Risk Assessment and Mitigation Phase

(Chapter SCG-Risk-1)

Incident Related to the High Pressure System (Excluding Dig-In)

May 17, 2021

TABLE OF CONTENTS

RISK: INCIDENT RELATED TO THE HIGH PRESSURE SYSTEM (EXCLUDING DIG-IN)

I. INTRODUCTION

The purpose of this Chapter is to present Southern California Gas Company's (SoCalGas or Company) risk control and mitigation plan for the Incident Related to the High Pressure System (Excluding Dig-In) risk (HP Incident risk). Each Chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014 and the Settlement Agreement included therein (the Settlement Decision).[1]

SoCalGas has identified and defined RAMP risks in accordance with the process described in further detail in Chapter SCG RAMP-B of this RAMP Report. On an annual basis, SoCalGas's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process. The ERR process influenced how risks were selected for inclusion in this 2021 RAMP Report, consistent with the Settlement Decision's directives, as discussed in Chapter SCG/SDGE RAMP-C.

The RAMP Report's purpose is to present a current assessment of key safety risks and the proposed activities for mitigating those risks. The RAMP Report does not request funding. Any funding requests will be made in SoCalGas's General Rate Case (GRC) application. The costs presented in this 2021 RAMP Report are those costs for which SoCalGas anticipates requesting recovery in its Test Year (TY) 2024 GRC. SoCalGas's TY 2024 GRC presentation will integrate developed and updated funding requests from the 2021 RAMP Report, supported by witness testimony.[2] This 2021 RAMP Report is presented consistent with SoCalGas's GRC presentation, in that the last year of recorded data (2020) provides baseline costs and cost estimates are provided for years 2022-2024, as further discussed in Chapter SCG/SDG&E RAMP-A. This 2021 RAMP Report presents capital costs as a sum of the years 2022, 2023, and 2024 as a three-year total; operations and maintenance (O&M) costs are only presented for TY 2024 (consistent with the GRC). Costs for each activity that directly addresses each risk are

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

provided where those costs are available and within the scope of the analysis required in this RAMP Report.

Throughout this 2021 RAMP Report activities are delineated between controls and mitigations, consistent with the definitions adopted in the Settlement Decision's Revised Lexicon. A "control" is defined as a "[c]urrently established measure that is modifying risk."[3] A "mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[4] Activities presented in this Chapter are representative of those that are primarily scoped to address SoCalGas's High Pressure Incident risk; however, many of the activities presented herein also help mitigate other areas.

As discussed in SCG/SDG&E RAMP-A and SCG/SDGE RAMP-C, SoCalGas has endeavored to calculate a Risk Spend Efficiency (RSE) for all controls and mitigations presented in this risk Chapter. However, for controls and mitigations where no meaningful data or subject matter expert (SME) opinion exists to calculate the RSE, SoCalGas has included an explanation why no RSE can be provided, in accordance with California Public Utilities Commission (CPUC or Commission) Safety Policy Division (SPD) staff guidance.[5] Activities with no RSE value presented in this 2021 RAMP Report are identified in Section V below.

SoCalGas has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the Commission and stakeholders in developing a more complete understanding of the breadth and quality of the Company's mitigation activities. These distinctions are discussed in the applicable control and mitigation narratives in Sections III and/or IV.

A. Risk Overview

The SoCalGas transmission and distribution system operates in 12 different counties and spans from the California-Arizona border to the Pacific Ocean and from the California-Mexico

---

[3] *Id*. at 16.

[4] *Id.* at 17.

[5] *See* Safety Policy Division Staff Evaluation Report on PG&E's 2020 Risk Assessment and Mitigation Phase (RAMP) Application (A.) 20-06-012 (November 25, 2020) at 5 ("SPD recommends PG&E and all IOUs provide RSE calculations for controls and mitigations or provide an explanation for why it is not able to provide such calculations.").

border to Fresno County. SoCalGas is the largest gas distribution operator in the nation and the second largest transmission operator in High Consequence Area (HCA) miles (as defined by the United States Department of Transportation (DOT)), with approximately 1,100 miles of HCA pipe out of 3,341 miles of transmission pipelines. In total, SoCalGas operates 6,685 miles of high-pressure pipelines in its service territory, which includes the 3,341 transmission miles.

The U.S. Department of Transportation Pipeline and Hazardous Materials and Safety Administration (PHMSA) and the American Society of Mechanical Engineers (ASME) pipeline integrity standard B31.8S,[6] "Managing System Integrity of Gas Pipelines," categorizes nine types of threats that could lead to a high pressure pipeline incident. Eight of those threat types are discussed in this Chapter and one - third party damage - is addressed in the Excavation Damage (Dig-In) on the Gas System risk Chapter. The eight types of threats covered in this Chapter include:

1) External Corrosion
2) Internal Corrosion
3) Stress Corrosion Cracking
4) Manufacturing Defect
5) Construction & Fabrication
6) Outside Forces
7) Incorrect Operation
8) Equipment Threat

These factors, also known as potential risk drivers, can work independently and/or interactively together. When a gas pipeline has a loss of product, PHMSA categorizes it as a non-hazardous release of gas or a leak. Specifically, when the loss of gas cannot be resolved by lubing, tightening or adjusting, it is defined as a "leak." A leak in and of itself may cause little-to-no risk of serious injury or fatality. Risk to the public and employees can increase when leaks are in close proximity to an ignition source and/or where there is a potential for gas to migrate into a confined space. The safety concern of the leak is addressed by SoCalGas's leak indication

[6] AMSE B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes. Recorded costs and forecast ranges are rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

prioritization and repair schedule procedures. In most cases, a pipe with a leak will continue to transport gas, and therefore is not considered a pipeline "failure" using the definition in ASME B31.8S.

However, in some instances a pipeline may be weakened to the extent that the pipe can overload and "break open" or burst apart. This is referred to as a pipeline rupture and considered a failure of the pipeline, as it can no longer function as intended. This type of failure could release a high level of energy, and sometimes ignite, resulting in damage to the surrounding area, injury, and/or loss of life.

The leak versus rupture failure mode is generally dependent on the stress to the pipe, the pipe material properties and the geometry of the latent weak point on a pipeline. As a general rule, the rupture failure mode does not occur on a pipeline operating under 30% of Specified Minimum Yield Strength (SMYS), unless there is an egregious pipe anomaly acting as an initiation growth point and there are interacting threats involved.

Due to the nature of a potential rupture failure mode, this risk category discusses the potential consequences of a rupture event occurring on the Company's high-pressure gas system. The extent of damage of an incident can be modeled through the use of a potential impact radius (PIR) around a pipe. PHMSA has incorporated the PIR into its methods for determining an HCA along a pipeline right-of-way. In addition, the presence of HCA miles in a high pressure system can indicate certain consequences of an incident to the public because HCAs consist of highly populated areas and identified sites where people regularly gather or live.

Applying mitigative measures as outlined in Title 49 of the Code of Federal Regulations (CFR) Section 192.935, such as increased inspections and assessments, additional maintenance, participation in a one-call system, community education and consideration of the installation of additional remote-controlled valves, can help reduce the likelihood or consequence of a rupture event in both high consequence and lesser populated areas.

The SoCalGas HP Incident risk is similar to the SDG&E HP Incident risk because the threats are the same and the system is managed in an integrated manner. Since the high-pressure pipeline system is managed by two operating departments (Transmission and Distribution), it is difficult to identify costs solely dedicated to high pressure pipelines managed by Distribution Operations. Therefore, the costs in this risk Chapter are primarily related to the Transmission Operations department.

B. Risk Definition

For purposes of this RAMP Report, SoCalGas's HP Incident risk is defined as the risk of failure of a high pressure pipeline,[7] which results in serious injuries, or fatalities, and/or damage to infrastructure. For purposes of this Chapter, the failure event would be from one of eight threats identified by PHMSA. The medium pressure assets operating at a pressure of 60 psig and less are included in the RAMP Chapter for incidents involving medium pressure pipelines. Events caused by third party dig-in damage are included in the Excavation Damage (Dig-In) on the Gas System risk Chapter.

