduce the
4 likelihood of future risk events and avoid significantly greater operational, customer, and
5 recovery impacts associated with incident response. The forecast difference for this category is
6 due to using a five-year average forecast instead of a 2024 forecast. The underlying scope of
7 work and risk control strategy remain unchanged from the RAMP filing.

8 **2. Forecast Method**

9 The forecast methodology developed for GT Leak Repair uses a five-year average based
10 on historical data from 2021 through 2025. Activities within this category are reactive in nature,
11 as leak occurrences cannot be predicted in advance. Because the workload is driven by
12 unplanned system conditions and regulatory requirements for timely repair, year-to-year activity
13 levels naturally fluctuate. Accordingly, the five-year average provides the most representative
14 basis for forecasting expected costs over the GRC period.

15 **3. Cost Drivers**

16 A primary cost driver is the need to address conditions that cause leakage in the
17 transmission system. These conditions often require immediate or near-term action to maintain
18 compliance with state and federal safety regulations and to reduce the likelihood of transmission
19 service interruptions. Additional cost drivers arise from several operational, environmental, and
20 market-based factors that directly affect the scope, schedule, and cost of individual projects such
21 as pipeline location, contractor availability, environmental permitting and compliance
22 requirements, and material and equipment availability and costs. Details related to these drivers
23 are described above in GT Pipeline Replacements.

D. GT Pipeline Relocation – Freeway (003030.000)

**TABLE GO-42
Capital Expenditures – GT Pipeline Relocation – Freeway**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
D. GT Pipeline Relocation – Freeway	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GT Pipeline Relocation – Freeway	2,503	2,122	2,121	2,120	2,120	2,120	2,120

1. Description

The forecasted capital expenditures for GT Pipeline Relocation – Freeway are required to support mandated relocations of SoCalGas transmission facilities when external agencies direct modifications to accommodate public infrastructure improvements. The scope of this work is defined by utility agreements with state and local agencies requiring pipeline adjustments when planned freeway construction activities conflict with existing SoCalGas assets. Additional detailed information supporting these expenditures is provided in my capital workpapers. *See Ex. SCG-05-CWP, WP #003030.*

Freeway-related relocation projects within SoCalGas’s service territory are initiated by the California Department of Transportation (Caltrans). When Caltrans determines that an existing transmission pipeline or related facility interferes with a planned freeway construction or reconstruction project, Caltrans formally notifies SoCalGas and requests relocation of the affected assets. These requests may involve rerouting pipelines that cross beneath or above freeway structures, adjusting pipeline alignments within Caltrans rights-of-way, or modifying aboveground facilities that would otherwise hinder the progress of a Caltrans project.

Transmission-grade pipes, valves, fittings, protective materials, and specialized construction equipment are subject to fluctuations in commodity markets and supply chain conditions, which contribute to project costs. Price volatility in steel and other materials can significantly affect the total cost of a relocation project, particularly when Caltrans schedules require procurement during periods of elevated market pricing or shortened lead times.

1 The timing, scope, and sequence of these relocations are driven by Caltrans project
2 schedules and budget cycles, which place these expenditures outside of SoCalGas's control.
3 Once Caltrans issues a relocation directive, SoCalGas is obligated to complete the required
4 modifications within the specified timeframe to avoid impeding freeway construction activities
5 and to comply with the terms of established utility agency agreements. Failure to complete this
6 work promptly could delay Caltrans's projects and expose SoCalGas to contractual, operational,
7 and regulatory risks.

8 Pipeline relocation work, particularly within freeway corridors, requires specialized
9 crews with advanced technical qualifications. These qualifications include certified welders,
10 operators trained to work in constrained right-of-way areas, and contractors experienced with
11 high-risk construction adjacent to active transportation infrastructure. The pool of contractors
12 with the expertise required for transmission pipeline relocation is limited, and demand for these
13 services often increases when multiple public infrastructure projects occur simultaneously. These
14 market conditions influence labor availability and cost and may lead to higher bid pricing.

15 **2. Forecast Method**

16 The forecast method developed for GT Pipeline Relocation – Freeway uses a five-year
17 average based on historical data from 2021 through 2025. Activities within this cost category are
18 primarily driven by Caltrans project schedules and budget cycles, resulting in workload
19 variability from year to year. This approach is appropriate as it captures historical spending
20 patterns while accounting for fluctuations in project timing and scope.

21 **3. Cost Drivers**

22 The underlying cost drivers for GT Pipeline Relocation – Freeway are primarily dictated
23 by external agency requirements, construction constraints, and market-based factors that
24 influence the overall cost and timing of these projects. Because these relocations occur only
25 when directed by Caltrans, the schedule, sequencing, and scope of work originate from Caltrans
26 planning and budget cycles. Once Caltrans identifies a conflict between a planned freeway
27 project and an existing SoCalGas transmission pipeline, SoCalGas must perform the relocation
28 work within the specified timeframe. These external dependencies create cost drivers that fall
29 outside the Company's operational control and may require rapid mobilization, extended
30 coordination, or accelerated construction.

The cost of GT Pipeline Relocation – Freeway projects is influenced by several factors inherent to working within freeway corridors. These include highly constrained work environments, the need for extensive coordination with Caltrans engineers and construction personnel, requirements for specialized traffic control, and limitations on work hours due to freeway closure windows or traffic management plans. Construction activities in these settings often require additional engineering review, more complex pipeline reroute design, and specialized construction methods to reduce disruption to freeway operations. These elements increase both the duration and cost of the work relative to typical pipeline construction.

Environmental compliance requirements also influence the cost and complexity of these projects. Activities associated with methane reduction under SB 1371 require additional planning, equipment, and construction steps to capture or minimize gas releases during pipeline shutdowns, tie-ins, and cutouts. These requirements increase the number of fittings, temporary systems, and contractor personnel involved, resulting in additional costs beyond the baseline construction scope.

E. GT Pipeline Relocation – Franchise/Private/ROW (003040.000)

**TABLE GO-43
Capital Expenditures – GT Pipeline Relocation – Franchise/Private/ROW**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
E. GT Pipeline Relocation – Franchise/Private/ROW	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GT Pipeline Relocation – Franchise, Private, ROW (Collectible)	1,868	2,593	2,591	2,591	2,590	2,589	2,590
2. GT Pipeline Relocation – Franchise, Private, ROW (Non-Collectible)	3,968	5,511	5,507	5,504	5,504	5,504	5,503
Total	5,837	8,104	8,098	8,095	8,094	8,093	8,093

1 **1. Description**

2 The forecasted capital expenditures for GT Pipeline Relocation – Franchise/Private/ROW
3 are required to support mandated relocations or modifications of existing SoCalGas transmission
4 facilities when directed by municipalities, private property owners, or other external agencies.
5 Such requirements are defined under franchise agreements with city and county governments, as
6 well as various ROW agreements and private easements. Relocations occur when existing
7 pipelines conflict with planned construction or reconstruction activities, including street
8 widening or resurfacing, storm drain or culvert installations, and municipal water, sewer, or
9 utility corridor improvements. Additional detailed information supporting this expenditure is
10 provided in my capital workpapers. *See Ex. SCG-05-CWP, WP #003040.*

11 Franchise/Private/ROW relocation projects are externally initiated, and their timing and
12 scope are determined entirely by the requesting agency, entity, or property owner. As a result,
13 these projects are difficult to forecast because they depend on local capital improvement plans,
14 private development schedules, and municipal budget approvals. When a relocation request is
15 issued, SoCalGas is obligated to complete its portion of the work within a time frame aligned
16 with the external construction schedule. This coordination is necessary to avoid delaying city
17 projects, utility corridor realignments, or private development activities, as well as to meet the
18 Company’s contractual obligations under relevant franchise and right-of-way agreements. The
19 nature of this work often requires extensive coordination with city engineers, public works
20 departments, utility planners, and private developers. Scope can vary significantly depending on
21 the extent of the conflict with existing facilities, the complexity of the municipal or private
22 project, and the physical characteristics of the construction area. Work may involve lowering or
23 shifting pipeline alignments to clear new grades, relocating pipelines out of conflict zones,
24 modifying adjacent appurtenances, or conducting tie-in activities within tight or restricted
25 spaces. These conditions frequently lead to increased engineering review, more constrained
26 construction access, and the need for specialized construction techniques tailored to urban or
27 semiurban environments.

28 SB 1371 also plays a factor in this forecasted capital expenditure. Under SB 1371,
29 SoCalGas must implement methane capture or cross-compression methods during pipeline
30 blowdowns associated with relocation activities. These requirements introduce additional
31 fittings, temporary compression equipment, and contractor personnel dedicated to gas handling,

1 which increases both the duration and cost of the work compared to traditional methods.
2 Compliance with environmental, air quality, and public safety regulations adds engineering and
3 operational considerations to project planning.

4 Additionally, franchise and ROW relocation projects often occur in congested corridors
5 where multiple utilities are located nearby. These areas present heightened operational risk and
6 require careful planning to avoid interference with other underground infrastructure. Traffic
7 control, nightwork requirements, environmental compliance, and coordination with municipal
8 inspectors can further impact project cost and duration.

9 Overall, the forecasted capital expenditures for GT Pipeline Relocation
10 Franchise/Private/ROW reflect the projects' mandatory, externally driven nature. The work is
11 required to maintain compliance with franchise and right-of-way agreements, accommodate city
12 and county infrastructure development, support private construction activity, and maintain safe
13 and reliable operation of the transmission system.

14 **2. Forecast Method**

15 The forecast method developed for GT Pipeline Relocation – Franchise/Private/ROW
16 uses a five-year average based on historical data from 2021 through 2025. Activities within this
17 cost element are primarily driven by municipalities, counties, private property owners, and other
18 external entities, resulting in workload variability from year to year. This approach is appropriate
19 as it captures historical spending patterns while accounting for fluctuations in project timing and
20 scope.

21 **3. Cost Drivers**

22 The underlying cost drivers for GT Pipeline Relocation – Franchise/Private/ROW stem
23 from a combination of external directives, construction complexity, regulatory requirements, and
24 coordination demands that directly affect project cost and schedule. These relocations are
25 requested by municipalities, counties, private property owners, or other external entities, and
26 often come with accelerated timelines tied to local capital improvement plans, street
27 reconstruction schedules, or private development milestones. Because SoCalGas must complete
28 relocation work in alignment with these external construction activities, the Company has limited
29 control over project timing, sequencing, or workload distribution, which contributes to cost
30 variability.

1 Significant drivers of cost for this category include labor and contractor services,
 2 materials and equipment requirements, and regulatory compliance requirements. Together, these
 3 factors form the primary cost drivers for GT Pipeline Relocation – Franchise/Private/ROW. They
 4 reflect the mandatory, externally governed nature of the work, the technical complexity of
 5 relocating transmission facilities in urban or constrained environments, and the regulatory,
 6 material, and labor conditions under which the projects must be executed.

7 **F. GT Compressor Stations (003050.000)**

8 **TABLE GO-44**
 9 **Capital Expenditures – GT Compressor Stations**

10

GAS TRANSMISSION & STORAGE (In 2025 \$)							
F. GT Compressor Stations	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GT Compressor Stations	22,542	8,424	21,632	26,261	8,924	8,924	8,923

11 **1. Description**

12 The forecasted capital expenditures for GT Compressor Stations support ongoing capital
 13 activities, including installing, replacing, and refurbishing equipment required to maintain the
 14 safe and reliable operation of the transmission system. Further details related to GT Compressor
 15 Stations are provided in my capital workpaper. *See Ex. SCG-05-CWP, WP #003050.*

16 SoCalGas operates seven compressor stations strategically located throughout its service
 17 territory. These facilities are essential to maintaining transmission system pressures and enabling
 18 the delivery of natural gas to storage fields, high-volume industrial and electric generation
 19 customers, and distribution systems that serve residential and commercial loads. The operational
 20 availability of these stations is fundamental to supporting statewide energy reliability,
 21 maintaining system throughput, and meeting downstream demand during both routine operations
 22 and peak system conditions. Compressor station performance affects multiple internal functions,
 23 including gas control, system operations, maintenance, and storage operations, making sustained
 24 capital investment critical.

25 Capital work at compressor stations has several primary drivers. It is primarily driven by
 26 regulatory requirements, minimizing unplanned equipment outages, and the need to maintain

1 compliance with air quality regulations, such as rules adopted by the SCAQMD and comparable
2 agencies in other jurisdictions. These rules may require upgrades to engine controls, exhaust
3 systems, or related components to comply with emissions limits, monitoring requirements, or
4 recording standards. Capital activities typically include planning, installation, construction,
5 testing, and project closeout for upgrades such as pipeline segment replacements within station
6 boundaries, valve replacements, control system enhancements, and refurbishment of auxiliary
7 systems that support engine operation.

8 The compressor stations' age is another factor for this forecasted capital expenditure.
9 Several compressor stations in SoCalGas's system have been in service for decades, and the age
10 of the underlying equipment contributes to an increasing need for capital investment to maintain
11 reliability, reduce the risk of unplanned outages, and support continued regulatory compliance.
12 Older facilities often require more extensive upgrades to foundational mechanical systems,
13 including cooling systems, lube oil systems, fuel gas supply systems, and structural supports for
14 rotating equipment. These upgrades are necessary to maintain safe operations and support the
15 installation of control technologies required by environmental and safety regulations.

16 Compressor stations also rely on specialized, high-cost mechanical and electrical
17 components, which represent another major cost driver. Equipment such as large horsepower
18 compressor engines, turbines, transmitters, cooling systems, and electronic control systems
19 require periodic replacement or refurbishment based on hours of operation, manufacturer
20 recommendations, or performance deterioration. Many of these components must be custom-
21 fabricated, procured from limited suppliers, or installed by technicians with highly specialized
22 skill sets.

23 In addition, compressor station operations must meet regulatory expectations, including
24 requirements for monitoring, emissions reporting, and technologies that support operating limits.
25 Meeting these requirements may require modernizing instrumentation, replacing outdated PLCs,
26 or installing updated safety shutdown and alarm systems. These activities are required to
27 maintain reliable day-to-day station performance and comply with regulatory obligations.

28 Overall, the capital expenditure forecasted for GT Compressor Stations reflects the
29 essential activities necessary to support safe and reliable compressor station operations, address
30 age-related equipment degradation, comply with air quality regulations, and maintain the
31 operational performance of the transmission system.

a. Description of RAMP Mitigations

Within this cost category, there are capital costs for risk control C136 (Compressor Stations – Capital) that were presented in the 2025 RAMP Report and is listed in Table GO-45. The activities described above support C136.

Activities that are compliance or mandated by CPUC or other agencies are listed in bold, and Appendix B attached to this testimony provides the details regarding these mandates for each control.

**TABLE GO-45
RAMP and GRC Risk Control/Mitigation Activities – Capital**

GT Compressor Stations				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (\$000s)
C136	Compressor Stations – Capital	104,608	53,032	(51,576)

b. Description of Selection and Prioritization of RAMP Risk Mitigations

The RAMP risk mitigation efforts are associated with specific actions, such as programs, projects, processes, and utilization of technology and are designed to address a specific safety and/or reliability risk. The Company’s selection and prioritization of these RAMP mitigation activities considered many factors when determining if these risk mitigation activities are an effective and worthwhile investment. The ERM process for identifying and assessing system risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

C136 addresses stress corrosion cracking, construction/fabrication issues, weather-related/external forces, and equipment failure, which are four of the potential drivers to the High-Pressure Gas System risk. If not addressed, these drivers could lead to a risk event resulting in serious injuries, fatalities, infrastructure damage, and environmental consequences. In prioritizing a proactive approach with these activities, SoCalGas seeks to reduce the likelihood of future risk events, and avoid significantly higher operational, customer and recovery impacts associated with responding to realized incidents.

1 The forecast difference for this category is due to using a zero-based forecast instead of a
2 2024 forecast. The underlying scope of work and risk control strategy remain unchanged from
3 the RAMP filing.

4 2. Forecast Method

5 The forecast method developed for GT Compressor Stations is zero-based. SoCalGas
6 evaluated historical expenditures from 2021 through 2025 and considered available information
7 on planned future projects. A zero-based approach was selected as the most appropriate
8 forecasting method based on the projects currently identified, while recognizing that additional
9 activities may emerge over the forecast period. For 2030 and 2031, specific projects are included
10 where a defined need has been identified. However, given that many future activities remain
11 undefined over this longer planning horizon, forecasted expenditures for those years are aligned
12 to the 2029 forecast level. This approach provides the best estimate of anticipated workload by
13 directly aligning projected expenditures with documented compressor conditions and applicable
14 regulatory requirements. *See* supplemental workpaper, Ex. SCG-05-CWP, WP #003050, for
15 calculation details.

16 3. Cost Drivers

17 The underlying cost drivers for GT Compressor Stations stem from operational,
18 regulatory, and equipment-related factors that directly affect compressor station reliability and
19 the continued safe performance of the transmission system. Regulatory requirements drive the
20 need to maintain system reliability and system throughput. Sustained capital investment is
21 therefore necessary to keep these facilities operational and able to support continuous delivery.

22 More than 70 projects have been identified within this cost category for the 2026-2029
23 period. As described in the Forecast Method above, for 2030 and 2031, forecasted expenditures
24 are aligned to the 2029 forecast level. Project costs vary widely based on scope and complexity,
25 ranging from thousands to millions of dollars. The projects described below are representative of
26 activities included in this cost category:

27 **North Needles Install Check Valves:** This project is needed to address safety and
28 operational risks at the North Needles Compressor Station related to potential backflow and
29 unstable operations during unit transitions. The proposed solution is the installation of check
30 valves in the discharge lines of Units 1, 2, and 3 to allow safe switching between units and to
31 prevent reverse flow through bypass valves under high differential pressure conditions. This

1 work mitigates the risk of equipment damage, unintended gas flow, and unsafe operating
2 conditions, thereby improving system reliability and operational safety.

3 **Wheeler Ridge Compressor Station Unit K501 Selective Catalytic Reduction (SCR)**

4 **Replacement:** This project is required to address degraded emissions performance on Unit K501
5 at the Wheeler Ridge Compressor Station, where elevated NOx levels have been identified due
6 to the existing SCR catalyst reaching the end of its service life. The proposed solution is the
7 replacement of the SCR catalyst and associated seals to restore effective NOx reduction within
8 the engine exhaust system. This work mitigates the risk of air permit non-compliance and
9 potential operational restrictions, while supporting continued reliable operation of Unit K501,
10 which is critical to maintaining system throughput and integrity.

11 **Wheeler Ridge SCR K301 Replacement:** This project is required to address the risk of
12 emissions non-compliance associated with the existing SCR system on Unit K301, whose
13 obsolete catalyst panels can no longer be replaced or maintained. The proposed solution is full
14 replacement of the current SCR system with a new, updated system to restore effective emissions
15 control. This action mitigates the risk of exceeding regulatory limits and a potential indefinite
16 unit shutdown, while supporting continued safe, compliant, and reliable operation of Unit K301.

17 Collectively, the cost drivers discussed above reflect the operational demands of
18 compressor station performance, the regulatory environment governing air emissions, the need
19 for safety, the market conditions impacting material and contractor availability, and the
20 challenges associated with aging infrastructure. The forecasted capital expenditures for GT
21 Compressor Stations are therefore necessary to maintain safe and reliable operation, support
22 system throughput, and comply with applicable regulatory and environmental requirements.

1 **G. GT Cathodic Protection (003060.000)**

2 **TABLE GO-46**
 3 **Capital Expenditures – GT Cathodic Protection**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
G. GT Cathodic Protection	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GT Cathodic Protection	19,933	11,338	8,752	8,220	21,329	21,328	21,328

4 **1. Description**

5 The forecasted capital expenditures for GT CP support the installation, replacement, and
 6 enhancement of CP systems, which are critical to maintaining the integrity of transmission
 7 pipelines and protecting them from external corrosion. CP is a corrosion control method that uses
 8 pipelines as the cathodic element in an electrochemical cell, preventing the metal loss that can
 9 occur when buried steel is exposed to corrosive soil environments. The equipment and activities
 10 funded through these capital expenditures are necessary not only to protect company assets, but
 11 also to comply with federal and state pipeline safety regulations requiring effective corrosion
 12 control, including 49 CFR §192.463.⁷⁴ Additional details supporting these expenditures are
 13 provided in my capital workpapers. *See* Ex. SCG-05-CWP, WP #003060.

14 GT CP work involves planning, engineering, installation, and project closeout for several
 15 types of corrosion mitigation infrastructure. A significant portion of the capital program involves
 16 installing or replacing rectifiers and deep well anode beds, which provide an impressed current
 17 required to maintain proper CP levels along transmission pipelines. These systems are
 18 foundational for maintaining adequate pipe-to-soil potentials and for supporting long-term
 19 corrosion protection across wide geographic areas.

20 Another component of this program is the installation of remote power sources. These
 21 remote power sources enable CP systems to operate in areas where access to traditional electrical
 22 infrastructure is limited or impractical. These installations provide greater location flexibility for
 23 CP equipment and support optimal placement of anode beds to enhance corrosion mitigation

⁷⁴ 49 CFR § 192.463 (External corrosion control: Cathodic protection).

1 performance. Remote power installations are particularly useful in rural areas, environmentally
2 sensitive locations, and regions with challenging terrain.

3 In addition to physical installations, the forecast includes expenditures for AC modeling,
4 surveys, and the construction of AC mitigation systems. Transmission lines often share corridors
5 with high-voltage electric transmission infrastructure, which can induce AC voltages on
6 pipelines. Modeling and mitigation are required to address these conditions, which may
7 accelerate corrosion or pose safety concerns during maintenance activities. Mitigation measures,
8 such as gradient control mats or zinc ribbon grounding, are designed and installed to reduce these
9 risks and maintain compliance with applicable standards.

10 Aging infrastructure is also another factor for this forecasted capital expenditure and
11 contributes further to investment needs. Many CP system components installed decades ago are
12 now reaching or have reached the end of their useful life. Deep well anode beds may require
13 reconstruction, rectifiers may require replacement due to obsolescence or declining output, and
14 older bonding or test point systems may no longer function reliably. As these systems age, the
15 frequency and scale of required capital improvements increase, placing upward pressure on total
16 program costs.

17 Overall, the capital forecast for GT Cathodic Protection reflects the ongoing needs of a
18 large and geographically diverse transmission pipeline system. Corrosion is a long-term,
19 progressive threat, and proactive CP investments reduce the likelihood of pipeline failures,
20 service disruptions, and elevated long-term costs. These investments are necessary to maintain
21 compliance with federal and state pipeline safety regulations, protect critical infrastructure
22 assets, and sustain long-term system reliability.

23 a. Description of RAMP Mitigations

24 Within this cost category, there are capital costs for risk control C104 (Cathodic
25 Protection – Capital) that were presented in the 2025 RAMP Report and are listed in Table GO-
26 47. The activities described above support C104.

27 Activities that are compliance or mandated by CPUC or other agencies are listed in bold,
28 and Appendix B attached to this testimony provides the details regarding these mandates for each
29 control.

TABLE GO-47
RAMP and GRC Risk Control/Mitigation Activities – Capital

GT Cathodic Protection				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (\$000s)
C104	Cathodic Protection – Capital	91,936	72,205	(19,731)

b. Description of Selection and Prioritization of RAMP Risk Mitigations

The RAMP risk mitigation efforts are associated with specific actions, such as programs, projects, processes, and utilization of technology and are designed to address a specific safety and/or reliability risk. The Company’s selection and prioritization of these RAMP mitigation activities considered many factors when determining if these risk mitigation activities are an effective and worthwhile investment. The ERM process for identifying and assessing system risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

C104 addresses external corrosion, internal corrosion, manufacturing defects, external forces, and equipment failure, which are five of the potential drivers to the High-Pressure Gas System risk. If not addressed, these drivers could lead to a risk event with potential consequences for customers, including serious injuries or fatalities, operational and reliability impacts, and environmental impacts. The CP projects in this category maintain system safety and reliability by protecting against corrosion and reducing the likelihood of a potential leak or other risk event. In prioritizing this proactive approach, SoCalGas seeks to reduce the likelihood of future risk events, and avoid significantly higher operational, customer and recovery impacts associated with responding to realized incidents.

The forecast difference for this category is due to using a zero-based forecast instead of a 2024 forecast. The known forecasted costs for projects in this category are expected to be lower than the historical spending levels in 2028-2031, which has led to a variance from the RAMP filing. The underlying scope of work and risk control strategy remain unchanged from the RAMP filing.

1 **2. Forecast Method**

2 The forecast method developed for GT CP is zero-based. SoCalGas evaluated historical
3 expenditures from 2021 through 2025 and considered available information on planned future
4 projects. A zero-based approach was selected as the appropriate forecasting method based on the
5 projects currently identified, while recognizing that additional activities may emerge over the
6 forecast period. For 2030 and 2031, specific projects are included where a defined need has been
7 identified; however, given that many future activities remain undefined over this longer planning
8 horizon, forecasted expenditures for those years are aligned to the 2029 forecast level. This
9 approach provides the best estimate of capital requirements by directly aligning projected
10 expenditures with documented cathodic protection needs, applicable regulatory requirements,
11 and supporting engineering evaluations. *See* supplemental workpaper, Ex. SCG-05-CWP, WP
12 #003060, for calculation details.

13 **3. Cost Drivers**

14 The underlying cost drivers for GT CP reflect the technical, operational, and
15 environmental factors that influence the scope and cost of corrosion control activities across the
16 transmission system. The projects in this category are driven by a need to protect transmission
17 pipelines against the effects of corrosion.