C. Scope

Table 1 below provides what is considered in and out of scope for the HP Incident risk in this RAMP Report.

Table 1: Risk Scope

In-Scope:	The risk of damage, caused by a high pressure system (maximum allowable operating pressure (MAOP) greater than 60 psig) failure event, which results in consequences such as injuries, fatalities or outages.
Data Quantification Sources:	SoCalGas engaged internal data sources for the calculation surrounding risk reduction; if data was insufficient, however, Industry or National data was supplemented and adjusted to fit the risk profile associated with the operating locations and parameters of the utilities. For example, certain types of incident events have not occurred within the SoCalGas service territory; therefore, expanding the quantitative needs to encompass industry data where said incident(s) have been recorded to provide a proximate is justified in establishing a baseline of risk and risk addressed by activities. See Appendix B for additional information.

II. RISK ASSESSMENT

In accordance with the Settlement Decision,[8] this section describes the risk bow tie, possible drivers, potential consequences, and the risk score for the HP Incident risk.

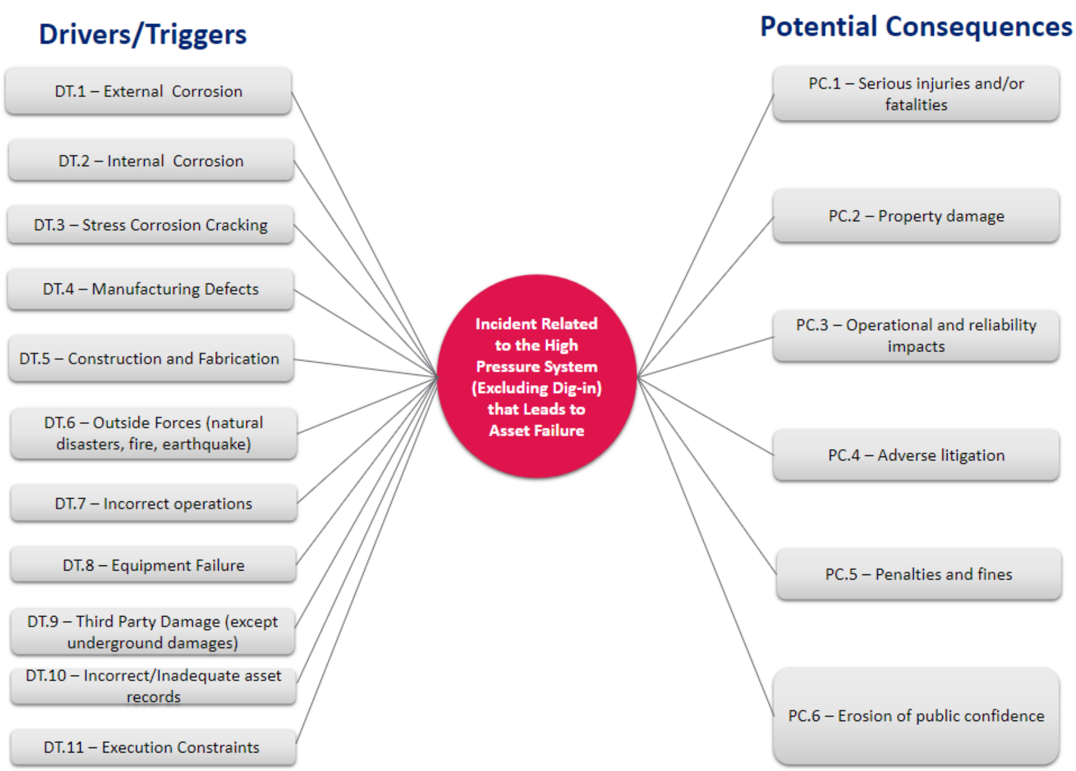
7 Maximum Allowable Operating Pressure (MAOP) at higher than 60 psig.

8 D.18-12-014 at 33, and Attachment A, A-11 ("Bow Tie").

A. Risk Bow Tie and Risk Event Associated with the Risk

The risk bow tie is a commonly used tool for risk analysis, and the Settlement Decision[9] instructs the utility to include a risk bow tie illustration for each risk included in RAMP. As illustrated in the risk bow tie shown below in Figure 1, the risk event (center of the bow tie) is a HP incident that leads to Asset Failure, the left side of the bow tie illustrates drivers/triggers that lead to the HP incident that Leads to Asset Failure, and the right side shows the potential consequences of the HP incident. SoCalGas applied this framework to identify and summarize the information provided in Figure 1. A mapping of each mitigation to the element(s) of the risk bow tie addressed is provided in Appendix A.

Figure 1: Risk Bow Tie



---

9 *Id.*

B. Cross-Functional Factors

The following cross-functional factors have programs and/or projects that affect one or more of the drivers and/or consequences of this risk: Energy Resilience, Emergency Planning and Response and Pandemic, Foundational Technology Systems, Physical Security, Asset and Records Management, Safety Management Systems, and Workforce Planning / Quality Workforce.

C. Potential Drivers/Triggers[10]

The Settlement Decision[11] instructs utilities to identify which element(s) of the associated risk Bow Tie each mitigation addresses. When performing the risk assessment for the HP Incident risk, SoCalGas identified potential leading indicators, referred to as drivers or triggers. These include:

- **DT.1 – External Corrosion:** A naturally occurring phenomenon commonly defined as the deterioration of a material (usually a metal) that results from a chemical or electrochemical reaction with its environment.[12]
- **DT.2 – Internal Corrosion:** Deterioration of the interior of an asset as a result of the environmental conditions on the inside of the pipeline. [13]
- **DT.3 – Stress Corrosion Cracking:** A type of environmentally-assisted cracking usually resulting from the formation of cracks due to various factors in combination with the environment surrounding the pipeline that together reduces the pressure-carrying capability of the pipe.[14],
- **DT.4 – Manufacturing Defect:** Attributable to a material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects, or in-service stresses such as vibration, fatigue and environmental cracking.
- **DT.5 – Construction and Fabrication:** Attributable to the construction methodology applied during the installation of pipeline components specifically

---

10 An indication that a risk could occur. It does not reflect actual or threatened conditions.

11 D.18-12-014 at Attachment A, A-11 (“Bow Tie”).

12 *See* AMSE B31.8S.

13 *Id*.

14 *Id*.

based on the vintage of the construction standards, fabrication techniques (welding, bending, etc.) and overall guiding regulations.

- **DT.6 – Outside Forces:** Attributable to causes not involving humans, but includes effects of climate change such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, and high winds.
- **DT.7 – Incorrect Operations:** May include a pipeline incident attributed to insufficient or incorrect operating procedures or the failure to follow a procedure.
- **DT.8 – Equipment Failure:** Attributable to malfunction of a component, including but not limited to, regulators, valves, meters, flanges, gaskets, collars, couples, etc.
- **DT.9 – Third-Party Damage (except for underground damages[15]):** Attributable to outside force damage other than excavation damage or natural forces such as damage by car, truck or motorized equipment not engaged in excavation, etc.
- **DT.10 – Incorrect/Inadequate Asset Records:** The use of inaccurate or incomplete information that could result in the failure to (1) construct, operate, and maintain SoCalGas's pipeline system safely and prudently; or (2) to satisfy regulatory compliance requirements.
- **DT.11 – Execution Constraints:** Events (excluding those covered by outside force damages) that impact the Company's ability to perform as anticipated. Examples include, but are not limited to: Materials and operational oversight, delays in response and awareness, resource constraints, and/or inefficiencies and reallocation of (human and material) resources, unexpected maintenance, or regulatory requirements.

[15] Underground damage would fall under the Excavation Damage risk Chapters in the RAMP Report.

D. Potential Consequences of Risk Event

Potential consequences[16] are listed to the right side of the risk bow tie illustration provided above. If one or more of the drivers/triggers listed above were to result in an incident, the potential consequences, in a reasonable worst-case scenario, could include:

- **PC.1 – Serious Injuries and/or Fatalities**
- **PC.2 – Property Damage**
- **PC.3 – Operational and Reliability Impacts**
- **PC.4 – Adverse Litigation**
- **PC.5 – Penalties and Fines**
- **PC.6 – Erosion of Public Confidence**

These potential consequences were used in the scoring of the HP Incident risk that occurred during the development of SoCalGas's 2020 Enterprise Risk Registry.

E. Risk Score

The Settlement Decision requires a pre- and post-mitigation risk calculation.[17] Chapter SCG/SDG&E RAMP-C of this RAMP Report explains the Quantification Overview that underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 2: Pre-Mitigation Analysis Risk Quantification Scores[18]

	LoRE	CoRE	Risk Score
Incident Related to the High Pressure System	8.64	538	4,644

Pursuant to Step 2A of the Settlement Decision, the utility is instructed to use actual results, where available, and appropriate data where actuals are not available (*e.g.*, Pipeline and Hazardous Materials Safety Administration data).[19] Historical PHMSA data and internal SME

16 D.18-12-014 at 16, and Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

17 *Id.* at Attachment A, A-11 ("Calculation of Risk").

18 The term "pre-mitigation analysis," in the language of the Settlement Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

19 *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

input was used to estimate the frequency of incidents. For additional sources refer to Appendix B.

III. 2020 CONTROLS

This section "[d]escribe[s] the controls or mitigations currently in place" as required by the Settlement Decision.[20] The activities in this section were in place as of December 31, 2020. Controls that will continue as part of the control and mitigation plan (Plan) are identified in Section IV.

Pursuant to CFR Title 49 Part 192 Subpart O, HCAs must be identified by the Company and are areas along the gas transmission right-of-way where there is increased building density or a proximity to certain types of gathering locations where there is an expected concentration of population. The establishment of areas of known greater consequential impact to the public institutes a different risk profile associated with HCA pipe as compared to high pressure pipe not located in an HCA. Therefore, SoCalGas set out to appropriately tranche controls and mitigations, where feasible, for the determination of costs and activity scope. Of note is that for the majority of the controls and mitigations subject to the HCA and non-HCA tranching, the work performed in the HCA is the same as in a non-HCA and as such, there is only a single description of the control and mitigation. These are identified by C#-T1: HCA; C#-T2: non-HCA nomenclature after the control name. Because SoCalGas does not track costs or scope for high pressure activities by HCA and non-HCA, a fixed 33% multiplier for HCA and a 67% multiplier for non-HCA (representing to ratio of total miles of pipe located in HCAs vs in non-HCAs) was applied to costs and scope for activities within these two tranches, unless otherwise noted. SoCalGas recognizes that this mileage methodology is only an approximation and where this assumption was deemed too gross (*i.e.*, unreliable), the tranche was not applied to an activity.

A. C1: Cathodic Protection (CP) – Capital

- **C1-T1: HCA; C1-T2: non-HCA**

Cathodic protection activities consist of the planning, installation, construction and closeout of rectifiers/deep well anode beds, remote power and pipeline coating replacements on transmission pipelines. Rectifiers/deep well anode beds are utilized to drive the electrochemical

[20] *Id*.

reaction required for cathodic protection via an impressed current system along SoCalGas pipelines. The utilization of remote power allows SoCalGas the flexibility to install impressed current systems without having to find a power supply and instead focus on the most effective placement for an impressed current system. Pipeline coating replacements allow SoCalGas to replace the pipeline's first line of defense against corrosion related defects and lower the amount of CP current needed to protect the newly recoated portion of pipeline. These activities are necessary to maintain or improve the pipelines CP system, extend the life of the pipeline, and maintain CP compliance prescribed by 49 CFR Subpart I – Requirements for Corrosion Control Section 192.463:

- Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.
- Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of §192.461.
- Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.
- Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

B. C2: Cathodic Protection - Maintenance

- **C2-T1: HCA; C2-T2: non-HCA**

Cathodic protection maintenance activities consist of annual electrical test station (ETS) reads, bi-monthly current source inspections and annual rectifier maintenance on transmission pipelines. The mentioned activities involve the following; read/record voltage and verify compliance, inspect ETS for signs of damage, verifying ID tags & test leads for correct information and good condition, verify rectifier proper operation, read/record voltage and amperage across rectifier, clean and tighten all current carrying connections on rectifier, clean all ventilating screens on rectifier units, calibrate voltage and amperage meters on rectifier, repair any damaged wires, check all fuses/circuit breakers, clean off rectifier unit, replace rectifier ID tags, diagnose and troubleshoot substandard conditions or out of tolerance reads. These activities are necessary to maintain or improve the pipelines CP system, extend the life of the pipeline, and maintain CP compliance prescribed by 49 CFR Subpart I – Requirements for Corrosion Control:

1. Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463.
2. Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months, to validate that it is operating.

C. C3: Leak Repair

- **C3-T1: HCA; C3-T2: non-HCA**

Leak repair activities consist of the planning, installation, construction and closeout of projects initiated due to leaks on transmission pipelines or appurtenances. Classification of leaks is based on relative degree of hazard and must be remediated in accordance with the timelines set out by General Order 112 F. Leak repair activities are necessary to uphold public safety, maintain system reliability, and meet regulatory requirements prescribed by 49 CFR 192 Subpart M – Maintenance Section 192.717:

- Each permanent field repair of a leak on a transmission line must be made by:
  - Removing the leak by cutting out and replacing a cylindrical piece of pipe; or
  - Repairing the leak by one of the following methods:

- Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS.
- If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.
- If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Megapascals) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.
- Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

D. C4: Leak Survey & Patrol

- **C4-T1: HCA; C4-T2: non-HCA**

Instrument Leak Survey & Patrol activities consist of semi-annual leak and patrol surveys, quarterly patrols and special leak and patrol surveys on transmission pipelines. The mentioned activities involve the following: observe surface conditions of right-of-way, detect leaks, report conditions affecting the safety or access of the pipeline, check for right-of-way encroachments, report nearby development, replace missing or damaged pipeline markers, inspect all railroad crossings and class 3/HCA locations. These activities are necessary to maintain or improve the pipeline system, extend the life of the pipeline, maintain pipeline compliance prescribed by 49 CFR 192 Subpart M - Maintenance Sections 192.705 and 192.706:

1. Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.
2. The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Maximum interval between patrols		
Class location of line	**At highway and railroad crossings**	**At all other places**
1, 2	7½ months; but at least twice each calendar year	15 months; but at least once each calendar year.
3	4½ months; but at least four times each calendar year	7½ months; but at least twice each calendar year.
4	4½ months; but at least four times each calendar year	4½ months; but at least four times each calendar year.

3. Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted:
   i. In Class 3 locations, at intervals not exceeding 7 1⁄2 months, but at least twice each calendar year; and
   ii. In Class 4 locations, at intervals not exceeding 4 1⁄2 months, but at least four times each calendar year.

E. C5: Pipeline Relocation/Replacement

- **C5-T1: HCA; C5-T2: non-HCA**

Pipeline relocation and replacement activities consist of planning, installation, construction and closeout of pipeline reroutes triggered by either weather-related external forces, municipality requests, right-of-way agreements, or class location changes. Pipeline replacements due to change in operating class are time sensitive and must be remediated within 24 months of the class location change. These relocation and replacement activities are necessary to reduce the potential for pipeline damage, uphold public safety, and maintain pipeline access.

F. C6: Shallow/Exposed Pipe Remediations

- **C6-T1: HCA, C6-T2: non-HCA**

Shallow or exposed pipe activities consist of the planning, installation, construction, and closeout of projects to add additional cover or protection to Transmission pipelines. Exposed pipelines are inspected for signs of corrosion, metallurgical flaws, construction flaws and mechanical damage. Concrete revetment mats (technology designed to help prevent shoreline erosion) and/or additional earth coverage are installed to prevent damage to exposed/shallow pipe caused by corrosion, third party damages, erosion, or other external forces. These activities are necessary to uphold public safety, reduce the potential for pipeline damage, and extend the life of the pipeline.