18 More than 70 projects have been identified within this cost category for the 2026-2029
19 period. As described in the Forecast Method above, for 2030 and 2031, forecasted expenditures
20 are aligned to the 2029 forecast level. Project costs vary widely based on scope and complexity,
21 ranging from thousands to millions of dollars. The projects described below are representative
22 of activities included in this cost category:

23 **L3000 MP 74.49 Deep Well Anode & CP Engine:** This project is required to correct an
24 out-of-tolerance cathodic protection condition on Line 3000 at Milepost 74.49 caused by a
25 failing anode well and aging CP power equipment that no longer meets operations standards. The
26 proposed solution is to complete CP upgrades through installation of a new anode well and
27 replacement of the CP engine, along with the necessary engineering, permitting, and construction
28 activities. This work mitigates the risk of corrosion-related damage, restores required CP
29 performance, maintains regulatory compliance, and protects the long-term integrity of the
30 pipeline.

L1181 MP 4.93 Deep Well and Rectifier Installation: This project is required to address insufficient cathodic protection performance on Line 1181 at Milepost 4.93, which poses a risk to long-term pipeline integrity. The proposed solution is installation of a 500-foot distributed wire anode system and rectifier, including associated trenching, aboveground facilities, and electrical connections. This work mitigates corrosion risk by improving CP effectiveness, supports continued regulatory compliance, and protects the long-term integrity and reliability of the pipeline.

L3000 MP 37.60 CPS: This project is required to address pipe degradation and the lack of an existing cathodic protection installation on Line 3000 at Milepost 37.60, which creates an increased risk of corrosion. The proposed solution is installation of a dedicated cathodic protection system, including a new deep-well anode, rectifier, pipeline tap, protective cage, and a self-contained power source. This work mitigates corrosion-related risk by restoring effective cathodic protection, supports long-term pipeline integrity, and maintains continued compliance with corrosion control requirements.

Collectively, the labor, material, and contractor requirements across the GT CP program is critical to preserving pipeline integrity, reducing long-term corrosion risk, supporting RAMP-related mitigation commitments, and maintaining compliance with applicable regulatory requirements.

H. Measurement & Regulation Stations (003080.000)

**TABLE GO-48
Expenditures – GT Measurement & Regulation Stations**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
H. GT Measurement & Regulation Stations	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GT Measurement & Regulation Stations	21,091	5,561	33,999	53,234	63,310	63,309	63,307

1. Description

The forecasted capital expenditures for GT Measurement and Regulation (M&R) Stations support the continued safe and reliable operation of the transmission system by funding the

1 installation, reconstruction, and modernization of large measurement and station assemblies that
2 serve transmission-level customers, as well as pressure-limiting stations located throughout the
3 transmission network. These facilities house equipment that regulates flow and controls pipeline
4 pressures, using valves and pressure-limiting devices that can be operated either locally by
5 personnel or remotely via the SCADA. Additional detailed information supporting this
6 expenditure is provided in my capital workpapers. *See* Ex. SCG-05-CWP, WP #003080.

7 GT M&R Stations incorporate a wide range of specialized equipment necessary for
8 precise measurement, pressure regulation, and system monitoring. These components include
9 PLCs, pressure transmitters, uninterruptible power supply systems, temperature sensors, gas
10 quality instrumentation, communication modules, and user interface technologies that support
11 both automated and operator-driven system management. Collectively, these systems form the
12 first line of defense against over-pressurization events by automatically adjusting or limiting
13 pressure during abnormal conditions. In addition, these stations play an increasingly important
14 role in enabling the integration of renewable natural gas (RNG) by providing accurate gas-
15 quality monitoring and reliable pressure control for new producers interconnecting to the
16 transmission system.

17 Capital activities within this category also include the planning, engineering, installation,
18 construction, and closeout associated with upgrading or replacing equipment at producer
19 interconnection vessels, large meters, M&R stations, Company-owned facilities serving
20 customer meter set assemblies (MSA), and control valve stations throughout the transmission
21 system. Many of these facilities contain equipment that has been in service for decades, and
22 aging infrastructure continues to drive the need for enhanced capital investments. As components
23 deteriorate or become obsolete, system reliability and functionality can be compromised,
24 requiring the installation of modern replacement systems that incorporate newer technologies,
25 improved sensing capabilities, and enhanced control logic.

26 These upgrades are necessary to maintain compliance with applicable safety,
27 measurement accuracy, and operational standards, and support system demand changes.
28 Enhanced control systems support more accurate gas flow monitoring, more precise pressure
29 control, and improved integration with SCADA, which collectively improve overall system
30 responsiveness and situational awareness. In addition, modern communication and data
31 management platforms enable more frequent monitoring, more detailed reporting, and faster

1 detection of abnormal conditions, supporting both operational performance and regulatory
2 compliance.

3 The forecasted capital expenditure for GT M&R Stations reflects the growing complexity
4 of transmission system operations and the need to sustain a high level of reliability. These
5 investments address aging infrastructure, regulatory requirements, the need for more advanced
6 monitoring and control technologies, and the demands associated with evolving gas supply
7 characteristics, including RNG. Together, these factors support the safe and efficient operation of
8 SoCalGas's transmission network and the ability to meet customer and system needs across the
9 service territory.

10 **a. Description of RAMP Mitigations**

11 Within this cost category, there are capital costs for risk control C151 (Measurement &
12 Regulation – Capital) that were presented in the 2025 RAMP Report and are listed in Table GO-
13 49. The activities described above support C151.

14 Activities that are compliance or mandated by CPUC or other agencies are listed in bold,
15 and Appendix B attached to this testimony provides the details regarding these mandates for each
16 control.

17 **TABLE GO-49**
18 **RAMP and GRC Risk Control/Mitigation Activities – Capital**
19

GT Measurement and Regulation Stations				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (\$000s)
C151	Measurement & Regulation Station – Capital	253,452	243,160	(10,292)

20 **b. Description of Selection and Prioritization of RAMP Risk**
21 **Mitigations**

22 The RAMP risk mitigation efforts are associated with specific actions, such as programs,
23 projects, processes, and utilization of technology and are designed to address a specific safety
24 and/or reliability risk. The Company's selection and prioritization of these RAMP mitigation
25 activities considered many factors when determining if these risk mitigation activities are an
26 effective and worthwhile investment. The ERM process for identifying and assessing system
27 risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

1 C151 projects address equipment failure at transmission measurement and regulation
2 stations. If not addressed, these drivers could lead to a risk event resulting in serious injuries,
3 fatalities, reliability issues and environmental consequences. In prioritizing a proactive approach
4 with these projects, SoCalGas seeks to reduce the likelihood of future risk events, and avoid
5 significantly higher operational, customer and recovery impacts associated with responding to
6 realized incidents.

7 The forecast difference for this category is due to using a zero-based forecast instead of a
8 2024 forecast. The known forecasted costs for projects in this category are expected to be lower
9 than the historical costs from 2024 which was used to forecast for the RAMP filing. The
10 underlying scope of work and risk control strategy remain unchanged from the RAMP filing.

11 2. Forecast Method

12 The forecast method developed for GT M&R is zero-based. SoCalGas evaluated
13 historical expenditures from 2021 through 2025 and considered available information on planned
14 future projects. A zero-based approach was selected as the most appropriate forecasting method
15 based on the projects currently identified, while recognizing that additional activities may
16 emerge over the forecast period. For 2030 and 2031, specific projects are included where a
17 defined need has been identified. However, given that many future activities remain undefined
18 over this long planning horizon, forecasted expenditures for those years are aligned to the 2029
19 forecast level. This approach provides the best estimate of anticipated workload by directly
20 aligning projected expenditures with documented measurement and regulation asset conditions
21 and applicable regulatory requirements. *See* supplemental workpaper, Ex. SCG-05-CWP, WP
22 #003080, for calculation details.

23 3. Cost Drivers

24 The underlying cost drivers for GT M&R Stations stem from multiple operational,
25 regulatory, and system-performance requirements that influence the scale and complexity of
26 capital work at these facilities. A significant cost driver is compliance with federal and state
27 safety regulations, which require utility operators to maintain accurate measurement, pressure
28 control, and overpressure protection equipment. To meet standards, M&R facilities must be
29 upgraded to incorporate enhanced safety features, more reliable pressure-limiting technology,
30 and improved monitoring systems that support safe operations and reduce risks to the public and
31 employees. These compliance-driven upgrades often involve modernizing control systems,

1 installing more advanced actuators and sensors, and improving the reliability and automation
2 capabilities of pressure-regulating equipment.

3 More than 60 projects have been identified within this cost category for the 2026-2029
4 period. As described in the Forecast Method above, for 2030 and 2031, forecasted expenditures
5 are aligned to the 2029 forecast level. Project costs vary widely based on scope and complexity,
6 ranging from thousands to millions of dollars. The projects described below are representative of
7 activities included in this cost category:

8 **Westside Station Redesign:** The Westside Station Upgrade project addresses safety,
9 reliability, and accessibility concerns associated with aging infrastructure currently in service.
10 The station contains antiquated controls, valves, piping, and communications equipment, with
11 unsupported components and an increased potential for leaks. Existing liquid knock-out vessels
12 are partially buried and cannot be fully inspected due to their configuration, including multiple
13 vessel penetrations through concrete vault walls and placement within deep vaults. Heavy vault
14 covers limit safe access, and a persistent wet, damp environment has resulted in accelerated
15 corrosion. This station is located within a residential neighborhood, further emphasizing the need
16 for system modernization. This project includes an engineered redesign to upgrade station
17 valves, controls, communications systems, clamp-on meters, vaults, and knock-out vessels. The
18 proposed improvements will enhance inspections, operational safety, reliability, and regulatory
19 compliance while replacing equipment no longer supported by the manufacturer.

20 **Salt Works Pressure Limiting Station (PLS):** The Salt Works PLS Station project
21 addresses ongoing reliability issues associated with existing underground service valves that are
22 located within the water table and are believed to contribute to internal valve damage. The
23 station is a dual-run configuration. One service valve is currently being replaced, and inspection
24 findings indicate the second run requires similar upgrades. To improve safety, reliability, and
25 maintainability, the project proposes a complete station rebuild that relocates both runs and
26 associated service valves above ground. All work is intended to enhance operational
27 performance while maintaining compliance with applicable regulatory requirements.

28 **Center Road Station Redesign:** This project is required to address reliability and
29 operational performance risks at the Center Road Station associated with aging and outdated
30 station components. The proposed solution is a targeted redesign that includes replacement of the
31 existing drip tank, upgrades from soft element regulators to modern control valves, and

1 replacement of valves, fittings, and associated piping within the existing station footprint. These
 2 improvements mitigate the risk of equipment failure and degraded performance, while
 3 maintaining system integrity and maintaining continued regulatory compliance.

4 The forecasted projects in this category are driven by regulatory obligations, aging
 5 infrastructure, increasing system performance needs, the integration of renewable gas resources,
 6 specialized labor requirements, and the rising cost of materials and advanced technology. These
 7 drivers necessitate proactive capital investment to maintain system reliability, support
 8 operational performance, and comply with evolving safety and measurement standards across the
 9 transmission system.

10 **I. GT Security and Auxiliary Equipment (003090.000)**

11 **TABLE GO-50**
 12 **Capital Expenditures – GT Security and Auxiliary Equipment**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
I. GT Security & Auxiliary Equipment	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GT Security & Auxiliary Equipment	2,276	11,313	16,247	17,933	19,066	19,066	19,065

13 **1. Description**

14 The forecasted capital expenditures for GT Security and Auxiliary Equipment support a
 15 broad range of facility upgrades necessary to maintain safe and reliable gas transmission
 16 operations. These expenditures primarily address the replacement, rehabilitation, and
 17 modernization of auxiliary systems that are essential for day-to-day facility functionality,
 18 including cooling systems, plant air systems, water systems, pumping equipment, and related
 19 support infrastructure at major transmission facilities. These systems enable reliable equipment
 20 operation, support emergency response capabilities, and maintain acceptable operating
 21 conditions for both personnel and critical assets. Additional detailed information supporting this
 22 expenditure is provided in my capital workpapers. *See Ex. SCG-05-CWP, WP #003090.*

23 Many auxiliary systems serving transmission facilities are aging or approaching the end
 24 of their useful lives and were not designed to accommodate current operational demands or
 25 modern performance expectations. Replacement and upgrade activities frequently involve

1 equipment-intensive installations, specialty fabrication, and coordinated construction sequencing
2 that must be performed within constrained operating environments. In many cases, work must be
3 coordinated with planned outages to minimize impacts to system availability, further increasing
4 project complexity and cost. These investments are necessary to avoid unplanned failures, reduce
5 operational risk, and maintain the long-term reliability of transmission facilities.

6 This work category also includes geohazard and erosion mitigation projects that address
7 site-specific risks such as slope instability, washouts, erosion, and earth movement affecting
8 transmission facilities and associated infrastructure. As facilities age and environmental
9 conditions evolve, geotechnical risks may increase, particularly at sites located in steep terrain,
10 flood-prone areas, or regions susceptible to soil movement. Mitigation measures often require
11 substantial civil construction, including grading, retaining structures, drainage improvements,
12 and ground stabilization, and are necessary to protect facility foundations, pipelines, and
13 auxiliary systems from damage or loss of function.

14 In addition, this forecasted capital expenditure includes structural and pipeline support
15 repairs, such as span reinforcements and support upgrades. These activities are required to
16 maintain structural integrity, and address deterioration caused by environmental exposure and
17 aging materials. Such projects often involve specialized construction methods, limited access,
18 and site-specific work constraints, contributing to higher unit costs.

19 A key cost driver in this work category is the implementation of physical security
20 enhancements at high-risk transmission facilities, including pressure-limiting stations, mainline
21 valve sites, and compressor stations. These facilities serve essential operational functions, and
22 unauthorized access, vandalism, or tampering could result in significant safety hazards, service
23 disruptions, or impacts to system integrity. Accordingly, these investments are required to reduce
24 the risk of intrusion and to safeguard critical assets. Typical capital activities under this category
25 include installing control shelters equipped with integrated video surveillance systems; deploying
26 perimeter cameras and motion-detection sensors at facility access points; constructing or
27 reinforcing secure fencing; and upgrading high-security key and access-control systems. Many
28 existing security systems at transmission facilities are aging, lack integration, or provide limited
29 reliability, resulting in nuisance alarms and reduced situational awareness. Modernization efforts
30 improve real-time visibility, enhance detection and notification capabilities, and provide more

1 dependable monitoring to support field personnel and Corporate Security’s ability to assess and
2 respond to potential threats.

3 As the threat environment continues to evolve, SoCalGas must take proactive steps to
4 strengthen the physical protection of transmission facilities. Unauthorized access to this
5 infrastructure could result in equipment damage, natural gas releases, operational interruptions,
6 or broader system impacts affecting public safety. The forecasted capital expenditures reflected
7 in the GT Security and Auxiliary Equipment work category therefore represent prudent
8 investments to deter intrusions and, unauthorized access, enhance detection and response
9 capabilities, and maintain compliance with standards and industry expectations for critical
10 infrastructure protection.

11 Collectively, these investments support the safety of employees and the public, protect
12 critical assets, and support the continued safe and reliable operation of the gas transmission
13 system.

14 2. Forecast Method

15 The forecast method developed for GT Security and Auxiliary Equipment is zero-based.
16 SoCalGas evaluated historical expenditures from 2021 through 2025 and considered available
17 information on planned future projects. The forecast is driven by the identification and
18 scheduling of a significantly larger number of defined, high-cost projects in the current planning
19 cycle compared to historical periods. Historical spending reflects limited and uneven activity, as
20 many security upgrades, auxiliary system replacements, geohazard mitigations, and structural
21 repairs were under evaluation, or not yet formally scoped. In contrast, the current forecast
22 captures a concentration of known projects addressing physical security vulnerabilities at critical
23 transmission facilities, replacement of aging auxiliary equipment essential to system reliability,
24 and site-specific civil and structural risks identified through updated assessments. These
25 activities are capital-intensive and episodic rather than recurring, making historical spending
26 levels a poor indicator of future needs. As a result, the forecast represents a step-change driven
27 by project timing and maturity, not a fundamental increase in baseline spending, and reflects a
28 more complete alignment of forecasted costs with identified asset condition, security, and risk
29 mitigation requirements. A zero-based approach was selected as the most appropriate forecasting
30 method based on the projects currently identified, while recognizing that additional activities
31 may emerge over the forecast period. For 2030 and 2031, specific projects are included where a

1 defined need has been identified. However, given that many future activities remain undefined
2 over this longer planning horizon, forecasted expenditures for those years are aligned to the 2029
3 forecast level. This approach provides the best estimate of anticipated workload by directly
4 aligning projected expenditures with known projects and current equipment conditions.
5 *See* supplemental workpaper, Ex. SCG-05-CWP, WP #003090, for calculation details.

6 3. Cost Drivers

7 The underlying cost drivers for GT Security and Auxiliary Equipment include the need to
8 maintain and modernize essential auxiliary systems, address site-specific civil and structural
9 risks, and respond to evolving regulatory and operational requirements. Key drivers include the
10 replacement of aging and obsolete auxiliary equipment, such as cooling, water, fire protection,
11 plant air, and pumping systems, that are critical to daily transmission operations and emergency
12 response. Additional drivers include geohazard and erosion mitigation needs at facilities located
13 in geotechnically sensitive areas, as well as structural and pipeline support repairs required to
14 preserve asset integrity and prevent deterioration. These investments are further influenced by
15 increasing project complexity, access constraints, and coordination with system outages.

16 Another key cost driver is compliance with federal and industry security standards,
17 including the TSA's expectations for critical energy infrastructure. These standards require
18 utilities to implement physical protection, monitoring systems, and access control measures that
19 reduce vulnerability to unauthorized access, tampering, or deliberate interference. As security
20 expectations grow more stringent, SoCalGas must enhance surveillance capabilities, improve
21 perimeter control, and strengthen its ability to detect, deter, and respond to potential threats.

22 More than 60 projects have been identified within this cost category for the 2026-2029
23 period. As described in the Forecast Method above, for 2030 and 2031, forecasted expenditures
24 are aligned to the 2029 forecast level. Project costs vary widely based on scope and complexity,
25 ranging from thousands to millions of dollars. The projects described below are representative of
26 activities included in this cost category:

27 **Blythe Plant 1 & 2 Evaporative Cooler Upgrade:** This project is required to address
28 safety, reliability, and functionality risks associated with aging infrastructure at the Blythe
29 Station. The proposed solution is to upgrade the existing evaporative cooling systems, replace
30 deteriorated water piping, improve station lighting, and upgrade entry doorways to modern
31 standards. This work mitigates the risk of cooling system underperformance, unsafe working

1 conditions, and limited access, while supporting reliable station operations, safer maintenance
2 activities, and extended service life of station assets.

3 **North Needles Water System Replacement:** This project is required to address
4 reliability and safety risks associated with aging and outdated water infrastructure at the North
5 Needles Station. The proposed solution is replacement of the existing firewater piping system
6 and installation of an independent auxiliary water system to modern standards. This work
7 mitigates the risk of unstable fire protection and water supply interruptions by improving system
8 resilience, providing operational redundancy, and enhancing overall station safety.

9 **Marvin & Davis MLV 1B Security Upgrade:** This project is required to address
10 ongoing security risks caused by repeated vandalism incidents at a site that is among the most
11 frequently targeted locations in the Beaumont District. The proposed solution is installation of a
12 solar-powered security system that includes surveillance cameras, intrusion detection equipment,
13 supporting structures, and an electrical cabinet housing recording and control components, with
14 enhanced nighttime visibility and active deterrence features. This work mitigates the risk of
15 property damage, equipment tampering, and service disruption by improving site visibility,
16 enabling real-time intrusion detection, and supporting timely response by Corporate Security to
17 protect critical assets. The benefits of this project include improved asset protection, reduced
18 vandalism-related costs, increased site safety, and enhanced remote monitoring capabilities, all
19 supported by a self-sustaining solar-powered system.

20 The projects forecasted in this category are driven by regulatory expectations, advanced
21 equipment requirements, facility-specific conditions, labor market constraints, and ongoing
22 technological modernization. These investments are necessary to mitigate security risks,
23 safeguard key transmission assets, and support the safe and reliable operation of SoCalGas's
24 system.

1 Forecasted capital expenditures in this testimony and the associated workpaper reflect the
2 continuation of CCM-driven OT and IT enhancements. These enhancements include completing
3 the Message Queuing Telemetry Transport (MQTT) communications infrastructure that provides
4 secure and reliable transmission of HCA methane sensor and EPM field data to Gas Control.
5 Forecasted expenditures will also be allocated towards new projects to upgrade and enhance
6 control room software applications originally implemented under CCM. These applications
7 support pipeline system change management, outage detection, system alerts, internal
8 workflows, and real-time data intake. Continued investment is required to maintain these
9 applications, update their functionality, prevent technical obsolescence, and maintain operational
10 continuity. Maintaining and upgrading these systems extends their useful life; strengthens system
11 security, performance, and resilience; and helps Gas Control operations remain compliant with
12 control room management requirements defined in PHMSA Rule 49 CFR § 192.631. These
13 requirements include providing system operators with adequate information to carry out their
14 roles and responsibilities and implementing robust change management processes when
15 modifying pipeline operations or deploying new technology. Lastly, investments are planned to
16 support operational efficiency and innovation within Gas Control. These new initiatives include
17 developing advanced analytical and predictive models to help operators forecast gas
18 consumption patterns and identify potential outage risks, implementing enterprise data
19 governance improvements, migrating management of change (MOC) systems to cloud-based
20 platforms, and modernizing AV systems within the control environment to support decision-
21 making and situational awareness.

22 **SCADA System Upgrade:** Investments are required for upgrades to the Gas Control
23 SCADA operating system and peripheral components, including backup and recovery systems,
24 updates to the SCADA training simulator to match the production environment, and
25 enhancements to multi-factor authentication systems used for secure SCADA access. These
26 upgrades improve cybersecurity posture, operational reliability, and operator training
27 capabilities.

28 **MAXIMO Upgrade:** Forecasted spending includes continued enhancements to
29 MAXIMO, the GT&S work order management and operations data system. Planned upgrades
30 include automating the processing of aerial leak survey data, automating work order creation in
31 AVEVA, and configuring MAXIMO to serve as the system of record for OT assets across the

1 transmission system. These enhancements are scheduled for completion in 2026 and are
2 expected to automate manual processes, improve asset traceability, and enhance regulatory
3 reporting. Beyond these efforts, SoCalGas is preparing for the future state of its data platform in
4 IT as the “Work Management Program Next Generation for Transmission and Storage” project
5 advances. This initiative is being developed as the future platform for work and asset processes
6 and will anchor upcoming phases of the OT roadmap by extending capabilities beyond what
7 MAXIMO supports today. Costs associated with the “Work Management Program Next
8 Generation for Transmission and Storage” project are summarized in the Information
9 Technology testimony (Ex. SCG-10).

10 **Cybersecurity:** These activities are to align with emerging cybersecurity requirements
11 and new TSA directives applicable to critical infrastructure operators.⁷⁵ These mandates require
12 utilities to modernize cyber systems, strengthen identity management and authentication systems
13 to promote secure access management, strengthen continuous monitoring tools, and deploy
14 enhanced controls for sensitive OT environments.

15 Collectively, these GT Technology and Software expenditures reflect the continued
16 evolution of OT and IT systems that support safe transmission system operations, enhance real-
17 time situational awareness, modernize field data acquisition, and uphold regulatory and
18 cybersecurity obligations. They form a critical component of the Company’s strategy to maintain
19 a modern, resilient, and secure control environment.

20 **2. Forecast Method**

21 The forecast methodology developed for GT Technology and Software is zero-based.
22 SoCalGas evaluated historical expenditures from 2021 through 2025 and considered available
23 information on planned future projects. A zero-based approach was selected as the most
24 appropriate forecasting method based on the projects currently identified, while recognizing that
25 additional activities may emerge over the forecast period. This approach is appropriate because
26 forecasted expenditures are developed from a baseline of current assumptions that best reflect
27 known operating conditions, system configurations, and regulatory requirements, rather than

⁷⁵ TSA, *Security Directives and Emergency Amendments* (January 15, 2026), available at:
<https://www.tsa.gov/sd-and-ea>.

1 relying on historical averages. See supplemental workpaper, Ex. SCG-05-CWP, WP
2 #003500, for details.

3 **3. Cost Drivers**

4 The cost drivers for GT Technology and Software are shaped by the need to support
5 current and future operational capabilities, technology modernization, and regulatory
6 compliance. SoCalGas forecasts a \$9,092,000 decrease from BY 2025 to TY 2028 for GT
7 Technology & Software. This reduction reflects the natural tapering of capital needs as several
8 major technology initiatives, specifically MAXIMO enhancements, CCM OT deployments, and
9 upgrades to control room software applications, are scheduled to conclude during the forecast
10 period. These projects were initiated to modernize Gas Control operations, support the CCM
11 program, and strengthen enterprise-wide OT capabilities. As these initiatives reach completion,
12 the associated capital expenditure correspondingly declines. However, ongoing investment
13 remains critical to maintaining a secure, reliable, and modern control environment.

14 A key cost driver is the need to prepare for future system requirements through continued
15 innovation and cybersecurity planning. As cybersecurity threats evolve and operational demands
16 become more complex, SoCalGas must invest in software platforms and digital infrastructure to
17 support real-time information availability and accurate system visualization that strengthens
18 situational awareness, support predictive analytics, and maintain secure, resilient system
19 operations. These investments are foundational to strategic innovation efforts across the
20 Company and are part of long-term planning for modern gas system operations.