G. C7: Pipeline Maintenance

- **C7-T1: HCA; C7-T2: non-HCA**

Pipeline Maintenance activities consist of class location surveys, valve inspections, vault inspections and bridge and span inspections on transmission pipelines. The mentioned activities involve the following: surveying lines to identify and report any changes in population density, verifying ID tags for correct information and good condition, partially operating the valves (*i.e.*, open/close), inspecting and servicing actuators, lubricating valves, checking for atmospheric corrosion, testing for combustible gas, inspecting covers, ventilation systems, structural condition of vaults, vault ladders, steps and handrails. These activities are necessary to maintain or improve the pipeline system, extend the life of the pipeline, maintain pipeline compliance prescribed by 49 CFR 192 Subpart M – Maintenance Sections 192.745 & 192.749:

- Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.
- Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.
- Each vault housing pressure regulating and pressure limiting equipment and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.
- If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.
- The ventilating equipment must also be inspected to determine that it is functioning properly.
- Each vault cover must be inspected to assure that it does not present a hazard to public safety.

H. C8: Right of Way

- **C8-T1: HCA; C8-T2: non-HCA**

Right of Way activities consist of planning, installation, construction and closeout of road regrading, erosion repairs, and gate/fence installations on transmission pipelines. These activities are necessary to provide safety to SoCalGas employees and the public, allow year-round critical access in order to execute span painting, pipeline maintenance, storm damage repairs, and vegetation removals. This control helps minimize third party damage, prevent wildfire damage, extend the life of the pipeline, and identify or remediate any developing system deficiencies during the performed activities.

I. C9: Class Location (Hydrotest)

- **C9-T1: HCA; C9-T2: non-HCA**

Class Location (Hydrotest) O&M activity involves hydro-testing transmission pipeline segments operating out of class due to new development increasing population density in the area surrounding the pipeline. This activity allows an operator to verify and continue operating the pipeline with integrity and confidence knowing that the original installed pipe meets the regulatory standards prescribed by 49 CFR 192 Subpart L – Operations Section 192.609 associated with the new class location and uphold public safety.

- Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:
  - The present class location for the segment involved.
  - The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.
  - The physical condition of the segment to the extent it can be ascertained from available records.
  - The operating and maintenance history of the segment.
  - The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and
  - The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

J. C10: Compressor Stations - Capital

Compressor station activities consist of the planning, installation, construction and closeout of compressor upgrades, pipe replacements, valve replacements, equipment upgrades including water, oil, and air systems at the compressor station. These upgrades are required over time due to normal wear and tear of compressor station equipment. These activities are necessary to maintain or improve system reliability, extend equipment and system life, and uphold public safety.

K. C11: Compressor Station - Maintenance

Compressor Station Maintenance activities consist of compressor unit inspections, primary and backup power generator inspections, fire water system and emergency system inspections, programable logic controllers (PLC) and instrumentation inspections, valve inspections, vessel inspections, tank inspections, scrubber inspections, relief valve inspections, actuator/controller and regulator inspections, and leak surveys on Compressor Stations equipment and pipeline systems. The above-mentioned activities involve the following: complete periodic performance analysis and time-based overhauls on main compressor units and generators; function testing of fire water systems and emergency systems (including Station ESD and gas detection systems); maintenance and calibration of PLC systems, pressure and temperature transmitters, flow meters, pressure regulators, uninterruptible power supply systems and gas quality systems; verifying ID tags for correct information and good condition; examining operating valves, inspecting and servicing actuators, and lubricating valves; checks for atmospheric corrosion; tests for combustible gas; testing/recording set points and/or verifying rupture disc rating; checking supply regulators for proper operation; checking for leakage; blowing/inspecting supply filters; checking hydraulic fluid levels; checking controller for proper operation; and testing/recording set points. These activities are necessary to maintain or improve the pipeline system, extend the life of the pipelines, maintain pipeline and station compliance prescribed by 49 CFR 192 Subpart M – Maintenance Sections 192.731:

- Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

- Any defective or inadequate equipment found must be promptly repaired or replaced.
- Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

L. C12: Measurement & Regulation – Capital

- **C12-T1: HCA; C12-T2: non-HCA**

Measurement & Regulation activities consist of the planning, installation, construction and closeout of redesigns/upgrades for producer vessels, meters, stations, Company-owned facilities at customer meter set assemblies and control valve stations on transmission pipeline systems. These upgrades are required to replace aging equipment with new equipment to enhance functionality. Both the safety and reliability of SoCalGas's transmission system is dependent on the meter and regulator equipment that is used to control the flow of natural gas in transmission pipelines through the use of valves and regulator stations. These activities are necessary to maintain or improve system reliability, extend equipment and system life, and uphold public safety.

M. C13: Measurement & Regulation Station – Maintenance

- **C13-T1: HCA; C13-T2: non-HCA**

Measurement & Regulation Station activities consist of valve inspections, vault inspections, producer station inspection, pressure limiting station inspections, relief valve inspections and actuator/controller, and regulator inspections on transmission pipelines. The mentioned activity involves the following: verifying ID tags for correct information and good condition; partially operating valves; inspecting and servicing actuators; lubricating valves; checking for atmospheric corrosion; testing for combustible gas; inspecting covers, ventilation systems, structural condition of vaults, vault ladders, and test/record set points; verifying rupture disc rating; checking supply regulators for proper operation; checking for leakage; blowing/inspecting supply filters; checking hydraulic fluid levels; checking controller for proper operation; and testing/recording set points. These activities are necessary to identify or remediate any developing system deficiencies during the performed activities, to maintain or improve the pipeline system, extend the life of the pipeline, and maintain pipeline compliance prescribed by 49 CFR 192 Subpart M – Maintenance Section 192.739:

A. Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

   i. In good mechanical condition;

   ii. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

   iii. Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a); and

   iv. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

B. For steel pipelines whose MAOP is determined under §192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	**Then the pressure limit is:**
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

N. C14: Odorization

Odorization activities consist of the delivery and safe storage of odorant at SoCalGas receipt points and the monthly odor intensity testing on transmission pipelines. Odorant deliveries are required throughout the year as the volume of odorant in the odorant tanks deplete at different rates based on gas throughput. The odorization is required to provide natural gas a readily detectable smell. The odor intensity testing involves the following: testing gas to verify a recognizable amount of gas odor is detectable, testing for any harmful components and calibrating appropriate equipment intervals. These activities are necessary to uphold public safety, maintain system reliability, meet regulatory requirements prescribed by 49 CFR 192 Subpart L – Operations Section 192.625:

a. A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

b. To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by—

   i. Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

   ii. Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.

O. C15: Security & Auxiliary Equipment

Security & auxiliary equipment activities consist of the planning, installation, construction and closeout of security cameras, lighting, gates, locks and equipment upgrades such as pipe supports, analyzers and Supervisory Control and Data Acquisitions (SCADAs) on transmission pipeline facilities. These upgrades are required to address the physical security for critical gas facilities owned and operated by SoCalGas. The loss of these facilities would have a significant impact on the normal operation of the Transmission system. These activities harden the security at pressure limiting stations, valve stations, compressor stations, increase personnel safety, and reduce the potential of system damage.

P. C16: SCADA Operation

Gas Control and the SCADA Operations group are responsible for the remote monitoring, control, and real-time operations of SoCalGas and SDG&E's combined gas-transmission system including associated pipelines, line compressor stations, and underground storage facilities. The SCADA Operations department manages the planning, operation, and maintenance of the SCADA system. The SCADA system provides for remote monitoring and operation of valves, compressors, pressure regulation equipment, and gas flow across the system. The organization's responsibilities include compliance with Control Room Management - PHMSA rule 49 CFR § 192.631 regarding alarm management, system change management, fatigue mitigation, system operating experience, and personnel training requirements.

Q. C17: Control Room Monitoring, Operation, and Fatigue Management

Control Room Monitoring and Operation activities consist of 24/7 operation of the transmission pipeline system in a real-time control room environment. This is necessary in order to provide a centralized and holistic view of system health, and where the remote monitoring and operation of valves, compressor stations, pressure regulation equipment, and gas flow across the system enables controllers to acknowledge, react and respond to both normal and abnormal operating conditions. This allows coordination of necessary pipeline shutdowns for maintenance and/or emergency measures. The control room serves as a communication center between various departments conducting maintenance on the transmission pipeline system, upholding public safety, maintaining system reliability, and developing a daily operating plan that includes demand forecasts and facility utilization. It also allows for preparation of contingencies for changes in system conditions resulting from changes in weather patterns and loads, forecast error, and abnormal operating condition.

Fatigue management consists of implementing methods to reduce risk associated with controller fatigue that could inhibit a controller's ability to carry out their role and responsibilities. In order to validate proper fatigue management, shift lengths and schedule rotations are established that provide controllers an adequate amount of rest, train controllers and supervisors to recognize the effects of fatigue, and educate controllers and supervisors in fatigue mitigation strategies. These methods are necessary to uphold public safety, maintain system reliability and meet regulatory requirements prescribed by 49 CFR 192 Subpart L – Operations Section 192.631:

As part of fatigue mitigation, each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

i. Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

ii. Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

iii. Train controllers and supervisors to recognize the effects of fatigue; and

iv. Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

R. C18: Gas Transmission Planning

Gas Transmission Planning is responsible for long-term planning and design of SoCalGas and SDG&E's gas transmission systems. This group continually assesses the transmission system's ability to: meet CPUC-mandated design standards, meet existing service obligations and satisfy new customer demand, provide new services and products to customers, and access new sources of natural gas supply. The department is also directly responsible for developing analysis and reporting on the system's ability to remain reliable through major system outages and making recommendations to maintain system resiliency. These activities are necessary to uphold public safety, maintain system reliability and meet regulatory requirements prescribed by 49 CFR 192.

S. C19: Engineering, Oversight and Compliance Review

Engineering, Oversight and Compliance Review activities consist of utility plan checks and review of all completed compliance orders on transmission pipeline systems. The compliance orders are the activities performed in the aforementioned controls: C2, C4, C7, C11, and C13. These activities are necessary to avoid third party damage, uphold the structural integrity of the pipeline, maintain feasible access to the pipeline system, verify we are meeting all regulatory standards prescribed by 49 CFR 192, comply with Company-issued Gas Standards, extend the life of the pipeline, uphold public safety, and maintain system reliability.

T. C20: Facilities Integrity Management Program (FIMP)

SoCalGas continues to develop a Facilities Integrity Management Program (FIMP) based on principles developed by the Canadian Energy Pipeline Association and the Pipeline Research Council International. The FIMP is not intended to duplicate any systems or processes that may already exist; rather, it is intended to supplement the already existing integrity management programs (*e.g.*, SIMP, Transmission Integrity Management Program (TIMP), and Distribution Integrity Management Program (DIMP)) to enhance the safety and integrity of SoCalGas's facility assets. FIMP will apply integrity management principles to facilities assets to reduce risks and promote operational excellence. Initial FIMP activities include program development and data collection and data integration efforts on pressure vessels, tanks, and certain piping at storage facilities and compressor stations.

U. C21: Integrity Assessments & Remediation

1. C21-T1: Transmission Integrity Management Program

Through the TIMP, per 49 CFR 192, Subpart O, SoCalGas is federally mandated to identify threats to transmission pipelines in HCAs, determine the risk posed by these threats, schedule prescribed assessments to evaluate these threats, collect information about the condition of the pipelines, and take actions to minimize applicable threat and integrity concerns to reduce the risk of a pipeline failure. At a minimum of every seven years, transmission pipelines located within HCAs are assessed using methods such as In-Line-Inspection (ILI), Direct Assessment, or Pressure Test, and remediated as needed.

Detected anomalies are classified and addressed based on severity with the most severe requiring immediate action. Remediations reduce risk by addressing areas where corrosion, weld or joint failure, or other forces are occurring or has occurred. Post-assessment pipeline repairs, when appropriate, and replacements are intended to increase public and employee safety by reducing or eliminating conditions that might lead to an incident. ILI is the primary assessment method used to identify potential pipeline integrity threats. When a threat is identified, SoCalGas acts in accordance with 49 CFR § 192.933 to reduce risk. These actions involve removing a pipeline from service or reducing operating pressure. In cases where the assessment involves a pressure test that has failed, immediate remediation is also required as the pressure test cannot be completed until the pipeline is repaired.

TIMP reduces the risk of failure to the transmission system and on a continual basis evaluates the effectiveness of the program and scheduled assessments. TIMP Risk Assessment evaluates the Likelihood of Failure (LOF) using the nine threat categories (External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing, Construction, Equipment, Third Party Damage, Incorrect Operations, and Weather Related and Outside Force) for transmission pipelines located within an HCA. Pipeline operational parameters and the area near the pipeline are considered to evaluate Consequence of Failure (COF). The LOF multiplied by the COF produces the pipelines Relative Risk Score. Further information is collected about the physical condition of transmission pipelines through integrity assessments. Action is taken to address applicable threats and integrity concerns to increase the safety and prevent pipeline failures.

The number and types of TIMP activities vary from year to year and are based on the timing of previous assessments done on the same locations. Approximately 1,100 miles out of 3,341 miles of SoCalGas's transmission pipelines are in HCA areas.[21]

2. C21-T2: Outside of High Consequence Area Assessments

Because a pipeline may consist of segments located inside and outside of HCAs, SoCalGas also assesses incidental non-HCA pipeline segments. Since SoCalGas does not plan assessments by consequence area, the overall assessment and remediation activities and costs have been tranched by applying a seven-year average of historical HCA versus non-HCA miles assessed.

Additionally, in October of 2019, PHMSA issued final rule of Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments. Published as the first of three parts, this final rule updates sections of 49 CFR §§ 191 and 192 and federally mandates gas operators to update or implement procedures accordingly.

Pursuant to 49 CFR §192.710, SoCalGas is newly required to assess transmission pipelines in medium consequence areas (MCAs) and non-HCA Class 3 and 4 locations. For reference, determination of the Class of a pipeline is dependent on the type and density of dwellings and human activity within 220 yards of the pipeline. The numbers and types of activities will vary from year to year and approximately 247 miles out of 3,341 miles of SoCalGas's transmission pipelines are located in MCAs or non-HCA Class 3 and 4 locations. At a minimum of every ten years, these transmission lines must be assessed using methods such as ILI, ECDA, and pressure testing. Like with TIMP assessments, detected anomalies will be classified and addressed based on severity. Remediations reduce risk by addressing areas where corrosion, weld or joint failure, or other forces are occurring or has occurred. Post-assessment pipeline repairs, when appropriate, and replacements are intended to increase public and

21 SoCalGas 2020 Annual DOT Report.

employee safety by reducing or eliminating conditions that might lead to an incident. When a threat is identified, SoCalGas will act in accordance with 49 CFR §§ 192.485, 192.711, and 192.713 to reduce risk. These actions involve removing a pipeline from service or reducing operating pressure. In cases where the assessment involves a pressure test that has failed, immediate remediation is also required as the pressure test cannot be completed until the pipeline is repaired.

These assessments are incremental to TIMP and serve to further minimize the risk of failure to the transmission system. Taking into consideration the difference in the risk profiles of HCAs and non-HCAs, the evaluation of these segments is modeled after the TIMP risk assessment and prompts similar actions to address applicable threats and integrity concerns to increase the safety and preclude pipeline failures.

V. C22: Pipeline Safety Enhancement Plan

SoCalGas and SDG&E's Pipeline Safety Enhancement Plan (PSEP) is an ongoing systematic effort to replace or pressure test all of the natural gas transmission pipelines that have not been tested or for which reliable records are not available, as directed by the California Public Utilities Commission in D.11-06-017 and later codified in California Public Utilities Code Sections 957 and 958. Separate from the testing or replacement of pipeline, PSEP also includes a valve enhancement plan, as required by the Commission in D.11-06-017.[22]

The primary objectives of PSEP are to enhance public safety, comply with Commission directives, maximize cost effectiveness, and minimize customer and community impacts from these safety investments. As directed by the Commission, the program includes a risk-based prioritization methodology that prioritizes pipelines located in more populated areas ahead of pipelines located in less populated areas and further prioritizes pipelines operated at higher stress levels above those operated at lower stress levels. PSEP is divided into two phases and each phase is further subdivided into two parts resulting in four separate phases described below, Phase 1A, Phase 1B, Phase 2A, and Phase 2B.[23]

---

[22] D.11-06-017, Conclusion of Law 9 at 30, and Ordering Paragraph (OP) 8 at 32.