21 Another significant cost driver is the need for technology upgrades. Many existing
22 SCADA hardware and software platforms are approaching the end of their useful life and will no
23 longer be supported by vendor-maintained operating systems after January 1, 2029. Replacement
24 of these systems is necessary to maintain a secure operating environment, preserve system
25 functionality, and avoid the continued reliance on obsolete or unsupported technology. In
26 addition, several control room applications deployed under CCM require ongoing upgrades,
27 enhancements, and periodic technology refreshes to maintain operational efficiency, incorporate
28 new cybersecurity features, and support the continued integration of advanced data and
29 monitoring tools. These upgrades sustain the long-term reliability of the technology backbone
30 used by Gas Control and Transmission Operations.

K. GS Compressor Stations (004010.000)

**TABLE GO-52
Capital Expenditures – GS Compressor Stations**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
K. GS Compressor Stations	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GS Compressor Stations	9,874	15,853	5,847	14,255	13,643	29,616	52,054

1. Description

The forecasts for Gas Storage (GS) Compressor Stations support routine capital improvements for compressors located at SoCalGas’s storage fields. Storage compressor units increase the pressure of natural gas so it can be injected into the underground reservoirs at the four storage fields operated by SoCalGas – Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey.

Gas storage compressor stations are essential to the operation and reliability of natural gas storage fields. They provide the mechanical energy required to inject natural gas into underground storage reservoirs at pressures sufficient to overcome reservoir pressure and geologic constraints. Without compressor stations, gas could not be reliably injected during storage replenishment periods, significantly limiting storage field operability and system flexibility. Compressor stations therefore serve as a critical interface between the transmission system and subsurface storage reservoirs, enabling seasonal balancing, system load management, and operational responsiveness during periods of peak demand, maintenance outages, or supply disruptions. Reliable compressor station operation is fundamental to maintaining storage deliverability, supporting system reliability, and ensuring safe, controlled gas movement throughout the storage cycle.

Examples of equipment within this area include internal combustion engines, high-pressure gas compressors, electric-driven compressors, cooling systems, plant air compressors, fire suppression systems, emission controls, and related control instrumentation. This category encompasses the capital expenditure required for overhauls, replacements, and upgrade of

1 storage field compressors to enhance reliability, extend equipment life, achieve environmental
2 compliance, and meet required injection capacities.

3 **Compressor Overhauls and Replacements:** These capital activities are required to
4 address aging and worn compressor equipment at storage facilities. These activities include the
5 rebuild, replacement, and decommissioning of compressors, engines, connecting rods, and other
6 critical components that have reached the end of their useful life or for which replacement parts
7 are no longer available. As compressors operate continuously during gas injection, they are
8 subject to normal wear and mechanical degradation, and after usage hour thresholds, these units
9 require planned overhauls or replacements. These overhauls and replacements are necessary to
10 maintain operational reliability, promote safety, and prevent unplanned equipment outages that
11 could threaten the continuity of gas supply during injection operations.

12 **Compressor Upgrades:** These capital improvements and enhancements to existing
13 compressor main units and ancillary equipment intend to sustain or improve reliability, safety,
14 environmental performance, and operational efficiency at storage fields. These projects address
15 obsolete equipment, aging infrastructure, and modernizing compressor equipment that support
16 compressor operations. Upgrades may involve improvements to compressor control panels,
17 monitoring, cooling, or emission equipment. These upgrades help reduce the likelihood of
18 equipment failures, minimize operational disruptions, and support gas injection operations.

19 Additional detailed information supporting this expenditure is provided in my capital
20 workpapers. *See* Ex. SCG-05-CWP, WP #004010.

21 **2. Forecast Method**

22 The forecast method developed for GS Compressor Stations is zero-based. SoCalGas
23 evaluated historical expenditures from 2021 through 2025 and considered available information
24 on planned future projects. A zero-based approach was selected as the most appropriate
25 forecasting method based on the projects currently identified, while recognizing that additional
26 activities may emerge over the forecast period. This approach provides the best estimate of
27 anticipated workload by directly aligning projected expenditures with documented compressor
28 station conditions and applicable regulatory requirements. *See* supplemental workpaper, Ex.
29 SCG-05-CWP, WP #004010, for details.

1 **3. Cost Drivers**

2 The underlying cost drivers for GS Compressor Stations stem from operational,
3 regulatory, asset, and equipment-related factors that directly affect compressor station reliability
4 and the continued safe performance of the gas storage system. Regulatory requirements drive the
5 need to maintain system reliability, environmental compliance, and system throughput. Sustained
6 capital investment is therefore necessary to keep these compressor stations operational and able
7 to support continuous delivery.

8 More than 30 projects have been identified within this cost category for the 2026-2031
9 period. Project costs vary widely based on scope and complexity, ranging from thousands to
10 millions of dollars. Project forecasts are in various stages of development, including planning,
11 construction, and closeout. The projects described below are representative of activities included
12 in this cost category. For additional details, *see* supplemental workpaper, Ex. SCG-CWP, WP#
13 004010, for details.

14 **Compressor Overhauls and Replacements:** Main Unit #7 Overhaul is required to
15 restore and sustain the compressor’s design efficiency, throughput capacity, and mechanical
16 reliability. Main Unit #7 has reached the end of its service life, and an overhaul is necessary to
17 avoid premature failure and the significantly higher cost associated with a full unit replacement.
18 Equipment overhauls are a fundamental component of lifecycle asset management and are
19 executed when accumulated wear and degradation dictate corrective action. This project is
20 necessary to maintain safe operation, restore and sustain unit efficiency and delivery capacity,
21 support continued compliance with environmental requirements, and support long term system
22 reliability. As part of the overhaul, a new compressor lube oil heater will be installed to support
23 proper oil temperature and viscosity during shutdown and startup conditions. Maintaining
24 adequate lube oil temperature reduces internal wear on critical components such as crankshaft
25 bearings, connecting rods, and related rotating assemblies, thereby extending the interval to the
26 next major overhaul. Without installation of new lube oil heaters, increased internal wear would
27 accelerate component degradation, shorten equipment life, and reduce the time between future
28 overhauls.

29 **Compressor Upgrades:** Aliso Canyon Compressor Heat Exchanger Cooling System
30 Upgrade implements the replacement and upgrade of the Ingersoll-Rand KVS compressors 1–3
31 heat exchanger cooling systems to address aging and obsolete fin-fan coolers and support

1 structures that no longer meet reliability, performance, or maintainability requirements. As both
 2 the structures and cooling coils are degrading, the risk of structure failure could cause injury to
 3 personnel and/or property. Coil failure could also result in a high-pressure gas leak. The upgrade
 4 replaces the existing coolers and reconstructs the cooler support structure, including construction
 5 of the K1, K2, and K3 support structures and installation of new fin-fan coolers. Each new
 6 cooling bundle is designed to handle engine jacket water, lubrication oil water, and air manifold
 7 cooling water, providing improved heat rejection, operational stability, and efficiency.

8 **L. GS Wells (004020.000)**

9 **TABLE GO-53**
 10 **Capital Expenditures – GS Wells**
 11

GAS TRANSMISSION & STORAGE (In 2025 \$)							
L. GS Wells	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GS Wells	37,563	43,775	50,319	70,420	77,457	85,199	93,716

12 **1. Description**

13 The forecast for gas storage (GS) wells supports the replacement of components on
 14 existing wells, as well as the design, drilling, and completion of replacement wells for the
 15 injection and withdrawal of natural gas and for reservoir observation purposes at the four storage
 16 fields operated by SoCalGas—Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey. This
 17 includes costs for well workover contractors (major well work), drilling contractors, and
 18 components such as tubing, casing, valves, pumps, and other downhole equipment. Additional
 19 detailed information supporting this expenditure is provided in my capital workpapers. *See*
 20 *Ex. SCG-05-CWP, WP #004020.*

21 Gas storage wells are the foundational assets of a natural gas storage field, providing the
 22 physical connection between aboveground facilities and the underground geologic formations
 23 where gas is stored. The ability to safely inject and withdraw natural gas, monitor reservoir
 24 conditions, manage fluids, and maintain mechanical integrity depends on the continued
 25 performance and integrity of these wells. Over time, storage wells are subject to mechanical
 26 wear, corrosion, changing reservoir conditions, and evolving regulatory requirements, all of

1 which can reduce deliverability or necessitate corrective action. Ongoing well maintenance,
2 replacement, and modernization are therefore critical to sustaining storage field capacity,
3 maintaining operational flexibility, complying with regulatory mandates, and enabling the safe
4 and reliable operation of the natural gas storage system. SoCalGas's natural gas storage facilities
5 are used for the injection and withdrawal of natural gas into underground reservoirs for storage,
6 consistent with the definition of an Underground Storage Project set forth in Cal. Code Reg.,
7 Title 14, § 1726.1(a)(6).⁷⁶ Non-gas storage wells, including monitoring, observation, and other
8 supporting wells, are also included within this definition, as further specified in each field's
9 Underground Storage Project Approval Letter (PAL).⁷⁷

10 **Abandonments:** SoCalGas plans to abandon wells with high operating costs and low or
11 declining productivity. In addition, certain abandonments involve removing wells and associated
12 operations from environmentally sensitive areas or locations outside the storage field fencelines.
13 Projected costs include the materials and services required to abandon the wells in a manner that
14 meets or exceeds CalGEM requirements. SoCalGas anticipates abandoning 16 storage wells
15 during the 2026 to 2028 period.

16 **Well Replacements:** This work is required to replace the deliverability of existing wells
17 and wells that have been abandoned. Replacing older, higher-cost wells with new, higher-
18 deliverability wells has the potential to reduce long-term operating costs by lowering the need for
19 mitigation measures, such as inner string installations and liner replacement projects. SoCalGas
20 plans to drill new wells to replace those abandoned for various reasons, including low
21 productivity, high operating costs, or failure to meet integrity testing requirements, and to
22 develop additional wells—such as water disposal wells—to support ongoing storage operations.
23 Advances in well design and completion techniques allow replacement wells to achieve greater
24 deliverability, potentially enabling better than a one-for-one replacement. Depending on the
25 storage field and its geology, a newly drilled and completed replacement may provide flow
26 capacity equivalent to two or more existing wells, potentially reducing the overall storage well
27 count and associated operating expenses. These projects include locating and preparing drill

⁷⁶ Cal. Code Reg., Title 14, § 1726.1(a)(6) (Definitions).

⁷⁷ The PAL is essentially a conditional license to operate from CalGEM. It is a general approval document and must be obtained by the operator prior to any injection or withdrawal as part of a UGS project and codifies the conditions of approval of the UGS project applying to all GS wells and the GS reservoir.

1 sites, procuring services and materials, and drilling and completing new replacement storage
 2 wells. SoCalGas anticipates drilling 11 replacement storage wells during the 2026 to 2028
 3 period, including injection/withdrawal, water disposal, liquid removal, and observation wells.

4 **Workovers:** Well workovers are critical maintenance activities performed on storage
 5 wells to support safety and integrity, and to maintain withdrawal and injection capacity. Wells
 6 may require workovers due to conditions such as wellhead upgrades, damaged liners,
 7 replacement of production equipment, production of reservoir sand, or failure of artificial lift
 8 equipment in fluid removal wells (encroachment into the storage reservoir), leading to a
 9 diminished number of wells available for withdrawal/injection operations. SoCalGas plans to
 10 complete 36 well workovers at the storage fields during the 2026 to 2028 period.

11 **a. Description of RAMP Mitigations**

12 Within this cost category, there are capital costs for risk control C402 (Well
 13 Abandonment/Replacement/Demo Verification and Monitoring Practices) that were presented in
 14 the 2025 RAMP Report and are listed in Table GO-54. The RAMP activities and costs identified
 15 within this workpaper for C402 are described in Section V.L.1 GS Wells. The variance between
 16 the 2025 RAMP capital forecast and 2028 GRC forecast is because the 2028 GRC forecast does
 17 not include any complex abandonments.

18 Activities that are compliance or mandated by CPUC or other agencies are listed in bold,
 19 and Appendix B attached to this testimony provides the details regarding these mandates for each
 20 control.

21 **TABLE GO-54**
 22 **RAMP and GRC Risk Control/Mitigation Activities – Capital**

GS Wells				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (\$000s)
C402	Well Abandonment/ Replacement/Demo Verification and Monitoring Practices	261,260	326,792	65,532

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

3 The RAMP risk mitigation efforts are associated with specific actions, such as programs,
4 projects, processes, and utilization of technology and are designed to address a specific safety
5 and/or reliability risk. The Company’s selection and prioritization of these RAMP mitigation
6 activities considered many factors when determining if these risk mitigation activities are an
7 effective and worthwhile investment. The ERM process for identifying and assessing system
8 risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

9 This mitigation was selected as a control for the Underground Storage Risk, which
10 includes the risk of failure of an underground gas storage well that results in serious injuries,
11 fatalities, and/or damage to the infrastructure. As described in the SoCalGas 2025 RAMP Report
12 (Chapter SCG-Risk-4), there are ten potential drivers/triggers of this risk. UGS addresses all ten
13 of these drivers including external corrosion; internal corrosion; manufacturing defects;
14 construction and fabrication; weather related and outside forces such as earthquake, erosion, and
15 other natural disasters; incorrect operations (including well interventions), equipment failure,
16 third party damage (excluding excavation damage), incorrect/inadequate asset records, and
17 execution constraints.

18 The 2025 RAMP Report also identifies seven potential consequences associated with
19 Underground Gas Storage Risk, all of which are addressed by UGS including serious injuries or
20 fatalities; property damage; operational and reliability impacts; adverse litigation, penalties and
21 fines; erosion of public confidence; and environmental impacts.

22 Underground gas storage assets are essential components of California’s reliable energy
23 delivery infrastructure. Accordingly, UGS activities and measures are designed to enhance the
24 safety and reliability of the natural gas infrastructure, mitigate associated risks, and comply with
25 state and federal regulations.

26 **2. Forecast Method**

27 The forecast method developed for GS Wells is zero-based. SoCalGas evaluated
28 historical expenditures from 2021 through 2025 and considered available information on planned
29 future projects. A zero-based approach was selected as the most appropriate forecasting method
30 based on the projects currently identified, while recognizing that additional activities may
31 emerge over the forecast period. For example, the number of new wells can vary each year

1 depending on the analysis of the need to maintain each storage field's injection/withdrawal
2 capacity, which has been reduced by abandonments and the encroachment of water into the gas
3 storage zone. This approach provides the best estimate of anticipated workload by directly
4 aligning projected expenditures with documented gas storage well conditions and applicable
5 regulatory requirements. *See* supplemental workpaper, Ex. SCG-05-CWP, WP #004020, for
6 calculation details.

7 **3. Cost Drivers**

8 The underlying cost drivers for GS Wells are regulatory compliance requirements that
9 require upgrades to meet federal and state safety standards and risk mitigation for public and
10 employee safety. Primary regulations governing underground storage operations and
11 maintenance activities include CalGEM requirements for California Underground Gas Storage
12 Projects (Cal. Code Reg., Title 14, § 1726, *et seq.*) and PHMSA Underground Natural Gas
13 Storage regulations (49 CFR § 192.12). These regulations include requirements and standards,
14 such as well construction, mechanical integrity testing, risk management, emergency response
15 plans, data management, monitoring and inspecting, wellhead and valve maintenance, and well
16 decommissioning. Another cost driver is the highly specialized nature of work performed on
17 high-pressure gas wells, as well as the skilled workforce and specialized equipment employed.
18 The costs are based on equipment and material pricing, qualified contractor availability, and
19 associated contractor rates.

20 The incremental cost increase from BY 2025 to the TY 2028 forecast is primarily driven
21 by increased well activity. Specifically, the TY 2028 forecast includes the drilling of four new
22 wells, compared to no wells completed in 2025, resulting in an increase of approximately
23 \$19,000,000. In addition, the TY 2028 forecast assumes seven well abandonments, compared to
24 four completed in 2025, contributing an incremental increase of approximately \$11,000,000.

1 M. GS Pipelines (004030.000)

2 TABLE GO-55
3 Capital Expenditures – GS Pipelines

GAS TRANSMISSION & STORAGE (In 2025 \$)							
M. GS Pipelines	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GS Pipelines	34,346	27,774	28,482	25,908	42,183	52,732	54,287

4 1. Description

5 The forecast for GS Pipelines supports the development, installation, modification, and
6 retrofitting of storage field pipelines, well laterals, and associated surface facilities required to
7 serve both new and existing well operations at the four storage fields operated by SoCalGas –
8 Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey. Additional supporting detail for this
9 expenditure is provided in my capital workpapers. *See* SCG-05-CWP, WP #004030.

10 Natural gas storage fields depend on an integrated network of pipelines, laterals, and
11 surface facilities to transport gas between underground storage reservoirs and aboveground
12 processing, compression, and transmission infrastructure. While storage wells provide access to
13 the subsurface reservoir, pipeline facilities are required to safely move gas for injection and
14 withdrawal, manage pressures and flow, connect wells to purification and compression systems,
15 and maintain operational flexibility and deliverability. These facilities are essential to restoring
16 and sustaining storage field capacity, complying with regulatory requirements, and supporting
17 reliable system operations.

18 Activities in this category include the construction and connection of new infrastructure;
19 enhancements to existing infrastructure to facilitate integration; restoration of withdrawal and
20 injection capacity; improvements to operational efficiency; and support for gas injection and
21 withdrawal operations. The scope also includes implementing or upgrading well automation
22 systems to enable remote monitoring, control, and optimization of well performance.

23 **Lateral Pipelines & Surface Facilities:** New lateral pipelines and surface facilities are
24 required to connect replacement gas storage wells (*see* Section V.L.1 GS Wells) following the
25 abandonment of wells driven by inspection findings, CalGEM requirements, and the increasing
26 cost and risk of operating aging assets. Surface facilities include well laterals, pipelines, civil

1 infrastructure, liquid handling equipment, cathodic protection systems, monitoring
2 instrumentation, and automated well control features, including well specific injection and
3 withdrawal block and choke valves operated by pneumatic actuators and controlled via localized
4 PLCs. CalGEM regulations require that wells and associated facilities maintain mechanical
5 integrity under anticipated operating conditions and that operators manage integrity risks
6 associated with well aging (Cal. Code Reg., Title 14⁷⁸ § 1726.4⁷⁹§ 1726.5). By adding new
7 laterals, replacement wells can be brought into service, restoring capacity and allowing
8 withdrawal to be spread across a larger group of wells. This reduces strain for individual wells
9 and helps extend the operating life of both new and existing assets.

10 **Well Automation:** Well instrumentation and control systems are incorporated into new
11 gas storage wells in accordance with CalGEM's well construction and monitoring requirements.
12 Cal. Code Reg., Title 14, § 1726.5 requires wells to be designed to maintain mechanical integrity
13 under anticipated operating conditions, and § 1726.7⁸⁰ requires monitoring capable of detecting
14 abnormal conditions and supporting timely response. Integrating automated monitoring and
15 control reduces operational risk, limits manual intervention, produces operational data points,
16 and optimizes resources.

17 **2. Forecast Method**

18 The forecast method developed for GS Pipelines is zero-based. SoCalGas evaluated the
19 historical expenditures from 2021 through 2025 and considered known system conditions,
20 planned future projects, and applicable regulatory requirements. A zero-based approach was
21 selected as the most appropriate forecasting method given the project-specific nature of pipeline,
22 lateral, and surface facility investments, while recognizing that additional activities may emerge
23 during the forecast period. This methodology provides the best estimate of anticipated workload
24 by directly aligning forecasted expenditures with the pipeline and surface facility infrastructure
25 required to support upcoming new wells, current operating conditions, existing system
26 configurations, and regulatory obligations. *See* supplemental workpaper, Ex. SCG-05-CWP, WP
27 #004030, for calculation details.

⁷⁸ Cal. Code Reg., Title 14, § 1726.4 (Underground Gas Storage Project Data Requirements).

⁷⁹ *Id.* § 1726.5 (Well Construction Requirements).

⁸⁰ *Id.* § 1726.7 (Monitoring Requirements).

1 **3. Cost Drivers**

2 The primary cost drivers for GS Pipelines are operational needs, regulatory compliance
3 requirements, asset condition considerations, and equipment related factors associated with
4 connecting storage wells to aboveground gas storage infrastructure. These pipelines and surface
5 facilities connect wells; transport gas between wells, compressor stations, and purification
6 systems; and support overall storage capacity, deliverability, and reliability requirements.

7 More than 60 projects have been identified within this cost category for the 2026-2031
8 period. Project costs vary widely based on scope, complexity, and site-specific conditions,
9 ranging from thousands to millions of dollars. Project statuses are in various stages of
10 development, including planning, design, engineering, construction, and closeout. The projects
11 described below are representative of activities included in this cost category. For additional
12 details, *see* supplemental workpaper, Ex. SCG-05-CWP, WP# 004030.

13 **La Goleta Well Laterals:** This project scope includes the design, installation, and
14 commissioning of new lateral lines, instrumentation, civil work, pipe headers, and fittings to
15 connect six wells scheduled for drilling in 2026 at the La Goleta Storage Field to the major gas
16 transmission lines supplying the dehydration plant. These new pipelines will support gas
17 withdrawal during the peak demand season and will also serve as injection lines during the
18 storage injection season.

19 The La Goleta Storage Field plays a critical role in supporting the overall reliability of
20 the SoCalGas natural gas system by providing strategically located storage capacity that
21 enhances deliverability to coastal and southern system areas during periods of high demand or
22 constrained pipeline supply. Reliable operation of the field helps mitigate system stress during
23 peak weather events, maintenance outages, or supply disruptions, thereby supporting continuous
24 service to customers and maintaining system flexibility.

25 La Goleta originally operated 18 injection and withdrawal wells, but currently only has
26 eight active wells due to prior abandonments. The addition of lateral and surface infrastructure to
27 support the new wells will restore the field's maximum production capacity, improve reliability,
28 and enhance operational flexibility. Restoring this capacity strengthens overall system reliability
29 by enabling withdrawal to be distributed across a broader population of wells, reducing strain on
30 individual assets, and supporting dependable gas delivery during critical operating conditions.

Honor Rancho WEZU 24 D, E, F, G, & H Wells Surface Facilities: This project will install laterals and associated surface facilities for five new gas storage wells to connect the wells to the existing field piping system and enable full storage injection and withdrawal operations. The scope includes surface piping, civil infrastructure, two phase separator, and automated well control features, including well-specific injection and withdrawal block and choke valves operated by pneumatic actuators and controlled through localized PLCs. These surface facilities provide the critical infrastructure required to safely monitor, control, separate, and protect produced fluids and gases while integrating the new wells into existing operations. Implementing automated control and protection systems improves operational reliability, enhances safety, and allows more precise well management, while maintaining compliance with applicable operational, safety, and regulatory requirements. This project is essential for placing the new wells into service and restoring long-term storage field capacity, reliability, and operational flexibility.

N. GS Purification Equipment (004040.000)

**TABLE GO-56
Capital Expenditures – GS Purification Equipment**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
N. GS Purification Equipment	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GS Purification Equipment	6,554	16,964	12,054	15,606	19,289	23,892	17,813

1. Description

The forecast for GS Purification Equipment supports the upgrade and improvement of gas purification systems necessary to maintain system deliverability and support compliance with pipeline quality gas standards at the four storage fields operated by SoCalGas – Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey. Additional supporting detail for these expenditures is provided in my capital workpapers. *See Ex. SCG-05-CWP, WP #004040.*

Natural gas storage fields require purification equipment to support compliance with applicable pipeline quality standards prior to delivery into the transmission system. During storage operations, natural gas can encounter formation water, hydrocarbons, sulfur compounds,

1 solids, and other contaminants that may be present in the reservoir or produced during injection
2 and withdrawal cycles. Without adequate purification, these contaminants can compromise gas
3 quality, damage pipeline and storage assets, and increase the risk of corrosion, hydrate
4 formation, equipment malfunction, and safety incidents. Purification systems, including
5 dehydration, filtration, separation, and emissions control equipment, are therefore essential to
6 protect system integrity, maintain operational reliability, support safe and compliant storage
7 operations, and provide customers with gas that meets regulatory and tariff requirements.

8 Aging infrastructure has increased the need for enhancements to complex purification
9 assets, including dehydration systems that are critical for controlling water content in the gas
10 stream and preventing operational issues such as corrosion, hydrate formation, and pipeline
11 damage.

12 The scope of work includes capital upgrades, such as replacements and improvements to
13 dehydrators, tanks (e.g., Triethylene Glycol tanks and sand tanks), glycol systems, coolers,
14 scrubbers, boilers, pumps, valves, piping, power supply, and controls and instrumentation. The
15 scope also includes specialized equipment, such as thermal oxidizers for emissions controls and
16 hydrogen sulfide (H₂S) removal systems, where required.

17 These investments are designed to improve system reliability, reduce the likelihood of
18 safety incidents, mitigate equipment failure risk, improve operational efficiency, and support
19 compliance with applicable federal, state, and local regulatory requirements, including those of
20 PHMSA, OSHA, EPA, FERC, NTSB, FEMA, the CPUC (including GO 58-A⁸¹), DOT,
21 SCAQMD, TSA, NFPA, and CalGEM.

22 a. Description of RAMP Mitigations

23 Within this cost category, there are capital costs for risk control C019 (Storage HP
24 Retrofits and Upgrades to Purification Equipment) that were presented in the 2025 RAMP
25 Report and are listed in Table GO-57. The RAMP activities and costs identified within this
26 workpaper for C019 are described in Section V.N.1. All cost forecasts included in this category
27 are associated with C019 and are required to meet safety, reliability, and regulatory requirements
28 across a wide range of federal, state, and local agencies, including PHMSA, OSHA, EPA, FERC,
29 NTSB, FEMA, the CPUC (including GO 58A), DOT, SCAQMD, TSA, NFPA, and CalGEM.