[23] Phase 2B pipelines are those that have documentation of a pressure test that predates the adoption of federal testing regulations in 1970, specifically, Part 192 Subpart J of Title 49 of the CFR. SoCalGas has not initiated any standalone Phase 2B projects to date and does not anticipate executing Phase 2B projects during the forecast period (2022-2024). Therefore, Phase 2B has not been assigned a control ID and will not be part of this RAMP filing.

PSEP Phase 1A, Phase 1B, and Phase 2A each include projects that recorded costs in 2020 and these phases are discussed below in this section and denoted with a control ID.[24] SoCalGas has not yet initiated any standalone Phase 2B projects and does not anticipate executing standalone Phase 2B projects during the TY 2024 GRC's 2022-2024 forecast period.

SoCalGas's PSEP is comprised of projects with spending that is classified in this RAMP Report as either "refundable" or "GRC based." Cost recovery for refundable projects occurs outside of the TY 2024 GRC but SoCalGas is including a discussion of these classes of projects in this RAMP Report to inform the Commission and stakeholders of these safety risk mitigating activities and to help eliminate potential confusion with projects for which SoCalGas will be requesting cost recovery in the TY 2024 GRC. The refundable PSEP projects are not included in the Plan and the GRC based projects are included in the Plan.

1. C22-T1: Phase 1A

Phase 1A encompasses replacing or pressure testing pipelines located in Class 3 and 4 locations and Class 1 and 2 locations in HCAs that do not have sufficient documentation of a pressure test to achieve at least 125% of the MAOP of the pipeline. For reference, determination of the Class of a pipeline is dependent on the type and density of dwellings and human activity within 220 yards of the pipeline. Phase 1A projects are classified as refundable and are tranched to reflect pipeline replacement projects and hydrotesting projects.

- C22-T1.1: Pipeline Replacement (Phase 1A, refundable, HCA)
- C22-T1.2: Hydrotesting (Phase 1A, refundable, HCA)

2. C22-T2: Phase 1B

The scope of Phase 1B is to replace pipelines installed prior to 1946 that are incapable of being assessed via inline smart inspection tools (non-piggable pipelines) with new pipe constructed using state-of-the-art methods and to modern standards, including current pressure test standards. Phase 1B projects are classified as both refundable and GRC base and may occur in HCA and non-HCA areas.

- C22-T2.1: Pipeline Replacement (Phase 1B, refundable, HCA)

[24] Some Phase 2B mileage has been incorporated into Phase 1A, 1B, and 2A project scopes to realize efficiencies and to enhance project constructability.

- C22-T2.2: Pipeline Replacement (Phase 1B, refundable, non-HCA)
- C22-T2.3: Pipeline Replacement (Phase 1B, GRC base, HCA)
- C22-T2.4: Pipeline Replacement (Phase 1B, GRC base, non-HCA)

C22-T2.3 projects are expected to begin during the 2022-2024 time period but have in-service dates beyond 2024 and as such, are not part of the Plan.

3. C22-T3: Phase 2A

Phase 2A encompasses replacing or pressure testing pipelines that do not have sufficient documentation of a pressure test to achieve at least 125% of MAOP and are located in Class 1 and 2 of non-HCAs. Phase 2A projects are classified as both refundable and GRC base, with the latter being the majority of the projects.[25]

- C22-T3.1: Pipeline Replacement (Phase 2A, refundable, non-HCA)
- C22-T3.2: Pipeline Replacement (Phase 2A, GRC base, non-HCA)
- C22-T3.3: Hydrotesting (Phase 2A, refundable, non-HCA)
- C22-T3.4: Hydrotesting (Phase 2A, GRC base, non-HCA)

4. C22-T4: Valve Enhancement Plan

The valve enhancement plan focuses on the modification or addition of valve infrastructure to identify, isolate, and contain escaping gas from transmission pipelines in the event of a pipeline rupture. The modifications include installing automated shut-off capability of the valves to enable a faster response time should a failure occur due to natural forces (such as natural disasters, fires, earthquakes, landslides), third party damage, vandalism, or other causes.

[25] In D.16-08-003 at OP 5 and 6, the CPUC approved an Energy Division proposal detailing a framework to incorporate PSEP into SoCalGas and SDG&E's next GRCs. Specifically, D.16-08-003 provided for two additional standalone applications for after-the-fact review of the costs incurred to complete Phase 1A projects and one forecast application for authorization to recover the costs of Phase 2 projects. All Phase 1A projects completed after the filing of the two reasonableness reviews, as well as remaining forecasted projects not included in the forecast application, were to be submitted for approval in subsequent GRCs.

Valve enhancement projects are classified as both refundable and GRC base and are tranched to reflect that projects may occur in HCA or non-HCA areas.

- C22-T4.1: Valve enhancement (refundable, HCA)
- C22-T4.2: Valve enhancement (refundable, non-HCA)
- C22-T4.3: Valve enhancement (GRC base, HCA)
- C22-T4.4: Valve enhancement (GRC base, non-HCA)

W. C23: Compressor Station Modernization Projects

The primary objectives of the compressor station modernization projects are to replace and modernize existing compressors and associated infrastructure to comply with air quality regulations while prioritizing reliability, capacity, and system resilience. In Decision 19-09-051,[26] the Commission recognized the importance of facility modernization projects and the role of compressor stations in maintaining operational reliability and safety of the gas transmission and storage system. The Commission encouraged SoCalGas to place a high priority on critical projects with aging compressors to address key risks that need to be mitigated in this area.

1. C23-T1: Blythe Compressor Station Modernization

The Blythe Compressor Station is an integral part of the SoCalGas natural gas transmission system where natural gas enters the State of California and is compressed and cooled for delivery to downstream stations and consumers. The station has been in operation since 1947 and currently consists of three compression plants known as Plant 1, Plant 2, and Plant 3. Plant 1 currently has 10 total compressors; seven compressors have been permanently decommissioned while the other three compressors currently remain in service.

---

[26] D.19-09-051 at 116-117 ("With respect to the requested amounts for this GRC, we note that other large-scale projects are being planned specifically for the Ventura Compressor Station and the Honor Rancho Compressor Station (and the Moreno Compressor station for SDG&E). Because we recognize the importance of the proposed projects and the role of compressor stations in maintaining operational reliability and safety of the gas transmission system, we find that it is prudent and reasonable to authorize the proposed projects and for SoCalGas to have the necessary funding to conduct these projects (and Moreno Compressor station for SDG&E). At this point, we do not find it necessary to deviate from current GRC practice and authorize funding only for specific projects because of the large scope covered in the GRC and because of the many challenges associated with planning and executing multiple and large projects within a specified timeframe. We do however encourage SoCalGas to place a high priority on critical projects under this category as most of its compressors are over 50 years old and because of key risks that need to be mitigated in this area. Therefore, we find that the requested amounts for Compressor Stations should be authorized.")

The scope of work for the Blythe Compressor Modernization project includes the installation of Plant 4, which includes two new gas turbine compressor units and the ability to install one additional compressor at a later time, overhauling and upgrading the existing five compressor units at Plant 2 to reduce emissions, installing one new operations building, and upgrading ancillary equipment and infrastructure to support the modifications to the facility. Upon commissioning of the Plant 4 compressors, the three operational Plant 1 compressors will be permanently decommissioned.

This project has a planned 2021 in-service date and as such, it is not part of the Plan. It is included in this RAMP Report for the Commission's and stakeholders' awareness of safety risk activities being pursued by SoCalGas.

2. C23-T2: Ventura Compressor Station Modernization

The Ventura Compressor Station is in the City of Ventura and is used to transfer natural gas from Los Angeles to SoCalGas's northern service territory. The existing facility uses three Cooper Superior reciprocating compressors. The scope of work for the Ventura Compressor Modernization project includes installation of four new reciprocating gas engine-driven compressors, a compressor building, an office and warehouse building, utilities, and associated controls, electrical, instrumentation and emission control equipment, and decommissioning of the existing equipment.