⁸¹ CPUC, GO 58-A (Standards for Gas Service).

1 The cost forecast difference is due to using a zero-based forecast instead of a historical base year
2 method forecast, while the underlying scope of work and risk control strategy remain unchanged.

3 Activities that are compliance or mandated by CPUC or other agencies are listed in bold,
4 and Appendix B attached to this testimony provides the details regarding these mandates for each
5 control.

6 **TABLE GO-57**
7 **RAMP and GRC Risk Control/Mitigation Activities – Capital**

GS Purification Equipment				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (\$000s)
C019	Storage HP Retrofits and Upgrades to Purification Equipment	50,476	76,600	26,124

8 **b. Description of Selection and Prioritization of RAMP Risk**
9 **Mitigations**

10 The RAMP risk mitigation efforts are associated with specific actions, such as programs,
11 projects, processes, and utilization of technology and are designed to address a specific safety
12 and/or reliability risk. The Company's selection and prioritization of these RAMP mitigation
13 activities considered many factors when determining if these risk mitigation activities are an
14 effective and worthwhile investment. The ERM process for identifying and assessing system
15 risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

16 Purification equipment activities address multiple threats to high-pressure gas system
17 safety and reliability, including corrosion, construction and fabrication issues, weather-related
18 and outside forces, and equipment failure. Upgrades and maintenance of dehydrators, coolers,
19 scrubbers, boilers, and tanks reduce the likelihood of pressure vessel, heat exchanger, or piping
20 failures and help support gas quality compliance with CPUC GO 58-A. By mitigating these risks,
21 these activities reduce the potential for serious safety incidents, property damage, operational and
22 reliability impacts, environmental harm, regulatory or legal exposure, and loss of public
23 confidence, thereby supporting the safe and reliable operation of storage facilities and
24 minimizing high-consequence outcomes for customers and surrounding communities. These
25 purification equipment activities reduce the likelihood and consequences of uncontrolled gas or

1 liquid releases, gas quality noncompliance, and equipment failures that could lead to safety
2 incidents, service interruptions, environmental impacts, or emergency response events, thereby
3 supporting safe, reliable gas delivery and protecting customers from high consequence
4 disruptions and cost volatility.

5 2. Forecast Method

6 The GS Purification Equipment forecast was developed using a zero-based forecasting
7 methodology. SoCalGas evaluated historical expenditures incurred from 2021 through 2025 and
8 considered known operating conditions, planned capital projects, and anticipated regulatory and
9 compliance requirements for the forecast period. A zero-based approach was selected as the most
10 appropriate forecasting method given the asset-specific nature of the identified projects and the
11 evolving condition of purification and dehydration equipment. This methodology directly aligns
12 projected expenditures with documented equipment conditions, system configurations, and
13 applicable regulatory requirements, rather than relying on historical spending trends. While
14 additional activities may emerge during the forecast period, the zero-based forecast represents
15 the Company's best estimate of anticipated workload at this time. *See* supplemental
16 workpaper, Ex. SCG-05-CWP, WP #004040, for calculation details.

17 3. Cost Drivers

18 The primary cost drivers for GS Purification Equipment consist of operational, regulatory,
19 asset condition, and equipment-specific factors necessary to support the delivery of
20 pipeline-quality gas. Ongoing investment is necessary to comply with gas quality standards,
21 emissions requirements, and safety regulations, and to maintain the reliable integration of
22 purified natural gas into the GT&S system.

23 More than 20 projects have been identified within this cost category for the 2026-2031
24 period. Individual project costs vary widely depending on scope, technical complexity, and
25 facility-specific conditions, ranging from thousands to millions of dollars. Project development
26 status varies across planning, design, construction, and closeout phases.

27 The examples provided below are representative of the types of projects included in this
28 cost category forecast. For additional details, *see* supplemental workpaper, Ex. SCG-05-CWP,
29 WP# 004040, for details.

30 **La Goleta Coalescer Installation F-101:** This project will complete the remaining
31 installation activities required to place the Absolute Filter Coalescer (F-101) into full service.

1 The coalescer is designed to remove entrained particulate solids and free liquid droplets from the
2 gas stream, reducing water content and supporting compliance with SoCalGas Rule 30
3 requirements. Currently, filtration is not in service for the gas stream, resulting in periodic spikes
4 in gas moisture content. Completion of the installation will integrate the coalescer into the
5 existing gas processing system, thereby enabling proper filtration and moisture control during
6 operations, improving gas quality, supporting regulatory compliance, and reducing the risk of
7 downstream equipment impacts from liquid or solid carryover.

8 **Honor Rancho Sand Tank Replacement:** This project consists of the removal of
9 existing sand separation equipment and the installation of a new, engineered sand trap/desander
10 system. The current sand tanks lack sufficient retention time and are unable to accommodate
11 high withdrawal rates and surge conditions. Sand, proppant, and debris generated during gas
12 withdrawal flow at high pressure and can cause internal damage to piping and equipment. The
13 upgraded sand tanks capture these byproducts, facilitating cleaner flow into oil settling tanks,
14 downstream brine filters, and disposal wells, thereby reducing maintenance costs, preventing
15 premature equipment failure, and lowering the risk of environmental downtime.

16 **Aliso Canyon Thermal Oxidizer Upgrade:** This project involves replacing the existing
17 flare system with a new thermal oxidizer, driven by environmental considerations to manage
18 emissions of hydrocarbon vapors released during the truck loading of crude oil and light
19 hydrocarbon condensates displaced from aboveground storage tanks. The project scope includes
20 engineering and design of the thermal oxidizer system; installation of two 10-horsepower
21 compressor skids and two associated air coolers to support the thermal oxidizer; and installation
22 of two 40-horsepower compressor skids serving the Dehy-1 area, along with all associated
23 piping, electrical and instrumentation, and civil and structural infrastructure.

24 All work will comply with applicable CPUC gas storage safety oversight requirements,
25 PHMSA 49 CFR § 192, applicable ASME codes for pressure systems, NFPA 54⁸² and
26 NFPA 850⁸³ for gas facilities, and Cal/OSHA (Cal. Code Reg., Title 8) workplace safety
27 standards.

⁸² NFPA 54 (National Fuel Gas Code).

⁸³ NFPA 850 (Standard for Fire Protection for Electric Generating Plants and High-Voltage Direct Current (HVDC) Converter Stations).

O. GS Auxiliary Equipment (004090.000)

TABLE GO-58
Capital Expenditures – GS Auxiliary Equipment

GAS TRANSMISSION & STORAGE (In 2025 \$)							
O. GS Auxiliary Equipment	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GS Auxiliary Equipment	34,438	49,646	59,251	86,000	80,748	64,816	64,658

1. Description

The forecasts for GS Auxiliary Equipment encompass upgrades and improvements to the infrastructure that supports gas storage field operations at the four storage fields operated by SoCalGas – Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey. Additional detailed information supporting this expenditure is provided in my capital workpapers. *See* Ex. SCG-05-CWP, WP #004090.

Natural gas storage fields rely upon a broad range of auxiliary equipment to support the safe, reliable, and continuous operation of core assets, including compressors, wells, pipelines, and purification systems. Such auxiliary equipment provides essential supporting functions—such as electrical power, automation, monitoring, communications, safety systems, and physical infrastructure—without which gas storage operations could not be conducted in a safe or reliable manner. Collectively, these systems facilitate the control, protection, and coordination of gas storage activities and are critical to maintaining operational readiness, enabling regulatory compliance, and supporting effective emergency response capabilities at storage facilities.

This category includes electrical systems; standby and backup power generators; utility upgrades, including water and power systems; instrumentation; equipment controls; field air compressors; odorization systems; site drainage; site infrastructure; tank farms; access roads; and communication systems. These assets are integral to storage field operations and are necessary to support safe operations, system monitoring, and personnel access.

Investments in auxiliary equipment address aging infrastructure and are intended to enhance system reliability, resilience, and safety while facilitating compliance with operational and regulatory standards.

1 **2. Forecast Method**

2 The GS Auxiliary Equipment forecast was developed using a zero-based forecasting
3 methodology. SoCalGas reviewed historical expenditures from 2021 through 2025 and
4 considered available information regarding planned future projects and known operational
5 requirements. A zero-based approach was selected as the most appropriate forecasting method
6 given the asset-specific nature of the identified projects and the condition-driven need for
7 upgrades across storage field auxiliary infrastructure. This approach provides the best estimate of
8 anticipated workload by directly aligning forecasted expenditures with documented needs for
9 electrical, security, and infrastructure upgrades, as well as current auxiliary system conditions at
10 storage fields. While additional activities may arise during the forecast period, the zero-based
11 forecast reflects the Company’s best estimate based on known information at this time.
12 *See* supplemental workpaper, Ex. SCG-05-CWP, WP #004090, for calculation details.

13 **3. Cost Drivers**

14 The underlying cost drivers for GS Auxiliary Equipment stem from operational,
15 regulatory, asset condition, technological obsolescence, and equipment-specific factors that
16 support the safe and reliable operation of the gas storage system. Continued investment is
17 required to replace or upgrade aging electrical systems and auxiliary infrastructure, reduce
18 operational risk, improve system reliability, and support safety and compliance requirements.

19 More than 150 projects have been identified within this cost category for the 2026-2031
20 period. Individual project costs vary widely based on scope, complexity and site-specific
21 conditions, ranging from thousands to millions of dollars. Project development spans multiple
22 phases, including planning, design, engineering, construction, and closeout. The projects
23 described below are representative examples of the activities included in this cost category
24 forecast. For additional details, *see* supplemental workpaper, Ex. SCG-05-CWP, WP#
25 004090, for details.

26 **Honor Rancho Electrical System Upgrade:** This project is to plan, engineer, design,
27 procure, and install four new Power Distribution Centers (PDC) at the Hillside, Dehydration
28 Plant, Tank Farm, and Plant 1, replacing the existing Motor Control Centers (MCC) to
29 modernize and upgrade the Honor Rancho Main Plant electrical distribution system. This
30 includes a new 16kV Southern California Edison (SCE) service being installed at the Hillside
31 PDC to strengthen the Station’s power source. The existing electrical system lacks modern safety

1 design features and architecture needed to support reliable and resilient operations. Upgrading
2 the system will improve personnel and equipment safety, reduce the risk of failures, and enhance
3 overall system reliability. In addition, the upgraded system will enable full integration with the
4 existing SCADA platform, allowing centralized monitoring and control of electrical and
5 instrumentation to support safer, more efficient operations. These upgrades will support and
6 maintain critical station loads required for continuous operations and uninterrupted monitoring
7 capabilities.

8 **Motor Control Center Upgrade (MCC):** This project is to replace the existing
9 overloaded MCC 2A/2B with new fully enclosed MCC equipment and enclosure, which provide
10 power to the Main Station, including the KVS compressors, Dehy-1, and Dehy-2. The project
11 scope includes the redesign and installation of new conduit and conductor pathways to serve
12 connected loads, as well as the removal of existing MCC components and conduits that are no
13 longer required. This upgrade is required due to the obsolescence of the existing system, the
14 unavailability of spare parts due to discontinued manufacturer support, limitations that prevent
15 the existing MCCs from communicating with facility systems, and expansion at the Main Station
16 that has led to overloaded conditions. Additionally, the existing system cannot interface with the
17 plant SCADA using current technology, limiting real-time monitoring, diagnostics, and overall
18 operational awareness. As the sole source of power for critical facilities, this lack of redundancy
19 creates a single point of failure, increasing the risk of widespread outages, disrupting operation
20 continuity, and posing potential safety concerns during equipment failures or maintenance
21 activities. This project is driven by compliance with the California Electrical Code, Cal. Code
22 Reg., Title 24⁸⁴ Part 3, and Cal/OSHA Electrical Title 8 (Electrical Safety Orders).⁸⁵

23 **La Goleta New Operation Building:** This project will construct a new operator's office
24 that in compliance with current industrial safety and workplace standards, such as OSHA 29
25 CFR 1910 Subpart E and Cal/OSHA Title 8. The existing building was built in the 1950s and no
26 longer satisfies modern requirements for ventilation, ergonomics, accessibility, emergency
27 egress, or functional workspace. The replacement facility will improve operator safety, provide a

⁸⁴ Cal. Code Reg., Title 24, Part 3 (California Electrical Code).

⁸⁵ Cal. Code Reg., Title 8 (Cal/OSHA Electrical Safety Orders).

functional environment that supports daily operational activities, enhance reliability, and align the site with current corporate and regulatory standards.

P. SIMP Execution (004410.000)

**TABLE GO-59
Capital Expenditures – SIMP Execution**

GAS TRANSMISSION & STORAGE (In 2025 \$)							
P. SIMP Execution	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. SIMP Execution ⁸⁶	36,307	56,282	59,730	89,342	81,051	81,493	74,790

1. Description

SIMP execution activities at the four storage fields operated by SoCalGas are managed by the GT&S organization. SIMP programmatic activities are managed by SoCalGas’s GESI organization. Costs associated with SIMP programmatic activities are summarized in the GESI Testimony (Ex. SCG-03). My testimony includes the capital costs for SIMP execution activities, which are divided into three categories: integrity assessments, remediations, and abandonments. Additional details supporting this expenditure are provided in my capital workpapers. *See* SCG-05-CWP, WP #004410.

The SIMP is critical to the safe and reliable operation of natural gas storage fields because it provides a structured framework through which the integrity of storage wells is assessed, maintained, and, where necessary, restored or retired. Storage wells operate under high pressures and complex geologic conditions and represent the primary interfaces between surface facilities and underground storage reservoirs. Over time, these wells are subject to corrosion, mechanical wear, material degradation, and changing reservoir conditions that can increase integrity risk if not proactively managed. SIMP execution activities, including integrity assessments, targeted remediations, and well abandonments, are therefore essential to identifying and addressing integrity threats before they escalate into safety incidents, environmental impacts, or loss of deliverability. By systematically managing well integrity, in accordance with state and

⁸⁶ Only SIMP execution costs are shown in this table.

1 federal regulations, SIMP supports continued operability of storage fields, protects public safety,
2 reduces operational risk, and promotes the long-term reliability of the natural gas storage system.

3 SIMP execution activities are governed by a comprehensive regulatory framework
4 established at the state and federal levels to promote the safety, integrity, and reliability of
5 underground natural gas storage operations. Primary drivers include the California Department
6 of Conservation, Geologic Energy Management Division (CalGEM) Underground Gas Storage
7 regulations set forth in Title 14, California Code of Regulations, Division 2, Chapter 4,
8 Subchapter 1, Article 5 (§1726–1726.10), which establish requirements for well construction,
9 integrity testing, monitoring, remediation, and abandonment. SIMP activities are also subject to
10 the PHMSA Underground Natural Gas Storage regulations (49 CFR § 192, Subpart A, §192.12),
11 which require operators to manage storage well integrity through risk-based integrity
12 management programs. In addition, SIMP execution must comply with applicable provisions of
13 the CPUC General Orders, site-specific Underground Storage Project Approval Letters (PALs)
14 issued by CalGEM, and other federal, state, and local environmental, safety, and occupational
15 regulations. Collectively, these regulatory requirements establish mandatory inspection intervals,
16 integrity performance standards, remediation thresholds, documentation, and reporting
17 obligations that directly drive SIMP assessment volumes, remediation scope, and abandonment
18 determinations.

19 **Integrity Assessments:** The SIMP execution team in the GT&S organization performs
20 integrity inspections of gas storage wells, including wellheads and completion assemblies, to
21 assess the pressure-containing capability of the well, detect potential leaks, and identify metal-
22 loss features in tubing and casing. These regular inspections enhance safety by reducing the risk
23 of well failure during operations. Pressure testing (1.15 x MAOP) and wall thickness inspections
24 (MFL and UT) are currently required for each gas storage well at a two-year recurring frequency,
25 unless a longer inspection interval is justified by inspection results and approved by CalGEM.
26 SoCalGas has submitted well-specific requests to CalGEM to extend the reassessment intervals
27 beyond the mandated 24-month interval. Since 2022, SoCalGas has been granted well
28 assessment extensions of up to seven years. As shown in my capital workpaper (*See SCG-05-*
29 *CWP, WP #004410*), the number of integrity assessments will increase in 2027 and will rise
30 substantially throughout the TY 2028 GRC period, as the wells that received CalGEM extensions

1 reach their new assessment deadlines and require completion of the assessments. SoCalGas
2 anticipates completing 61 integrity assessments over the 2026-2028 period.

3 **Remediations:** Integrity assessments can result in remediation activities that reduce the
4 risk of failure during operations. These remediation activities may include replacing the
5 wellhead, replacing wellhead valves, replacing the tubing and packer, casing expansions,
6 installing a new inner casing string, replacing the production liner, installing subsurface safety
7 valves, and re-drilling. These activities adhere to current regulatory standards and enhance safety
8 and operational reliability. Inner casing strings are installed to enhance wellbore integrity based
9 on assessment evaluations and to extend well life. They are typically installed on wells with
10 lower remaining life (+/- 2 years). Additionally, SoCalGas continuously monitors tubing and
11 casing annulus pressures, as required by CalGEM regulations. If sustained casing pressures are
12 detected, SoCalGas conducts diagnostic investigations and remediations, as needed, to assess
13 casing integrity. In 2022, SoCalGas initiated diagnostic investigations followed by casing
14 expansions to remediate sustained casing pressure in certain wells. Casing expansions involve
15 using specialized tools to increase casing diameter and seal the microannulus, thereby extending
16 well life. SoCalGas may perform re-drills to extend the life of the existing wells. Redrills include
17 plugging back the existing production liner, drilling a sidetrack, and constructing a new wellbore
18 while utilizing the existing surface and production casings. SoCalGas anticipates completing 32
19 remediations over the 2026-2028 period.

20 **Abandonments:** SoCalGas may abandon an injection/withdrawal well, rather than
21 continue using it for gas storage operations due to integrity considerations and risk reduction. To
22 abandon a well, SoCalGas isolates the well from the injection and withdrawal operation system,
23 removes the wellhead and casing to a specified depth, performs critical zone remediations as
24 mandated by CalGEM, installs mechanical barriers at key intervals, fills the wellbore with
25 cement to the total effective depth, and restores the surface location. All wells abandoned under
26 SIMP would have undergone logging, inspections, diagnostics, and remediation efforts prior to
27 the decision to abandon the well. SoCalGas anticipates abandoning six wells over the 2026-
28 2028 period.

29 a. **Description of RAMP Mitigations**

30 Within this cost category, there are capital costs for risk control C401 (SIMP) that were
31 presented in the 2025 RAMP Report and are listed in Table GO-60. The RAMP activities and

costs identified within this workpaper for C401 are described in Section V.P.1. All capital SIMP activities included in this testimony, including integrity assessments, remediations, and abandonments, serve as risk control measures for the risks identified under C401. These activities support the safety, integrity, and reliability of the underground gas storage system and are primarily driven by CalGEM requirements outlined in the California Underground Gas Storage regulations (Cal. Code Reg., Title 14, §1726) and the PHMSA Underground Natural Gas Storage regulations (49 CFR §192.12).

Activities that are compliance or mandated by CPUC or other agencies are listed in bold, and Appendix B attached to this testimony provides the details regarding these mandates for each control.

**TABLE GO-60
RAMP and GRC Risk Control/Mitigation Activities – Capital**

SIMP Execution				
ID	Control/Mitigation Name	2025 RAMP 2028-2031 In 2024 \$ (000s)	2028 GRC 2028-2031 In 2025 \$ (000s)	Change (\$000s)
C401	Storage Integrity Management Program (SIMP)	267,304 ⁸⁷	326,676 ⁸⁸	59,372
TOTAL		267,304	326,676	59,372

b. Description of Selection and Prioritization of RAMP Risk Mitigations

The RAMP risk mitigation efforts are associated with specific actions, such as programs, projects, processes, and utilization of technology and are designed to address a specific safety and/or reliability risk. The Company's selection and prioritization of these RAMP mitigation activities considered many factors when determining if these risk mitigation activities are an effective and worthwhile investment. The ERM process for identifying and assessing system risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

⁸⁷ The 2028-2031 RAMP capital forecast for C401 is \$269.5 million. The cost shown in the table represents the RAMP capital forecast allocated to this workpaper representing 99% of the total activity. The other portion of costs for C401 can be found in the GESI Testimony (Ex. SCG-03).

⁸⁸ SIMP execution costs included in this testimony.

1 C401 includes the risk of failure of an underground gas storage well that results in serious
2 injuries, fatalities, and/or damage to the infrastructure. As described in the 2025 RAMP Report
3 (Chapter SCG-Risk-4), there are ten potential drivers/triggers of this risk. SIMP addresses all ten
4 of these drivers, which are external corrosion; internal corrosion; manufacturing defects;
5 construction and fabrication; weather-related and outside forces such as earthquake, erosion, and
6 other natural disasters; incorrect operations (including well interventions); equipment failure;
7 third-party damage (excluding excavation damage); incorrect/inadequate asset records; and
8 execution constraints.

9 The 2025 RAMP Report also identifies seven potential consequences. All are addressed
10 by SIMP, which are serious injuries or fatalities, property damage, operational and reliability
11 impacts, adverse litigations, penalties and fines, erosion of public confidence, and environmental
12 impacts.

13 Underground gas storage assets are essential components of California's reliable energy
14 delivery infrastructure. Accordingly, SIMP activities and measures are designed to enhance the
15 safety and reliability of the natural gas infrastructure, mitigate associated risks, and comply with
16 state and federal regulations.

17 The increase in the 2028 GRC forecast relative to the forecasted amount in the 2025
18 RAMP is primarily attributed to the difference in the number of assessments included in each
19 forecast. Assessment volume is the primary cost driver, and the 2028 GRC forecast incorporates
20 the most recent projection, which is a higher number of assessments.

21 2. Forecast Method

22 The forecast method developed for capital SIMP Execution is zero-based. This approach
23 is appropriate because historical data, including the base year, is not representative of future
24 forecasted activity due to extensions approved by CalGEM for well integrity assessments and
25 real-time surveillance data requirements. SoCalGas has been receiving well assessment
26 extensions of up to seven years, in lieu of CalGEM's standard two-year well assessment
27 requirement. These mandated assessment intervals and granted extensions enable the Company
28 to forecast the timing and volume of assessments, as well as associated remediation and
29 abandonment activities, and to incorporate these forecasts into future planning. See supplemental
30 workpaper Ex. SCG-05-CWP, WP #004410, for details.

1 **1. Description**

2 The forecasts for GT Capital Tools support the tools and equipment used by GT field
3 personnel to inspect, maintain, and repair pipeline systems and associated appurtenances.
4 Investments cover the replacement of tools that are damaged, broken, technologically outdated,
5 or have reached the end of their useful life. Additionally, SoCalGas invests in new tools designed
6 to reduce customer disruptions, improve pipeline documentation, enhance system safety, and
7 protect employee safety. Calculation details are found in my capital workpapers. *See Ex. SCG-*
8 *05-CWP, WP #007060.*

9 **2. Forecast Method**

10 The forecast method developed for GT Capital Tools uses a five-year average based on
11 historical data from 2021 through 2025. This approach is appropriate because capital tool
12 requirements vary annually based on condition-driven replacement needs and the introduction of
13 new tools necessary to support evolving field operations. The historical five-year spending
14 pattern captures this variability and reflects the recurring, but non-uniform nature of capital tool
15 needs.

16 **3. Cost Drivers**

17 The underlying cost drivers for GT Capital Tools relate to:

- 18 • **Tool Replacement:** Replacement of tools exposed to harsh field conditions,
19 including shock, vibration, moisture, and dust, which accelerate wear and
20 deterioration;
- 21 • **Safety and Reliability:** Continued need to equip employees with tools that meet
22 safety standards and support reliable pipeline operations;
- 23 • **Environmental Exposure:** Tools used in rugged outdoor environments require
24 durable materials and specialized designs, increasing procurement costs; and
- 25 • **Lifecycle Management:** Planned replacement of tools that have outlived their
26 useful life to maintain compliance and operational readiness.

S. GS Capital Tools (007080.000)

TABLE GO-63
Capital Expenditures – GS Capital Tools

GAS TRANSMISSION & STORAGE (In 2025 \$)							
S. GS Capital Tools	2025 Adjusted-Recorded (000s)	Est. 2026 (000s)	Est. 2027 (000s)	Est. 2028 (000s)	Est. 2029 (000s)	Est. 2030 (000s)	Est. 2031 (000s)
1. GS Capital Tools	227	188	188	188	188	188	188

1. Description

The forecasts for GS Capital Tools support the necessary tools for storage fields, including essential components required for maintenance, repairs, and system reliability. These tools support the integration of new equipment, compliance, and operational integrity across storage facilities. The specific details regarding GS Capital Tools are found in my capital workpapers. *See* Ex. SCG-05-CWP, WP #007080.

2. Forecast Method

The forecast method developed for GS Capital Tools uses a five-year average based on historical data from 2021 through 2025. This approach is appropriate because capital tool requirements vary annually based on condition-driven replacement needs and the introduction of new tools necessary to support evolving field operations. The historical five-year spending pattern captures this variability and reflects the recurring, but non-uniform nature of capital tool needs.

3. Cost Drivers

The underlying cost drivers for GS Capital Tools relate to frequent replacement of tools exposed to harsh field conditions, including shock, vibration, moisture, and dust, which accelerate wear and deterioration. Other cost drivers include:

- Continued need to equip employees with tools that meet safety standards and support reliable storage operations;
- Adoption of advanced tools that improve operational efficiency and measurement accuracy such as mobile robotics to reduce manual labor;
- Tools used in outdoor environments require durable materials and specialized

1 equipment for compressor overhauls; and

- 2 • Planned replacement of tools that have outlived their useful life to maintain
3 compliance and operational readiness.

4 VI. RISK ASSESSMENT MITIGATION PHASE (RAMP) INTEGRATION

5 A. GRC Risk Controls/Mitigations and Benefit Cost Ratios

6 As previously discussed, certain costs supported in this testimony are for
7 Control/Mitigation activities described in SoCalGas's 2025 RAMP Report⁸⁹ for activities
8 designed to reduce risk. Specifically, the controls and mitigations in this testimony were included
9 in: SCG-Risk-1 (Excavation Damage), SCG-Risk-2 (High Pressure Gas System), and SCG-Risk-
10 4 (Underground Gas Storage). As further reference, a roadmap matching controls and mitigations
11 to both the 2025 RAMP and the TY 2028 GRC testimony is appended to Ex. SCG-02B/SDGE-
12 02B. Table GO-64 summarizes the Control/Mitigation BCRs based on the costs⁹⁰ in this
13 testimony and estimated in the 2025 RAMP with the associated BCRs. Controls/Mitigations that
14 are mandated by CPUC or other agencies are listed in bold in Table GO-64, and are listed in
15 Appendix B, attached to this testimony, providing the details regarding the respective mandates
16 for each Control/Mitigation. Appendix F provides a GRC workpaper breakdown for the RAMP
17 controls and mitigations sponsored in this testimony.

18 **TABLE GO-64**
19 **Comparison of RAMP and GRC Risk Control/Mitigation Benefit Cost Ratios**
20

GAS TRANSMISSION & STORAGE							
ID	Control/Mitigation Name	2025 RAMP Direct, in 2024\$ (000s) 2028-2031			2028 GRC Direct, in 2025 \$ (000s) 2028-2031		
		BCR Societal	BCR Hybrid	BCR WACC	BCR Societal	BCR Hybrid	BCR WACC
C002	Damage Prevention Activities⁹¹	18.23	19.49	18.28	151.11	159.91	151.46
C010	Pipeline Monitoring Technologies	1.46	1.10	0.93	7.27	5.23	4.43

⁸⁹ A.25-05-010.

⁹⁰ Post-test year forecasts can be found in the detailed workpapers Ex. SCG-28-WP and Ex. SCG-28-CWP.

⁹¹ Common risk mitigation with GESI and GD witness areas.

GAS TRANSMISSION & STORAGE							
		2025 RAMP Direct, in 2024\$ (000s) 2028-2031			2028 GRC Direct, in 2025 \$ (000s) 2028-2031		
ID	Control/Mitigation Name	BCR Societal	BCR Hybrid	BCR WACC	BCR Societal	BCR Hybrid	BCR WACC
C014	Storage HP Field Maintenance – Aboveground Facilities	0.33	0.35	0.33	0.31	0.33	0.31
C016	Storage HP Field Maintenance - Aboveground Piping	0.31	0.33	0.31	0.29	0.30	0.29
C019	Storage HP Retrofits and Upgrades to Purification Equipment	14.71	15.76	14.71	10.41	11.06	10.46
C104	Cathodic Protection – Capital	3.67	3.92	3.67	5.64	6.05	5.73
C105	SCADA Operations	1.85	1.85	1.85	3.54	3.56	3.56
C108	Cathodic Protection – Maintenance	20.99	22.43	20.98	43.77	46.22	43.76
C109	Control Room Monitoring Operation and Fatigue Management	0.73	0.79	0.73	0.36	0.39	0.37
C113	Leak Repair	3.30	3.31	3.30	10.18	10.65	10.23
C117	Leak Survey & Patrol	1.46	1.57	1.47	0.57	0.60	0.57
C125	Pipeline Relocation/ Replacement	0.21	0.08	0.06	0.29	0.09	0.06
C126	Shallow/Exposed Pipe Remediations	0.68	0.14	0.09	0.49	0.08	0.04
C132	Pipeline Maintenance	18.81	19.78	18.82	15.71	16.48	15.72
C136	Compressor Stations - Capital	3.73	1.66	1.29	8.71	3.64	2.84
C142	Compressor Station – Maintenance	0.40	0.42	0.40	0.29	0.31	0.29

GAS TRANSMISSION & STORAGE							
ID	Control/Mitigation Name	2025 RAMP Direct, in 2024\$ (000s) 2028-2031			2028 GRC Direct, in 2025 \$ (000s) 2028-2031		
		BCR Societal	BCR Hybrid	BCR WACC	BCR Societal	BCR Hybrid	BCR WACC
C145	Class Location (Hydrotest)	0.48	0.52	0.48	6.74	7.13	6.74
C151	Measurement & Regulation Station – Capital	0.83	0.32	0.24	1.42	0.53	0.39
C155	Measurement & Instrumentation Maintenance	1.48	1.58	1.48	1.34	1.41	1.34
C160	Odorization	0.07	0.07	0.07	0.11	0.12	0.11
C401	Storage Integrity Management Program (SIMP) ⁹²	1.80	0.75	0.74	3.38	0.97	0.96
C402	Well Abandonment/ Replacement/Demo Verification and Monitor	4.00	1.65	1.64	1.92	0.69	0.68
C408	Storage Field Maintenance – Underground Components	10.27	10.38	10.35	5.54	5.59	5.56

B. Justification For Proposed Mitigations with BCRs <1

The Risk-Based Decision-Making Framework (RDF) prescribes a methodology for calculation of BCRs under three discount rates as detailed in Table GO-64. Certain of these calculations result in a BCR that is less than one. SoCalGas justifies the selection of these mitigations based on a thorough analysis of operational considerations. Details regarding the justification for each mitigation are provided in Table GO-65 and are compiled with all mitigations in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B). A list of compliance drivers is attached to this testimony in Appendix B.

⁹² Common risk mitigation with GESI witness area.

1
2
3

**Table GO-65
Control/Mitigation Justification**

ID	Control/Mitigation Name	Justification
C014	Storage HP Field Maintenance – Aboveground Facilities	<p>These activities are required to comply with federal and state regulations, including 49 CFR §192.605 and § 192.12, as well as applicable environmental and air quality regulations, which establish standards for the safe operation, monitoring, and maintenance of storage compressors, dehydration systems, and auxiliary equipment. These activities include inspections, preventive maintenance, equipment monitoring, emissions control system maintenance, and timely repairs necessary to maintain compressors, treatment systems, and supporting infrastructure in a safe and operable condition. They also support emergency preparedness and compliance with CARB methane monitoring and emissions requirements.</p> <p>Therefore, despite a benefit-cost ratio below 1, these activities are necessary to meet regulatory requirements, protect public and employee safety, maintain system reliability, and reduce the likelihood and consequences of equipment failures and environmental incidents.</p>
C016	Storage HP Field Maintenance – Aboveground Piping	<p>These activities are required to comply with federal and state regulations, including 49 CFR §192.605–§ 192.613, which establish requirements for the inspection, maintenance, and safe operation of pipelines and associated surface piping at storage facilities. These activities include routine inspections, valve maintenance, corrosion control, leak detection, integrity assessments, and timely repairs necessary to identify abnormal operating conditions and maintain piping systems in a safe and operable condition. They also support emergency response obligations and safe system isolation during maintenance or unplanned events. Therefore, despite a benefit-cost ratio below 1, these activities are necessary to meet regulatory requirements, protect public and employee safety, maintain system reliability, and reduce the likelihood and consequences of pipeline failures, service disruptions, and environmental impacts.</p>
C109	Control Room Monitoring Operation and Fatigue Management	<p>A 24/7 control room with real-time operational monitoring and control enables the Company to quickly detect, prevent, and respond to high-pressure</p>

ID	Control/Mitigation Name	Justification
		<p>gas pipeline failures by identifying rupture indicators such as pressure drops, low-pressure alarms, telemetry issues, and external emergency calls. Continuous monitoring allows controllers to recognize abnormal operating conditions early and take proactive actions—such as adjusting valves and compressor stations or dispatching field personnel—to prevent issues from escalating into emergencies. In the event of a failure, the control room supports a rapid response by isolating affected pipeline segments, coordinating field remediation, and implementing contingency plans to protect public safety, minimize environmental impacts, and maintain system reliability. In addition, these activities are needed to maintain compliance with 49 CFR §192.631, §192.605, §192.615, and §192.636. Accordingly, the investment is warranted despite a BCR below 1.</p>
C117	Leak Survey & Patrol	<p>Leak surveys, patrols, and standby services are mandated and required per 49 CFR §192.705–192.723 and CPUC GO 112-F to identify leaks, abnormal operating conditions, third-party activities, and other threats that may affect safe operation, with increased frequency required for higher-risk and re-classified locations. These activities support emergency response obligations under 49 CFR §192.615 and California oversight requirements, including monitoring excavation near high-pressure pipelines and responding to natural disasters. Therefore, despite a BCR below 1, the work is necessary to meet regulatory requirements, protect public safety, and reduce the likelihood of pipeline failures.</p>
C125	Pipeline Relocation/ Replacement	<p>Pipeline replacements are required to address deteriorated conditions, external damage, geohazards, right-of-way constraints, and class location changes identified through inspections and assessments. These activities support compliance with 49 CFR § 192 Subpart M. Despite a BCR below 1, these projects are necessary to reduce integrity risks, support safe operation, and meet mandatory regulatory obligations across the transmission system. Activities such as methane reduction and gas capture under SB 1371 are also required to ensure continued compliance with environmental and regulatory standards.</p>

ID	Control/Mitigation Name	Justification
C126	Shallow/Exposed Pipe Remediations	Projects addressing shallow or exposed pipelines caused by erosion, land movement, hydrotechnical issues, or agricultural activities are required to reduce risks from corrosion, third-party damage, and instability through added cover or protective measures and maintain compliance with 49 CFR § 192 Subpart M. Despite a BCR below 1, these activities are necessary to maintain system safety, reliability and to maintain compliance with federal regulations.
C142	Compressor Station – Maintenance	Despite a BCR below 1, these activities are necessary to meet mandatory regulatory and safety requirements (49 CFR § 192 operational and maintenance requirements, § 192.605 and § 192.615 emergency planning, CPUC GO 112-F, and SCAQMD and other air quality regulations) and to address age-related equipment degradation. These projects are essential to maintaining safe and reliable compressor station operations, ensuring system pressure control, reducing unplanned outages, and supporting transmission system reliability under both normal and peak operating conditions.
C151	Measurement & Regulation Station Capital	Despite a BCR below 1, these activities are necessary to meet mandatory safety, measurement accuracy, and operational requirements (49 CFR § 192 pressure control and overpressure protection requirements, PHMSA integrity and monitoring expectations, and CPUC GO 112-F). These projects address aging and obsolete infrastructure, support evolving regulatory expectations, and enable advanced monitoring, SCADA integration, and RNG interconnections, which are essential to maintaining system safety, reliability, and compliance across the transmission network.
C160	Odorization	Despite a BCR below 1, odorization activities are necessary to meet mandatory public safety and pipeline safety requirements (49 CFR §192.625 odorization standards and PHMSA operating requirements) which requires gas to contain a readily detectable odorant. These activities, including routine odor-intensity testing, odorant storage and handling, and continuous odorant availability, are essential to protecting public safety, supporting early leak detection, and maintaining regulatory compliance across the transmission system.

ID	Control/Mitigation Name	Justification
C401	Storage Integrity Management Program (SIMP)	<p>This mitigation is required to comply with both federal and state regulations governing underground gas storage projects. At the federal level, 49 CFR §192.12, effective in 2020, mandates the implementation of an integrity management framework consistent with API Recommended Practice 1171 to promote the safe and reliable operation of underground gas storage facilities. At the state level, underground natural gas storage facilities are regulated under the Cal. Code Reg., Title 14, §1726, effective in 2018, which established requirements for underground natural gas storage projects. In accordance with these regulatory requirements, SoCalGas performs monitoring activities and integrity assessments on gas storage wells at mandated prescribed intervals to identify potential issues. Subsequently, assessment and monitoring data are evaluated to determine the actions necessary to maintain well integrity, regulatory compliance, and safety. Post-assessment mitigation measures may include well remediation or abandonment, as appropriate.</p>
C402	Well Abandonment/ Replacement/Demo Verification and Monitor	<p>Gas storage well abandonment, replacement, and workover activities are required to comply with state and federal regulations, including CalGEM requirements for Underground Gas Storage projects (Cal. Code Reg., Title 14, §1726, <i>et seq.</i>) and PHMSA regulations (49 CFR §192.12), which establish standards for well integrity, monitoring, maintenance, and decommissioning. These activities are necessary for wells to meet mechanical integrity requirements, operate safely under changing reservoir conditions, and be properly abandoned when no longer fit for service. Replacement wells and workovers are essential to maintain injection and withdrawal capacity, address degradation mechanisms such as corrosion, material fatigue, and equipment failure, and support safe and reliable storage field operations. Continued assessment and monitoring activities also provide critical data to identify emerging integrity risks early and support timely, risk-informed intervention. Therefore, despite a BCR below 1, these activities are necessary to meet regulatory</p>

ID	Control/Mitigation Name	Justification
		requirements, maintain system reliability, protect public and employee safety, and reduce the likelihood of well failures and associated impacts.

1 **C. Changes From 2025 RAMP Report**

2 Since the timing of the filing of the 2025 RAMP Report in May 2025, some
3 circumstances may have changed that impact the control/mitigation scope – including units,
4 costs, and other factors that influence the forecast. In addition, updates may have occurred that
5 affect the underlying assumptions used to calculate the BCRs, as described in the RDF
6 Integration testimony (Ex. SCG-02B/SDGE-02B). Key changes impacting the forecasts include:

7 **Organization of RAMP and GRC:** The 2025 RAMP Report is organized into risk
8 chapters based on the types of risk events being mitigated, whereas the 2028 GRC is organized
9 by witness areas aligned with the Company’s operational structure. As a result, individual
10 RAMP mitigation costs may be allocated across multiple witness areas in the 2028 GRC. My
11 testimony has common risk mitigations with the GESI witness area (Ex. SCG-03) and GD
12 witness area (Ex. SCG-04).

13 **Recategorization of Aboveground Gas Storage Assets:** As part of the annual
14 Enterprise Risk Registry process, aboveground gas storage assets and the associated controls and
15 mitigations were recategorized, moving from the High Pressure Gas System risk to the Gas
16 Storage System risk.

17 **Differences in Forecast Methodology:** In addition to structural differences, the 2025
18 RAMP Report and 2028 GRC forecasts for GT&S were developed using different forecasting
19 methodologies, reflecting the distinct objectives of each filing.

20 The 2025 RAMP Report forecast was developed by using alternate forecasting methods.
21 The 2028 GRC forecast reflects the current understanding of system conditions and program
22 needs, allowing SoCalGas to apply forecasting methods that are better aligned with current
23 operational requirements.

24 For these reasons, the 2025 RAMP Report and 2028 GRC forecasts should be viewed as
25 complementary rather than directly comparable. Variances between the two filings should
26 therefore be interpreted in the context of these differing structures and methodologies. The
27 difference in structure, cost, and units has been identified and explained, where applicable, in
28 individual sections of this testimony.

1 **D. Feedback from Safety Policy Division and Parties**

2 The Commission’s Safety Policy Division (SPD) issued their assessment report on
3 October 10, 2025, regarding the Companies’ 2025 RAMP Reports. Parties subsequently served
4 opening and reply comments on November 17, 2025, and December 1, 2025, respectively.
5 Appendix B, 2025 RAMP Report Stakeholder Recommendations and Companies’ Response, in
6 the RDF Integration testimony (Ex. SCG-02B/SDGE-02B) appends a summary of the feedback
7 and recommendations received and the Companies’ responses. Appendix E addresses SPD 4.5,
8 which asks for a list of relevant surface controls, their asset locations, their owning chapter, and
9 where the BCRs are reported. These surface controls are in SCG-Risk-4 (Gas Storage System)
10 and their BCRs are provided at the field level, which is the level of granularity provided in the
11 Main Workbook.

12 **E. CAVA Integration**

13 Pursuant to Commission decisions in the Climate Adaptation OIR (R.18-04-019),
14 SoCalGas performed a Climate Adaptation Vulnerability Assessment (CAVA) focused on years
15 2030, 2050, and 2070, with the aim of identifying asset and operational vulnerabilities to climate
16 hazards across the SoCalGas system. Some of the climate hazards that will have short- and long-
17 term ramifications in the Southern California region include extreme temperatures, wildfire,
18 inland flooding, coastal flooding and erosion, and landslides. Climate change is recognized as a
19 factor that can drive, trigger, or exacerbate multiple RAMP risks. Implementing climate change
20 adaptation measures and integrating climate vulnerability considerations into RAMP controls
21 and mitigations can enhance system infrastructure longevity and reduce the severity of long-term
22 negative climate impacts. The controls and mitigations described in further detail in this chapter,
23 as shown below, align with the goal of increasing SoCalGas’s physical and operational resilience
24 to the increasing frequency and intensity of climate hazards. Additional information on the
25 CAVA is provided in the Testimony of GESI (Ex. SCG-03).

TABLE GO-66
RAMP Controls and Mitigations Aligned with Climate Hazards

Potential Climate Hazard(s)	Relevant ID	Relevant Control/Mitigation	Risk Chapter
Inland Flooding and Landslides	C010	Pipeline Monitoring Technologies	High-Pressure Gas System
Inland and Coastal Flooding, Coastal Erosion, Landslides, and Wildfires	C014	Storage Field Maintenance Aboveground Facilities	
Inland and Coastal Flooding, Coastal Erosion, Landslides, and Wildfires	C016	Storage Field Maintenance Aboveground Piping	
Inland Flooding and Landslides	C019	Storage Upgrade to Purification Equipment	
Inland Flooding and Landslides	C104	Cathodic Protection – Capital	
Inland Flooding and Landslides	C105	SCADA Operations	
Inland Flooding and Landslides	C109	Control Room Monitoring, Operation and Fatigue Management	
Inland Flooding and Landslides	C113	Leak Repair	
Inland Flooding and Landslides	C125	Pipeline Relocation/Replacement	
Inland Flooding and Landslides	C126	Shallow Exposure/Exposed Pipe Remediations	
Inland Flooding, Landslides, and Wildfires	C401	Storage Integrity Management Program (SIMP)	
Inland and Coastal Flooding, Coastal Erosion, and Landslides	C402	Well Abandonment, Replacement Demo Verification, and Monitoring Practices	
Inland Flooding, Landslides, and Wildfires	C408	Storage Field Maintenance – Underground Components	

VII. DEFERRED WORK

D.24-12-074 requires that for the 2028 GRC, if SoCalGas requests funding for work that was authorized in the TY 2024 GRC but not yet performed, SoCalGas must use a Deferred Work Framework (DWF) that shows the deferred work related to safety and reliability at the program level. The DWF and principles are described in the Compliance testimony (Ex. SCG-30/SDGE-36). This testimony requests funds for the qualifying deferred work projects or activities listed in Table GO-67. The circumstances that caused the delay and any changes in scope are described below.

The Commission has consistently acknowledged that a utility may reprioritize funds that were authorized in the prior GRC.⁹³ GT&S continuously evaluates its portfolio of planned work to align with system safety, asset integrity, environmental stewardship, and regulatory compliance requirements. As part of this ongoing process, GT&S routinely reassesses project timing, scope, and priority based on current system conditions, resource availability, risk assessments, and operational needs. GT&S remains committed to completing all necessary work in a timely manner to maintain safe, reliable, and resilient GT&S operations, consistent with applicable codes, standards, and regulations.

**TABLE GO-67
Deferred Work**

Deferred Work Program/Activity	O&M/ Capital	TY 2024 GRC Exhibit	TY2024 Authorized Funding In 2021 \$ (000s)	TY2028 Funding Request In 2025 \$ (000s)
A. AC – KVS Coolers Repl Project (E6-E8)	Capital	SCG-10-CWP-R 00411	12,000	11,098
B. AC – East Field Oil Shipping Line	Capital	SCG-10-CWP-R 00413	3,400	3,000

A. AC - KVS Coolers Repl Project (E6-E8)

1. Activity Scope

This project replaces aging and obsolete KVS Compressor 1–3 fin-fan heat exchanger cooling systems and support structures at Aliso Canyon Storage facility to improve reliability, performance, and maintainability. The scope includes phased reconstruction of cooler support structures and installation of new, more efficient fin-fan coolers for units K1, K2, and K3. Each new cooling bundle is designed to handle engine jacket water, lubrication oil water, and air manifold cooling water, enhancing heat rejection and operational stability. The work encompasses engineering, design, procurement, installation, and commissioning of the upgraded systems. The scope of this activity as requested in TY 2024 GRC has not changed.

2. Reason for Deferral

This project was deferred due to the reprioritization of capital to address higher priority operational, safety, and regulatory compliance requirements. This reprioritization was primarily

⁹³ See D.24-12-074 at 1091 (Ordering Paragraph (OP) 11); D.20-01-002 at 38.

1 driven by higher than forecasted costs associated with SCAQMD Regional Clean Air Incentives
2 Market (RECLAIM⁹⁴ compliance projects, which required reallocation of capital resources.
3 Representative projects executed in lieu of the deferred work include the Playa del Rey (PDR)
4 and Aliso Canyon RECLAIM Lean Burn projects. The PDR RECLAIM project experienced
5 schedule extensions and scope expansion, including the addition of air cooler exchangers, fin-fan
6 coolers, and new electrical infrastructure necessary to support supercharger installations required
7 for permit compliance. Similarly, the Aliso Canyon RECLAIM Lean Burn project required
8 additional engineering and construction efforts beyond original estimates to meet applicable
9 regulatory requirements.

10 The increases in scope and associated costs of critical compliance driven projects
11 constrained available capital funding, necessitating the deferral of the AC - KVS Coolers
12 Replacement Project.

13 B. AC – East Field Oil Shipping Line

14 1. Activity Scope

15 This project replaces an existing plastic oil shipping line in the east field with a new steel
16 pipeline to improve safety and system reliability. The current plastic line is vulnerable to heat,
17 damage, and degradation, creating a risk of leaks, spills, and fire hazards, particularly near
18 environmentally sensitive areas. The upgrade includes removal of the existing line and
19 installation of a buried, protected steel pipeline designed for service conditions. The primary
20 driver is risk mitigation to prevent spills and fire incidents while supporting compliance with
21 safety and environmental regulations. The scope of this activity as requested in TY 2024 GRC
22 has not changed.

23 2. Reason for Deferral

24 This project was deferred due to the reprioritization of capital to address higher priority
25 operational, safety, and regulatory compliance requirements. This reprioritization was primarily
26 driven by higher than forecasted costs associated with SCAQMD RECLAIM compliance
27 projects, which required reallocation of capital resources. Representative projects executed in

⁹⁴ 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.

1 lieu of the deferred work include the Playa del Rey (PDR) and Aliso Canyon RECLAIM Lean
2 Burn projects. The PDR RECLAIM project experienced schedule extensions and scope
3 expansion, including the addition of air cooler exchangers, fin-fan coolers, and new electrical
4 infrastructure necessary to support supercharger installations required for permit compliance.
5 Similarly, the Aliso Canyon RECLAIM Lean Burn project required additional engineering and
6 construction efforts beyond original estimates to meet applicable regulatory requirements.

7 The increases in scope and associated costs of critical compliance driven projects
8 constrained available capital funding, necessitating the deferral of the AC – East Field Oil
9 Shipping Line project.

10 **VIII. CONCLUSION**

11 SoCalGas respectfully requests that the Commission adopt the GT&S forecasts for TY
12 2028 O&M and for capital as reflected in Appendix C, as sponsored in this testimony. The
13 record demonstrates that these forecasts are reasonable, necessary, and cost-effective, and that
14 they are fully aligned with the Commission’s core objectives of safety, reliability, affordability,
15 and operational efficiency.

16 The forecasts reflect a disciplined and transparent forecasting methodology. O&M
17 estimates are anchored in BY 2025 foundation, with targeted incremental adjustments to reflect
18 identifiable changes in workload, regulatory requirements, asset conditions, and system
19 complexity. Capital forecasts use zero-based or historical-average methodologies, as appropriate,
20 and are supported by identified projects, regulatory mandates, and demonstrated system needs.
21 Taken together, these approaches provide a prudent and well-supported estimate of the resources
22 required to operate and maintain the GT&S system safely and reliably at the lowest reasonable
23 cost.

24 The activities funded through these forecasts are essential to meeting SoCalGas’s safety
25 and compliance obligations under applicable federal and state requirements, including PHMSA’s
26 49 CFR § 192, CPUC GO 112-F, CalGEM’s underground storage requirements, CARB’s
27 methane emission regulations, and federal and state greenhouse gas reporting programs. These
28 mandates require continuous inspection, monitoring, maintenance, integrity testing, and
29 extensive documentation across the transmission system, compressor stations, and Company’s
30 four underground storage fields. This associated work is not discretionary; rather it is
31 foundational to safe natural gas operations in Southern California.

1 The forecasts further support critical reliability and resilience functions across the GT&S
2 system. Funded activities include compressor and storage stations inspection and maintenance,
3 leak repairs, right-of-way management, pipe coating and corrosion mitigation, and system
4 modernization initiatives. Targeted incremental investments associated with automated valve
5 maintenance, methane monitoring, vegetation management, damage prevention, operational
6 technology monitoring, pipeline class-location impacts, and enhanced personnel protective
7 equipment and training reflect evolving risk profiles and regulatory expectations. In addition,
8 integrity work performed under the SIMP remains vital to maintaining safe, compliant and
9 reliable underground gas storage operations. These prudent investments reduce the likelihood of
10 system failures, outages, and environmental impacts, and help mitigate higher long-term costs.