IV. 2022-2024 CONTROL & MITIGATION PLAN

This section contains a table identifying the controls and mitigations comprising the portfolio of mitigations for this risk.[27]

All of the activities discussed in Section III above, except for the PSEP related activities with cost recovery via a mechanism outside of the upcoming GRC, and the Blythe Compressor Station Modernization project, are expected to continue during the TY 2024 GRC and are

included in the plan. For clarity, a current activity that is included in the plan may be referred to as either a control and/or a mitigation. For purposes of this RAMP, a control that will continue as a mitigation retains its control ID unless the size and/or scope of that activity will be modified, in which case that activity's control ID will be replaced with a mitigation ID. The table below shows which activities are expected to continue.

[27] *See* D.18-12-014, Attachment A at A-14 ("Mitigation Strategy Presentation in the RAMP and GRC")

Table 3: Control and Mitigation Plan Summary

Line No.	Control/ Mitigation ID	Control/Mitigation Description	2020 Controls	2022-2024 Plan
1	C1	Cathodic Protection – Capital	X	X
2	C2	Cathodic Protection – Maintenance	X	X
3	C3	Leak Repair	X	X
4	C4	Leak Survey and Patrol	X	X
5	C5	Pipeline Relocation/Replacement	X	X
6	C6	Shallow/Exposed Pipe Remediation	X	X
7	C7	Pipeline Maintenance	X	X
8	C8	Right of Way	X	X
9	C9	Class Location - Hydrotest	X	X
10	C10	Compressor Stations – Capital	X	X
11	C11	Compressor Stations – Maintenance	X	X
12	C12	Measurement & Regulation - Capital	X	X
13	C13	Measurement & Regulation – Maintenance	X	X
14	C14	Odorization	X	X
15	C15	Security and Auxiliary Equipment	X	X
16	C16	SCADA Operation	X	X
17	C17	Control Room Monitoring, Operation, and Fatigue Management	X	X
18	C18	Gas Transmission Planning	X	X
19	C19	Engineering, Oversight and Compliance Review	X	X
20	C20	Facility Integrity Management Plan	X	X
21	C21	Integrity Assessments & Remediation	X	X
22	C22-T1.1 C22-T1.2	PSEP, Phase 1A - Refundable	X	No
23	C22-T2.1 C22-T2.2	PSEP, Phase 1B – Pipeline Replacement (Refundable)	X	No
24	C22-T2.3	PSEP, Phase 1B – Pipeline Replacement (GRC) - HCA	No	No

Line No.	Control/ Mitigation ID	Control/Mitigation Description	2020 Controls	2022-2024 Plan
25	C22-T2.4	PSEP, Phase 1B – Pipeline Replacement (GRC) – non-HCA	X	X
25	C22-T3.1	PSEP, Phase 2A – Pipeline Replacement (Refundable)	X	No
26	C22-T3.2	PSEP, Phase 2A – Pipeline Replacement (GRC)	X	X
27	C22-T3.3	PSEP, Phase 2A – Hydrotesting (Refundable)	X	No
28	C22-T3.4	PSEP, Phase 2A – Hydrotesting (GRC)	X	X
29	C22-T4.1 C22-T4.2	PSEP, Valve Enhancement (Refundable)	X	No
30	C22-T4.3 C22-T4.4	PSEP, Valve Enhancement (GRC)	X	X
31	C23-T1	Blythe Compressor Station Modernization	X	No
32	C23-T2	Ventura Compressor Station Modernization	X	X
33	C23-T3	Honor Rancho Storage Field	No	No
34	M1	Gas Transmission Safety Rule – MAOP Reconfirmation	No	X
35	M2	Gas Transmission Safety Rule – Material Verification	No	X

For activities SoCalGas plans to perform that remain unchanged, refer to the descriptions in Section III. If changes to the various activities are anticipated, such modifications are further described in the section below.

A. Changes to 2020 Controls

1. C21-T2: Integrity Assessments & Remediation

As described above in Section III, the Integrity Assessments & Remediation mitigation has been expanded beyond TIMP to include the outside of HCA assessments required by PHMSA's Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments final rule. Specifically, 49 CFR § 192.710 requires operators to assess transmission pipelines in medium consequence areas (MCAs) and non-HCA Class 3 and 4 locations. At a minimum of every ten years, these transmission lines must be assessed using methods such as ILI, ECDA, and pressure testing. Accordingly, SoCalGas has incorporated approximately 247 miles of non-HCA pipelines into the Company's assessment plan. In order to account for the difference in risk profiles between pipelines located in HCAs versus non-HCAs, SoCalGas has tranched the Integrity Assessments and Remediation control accordingly.

2. C22-T3 PSEP Phase 2A

With the submittal of its 2017 Forecast Application (A.17-03-021) and TY 2019 GRC (A.17-10-008), SoCalGas began to transition from implementing Phase 1A and Phase 1B projects to Phase 2A projects. Pursuant to Commission Decision 16-08-003, SoCalGas was ordered to submit for approval any remaining Phase 2A projects not included in the 2017 Forecast Application in the Test Year 2019 (TY 2019) and subsequent GRCs.[28] Phase 2A primarily includes pressure testing, and to a lesser degree, replacement, of transmission pipe located in less populated areas. Many of the pipeline sections that will be addressed as part of Phase 2A serve as backbone transmission lines that provide critical capacity for the overall transmission system. Aligning with a full transition to Phase 2A scoped projects, SoCalGas anticipates a significant increase in the amount of mileage and costs to execute Phase 2A projects during the TY 2024 GRC's 2022-2024 forecast period.

3. PSEP Phase 2B

Phase 2B pipelines are those that have documentation of a pressure test that predates the adoption of federal testing regulations in 1970, specifically, Part 192 Subpart J of Title 49 of the CFR. Due to the prioritization of Phase 2A (and Phase 1B) projects, SoCalGas does not currently anticipate completing any standalone Phase 2B projects during the 2022-2024 forecast period. However, as ordered in D.19-09-051, SoCalGas is currently performing an evaluation of Phase 2B pipeline mileage and plans to file certain components of its PSEP Phase 2B implementation plan, including: identified Phase 2B pipeline segments, a Phase 2B decision tree, and the results of an independent engineering review of the Phase 2B decision tree, as part of its TY 2024 GRC application.

---

[28] D.16-08-003 at OP 5 and 6.

B. 2022 – 2024 Mitigations

1. Gas Transmission Safety Rule Implementation

In October of 2019, PHMSA issued the final rule of Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments. Published as the first of three parts, the final rule updates sections of 49 CFR §§ 191 and 192 and federally mandates gas operators to update or implement procedures accordingly.

There are three new sections with which SoCalGas must comply that require new risk mitigating programs: Outside-of-HCA Assessments (49 CFR § 192.710), which has been addressed under C21, Maximum Allowable Operating Pressure (MAOP) Reconfirmation (49 CFR § 192.624), and Material Properties and Attributes Verification (49 CFR § 192.607).

- **M1: Gas Transmission Safety Rule - MAOP Reconfirmation**
  - **M1-T1: HCA; M1-T2: non-HCA**

Pursuant to 49 CFR § 192.624, SoCalGas is required to reconfirm – by July 2035 – the MAOP of transmission lines that either: 1) do not have traceable, verifiable, or complete pressure test records in accordance with 49 CFR § 192.517(a) and are located in HCAs or Class 3 or 4 locations, or 2) have an MAOP established in accordance with 49 CFR § 192.619(c), have an MAOP greater than 30% SMYS, and are located in HCAs, Class 3 or 4 locations, or – where the segment can accommodate an in-line inspection tool – MCAs.