11 Environmental compliance programs included in the forecasts, such as the CARB Oil &
12 Gas Rule leak-detection requirements and Subpart W greenhouse gas measurements, advance
13 California's emissions-reduction objectives while keeping storage fields and compressor stations
14 compliant with state and federal regulations.

15 Taken together, the GT&S forecast provides the resources necessary to perform the daily
16 work that protects public and employee safety, maintains system reliability, fulfills regulatory
17 obligations, and meets customer needs across the Company's service territory. The requested
18 costs are appropriate to meet these responsibilities and represent a reasonable and necessary
19 investment to sustain safe and reliable service at the lowest reasonable cost. For these reasons,
20 SoCalGas respectfully requests Commission approval of the O&M and capital forecasts for TY
21 2028 and associated years.

22 Accordingly, SoCalGas respectfully requests that the Commission approve the proposed
23 TY 2028 O&M funding level of \$129,075,000, and capital expenditure forecast as reflected in
24 Appendix C.

25 This concludes my prepared direct testimony.

1 **IX. WITNESS QUALIFICATIONS**

2 My name is Gina Orozco. My business address is 555 West Fifth Street, Los Angeles,
3 California, 90013. I am employed by SoCalGas as Vice President – GT&S Operations, with
4 responsibility for the SoCalGas GT&S systems, and SDG&E’s Moreno Compressor Station. I
5 have been employed by SoCalGas since 1990. I have 36 years of experience in the utility
6 industry. While at SoCalGas, I have held various staff and line positions in the functional areas
7 of GT&S Operations, Gas Distribution Field Operations and Technical Services, Gas
8 Engineering and System Integrity, Gas Operations Services, Gas System Operations, and Human
9 Resources.

10 My present responsibilities include providing leadership to professionals responsible for
11 scheduling, controlling, transporting, and storing gas energy to support safe and reliable delivery
12 through the storage and transmission pipeline network. This encompasses the operation,
13 maintenance, installation, and replacement of GT&S systems at SoCalGas and SDG&E’s
14 Moreno Compressor Station. Furthermore, I lead the GT&S PMO group, which supports project
15 management standards and frameworks, establishes governance structures, and provides
16 technical support for GT&S project management and construction activities. These
17 responsibilities include procurement, process improvements to enhance efficiency, development
18 and management of O&M and capital budgets, and Regulatory & Performance Management.

19 I earned a Bachelor of Science Degree in Electrical Engineering from California State
20 University, Los Angeles, and an Executive Master of Business Administration from Claremont
21 Graduate University.

22 I sponsor the TY 2028 GRC testimony for SoCalGas’s GT&S O&M expenses and capital
23 spending plan.

24 I have previously testified before the Commission.

APPENDIX A
GLOSSARY OF TERMS

APPENDIX A
Glossary of Terms

ACRONYM	DEFINITION
AC	Alternating Current
API	American Petroleum Institute
AV	Audio-visual
AWS	Amazon Web Services
BCR	Benefit Cost Ratio
BTS	Backbone Transportation Service
BY	Base Year
CalGEM	California Geologic Energy Management Division
CalTrans	California Department of Transportation
CARB	California Air Resources Board
CAT	Core Aggregation Transportation
CAVA	Climate Adaptation Vulnerability Assessment
CCM	Control Center Modernization
CCR	California Code of Regulations
CEH	California Energy Hub
CFR	Code of Federal Regulations
CP	Cathodic Protection
CPUC	California Public Utilities Commission
CTA	Core Transportation Agent
CUPA	Certified Unified Program Agencies
DC	Direct Current
DOT	United States Department of Transportation
DRS	Distribution Regulator Station
DWF	Deferred Work Framework
ELS	Electronic Logging System
EPA	Environmental Protection Agency
EPM	Electronic Pressure Monitors
ERM	Enterprise Risk Management
ESD	Emergency Shutdown
ETS	Electrical Test Station
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FOM	Field Operations Manager
FTE	Full-Time Equivalent
FR	Flame Resistant
GESI	Gas Engineering & System Integrity
GHG	Greenhouse Gas

ACRONYM	DEFINITION
GHGRP	Greenhouse Gas Reporting Program
GIS	Geographic Information System
GMP	Geohazard Management Program
GO	General Order
GS	Gas Storage
GSEP	Gas Safety Enhancement Program
GT	Gas Transmission
GT&S	Gas Transmission & Storage
HCA	High Consequence Area
I&C	Instrumentation & Control
ICS	Incident Command Structure
IOC	Integrated Operations Center
IPR	Inflow Performance Relationship
IT	Information Technology
LDAR	Leak Detection and Repair
LEL	Lower Explosive Limit
MAOP	Maximum Allowable Operating Pressure
MCC	Motor Control Center
MFL	Magnetic Flux Leakage
MOC	Management of Change
MQTT	Message Queuing Telemetry Transport
MRR	Mandatory Greenhouse Gas Reporting Regulation
MSA	Meter Set Assemblies
NAESB	North American Energy Standards Board
NFPA	National Fire Protection Association
NTSB	National Transportation Safety Board
OFO	Operational Flow Order
OPM	Optical Pipeline Monitoring
OSHA	Occupational Safety and Health Administration
OT	Operational Technology
PDC	Power Distribution Center
PDR	Playa Del Rey
PHMSA	Pipeline Hazardous Materials Safety Administration
PLC	Programmable Logic Controller
PLS	Pressure Limiting Station
psig	Pounds per Square Inch Gauge
RDF	Risk-Based Decision-Making Framework
RECLAIM	Regional Clean Air Initiatives Market
RNG	Renewable Natural Gas
ROW	Right of Way
RP	Recommended Practice

ACRONYM	DEFINITION
RTU	Remote Terminal Unit
SAPT	Standard Annular Pressure Test
SB	Senate Bill
SBCAPCD	Santa Barbara County Air Pollution Control District
SCADA	Supervisory Control and Data Acquisition
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCG	SoCalGas
SCR	Selective Catalytic Reduction
SIMP	Storage Integrity Management Program
SIMPBA	SIMP One-Way Balancing Account
SPD	Safety Policy Division
TEG	Tri-ethylene Glycol
TIMP	Transmission Integrity Management Program
TSA	Transportation Security Administration
TY	Test Year
UIC	Underground Injection Control
UT	Ultrasonic Testing
VOC	Volatile Organic Compound
VSAT	Very Small Aperture Terminal

APPENDIX B
CONTROLS AND MITIGATIONS COMPLIANCE DRIVER ROADMAP

APPENDIX B

Controls and Mitigations Compliance Driver Roadmap

The table below indicates the compliance drivers that underpin Risk Controls/Mitigations identified in testimony.

Control/ Mitigation ID	Control/Mitigation Description	Compliance Driver
C002	Damage Prevention Activities	49 CFR § 192 CPUC GO-112F California Gov Code 4216
C014	Storage HP Field Maintenance – Aboveground Facilities	PHMSA, OSHA, EPA, FERC, NTSB, FEMA, CPUC, DOT. LA County, CA state and city compliance requirements, CARB, SCAQMD, National Fire Protection Agency (NFPA), CalGEM
C016	Storage HP Field Maintenance – Aboveground Piping	PHMSA, OSHA, EPA, FERC, NTSB, FEMA, CPUC, DOT. LA County, CA state and city compliance requirements, CARB, SCAQMD, National Fire Protection Agency (NFPA), CalGEM, California Code of Regulations, Title 14. Section 1774.2.
C019	Storage HP Upgrade to Purification Equipment	PHMSA, OSHA, Env Protection Agency (EPA), FERC, NTSB, FEMA, CPUC GO 58A, DOT, SCAQMD, TSA - Transportation Security Administration, CalGEM, National Fire Protection Agency (NFPA)
C104	Cathodic Protection – Capital	49 CFR 192, Subpart I
C105	SCADA Operations	49 CFR § 192.631
C108	Cathodic Protection – Maintenance	49 CFR 192, Subpart I
C109	Control Room Monitoring Operation and Fatigue Management	49 CFR §192.631 49 CFR §192.605 49 CFR §192.615 49 CFR §192.636
C113	Leak Repair	49 CFR 192 Subpart M
C117	Leak Survey & Patrol	49 CFR 192 Subpart M

Control/ Mitigation ID	Control/Mitigation Description	Compliance Driver
C125	Pipeline Relocation/Replacement	49 CFR 192 Subpart M
C126	Shallow/Exposed Pipe Remediations	49 CFR 192 Subpart M
C132	Pipeline Maintenance	49 CFR 192 Subpart M
C136	Compressor Stations – Capital	49 CFR 192 Subpart M
C142	Compressor Station – Maintenance	49 CFR 192 Subpart M
C145	Class Location (Hydrotest)	49 CFR 192 Subpart L
C151	Measurement & Regulation Station – Capital	49 CFR 192 Subpart M
C155	Measurement & Instrumentation – Maintenance	49 CFR 192 Subpart M
C160	Odorization	49 CFR 192 Subpart L
C401	Storage Integrity Management Program (SIMP)	CPUC, CalGEM (California Code of Regulations, Title 14, Division 2, Chapter 4, Subchapter 1, Article 4, Section 1726), PHMSA (49 CFR Part §192, Subpart A, 192.12, Underground Natural Gas Storage Facilities)
C402	Well Abandonment, Replacement, Demo Verification, and Monitoring Practices	CalGEM (CCR, Title 14, Division 2, Chapter 4, Subchapter 1, Article 4, Section 1726, PHMSA Regulations (49 CFR Part §192, Subpart A, 192.12, Underground Natural Gas Storage Facilities)
C408	Storage Field Maintenance – Underground Components	CalGEM (CCR, Title 14, Division 2, Chapter 4, Subchapter 1, Article 4, Section 1726, PHMSA Regulations (49 CFR Part §192, Subpart A, 192.12, Underground Natural Gas Storage Facilities)

APPENDIX C
CAPITAL EXPENDITURES

Southern California Gas Company
Capital Expenditures
(In Thousands of 2025 \$)

Gas Transmission & Storage	2026	2027	2028	2029	2030	2031
Total Capital	316,113	384,533	515,206	549,285	572,537	593,402
2026 - 2028 Capital Request	316,113	384,533	515,206	-	-	-
Post-Test Year Capital Forecast	-	-	-	549,285	572,537	593,402

Southern California Gas Company
Capital Expenditures
(In Thousands of 2025 \$)

Gas Transmission & Storage							
2026 - 2028 Capital Request							
Category	Workpaper Sub	Workpaper Description	In-Service Date	2026	2027	2028	
GT Pipelines New Additions	003010.001	GT Pipelines New Additions	Routine	1,281	1,279	1,278	
	003010.002	GT Pipelines New Additions	Routine	67	67	67	
GT Pipelines New Additions Total				1,348	1,346	1,345	
GT Pipelines Replacements	003020.001	GT Pipelines Replacements	Routine	34,314	53,216	75,694	
GT Pipelines Replacements Total				34,314	53,216	75,694	
GT Leak Repair	003020.001	GT Leak Repair	Routine	16,212	16,198	16,190	
GT Leak Repair Total				16,212	16,198	16,190	
GT Pipeline Relocation - Freeway	003030.001	GT Pipeline Relocation - Freeway	Routine	2,122	2,121	2,120	
GT Pipeline Relocation - Freeway Total				2,122	2,121	2,120	
GT Pipeline Relocation - Franchise/Private/ROW	003040.001	GT Pipeline Relocation - Franchise/Private/ROW	Routine	2,593	2,591	2,591	
	003040.002	GT Pipeline Relocation - Franchise/Private/ROW	Routine	5,511	5,507	5,504	
GT Pipeline Relocation - Franchise/Private/ROW Total				8,104	8,098	8,095	
GT Compressor Stations	003050.001	GT Compressor Stations	Routine	8,424	21,632	26,261	
GT Compressor Stations Total				8,424	21,632	26,261	
GT Cathodic Protection	003060.001	GT Cathodic Protection	Routine	11,338	8,752	8,220	
GT Cathodic Protection Total				11,338	8,752	8,220	
GT Measurement & Regulation Stations	003080.001	GT Measurement & Regulation Stations	Routine	5,561	33,999	53,234	
GT Measurement & Regulation Stations Total				5,561	33,999	53,234	
GT Security and Auxiliary Equipment	003090.001	GT Security and Auxiliary Equipment	Routine	11,313	16,247	17,933	
GT Security and Auxiliary Equipment Total				11,313	16,247	17,933	
GT Technology & Software	003500.001	GT Technology & Software	Routine	5,370	5,529	2,871	
GT Technology & Software Total				5,370	5,529	2,871	
GS Compressor Stations	004010.001	GS Compressor Stations	Routine	15,853	5,847	14,255	
GS Compressor Stations Total				15,853	5,847	14,255	
GS Wells	004020.001	GS Wells	Routine	24,438	18,742	26,827	
	004020.002	GS Wells	Routine	10,199	17,540	22,172	
	004020.003	GS Wells	Routine	9,138	14,037	21,421	
GS Wells Total				43,775	50,319	70,420	
GS Pipelines	004030.001	GS Pipelines	Routine	27,774	28,482	25,908	
GS Pipelines Total				27,774	28,482	25,908	
GS Purification Equipment	004040.001	GS Purification Equipment	Routine	16,964	12,054	15,606	
GS Purification Equipment Total				16,964	12,054	15,606	
GS Auxiliary Equipment	004090.001	GS Auxiliary Equipment	Routine	49,646	59,251	86,000	
GS Auxiliary Equipment Total				49,646	59,251	86,000	
SIMP Execution	004410.001	SIMP Execution	Routine	56,282	59,730	89,342	
SIMP Execution Total				56,282	59,730	89,342	
GT Buildings & Improvements	006030.001	GT Buildings & Improvements	Routine	1,304	1,303	1,303	
GT Buildings & Improvements Total				1,304	1,303	1,303	
GT Capital Tools	007060.001	GT Capital Tools	Routine	221	221	221	
GT Capital Tools Total				221	221	221	
GS Capital Tools	007080.001	GS Capital Tools	Routine	188	188	188	
GS Capital Tools Total				188	188	188	
Grand Total				316,113	384,533	515,206	

Southern California Gas Company
Capital Expenditures
(In Thousands of 2025 \$)

Gas Transmission & Storage									
Post-Test Year Capital Forecast									
Category	Workpaper Sub	Workpaper Description	In-Service Date	2026	2027	2028	2029	2030	2031
GT Pipelines New Additions	003010.001	GT Pipelines New Additions	Routine	-	-	-	1,278	1,278	1,278
	003010.002	GT Pipelines New Additions	Routine	-	-	-	67	67	67
GT Pipelines New Additions Total				-	-	-	1,345	1,345	1,345
GT Pipelines Replacements	003020.001	GT Pipelines Replacements	Routine	-	-	-	90,284	90,283	90,280
GT Pipelines Replacements Total				-	-	-	90,284	90,283	90,280
GT Leak Repair	803020.001	GT Leak Repair	Routine	-	-	-	16,188	16,188	16,187
GT Leak Repair Total				-	-	-	16,188	16,188	16,187
GT Pipeline Relocation - Freeway	003030.001	GT Pipeline Relocation - Freeway	Routine	-	-	-	2,120	2,120	2,120
GT Pipeline Relocation - Freeway Total				-	-	-	2,120	2,120	2,120
GT Pipeline Relocation - Franchise/Private/ROW	003040.001	GT Pipeline Relocation - Franchise/Private/ROW	Routine	-	-	-	2,590	2,589	2,590
	003040.002	GT Pipeline Relocation - Franchise/Private/ROW	Routine	-	-	-	5,504	5,504	5,503
GT Pipeline Relocation - Franchise/Private/ROW Total				-	-	-	8,094	8,093	8,093
GT Compressor Stations	003050.001	GT Compressor Stations	Routine	-	-	-	8,924	8,924	8,923
GT Compressor Stations Total				-	-	-	8,924	8,924	8,923
GT Cathodic Protection	003060.001	GT Cathodic Protection	Routine	-	-	-	21,329	21,328	21,328
GT Cathodic Protection Total				-	-	-	21,329	21,328	21,328
GT Measurement & Regulation Stations	003080.001	GT Measurement & Regulation Stations	Routine	-	-	-	63,310	63,309	63,307
GT Measurement & Regulation Stations Total				-	-	-	63,310	63,309	63,307
GT Security and Auxiliary Equipment	003090.001	GT Security and Auxiliary Equipment	Routine	-	-	-	19,066	19,066	19,065
GT Security and Auxiliary Equipment Total				-	-	-	19,066	19,066	19,065
GT Technology & Software	003500.001	GT Technology & Software	Routine	-	-	-	2,542	2,421	3,724
GT Technology & Software Total				-	-	-	2,542	2,421	3,724
GS Compressor Stations	004010.001	GS Compressor Stations	Routine	-	-	-	13,643	29,616	52,054
GS Compressor Stations Total				-	-	-	13,643	29,616	52,054
GS Wells	004020.001	GS Wells	Routine	-	-	-	47,519	45,018	60,022
	004020.002	GS Wells	Routine	-	-	-	11,552	14,527	12,740
	004020.003	GS Wells	Routine	-	-	-	18,386	25,654	20,954
GS Wells Total				-	-	-	77,457	85,199	93,716
GS Pipelines	004030.001	GS Pipelines	Routine	-	-	-	42,183	52,732	54,287
GS Pipelines Total				-	-	-	42,183	52,732	54,287
GS Purification Equipment	004040.001	GS Purification Equipment	Routine	-	-	-	19,289	23,892	17,813
GS Purification Equipment Total				-	-	-	19,289	23,892	17,813
GS Auxiliary Equipment	004090.001	GS Auxiliary Equipment	Routine	-	-	-	80,748	64,816	64,658
GS Auxiliary Equipment Total				-	-	-	80,748	64,816	64,658
SIMP Execution	004410.001	SIMP Execution	Routine	-	-	-	81,051	81,493	74,790
SIMP Execution Total				-	-	-	81,051	81,493	74,790
GT Buildings & Improvements	006030.001	GT Buildings & Improvements	Routine	-	-	-	1,303	1,303	1,303
GT Buildings & Improvements Total				-	-	-	1,303	1,303	1,303
GT Capital Tools	007060.001	GT Capital Tools	Routine	-	-	-	221	221	221
GT Capital Tools Total				-	-	-	221	221	221
GS Capital Tools	007080.001	GS Capital Tools	Routine	-	-	-	188	188	188
GS Capital Tools Total				-	-	-	188	188	188
Grand Total				-	-	-	549,285	572,537	593,402

APPENDIX D
COMPRESSOR TIME STUDY
(PUBLIC)



Compressor Station Time Study Analysis

Prepared for **Southern California Gas Company - GTTS**

May 20, 2026

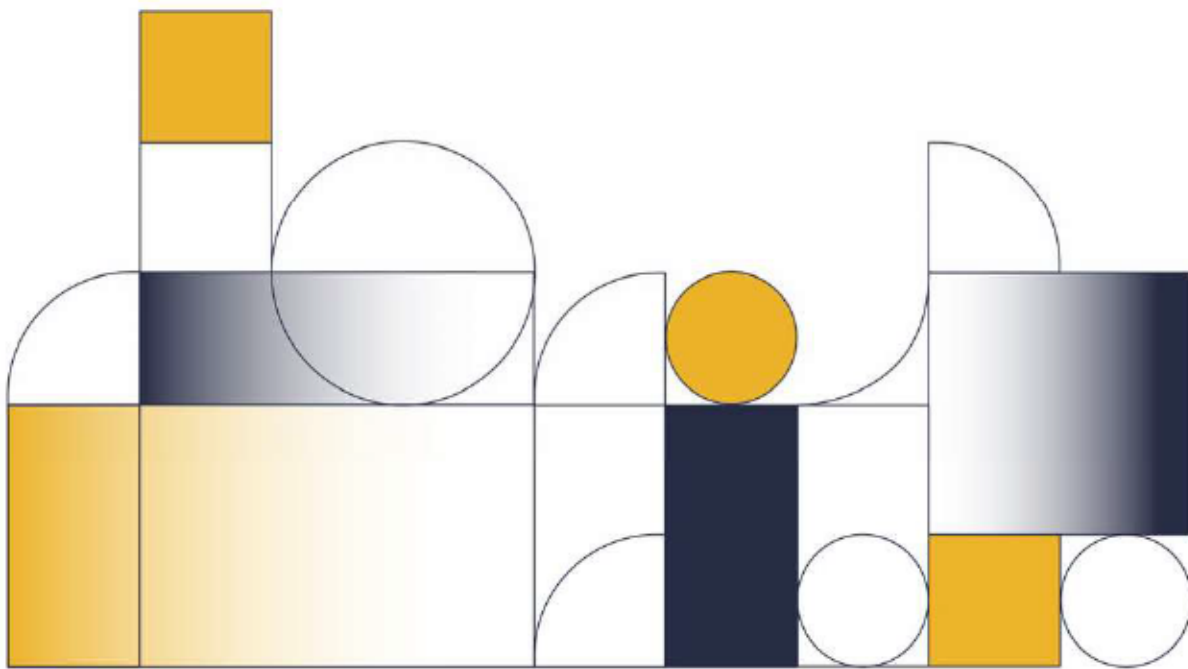


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1. Introduction & Background

The California Public Utilities Commission (Commission) directed Southern California Gas Company (SoCalGas) as follows: "In the next GRC, SoCalGas shall provide a time study documenting the time needed to perform employee tasks to support a reasonable level of staffing for Compressor Operations.

1.1 Purpose of the Time Study

The purpose of this study was to perform a systematic measurement and analysis of the time required by SoCalGas employees to perform defined operational tasks. Key operational tasks identified to be evaluated at the onsite of this time study included:

- **Shift Change Briefing:** Initial overview of Station Control Panel, ongoing work from previous shift, notes from Gas Control, status of units, reviewing and signing work permits for contract crews.
- **Compressor start-up:** Prestart checks of valve and JOA switches, start permissive, initiate compressor start sequence, monitor pressure build-up, and ensure that the unit is operating at proper load step.
- **Operational Rounds/Monitoring:** Regularly checking gauges and data logging systems for pressure, flow rate, temperature, and engine performance.
- **Parameter adjustments:** Making minor adjustments to compressor speed or discharge pressure based on Gas Control rate cycle changes and pipeline demand.
- **Mechanical Maintenance tasks:** Routine lubrication, filter changes, and minor repairs.
- **Instrument/Control System Tasks:** Routine checks, odorant monitoring, and equipment repairs.
- **Alarm response:** Identifying and addressing alarm conditions related to pressure, temperature, or equipment malfunction.
- **Facility operations:** staff hours dedicated to facility operations.
- **Shopwork:** housekeeping (i.e., dust and debris removal, landscaping, keeping workspaces accessible), tool organization, maintenance and cleaning.
- **Data recording:** Logging operational data into designated systems.

The goal of this study was to assess the workload at each of the stations, identify any potential efficiency improvements and develop operation and staffing recommendations. Specifically, this study focused on:

- **Performance standards:** Develop benchmarks for expected task times based on the study findings.
- **Staffing requirements:** Assess the required personnel based on the workload and task duration. Also ensure adequate staffing to reduce excessive overtime, prioritizing safety and health of employees, and meeting projected budgets.
- **Training needs:** Identify areas where additional training could improve efficiency.
- **Safety considerations:** Prioritize safety procedures and ensure compliance with industry regulations. Ensure adequate staffing is available to perform work during a given shift.

- **Impact to support organizations outside of Operations:** Analyze additional tasks generated from operations that are either completed or impact additional organizations outside of the Compressor Station Operations organization.
- **Identifying bottlenecks:** Analyze the data to identify tasks or processes that significantly contribute to overall cycle time and can be optimized.

1.2 Scope of Analysis

Seven (7) compressor stations were evaluated as part of this study to meet with to determine “a reasonable level of staffing for Compressor Operations” per the Commission request. The compressor stations included: Blythe, North Needles, South Needles, Kelso, Newberry, Ventura, and Wheeler Ridge.

As of December 31, 2025, there were 57 management, Represented, engineering and technical operations support, and administrative employees supporting the operations and maintenance activities at the seven (7) compressor stations. A breakdown of the employees by management, engineering and technical support and station is provided Table 1 below. SoCalGas provided the following clarifications regarding the stations support personnel:

- The Field Operations Manager oversees the operations and maintenance for the seven (7) compressor stations.
- The Station Operations Manager – West oversees the Ventura and Wheeler Ridge stations.
- The Stations Operations Manager – East oversees the Blythe, Needles North, Needles South, Kelso, and Newberry stations.
- The Needles North, Needles South, and Kelso stations are operated and maintained by a core team of maintenance specialists, station technicians, instrumentation technicians, and operations specialists who are assigned across the three (3) stations based on operational requirements and task assignments. Within Table 1 and the remainder of this document, they are collectively included under the Needles location.

Table 1: SoCalGas Compressor Station Personnel

Location	Title	No. of Individuals
Management		
N/A	Field Operations Manager	1
N/A	Station Operations Manager – West	1
N/A	Station Operations Manager – East	1
Engineering and Technical Operations Support		
N/A	Engineering Team Lead	1
N/A	Technical Specialist	1
N/A	Engineer I	1
Administration		
N/A	Administration Clerk	1
Supervisors and Represented Employees		
Blythe	Station Maintenance Supervisor	1
Blythe	Station Operations Supervisor	1
Blythe	Senior Instrumentation Specialist	1
Blyth	Instrumentation Specialist	4

Location	Title	No. of Individuals
Blythe	Senior Station Operations Specialist	1
Blythe	Station Operations Specialist	7
Blythe	Station Maintenance Specialist	3 ¹
Blythe	Station Technician	2
Blythe	T&S Inventory & Admin Tech	0 ²
Needles	Station Maintenance Supervisor	1
Needles	Senior Instrumentation Specialist	0 ³
Needles	Instrumentation Specialist	3 ⁴
Needles	Senior Station Maintenance Specialist	1
Needles	Station Maintenance Specialist	4
Needles	Station Operations Specialist	4 ⁵
Needles	Station Technician	3
Needles	T&S Inventory & Admin Tech	1
Newberry	Station Maintenance Supervisor	1
Newberry	Instrumentation Specialist	3
Newberry	Senior Station Maintenance Specialist	1
Newberry	Station Maintenance Specialist	2
Newberry	Station Technician	1
Ventura	Instrumentation Specialist	1
Ventura	Station Maintenance Specialist	1
Wheeler Ridge	Station Maintenance Supervisor	1
Wheeler Ridge	Instrumentation Specialist	2
Wheeler Ridge	Senior Station Maintenance Specialist	1

¹ Blythe has four (4) Station Maintenance Specialists positions. One of the positions was vacant during 2025.

² Blythe has one T&S Inventory & Admin Tech position. The position was vacant in 2025.

³ Needles has one Senior Instrumentation Specialist position. The position was vacant in 2025.

⁴ Needles has four (4) Instrument Specialist positions. One of the positions was vacant during 2025.

⁵ Needles has five (5) Station Operations Specialists positions. One of the positions was vacant during 2025.

Organization charts specific to each station location are provided in Sections 3.1.1 to 3.1.5.

2. Methodology

This time study was completed using data from multiple sources including:

- Stopwatch observations of SoCalGas technicians and specialists completing work orders (Manually timing each task using a stopwatch to record the duration of each activity);
- Work sampling (Observing and recording random samples of activities throughout the shift to estimate overall time distribution);
- Interviews with administrative support, technicians, specialists, supervisors, Station Operations Managers, and Field Operations Manager;
- Maximo exports (Data extraction from Maximo [in coordination with Operations] for actuals on work orders, task types, and durations); and
- SAP exports (Cost center extractions to identify internal and external hours and costs billed to the stations).

2.1 Time Study Approach

The time study approach required the deployment of observers to the compressor stations to record time taken per task across different shifts and operating conditions. During these site visits, stopwatch studies, work sampling, and interviews were all completed to gather baseline information regarding the current expected times. The stopwatch studies were used for repetitive/time-bound tasks (e.g., compressor start-up, daily rounds). Observed work orders included non-sequential and event driven tasks (e.g., shift change briefings, operational rounds, data recording, instrumentation checks/repairs, etc.)

2.2 Interviews

Interviews were conducted with Management, Supervisors, Engineering, Administrative and Represented employees to discuss processes for generating, performing, and documenting the completion of a work order. This information was used to identify baseline measurements to compare tracked data.

Interviews with Management and Supervisors identified that hours worked by these individuals were not allocated directly to any work orders, but that their time is spent throughout each working day to ensure work orders are completed within compliance deadlines and that the compressor stations operate safely and efficiently. Supervisor time for a work order likely would be documented in Maximo once the Supervisor worked a minimum of 50 hours for the week and was working overtime to complete the work order.

To identify the time spent on key operational tasks by management, supervisors, and engineering an overall percentage of time was applied to the Maximo data by work order.

Administrative support includes generating the work orders for each of the stations monthly and distributing to the stations, receiving completed work orders and inputting time to complete each work order into Maximo as well as manually entering the represented employee hours in Maximo, as well as MyTime. Interviews with administrative support indicate that on average 50% of their work week is spent on the data entry for the work orders, and their remaining time is spent entering time charges for represented employees.

2.3 Analytical Framework

Operations and maintenance activities and the number of hours to complete each activity are tracked for each compressor station as a work order in SoCalGas's Maximo system. To evaluate the number of hours to complete the key operational tasks identified in Section 1.1, data was gathered from Maximo for each of the compressor stations.

2.4 Assumptions

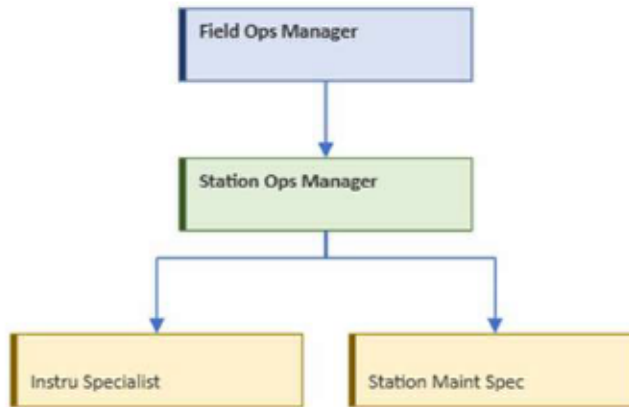
The following assumptions were used during the completion of this study to identify the level of staffing necessary for operations at each of the compressor stations.

- Baseline work hours include job duties, training hours, and paid time off (sick time and vacation);
- Managers work a standard 2,080-hour, yearly work schedule with no overtime captured;
- Supervisors work a standard 2,080-hour, yearly work schedule with limited overtime hours captured, typically after the Supervisor has worked a 50-hour work week;
- Represented employees included Station Operations Specialists, Maintenance Specialists, Instrument Specialists, and Station Technicians. All represented positions are eligible for overtime;
- Administrative support consists of generating work orders from Maximo, providing work orders to each station, entering work orders and employee time into Maximo, and entering employee time into MyTime.
- Administration support time is not documented in Maximo. It is assumed that Administrative support equated to an average of 50% of their time per week for all stations. Administrative time is not tracked per station;
- Managers and Supervisors contribute to completion of work order, but their time spent is not documented in Maximo;
- Current employee count for Represented employees and Supervisors was based on the number of individuals working at the compressor station as of December 31, 2025;
- Due to database report groupings, the employees at North Needles, South Needles, and Kelso stations are included in the reporting for "Needles". The employees can work at either of the stations on any given day depending on work required to be completed for safe and efficient operations;
- Baseline of 2,080 hours was to determine one FTE;
- Data received from Maximo exports captures associated time for each station by employee and any respective tasks, and was based on a list of employees working at the stations in 2025 provided by SoCalGas;
- Data received from SAP exports contained time and direct costs relevant to the station employees working at the stations between January 1, 2025, and December 31, 2025;
- All active employee time provided related to the operations of the compressor stations and does not include time that compressor stations spend on projects funded through other programs such as Compressor Services Group, RNG sites or other refundable projects; and
- Individuals who could not be observed during the study but were interviewed, provided reasonably accurate estimated for completed work.

3.1.4 Ventura Station

As of December 2025, Ventura Station has 2 Represented employees and no supervisors (See Figure 4). Operationally, Ventura operates at a smaller volume than Blythe and Needles. Additionally, operations are handled by the SoCalGas Control Center. Employees work 8-hour shifts at the Ventura station.

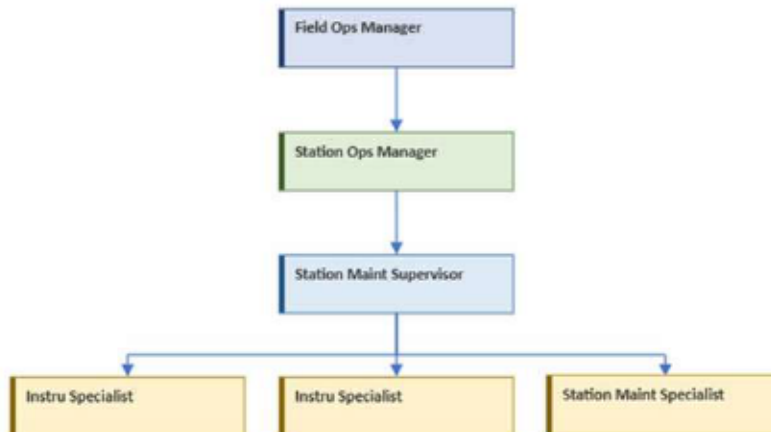
Figure 4: Ventura Station Organization Chart



3.1.5 Wheeler Ridge Station

As of December 31, 2025, Wheeler Ridge Station employs 4 personnel, consisting of 3 Represented employees and 1 supervisor (See Figure 5). Similarly to Ventura, Wheeler Ridge Station operates at a smaller volume as compared to Blythe and Needles stations. Employees work 8-hour shifts at the Wheeler Ridge Station.

Figure 5: Wheeler Ridge Station Organization Chart



4. Work Order Task Breakdown

The total number of work orders varies between the different stations due to different equipment and operating systems. Work orders are completed on a daily, weekly, monthly, and annual basis depending on the work order. Compliance dates are included on the work orders to identify the date by which the work order must be completed. SoCalGas has assigned work orders into six (6) work order types:

- PM – Preventative Maintenance
 - Typical station daily rounds, monthly inspections, servicing, replacement of components on a specific interval
- PM+ - Preventative Maintenance Plus
 - Operations rounds
- CM – Corrective Maintenance
 - Fixed, compliance work, generated by Represented employees based on observations
- CPM – Compliance Preventative Maintenance
 - Audited by Commission, calibrations on equipment
- CCM – Compliance Corrective Maintenance
 - Non-reoccurring work orders generated if CM work orders require additional tasks
- PRJCP – Project Capital
 - Non-reoccurring work orders generated for capital projects completed for operations and maintenance of the stations

SoCalGas's process for completing PM, PM+ and CPM work orders include the following:

1. Start of each month Administrative support prints the work orders from Maximo and converted into a PDF format. Each work order is printed as a separate form. The forms are combined into one file and distributed through email to each of the compressor station Managers.
2. Managers print and separate each work order form and distribute the work orders to the appropriate Supervisors.
3. Supervisors review the work orders and distribute the work orders to the appropriate Represented employee (i.e., Instrumentation Specialist, Maintenance specialist, Operations Specialist, Station Tech, etc.) based on the work order type and compliance date. Work orders are prioritized to ensure that they are completed by the compliance date listed on the work order.
4. Represented employees complete the task on the assigned work order and document the work completed on the work order form
5. Represented employees record their time spent on the work order on their timesheet. The completed work order and timesheet are sent to the Administrative support for input into Maximo and the MyTime systems.
6. Administrative support sends the work order to the Supervisor for review and sign off. Once signed the work order is returned to Administrative support to file as completed.

CM, CCM, and PRJCP work orders are non-reoccurring and are generated by Managers, Supervisors, Engineering support or Represented employees based on identified needs for

maintenance, equipment repairs or other projects that do not fall under the typical station operations and maintenance. Work orders are generated in Maximo and then printed at the station. Steps 4, 5, and 6 are then followed for the completion of these work orders.

4.1 Stopwatch Studies and Work Sampling

Campos EPC (Campos) deployed personnel to each of the seven (7) compressor stations to observe the completion of work orders by station personnel. Campos spent one working day at each of the compressor stations and was present at the start of each shift to determine the work orders or other activities planned for completion on that day. During the observations, Campos individuals performed stopwatch observations and/or work sampling based on the tasks being completed. Observations were logged, and times noted for those observations where stopwatch observations were completed. Some work sampling observations were noted as being started on the previous day prior to Campos's arrival or would extend into the next day. Durations noted for work sampling observations were based on input provided by the Represented employee regarding time frame for them to complete. Common work orders observed during the site visits included:

- Shift change briefings
- Operational Rounds/Monitoring
- Mechanical Maintenance routine checks
- Instrument/Control System routine checks
- Alarm Response
- Data Logging/Recording

Data sheets documenting the work orders observed, start and stop times for stopwatch observations, time frames for completion for work sampling observation, and observer notes for each station are provided in Attachment A.

3.2 Maximo and SAP Data Sets

SoCalGas uses Maximo as its system to manage, maintain and track work orders. Reports were generated by Maximo to obtain the data required to evaluate time spent on work orders. Initially, the Metric Labor data report was generated, which provided: station location, work order number, work order description, work type, date, craft (e.g., station technician, operations specialist, maintenance specialist, etc.) to capture the labor hours (regular time and premium (overtime) hours) spent on work orders. Upon review of this data, it was noted that there were several employees missing in the data set and their time was not being accounted for. To ensure that the most complete set of data was used, the Labor by Employee report was used for this time study. Individual reports were generated for each employee working at a compressor station, as identified in an organization chart provided by SoCalGas. These reports included: station location, work order number, work order description, work type, date, craft, regular hours and premium hours. The Labor by Employee reports were combined to allow for ease in evaluating total hours, averages by work order type, evaluation by station averages for work order completion across the stations, and by key operational type. The Maximo data also included employee time for training, travel, and non-working compensated time (e.g., vacation, sick time, holiday, jury duty, etc.)

The data reports generated from Maximo included data from January 1, 2025, to December 31, 2025, for this time study analysis. Attachment B includes the value used to develop the data summaries provided in Section 5.

5. Data Analysis

Stopwatch time studies and work sampling and analysis of employee labor time from the Maximo and SAP systems was used to identify the amount of time needed to operate and maintain compressor stations. Table 2 summarizes the total hours reported for each of the SoCalGas compressor stations in 2025.

Table 2: 2025 Total Hours by Compressor Station

Compressor Station	No. of Work Orders	No. of Represented Employees	No. Supervisors	Represented Employees			Supervisors ¹	Administrative ²	Total Hours ³
				Regular Hours	Premium Hours	Total Hours			
Blythe	2,715	18	2	33,516	8,906	42,422	4,160	277	46,859
Needles	2,822	15	1	34,365	3,566	37,931	2,080	288	40,299
Newberry	2,310	7	1	14,114	881	14,995	2,080	236	17,311
Ventura	415	2	0	3,101	160	3,261	---	42	3,303
Wheeler Ridge	1,926	3	1	4,154	848	5,002	2,080	197	7,279
Total All Stations	10,188	45	5	89,250	14,360	103,610	10,400	1,040	115,051

¹ Based on the assumption that Supervisors work full-time on the operations and maintenance at the compressor stations equal to 2,080 hours per year.

² Hours for Administrative support are approximate and based on percentage of total work orders for each station at 50% of their time per week (1,040 hours per year). Percentage of total work orders per station: Blythe – 27%, Needles – 28%, Newberry – 23%, Ventura – 4%, and Wheeler Ridge – 19%

³ Total hours do not include Management hours since Managers oversee multiple locations and do not track hours per station.

4.1 Analysis of the Maximo Data

Using the data generated by Maximo, the total number of hours per key operational task were completed based on work order type were determined for each the stations. These hours include regular hours and premium (overtime) hours for each of the key tasks and are summarized in Section 4.1.1 to 4.1.5.

4.1.1 Blythe Station

The key operational tasks for Blythe are included in the table below (see Table 3). No CCM or PRJCP tasks were reported for Blythe station in 2025.

Table 3: Key Operational Task Hours for Blythe Station

Workorder Type	Key Operational Task	Regular Hours	Premium Pay Hours	Total Hour
PM	Compressor Start-Up	62.00	---	62.00
	Operational Rounds/Monitoring	324.83	2.75	327.58
	Parameter Adjustments	31.75	3.00	34.75
	Mechanical Maintenance	588.50	6.25	594.75
	Instrument/Control System	134.25	---	134.25
	Alarm Response	68.00	1.50	69.50
	Shopwork	94.75	0.50	95.25
	Data Recording	21.75	---	21.75

Workorder Type	Key Operational Task	Regular Hours	Premium Pay Hours	Total Hour
PM+	Operational Rounds/Monitoring	983.50	22.25	1,005.75
	Parameter Adjustments	22.50	---	22.50
	Mechanical Maintenance	331.75	13.75	345.50
	Instrument/Control System	449.00	5.25	454.25
	Alarm Response	82.25	---	82.25
	Shopwork	44.25	2.00	46.25
	Data Recording	42.75	0.50	43.25
CM	Compressor Start-Up	138.50	19.00	157.50
	Operational Rounds/Monitoring	188.25	26.25	214.50
	Parameter Adjustments	416.50	466.25	882.75
	Mechanical Maintenance	5,389.00	2,972.25	8,361.25
	Instrument/Control System	123.00	34.75	157.75
	Alarm Response	175.25	34.25	209.50
	Shopwork	203.25	45.00	248.25
	Data Recording	340.25	236.25	576.50
CPM	Operational Rounds/Monitoring	69.50	3.00	72.50
	Mechanical Maintenance	14.50	---	14.50
	Instrument/Control System	52.50	---	52.50
	Alarm Response	11.50	---	11.50
	Data Recording	5.50	6.75	12.25
N/A	Facility Operations	11,883.50	4,769.25	16,652.75
N/A	Shopwork – No Assigned WO	1,717.50	49.75	1,767.25
N/A	Shift Change Briefings/Meetings	1,549.45	29.50	1,578.95

Key operational tasks for each work order type were totaled together and an average of the time spent was determined based using the total number of work orders for the particular task. Additionally the lowest and highest number of hours spent on the task were reported and compared to the observations from the field visits. The data is summarized by task in Table 4.

Table 4: Analysis of Hours for Key Operational Tasks for Blythe Station

Key Operational Tasks	Total No. WO	Total Hours (Maximo)	Average per WO (Hours)	Lowest Reported WO (Hours)	Highest Reported WO (Hours)	Field Observation (Hours)
Compressor Start-Up	45	219.50	4.88	0.25	8	N/A
Operational Rounds/Monitoring	808	1,620.33	2.01	0.00	15	2
Parameter Adjustments	66	940.00	14.24	0.25	19.25	N/A
Mechanical Maintenance	938	9,316.00	9.93	0.00	22	N/A
Instrument/Control System	340	798.75	2.35	0.00	7	8
Alarm Response	186	372.75	2.00	0.00	10	N/A
Shopwork	223	389.75	1.75	0.25	9	N/A
Data Recording	109	653.75	6.00	0.00	17.5	0.25

For the Blythe station, the field observation times were within the ranges identified for the year with the exception of the instrumentation/control system task. During observations at the station, the instrumentation task completed included annual maintenance for the compressor station, which typically requires a longer time for completion as compared to daily, weekly and monthly instrumentation/control tasks taken completed throughout the year.

4.1.2 Needles Station

The key operational tasks for Needles are included in Table 5. These represent all tasks completed at Needles station in 2025.

Table 5: Key Operational Task Hours for Needles Station

Workorder Type	Key Operational Task	Regular Hours	Premium Pay Hours	Total Hour
PM	Compressor Start-Up	2.00	---	2.00
	Operational Rounds/Monitoring	816.75	5.50	822.25
	Mechanical Maintenance	1,266.85	4.00	1270.85
	Instrument/Control System	142.50	4.25	146.75
	Alarm Response	85.50	---	85.50
	Shopwork	240.25	---	240.25
	Data Recording	126.00	1.00	127.00
PM+	Operational Rounds/Monitoring	1,820.25	40.5	1,860.75
	Parameter Adjustments	34.25	0.25	34.50
	Mechanical Maintenance	610.83	5.50	616.33
	Instrument/Control System	672.00	4.00	676.00
	Alarm Response	0.25	1.75	2.00
	Shopwork	12.25	1.00	13.25
	Data Recording	132.83	6.00	138.83
CM	Compressor Start-Up	45.00	32.50	77.50
	Operational Rounds/Monitoring	33.25	4.50	37.75
	Parameter Adjustments	34.50	29.75	64.25
	Mechanical Maintenance	4,388.00	1,534.00	5,922.00
	Instrument/Control System	2,482.00	122.00	2,604.00
	Alarm Response	16.25	10.50	26.75
	Shopwork	115.00	148.75	263.75
	Data Recording	288.00	41.50	329.50
CPM	Operational Rounds/Monitoring	106.75	1.00	107.75
	Mechanical Maintenance	16.50	---	16.50
	Instrument/Control System	184.00	6.50	190.50
	Alarm Response	14.75	1.00	15.75
	Data Recording	164.55	3.50	168.05
CCM	Instrument/Control System	20.00	25.50	45.50
PRJCP	Compressor Start-Up	12.25	10.75	23.00

Workorder Type	Key Operational Task	Regular Hours	Premium Pay Hours	Total Hour
	Operational Rounds/Monitoring	43.25	2.25	45.50
	Mechanical Maintenance	145.00	158.75	303.75
	Data Recording	14.50	1.75	16.25
N/A	Facility Operations	9,267.66	1,286.50	10,554.16
N/A	Shopwork – No Assigned WO	4,425.50	1.00	4,426.50
N/A	Shift Change Briefing/Meetings	346.00	10.00	356.00

Key operational tasks for each work order type were totaled together and an average of the time spent was determined based using the total number of work orders for the particular task. Additionally the lowest and highest number of hours spent on the task were reported and compared to the observations from the field visits. The data is summarized by task in Table 6.

Table 6: Analysis of Hours for Key Operational Tasks for Needles Station

Key Operational Tasks	Total No. WO	Total Hours (Maximo)	Average per WO (Hours)	Lowest Reported WO (Hours)	Highest Reported WO (Hours)	Field Observation (Hours)
Compressor Start-Up	13	102.50	7.88	0.50	10.00	N/A
Operational Rounds/Monitoring	826	2,874.00	3.48	0.00	10.00	0.50
Parameter Adjustments	30	98.75	3.29	0.50	10.00	N/A
Mechanical Maintenance	1032	8,129.43	7.88	0.00	20.00	10.00* 12.00*
Instrument/Control System	221	3,662.75	16.57	0.00	20.00	1.00
Alarm Response	81	130.00	1.60	0.25	6.00	N/A
Shopwork	319	517.25	1.62	0.25	11.00	N/A
Data Recording	234	779.63	3.33	0.25	20.00	0.25

*Two work study observations were completed simultaneously at the Needles station for the Mechanical Maintenance task

Field observation times were within the ranges identified for the year at the Needles station.

4.1.3 Newberry Station

The key operational tasks for Newberry station are included in Table 7. No PRJCP tasks were reported for Newberry station in 2025.

Table 7: Key Operational Task Hours for Newberry Station

Workorder Type	Key Operational Task	Regular Hours	Premium Pay Hours	Total Hour
PM	Compressor Start-Up	1.50	---	1.50
	Operational Rounds/Monitoring	501.75	17.25	519.00
	Mechanical Maintenance	339.25	9.00	348.25
	Instrument/Control System	178.25	4.75	183.00
	Alarm Response	12.00	---	12.00
	Shopwork	34.50	1.00	35.50
	Data Recording	261.50	5.25	266.75
PM+	Operational Rounds/Monitoring	652.00	18.50	670.50
	Mechanical Maintenance	832.50	18.00	850.50
	Instrument/Control System	190.50	1.25	191.75
	Alarm Response	20.75	---	20.75
	Shopwork	79.00	---	79.00
	Data Recording	105.75	2.00	107.75
CM	Compressor Start-Up	112.50	36.75	149.25
	Operational Rounds/Monitoring	660.25	136.75	797.00
	Parameter Adjustments	23.50	2.25	25.75
	Mechanical Maintenance	3,405.00	230.05	3,635.05
	Instrument/Control System	289.75	31.50	321.25
	Alarm Response	46.00	14.50	60.50
	Shopwork	161.25	15.75	177.00
	Data Recording	590.25	54.50	644.75
CPM	Operational Rounds/Monitoring	103.00	9.00	112.00
	Mechanical Maintenance	23.25	---	23.25
	Instrument/Control System	104.25	3.75	108.00
	Alarm Response	6.00	---	6.00
	Data Recording	33.00	13.50	46.50
CCM	Instrument/Control System	1.00	---	1.00
N/A	Facility Operations	1,503.75	178.50	1,682.25
N/A	Shopwork – No Assigned WO	146.00	---	146.00
N/A	Shift Change Briefing/Meetings	1,301.00	40.50	1,341.50

Key operational tasks for each work order type were totaled together and an average of the time spent was determined based using the total number of work orders for the particular task. Additionally the lowest and highest number of hours spent on the task were reported and compared to the observations from the field visits. The data is summarized by task in Table 8.

Table 8: Analysis of Hours for Key Operational Tasks for Newberry Station

Key Operational Tasks	Total No. WO	Total Hours (Maximo)	Average per WO (Hours)	Lowest Reported WO (Hours)	Highest Reported WO (Hours)	Field Observation (Hours)
Compressor Start-Up	22.00	150.75	6.85	0.25	8.00	N/A
Operational Rounds/Monitoring	832.00	2,098.50	2.52	0	12.00	N/A
Parameter Adjustments	5.00	25.75	5.15	0.5	7.00	N/A
Mechanical Maintenance	734.00	4,857.05	6.62	0	14.50	6.25* 2* 1*
Instrument/Control System	275.00	805.00	2.93	0.25	12.50	N/A
Alarm Response	24.00	99.25	4.14	0.25	7.00	0.5 ^(a) 2*
Shopwork	135.00	114.50	0.85	0	11.00	N/A
Data Recording	269.00	1,065.75	3.96	0.25	11.00	N/A

* Multiple tasks were observed

^(a) Task was started prior to Campos representative arrival at the station. Total time based on information provided by the Represented Employee upon completion of the task.

Field observation times were within the ranges identified for the year at Newberry station.

4.1.4 Ventura Station

The key operational tasks for Ventura station are included in Table 9. No CPM tasks were reported for the station in 2025.

Table 9: Key Operational Task Hours for Ventura Station

Workorder Type	Key Operational Task	Regular Hours	Premium Pay Hours	Total Hour
PM	Compressor Start-Up	7.00	---	7.00
	Operational Rounds/Monitoring	303.00	1.00	304.00
	Parameter Adjustments	13.00	7.00	20.00
	Mechanical Maintenance	38.00	1.00	39.00
	Instrument/Control System	19.00	---	19.00
	Shopwork	14.00	---	14.00
	Data Recording	28.75	---	28.75
PM+	Compressor Start-Up	5.00	---	5.00
	Operational Rounds/Monitoring	216.00	9.25	225.25
	Parameter Adjustments	11.00	---	11.00
	Mechanical Maintenance	632.67	50.08	682.75
	Instrument/Control System	3.00	---	3.00
	Alarm Response	2.50	---	2.50
	Shopwork	2.00	---	20.00
Data Recording	16.00	1.00	17.00	
CM	Operational Rounds/Monitoring	37.50	1.00	38.50

Workorder Type	Key Operational Task	Regular Hours	Premium Pay Hours	Total Hour
	Mechanical Maintenance	1,158.5	59.53	1,218.03
	Instrument/Control System	20.00	---	20.00
	Shopwork	53.50	18.00	71.50
	Data Recording	0.25	---	0.25
CPM	Operational Rounds/Monitoring	10.00	---	10.00
	Mechanical Maintenance	12.00	---	12.00
	Instrument/Control System	1.00	---	1.00
	Alarm Response	4.50	1.50	6.00
	Data Recording	5.00	---	5.00
PRJCP	Mechanical Maintenance	20.00	3.25	23.25
N/A	Facility Operations	18.35	4.00	22.35
N/A	Shopwork – No Assigned WO	---	---	---
N/A	Shift Change Briefing/Meetings	5.50	---	5.50

Key operational tasks for each work order type were totaled together and an average of the time spent was determined based using the total number of work orders for the particular task. Additionally the lowest and highest number of hours spent on the task were reported and compared to the observations from the field visits. The data is summarized by task in Table 10.

Table 10: Analysis of Hours for Key Operational Tasks for Ventura Station

Key Operational Tasks	Total No. WO	Total Hours (Maximo)	Average per WO (Hours)	Lowest Reported WO (Hours)	Highest Reported WO (Hours)	Field Observation (Hours)
Compressor Start-Up	10.00	12.00	1.20	0.0	2.00	N/A
Operational Rounds/Monitoring	236.00	577.75	2.45	0.5	10.00	0.5
Parameter Adjustments	7.00	31.00	4.43	2.0	10.50	N/A
Mechanical Maintenance	98.00	1975.03	20.15	0.28	21.00	4.75* 1.75*
Instrument/Control System	7.00	43.00	6.14	1.0	15.00	N/A
Alarm Response	4.00	8.50	2.13	1.5	3.00	N/A
Shopwork	12.00	87.50	7.29	0.0	12.50	N/A
Data Recording	40.00	51.00	1.28	0.0	5.00	N/A

* Multiple tasks were observed

Limited work was being performed during the field visit to the Ventura station. Field observation times for the mechanical maintenance tasks were well below the average for the ranges identified for the year at Ventura station.

4.1.5 Wheeler Ridge Station

The key operational tasks for Wheeler Ridge station are included in Table 11. No CCM tasks were reported for the station in 2025.

Table 11: Key Operational Task Hours for Wheeler Ridge Station

Workorder Type	Key Operational Task	Regular Hours	Premium Pay Hours	Total Hour
PM	Compressor Start-Up	1.00	---	1.00
	Operational Rounds/Monitoring	652.25	57.50	709.75
	Mechanical Maintenance	86.25	17.25	103.5
	Instrument/Control System	54.50	2.00	56.50
	Data Recording	9.50	---	9.50
PM+	Compressor Start-Up	1.00	---	1.00
	Operational Rounds/Monitoring	712.25	232.75	945.00
	Parameter Adjustments	3.75	4.25	8.00
	Mechanical Maintenance	77.50	22.50	100.00
	Instrument/Control System	422.50	23.50	446.00
	Alarm Response	12.50	3.75	16.25
	Data Recording	28.00	1.00	29.00
CM	Compressor Start-Up	17.75	13.50	31.25
	Parameter Adjustments	1.00	4.00	5.00
	Mechanical Maintenance	216.50	67.50	284.00
	Instrument/Control System	226.00	66.75	292.75
	Alarm Response	10.00	12.00	22.00
	Shopwork	29.75	44.00	73.75
	Data Recording	60.00	18.00	78.00
CPM	Operational Rounds/Monitoring	31.50	1.50	33.00
	Mechanical Maintenance	6.50	---	6.50
	Instrument/Control System	57.50	14.00	71.50
	Alarm Response	12.00	1.00	13.00
	Data Recording	5.50	0.00	5.50
PRJCP	Operational Rounds/Monitoring	108.75	0.50	109.25
	Mechanical Maintenance	203.75	124.25	328.00
	Shopwork	0.25	---	0.25
	Data Recording	16.00	6.25	22.25
N/A	Facility Operations	216.25	75.00	291.25
N/A	Shopwork – No Assigned WO	---	---	---
N/A	Shift Change Briefing/Meetings	143.25	18.75	162.00

Key operational tasks for each work order type were totaled together and an average of the time spent was determined based using the total number of work orders for the particular task. Additionally the lowest and highest number of hours spent on the task were reported and compared to the observations from the field visits. The data is summarized by task in Table 12.

Table 12: Analysis Hours for Key Operational Tasks for Wheeler Ridge Station

Key Operational Tasks	Total No. WO	Total Hours (Maximo)	Average per WO (Hours)	Lowest Reported WO (Hours)	Highest Reported WO (Hours)	Field Observation (Hours)
Compressor Start-Up	6.00	33.25	5.54	0.0	11.50	N/A
Operational Rounds/Monitoring	1,508.00	1,797.00	1.19	0.0	9.50	1.00* 0.5*
Parameter Adjustments	32.00	13.00	0.41	0.25	4.00	N/A
Mechanical Maintenance	239.00	822.00	3.44	0.0	12.00	3.00* 2.25*
Instrument/Control System	85.00	866.75	10.20	0.0	12.00	N/A
Alarm Response	22.00	51.25	2.33	0.5	9.00	N/A
Shopwork	16.00	74.00	4.63	0.0	8.00	N/A
Data Recording	18.00	144.25	8.01	0.5	10.50	N/A

Field observation times were within the ranges identified for the year at Newberry station.

4.1.6 Benefit Hours

SoCalGas provides benefit hours that employees can use for specific situations, such as:

- Holidays
- Vacation
- Sick time
- Bereavement
- Jury Duty
- Personal Business

This time is tracked in Maximo for Represented employees. Additionally, time spent on travel, training, testing and in-lieu of regulation (comp time) are also tracked and contribute to the total hours for the operations and maintenance of the compressor stations. These hours are summarized for each of the compressor stations in Table 13.

Table 13: Summary of Benefit Hours per Station

Station	No. of Employees	Description	Hours	Avg. Hours/ Employee
Blythe	20	Benefit Hours	5,090.00	254.50
		Travel	25.00	1.25
		Training	1,267.75	63.39
		In-Lieu of Regulation	1,729.75	86.49
Needles	16	Benefit Hours	4,750.00	296.88
		Travel	44.00	2.75
		Training	1,109.25	69.02
		In-Lieu of Regulation	396.75	24.80
Newberry	6	Benefit Hours	1,564.5	260.75
		Travel	107.75	17.76
		Training	695.50	115.92
		In-Lieu of Regulation	64.00	10.67
Ventura	2	Benefit Hours	374.00	187.00
		Travel	0.00	---
		Training	39.00	19.5

Station	No. of Employees	Description	Hours	Avg. Hours/ Employee
		In-Lieu of Regulation	16.00	8.00
Wheeler Ridge	4	Benefit Hours	561.50	140.38
		Travel	---	---
		Training	171.50	42.88
		In-Lieu of Regulation	13.50	3.38

6. Conclusions

The Commission directed SoCalGas to conduct a comprehensive time study to document the labor required to perform employee tasks and support an appropriate staffing level for Compressor Operations. In response, SoCalGas engaged Campos EPC to conduct a full staffing and time-study evaluation across its compressor station network.

The study encompassed seven (7) compressor stations operated by SoCalGas –Blythe, North Needles, South Needles, Kelso, Newberry Springs, Ventura, and Wheeler Ridge. The total workforce for the compressor stations consists of 57 management, engineering support, administrative support and Represented employees.

This study found that between January 1 and December 31, 2025, a total of 115,051 hours were spent on operations and maintenance activities for all seven compressor stations. These hours do not include Management, and the Supervisor and Administrative support were developed based on information provided by SoCalGas since hours for these positions are not tracked in Maximo. Total hours for each of the stations is provided in Table 14. The total hours reported include hours spent on key operational tasks, benefit hours, comp time, travel time and training.

Table 14: Summary of Total Hours per Station for 2025

Compressor Station	No. of Work Orders	No. of Represented Employees	No. Supervisors	Total Hours ³
Blythe	2,715	18	2	46,859
Needles	2,822	15	1	40,299
Newberry	2,310	7	1	17,311
Ventura	415	2	0	3,303
Wheeler Ridge	1,926	3	1	7,279
Total All Stations	10,188	45	5	115,051

The report was completed using the best available data provided by SoCalGas and information provided in interviews with the station Represented employees, supervisors and managers.

Areas where bottlenecks and inefficiencies were identified include:

- Hours and tasks are entered into Maximo manually. This leads to data entry errors and incomplete descriptions for the tasks performed.
- Maximo data entries are not reviewed for accuracy. It was identified that some employees may not label the location of the work, causing their data to not be readily available when pulling reports per station.
- Management/supervisors do not enter time into Maximo, so their time dedicated to work orders is not captured. Instead, an overall total up to 40-hour work week is dispersed to categories. They also track minimal overtime, usually after 50 hours of work in a week. This causes a gap in where management/supervisor time is relevant to tasks and limits the accuracy of their hours spent at the stations

- Observations performed at the compressor stations found that the key operational tasks were completed in line with average time spent on the same tasks in 2025. However, there is no baseline established for task completion time. Additionally, the Campos observers were on site for one day only and observed a limited number of tasks. To fully perform a time study, an evaluation of all tasks multiple times is recommended to establish baselines and identify areas where efficiencies may be recognized. This would also allow for a consistent check of the accuracy of the data being entered into Maximo.

Manual data entry emerged as a critical bottleneck in this study, directly limiting operational accuracy and efficiency. Reliance on manual inputs in Maximo resulted in inconsistent tracking, with most activities recorded using broad time estimates rather than actual durations. This not only undermines data reliability but also introduces avoidable errors. Implementing standardized procedures and transitioning to automated data capture will dramatically improve data integrity, identify true operational bottlenecks, support continuous improvement efforts, and enable leadership to make decisions based on accurate, actionable information. Enhanced training ensures employees are fully equipped to leverage these tools, creating a sustainable system of visibility, accountability, and operational excellence.

ATTACHMENT A – STOPWATCH OBSERVATIONS

Compressor Station Time Study

Compressor Station
Blythe Station

Date
Tuesday, December 9, 2025

Recorder
Ty Jones

Index	Key Operation Task	Workorder	Date	Start Time	Duration (Hours)	Duration (Minutes)	End Time	Station's Labor Category	Comment
█	██████████ ██████████	██████████	██████		█			██████ ██████	██████████
█	██████ ██████████	██████████ ██████████	██████		█			██████ ██████	██████████
█			██████			█		██████ ██████	██████████
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Confidential and Protected Materials Pursuant to PUC Section 583, G.O. 66-D Revision 3
Compressor Station Time Study

█	██████████ ██████	██████████	██████████		██████	██████		██████████ ██████████	██████████
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Confidential and Protected Materials Pursuant to PUC Section 583, G.O. 66-D Revision 3
Compressor Station Time Study

Compressor Station
Kelso Station

Date
Wednesday, December 3, 2025

Recorder
Ty Jones

Index	Key Operation Task	Workorder	Date	Start Time	Duration (Hours)	Duration (Minutes)	End Time	Station's Labor Category	Comment
█	██████████ ██████	██████████	██████			██		██████████	██████████
█	██████████ ██████	██████████	██████			██		██████████	██████████
█	██████████ ██████	██████████	██████		██	██		██████████	██████████
█	██████████ ██████	██████████	██████		██			██████████	██████████
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Compressor Station Time Study

Compressor Station Time Study

Confidential and Protected Materials Pursuant to PUC Section 583, G.O. 66-D Revision 3
Compressor Station Time Study

Compressor Station
Wheeler Ridge Station

Date
Tuesday, December 9, 2025

Recorder
Crystal De Arcos

Index	Key Operation Task	Workorder	Date	Start Time	Duration (Hours)	Duration (Minutes)	End Time	Station's Labor Category	Comment
1	[REDACTED]	[REDACTED]	[REDACTED]					[REDACTED]	[REDACTED]
2	[REDACTED]	[REDACTED]	[REDACTED]					[REDACTED]	[REDACTED]
3	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]			[REDACTED]	[REDACTED]	[REDACTED]

ATTACHMENT B – MAXIMO DATA

Maximo dataset file provided separately (2025 Maximo Station Task Hour.xls). Maximo data assumptions include:

Facility Operations hours were not assigned to a specific key operational task and determined by combining the following under "No Work Type" worktype:

- Haz Mat
- IAC
- Material
- Ops Field Station
- Admin
- Clean

Benefit Hours were determined by including:

- Holidays
- Vacation
- Sick time
- Bereavement
- Jury Duty
- Personal Business

In-Lieu of Regulation hours were determined by including:

- In-Lieu of Regulation
- Other Non Pay
- Co-CONV (9-hour rest rule)

APPENDIX E
SURFACE EQUIPMENT CONTROL ASSETS

Storage Field	Well Names	Surface Control Assets (Well Specific)			
Aliso Canyon	67 Wells: FF 32, FF 32 A, FF 32 B, FF 32 D, FF 32 F, FF 32 G, FF 32 H, FF 33, FF 34 A, FF 34 BR, FF 35 A, FF 35 B, FF 35 C, FF 35 D, FF 35 E, FF 36 A, FF 36 B, FF 36 C, MA 1B, P 24 A, P24 B, P25 R, P 26 B, P 26 D, P 26 E, P 32 C, P32 D, P 37, P 42 A, P 44, P 46, P 50 B, P 50 C, P 66 A, P 69 A, P 69 C, P 69 D, P 69 E, P 69 F, P 69 G, P 69 H, P 69 J, P 69 K, P 72 A, P 72 B, SS 4 O, SS 5, SS 6, SS 9, SS 10, SS 26, SS 31, SS 44 B, WARD 3A, FF 32 C, P 26 A, P 39 A, SS 1, P 1, P 17, P 18, P 2, P 20, P 63, P 32, P 53	756 Manual Surface valves consisting of: Crown valves, master valves, tubing kill wing valves, tubing production wing valves, casing kill wing valves, casing production wing valves, and annulus valves	67 Surface safety valves	260 Individual monitors for tubing, casing and annulus pressures	114 Methane monitors
Honor Rancho	24 Wells: WEZU 5, WEZU 7, WEZU 9, WEZU 13A, WEZU 14, WEZU 15, WEZU 16A, WEZU 17, WEZU 18B, WEZU 18C, WEZU 18D, WEZU 18E, WEZU 22, WEZU 23, WEZU 24, WEZU 24A, WEZU 24B, WEZU 25A, WEZU 25C, WEZU C-1, WEZU C-2A, WEZU C-3A, WEZU C-3B, WEZU C-6A	364 Manual Surface valves consisting of: Crown valves, master valves, tubing kill wing valves, tubing production wing valves, casing kill wing valves, casing production wing valves, and annulus valves	24 Surface safety valves	92 Individual monitors for tubing, casing and annulus pressures	46 Methane monitors
La Grleta	13 Wells: EDWARDS 2, MILLER 1, MILLER 2, MILLER 4, MILLER 6, MILLER 10, MILLER 11, MILLER 12, MORE 2, TODD 1, TODD 2, MORE 1, CB42	170 Manual Surface valves consisting of: Crown valves, master valves, tubing kill wing valves, tubing production wing valves, casing kill wing valves, casing production wing valves, and annulus valves	13 Surface safety valves	46 Individual monitors for tubing, casing and annulus pressures	22 Methane monitors
Playa Del Rey	26 Wells: F 1, L 4, MCADAMS 1, MCADAMS 2, SO CAL 1, SO CAL 5, SO CAL 6, SO CAL 7, VIDOR 12, VIDOR 13, VIDOR 16, VIDOR 17, DEL REY 5, DEL REY 9, DEL REY 11, DEL REY 12, DEL REY 13, VIDOR 15, VIDOR 1, VIDOR 2, VIDOR 3, VIDOR 14, DEL REY 14, DEL REY 15, VIDOR 16, DEL REY 18	270 Manual Surface valves consisting of: Crown valves, master valves, tubing kill wing valves, tubing production wing valves, casing kill wing valves, casing production wing valves, and annulus valves	26 Surface safety valves	96 Individual monitors for tubing, casing and annulus pressures	24 Methane monitors

APPENDIX F
GRC-RAMP INTEGRATION

Area: GAS TRANSMISSION & STORAGE

Witness: Gina Orozco

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
003020.001	GT Pipelines Replacement s	2CR02 C125	SCG-Risk-2 High Pressure Gas System Pipeline Relocation/Replacement	Miles of Pipe	40,098	30,058	40,389	25,837	32,675	32,675	32,674	3,357	3,357	3,357	3,357	3,357	3,357	3,357
003020.001	GT Pipelines Replacement s	2CR02 C126	SCG-Risk-2 High Pressure Gas System Shallow/Exposed Pipe Remediations	Miles of Pipe	7,544	4,258	12,847	49,857	57,609	57,608	57,606	3,357	3,357	3,357	3,357	3,357	3,357	3,357
003050.001	GT Compressor Stations	2CR02 C136	SCG-Risk-2 High Pressure Gas System Compressor Stations - Capital	Miles of Pipe	22,542	8,424	21,632	26,261	8,924	8,924	8,923	3,357	3,357	3,357	3,357	3,357	3,357	3,357
003080.001	GT Cathodic Protection	2CR02 C104	SCG-Risk-2 High Pressure Gas System Cathodic Protection - Capital	Miles of Pipe	19,933	11,338	8,752	8,220	21,329	21,328	21,328	3,357	3,357	3,357	3,357	3,357	3,357	3,357
003080.001	GT Measurement & Regulation Stations	2CR02 C151	SCG-Risk-2 High Pressure Gas System Measurement & Regulation Station Capital	Miles of Pipe	21,092	5,561	33,999	53,234	63,310	63,309	63,307	3,357	3,357	3,357	3,357	3,357	3,357	3,357

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 TRANSMISSION & STORAGE

Witness: Gina Orozco

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
004020.001	GS Wells - New Wells	2CR04 C402	SCG-Risk-4 Gas Storage System Well Abandonment/Replacement/Demo Verification and Monitor	Wells	7,513	24,438	18,742	26,827	47,519	45,018	60,022	1	4	3	4	5	3	4
004020.002	Well Abandonments	2CR04 C402	SCG-Risk-4 Gas Storage System Well Abandonment/Replacement/Demo Verification and Monitor	Wells	11,420	10,199	17,540	22,172	11,552	14,527	12,740	7	4	5	7	3	4	3
004020.003	Well Workovers	2CR04 C402	SCG-Risk-4 Gas Storage System Well Abandonment/Replacement/Demo Verification and Monitor	Wells	18,629	9,138	14,037	21,421	18,388	25,654	20,954	28	10	11	15	15	20	18
004040.001	GS Purification Equipment	2CR04 C019	SCG-Risk-4 Gas Storage System Storage HP Retrofits and Upgrades to Purification Equipment	Storage Fields	6,553	16,964	12,054	15,606	19,289	23,892	17,813	4	4	4	4	4	4	4
004410.001	SIMP execution	2CR04 C401	SCG-Risk-4 Gas Storage System Storage Integrity Management Program (SIMP)	Wells	38,307	56,282	59,730	89,342	81,051	81,493	74,790	19	25	30	44	45	48	26

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 TRANSMISSION & STORAGE

Witness: Gina Orozco

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
B03020.001	Leak Repair	2CR02 C113	SCG-Risk-2 High Pressure Gas System Leak Repair	Miles of Pipe	16,521	16,212	16,198	16,190	16,188	16,188	16,187	3,357	3,357	3,357	3,357	3,357	3,357	3,357

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 TRANSMISSION & STORAGE

Witness: Gina Orozco

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		
2200-0329.00	GAS CONTROL SCADA OPERATION	2OR02 C105	SCG-Risk-2 High Pressure Gas System SCADA Operations	FTEs	1,914	1,435	2,104	2,323	2,347	2,347	2,347	7	9	11	12	12	12	12		
2200-2289.00	Gas Control	2OR02 C109	SCG-Risk-2 High Pressure Gas System Control Room Monitoring Operation and Fatigue Management	FTEs	5,493	5,616	5,973	6,329	6,686	6,686	6,686	38	39	41	44	46	46	46		
2GT000.000	GT Pipeline and Instrumentation Operations	2OR02 C002	SCG-Risk-2 High Pressure Gas System Damage Prevention Activities - Gas	Miles of Pipe	1,675	1,694	1,693	1,692	1,692	1,692	1,692	3,357	3,357	3,357	3,357	3,357	3,357	3,357		
2GT000.000	GT Pipeline and Instrumentation Operations	2OR02 C010	SCG-Risk-2 High Pressure Gas System Pipeline Monitoring Technologies	Miles of Pipe	0	44	64	275	275	275	275	3,357	3,357	3,357	3,357	3,357	3,357	3,357		
2GT000.000	GT Pipeline and Instrumentation Operations	2OR02 C117	SCG-Risk-2 High Pressure Gas System Leak Survey & Patrol	Miles of Pipe	2,546	2,574	2,573	2,571	2,571	2,571	2,571	3,357	3,357	3,357	3,357	3,357	3,357	3,357		

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 TRANSMISSION & STORAGE

Witness: Gina Orozco

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
2GT000.000	GT Pipeline and Instrumentation on Operations	2OR02 C132	SCG-Risk-2 High Pressure Gas System Pipeline Maintenance	Miles of Pipe	8,968	9,839	10,442	11,055	11,010	11,013	11,013	3,357	3,357	3,357	3,357	3,357	3,357	3,357
2GT000.000	GT Pipeline and Instrumentation on Operations	2OR02 C155	SCG-Risk-2 High Pressure Gas System Measurement & Instrumentation on Maintenance	Miles of Pipe	5,515	5,577	5,573	5,569	5,569	5,569	5,569	3,357	3,357	3,357	3,357	3,357	3,357	3,357
2GT000.000	GT Pipeline and Instrumentation on Operations	2OR02 C160	SCG-Risk-2 High Pressure Gas System Odorization	Miles of Pipeline Hydrotest	380	384	384	383	383	383	383	3,357	3,357	3,357	3,357	3,357	3,357	3,357
2GT000.001	GT Compressor Station Operations	2OR02 C142	SCG-Risk-2 High Pressure Gas System Compressor Station - Maintenance	Miles of Pipe	12,970	13,376	14,207	14,431	14,331	14,892	14,805	3,357	3,357	3,357	3,357	3,357	3,357	3,357
2GT000.002	GT Cathodic Protection	2OR02 C108	SCG-Risk-2 High Pressure Gas System Cathodic Protection - Maintenance	Miles of Pipe	1,656	1,678	1,677	1,793	1,793	1,793	1,793	3,357	3,357	3,357	3,357	3,357	3,357	3,357

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 TRANSMISSION & STORAGE

Witness: Gina Orozco

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
2GT000.003	GT Technical Services	2OR02 C145	SCG-Risk-2 High Pressure Gas System Class Location (Hydrotest)	Miles of Pipe	0	0	51	51	51	51	51	3,357	3,357	3,357	3,357	3,357	3,357	3,357
2GT001.000	Underground Storage	2OR04 C408	SCG-Risk-4 Gas Storage System Storage Field Maintenance - Underground Components	Storage Fields	2,654	2,714	2,788	2,823	2,879	2,936	2,965	4	4	4	4	4	4	4
2GT001.001	SIMP Execution	2OR04 C401	SCG-Risk-4 Gas Storage System Integrity Management Program (SIMP)	Wells	13,627	15,255	13,889	13,829	13,728	14,928	13,728	40	41	32	36	34	44	31
2GT002.000	Aboveground Storage	2OR04 C014	SCG-Risk-4 Gas Storage System Storage HP Field Maintenance-Aboveground Facilities		3,881	3,925	4,041	4,262	4,262	4,262	4,262	4	4	4	4	4	4	4
2GT002.000	Aboveground Storage	2OR04 C016	SCG-Risk-4 Gas Storage System Storage HP Field Maintenance-Aboveground Piping		711	719	1,248	1,600	1,599	1,599	1,599	4	4	4	4	4	4	4

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 TRANSMISSION & STORAGE

Witness: Gina Orozco

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
2GT002.001	Gas Storage Fields	2OR04 C014	SCG-Risk-4 Gas Storage System Storage HP Field Maintenance-Aboveground Facilities		29,705	30,066	30,657	31,356	33,277	33,820	33,689	4	4	4	4	4	4	4
2GT002.001	Gas Storage Fields	2OR04 C016	SCG-Risk-4 Gas Storage System Storage HP Field Maintenance-Aboveground Piping		2,888	2,712	3,064	3,063	3,062	3,061	3,061	4	4	4	4	4	4	4

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).