PHMSA has required operators to document MAOP reconfirmation procedures by July 1, 2021, and SoCalGas is in the process of developing its MAOP reconfirmation program in accordance with the final rule. Separate from the state-mandated PSEP, SoCalGas has preliminarily identified approximately 1,100 miles out of 3,341 miles of SoCalGas's transmission pipelines that fall within the scope of MAOP reconfirmation per 49 CFR § 192.624. For these transmission lines, reconfirmation would be performed using one of six allowable methods: pressure testing, replacement, pressure reduction, engineering critical assessment (ECA), pressure reduction for lines with a small PIR, and alternative technology approved by PHMSA.

The MAOP reconfirmation program will include a risk-based prioritization methodology that considers, amongst other elements, pipeline location and stress level and will reduce risk of failure to the transmission system through re-evaluation of the pipeline's MAOP and, when necessary, repair/remediation of each transmission line that is within the scope.

The MAOP reconfirmation plan and program are currently in development and SoCalGas's forecast of activities and costs are initial estimates.

- **M2: Gas Transmission Safety Rule – Material Properties and Attributes Verification**
  - **M2-T1: HCA; M2-T2: non-HCA**

Pursuant to 49 CFR § 192.607, SoCalGas is required to develop and implement procedures to opportunistically verify the material properties and attributes of transmission pipelines and associated components that do not have "traceable, verifiable, and complete"[29] records. Procedures will address nondestructive or destructive tests, examinations, and assessments, as well as sampling requirements established by 49 CFR § 192.607. If SoCalGas should find materials that are not consistent with existing information or expectations, SoCalGas will address these findings in accordance with 49 CFR § 192.607 and may re-evaluate a pipeline's MAOP.

The Material Verification plan and program are currently in development and SoCalGas's forecast of activities and costs are initial estimates

2. C23: Compressor Station Modernization Projects

In addition to the currently active modernization projects discussed above (C23-T1 and C23-T2), below is a description of a mitigation project SoCalGas plans to begin in the TY 2024 GRC's 2022-2024 forecast period but which has a scheduled in-service date after the 2024 test year. As such it is not part of the plan. It is included in this RAMP Report for the Commission's and stakeholders' awareness of safety risk activities being pursued by SoCalGas.

- **C23-T3: Honor Rancho Storage Field**

The Honor Rancho Storage Field Compressor Station is an integral part of the SoCalGas natural gas storage system that balances supply with customer demand. The station has been in operation since 1975 and consists of five Enterprise DeLaval reciprocating engine driven compressors.

[29] 49 CFR §§ 191, 192.

The scope of work for the Honor Rancho Compressor Station Modernization project includes the installation of four new gas and two new electric-driven compressors, associated building(s), electrical infrastructure, instrumentation, emissions control equipment, and associated controls. Accordingly, we will retire the existing engine-driven compressors, remove their associated ancillary systems, and demolish the existing compressor building. This project will replace gas engine-driven compressors and bring Honor Rancho Compressor Station into compliance with recently amended South Coast Air Quality Management District (SCAQMD) emissions limits.

V. COSTS, UNITS, AND QUANTITATIVE SUMMARY TABLES

The tables in this section provide a summary of the risk control and mitigation plan, including the associated costs, units, and the RSEs, by tranche. When an RSE could not be performed, an explanation is provided. SoCalGas does not account for and track costs by activity or tranche; rather, SoCalGas accounts for and tracks costs by cost center and capital budget code. The costs shown were estimated using assumptions provided by SMEs and available accounting data.

Table 4: Risk Control and Mitigation Plan - Recorded and Forecast Dollars Summary[30]
(Direct After Allocations, In 2020 $000)

ID	Control/Mitigation Name	Recorded Dollars		Forecast Dollars			
		2020 Capital[31]	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
C1-T1	Cathodic Protection – Capital (HCA)	$3932	-	$14,451	$17,493	-	-
C1-T2	Cathodic Protection – Capital (non-HCA)	$7,984	-	$29,339	$35,516	-	-
C2-T1	Cathodic Protection – Maintenance (HCA)	-	$402	-	-	$344	$440
C2-T2	Cathodic Protection – Maintenance (non-HCA)	-	$815	-	-	$699	$893
C3-T1	Leak Repair (HCA)	$3,655	-	$10,949	$13,253	-	-

30 Recorded costs and forecast ranges are rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding. The figures provided are direct charges and do not include Company loaders, with the exception of vacation and sick. The costs are also in 2020 dollar and have not been escalated to 2021 amounts. The capital presented is the sum of the years 2022, 2023, and 2024, or a three-year total. Years 2022, 2023 and 2024 are the forecast years for SoCalGas's Test Year 2024 GRC Application.

31 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2020 "baseline" capital costs associated with Controls. The 2020 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

ID	Control/Mitigation Name	Recorded Dollars		Forecast Dollars			
		2020 Capital[31]	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
C3-T2	Leak Repair (non-HCA)	$7,420	-	$22,228	$26,907	-	-
C4-T1	Leak Survey & Patrol (HCA)	-	$242	-	-	$249	$318
C4-T2	Leak Survey & Patrol (non-HCA)	-	$492	-	-	$505	$645
C5-T1	Pipeline Relocation/Replacement (HCA)	$9,607	-	$20,787	$25,164	-	-
C5-T2	Pipeline Relocation/Replacement (non-HCA)	$19,506	-	$42,205	$51,090	-	-
C6-T1	Shallow/Exposed Pipe Remediations (HCA)	$2,149	-	$4,178	$5,057	-	-
C6-T2	Shallow/Exposed Pipe Remediations (non-HCA)	$4,363	-	$8,483	$10,269	-	-
C7-T1	Pipeline Maintenance (HCA)	-	$131	-	-	$134	$171
C7-T2	Pipeline Maintenance (non-HCA)	-	$266	-	-	$272	$347
C8-T1	Right of Way (HCA)	-	$1,263	-	-	$768	$981
C8-T2	Right of Way (non-HCA)	-	$2,564	-	-	$1,559	$1,992
C9-T1	Class Location – Hydrotest (HCA)	-	$0	-	-	$214	$273
C9-T2	Class Location – Hydrotest (non-HCA)	-	$0	-	-	$434	$555
C10	Compressor Station – Capital	$94,601	-	$58,018	$70,233	-	-
C11	Compressor Station - Maintenance	-	$7,446	-	-	$7,312	$9,343
C12-T1	Measurement & Regulation – Capital (HCA)	$5,836	-	$26,421	$31,984	-	-

ID	Control/Mitigation Name	Recorded Dollars		Forecast Dollars			
		2020 Capital[31]	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
C12-T2	Measurement & Regulation – Capital (non-HCA)	$11,850	-	$53,644	$64,937	-	-
C13-T1	Measurement & Regulation Station – Maintenance (HCA)	-	$682	-	-	$601	$767
C13-T2	Measurement & Regulation Station – Maintenance (non-HCA)	-	$1,385	-	-	$1,219	$1,558
C14	Odorization	-	$818	-	-	$648	$784
C15	Security and Auxiliary Equipment	$5,416	-	$12,887	$15,600	-	-
C16	SCADA Operation	-	$730	-	-	$727	$929
C17	Control Room Monitoring, Operation and Fatigue Management	-	$4,208	-	-	$2,978	$1,056
C18	Gas Transmission Planning	-	$750	-	-	$522	$667
C19	Engineering, Oversight and Compliance Review	-	$2,881	-	-	$2,057	$2,629
C20	Facility Integrity Management Program	N/A	$715	N/A	N/A	$3,284	$6,100
C21-T1	Integrity Assessments & Remediation (HCA)	$34,008	$46,410	$158,154	$202,086	$20,581	$26,297
C21-T2	Integrity Assessments & Remediation (Non-HCA)	$42,387	$57,844	$262,520	$335,442	$33,579	$42,906
C22-T2.4	PSEP: Pipeline Replacement (Phase 1B, GRC base, non-HCA)	$34,155	N/A	$65,785	$79,634	N/A	N/A

ID	Control/Mitigation Name	Recorded Dollars		Forecast Dollars			
		2020 Capital[31]	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
C22-T3.2	PSEP: Pipeline Replacement (Phase 2A, GRC base, non-HCA)	$4,645	N/A	$88,982	$107,715	$45	$55
C22-T3.4	PSEP: Hydrotesting (Phase 2A, GRC base, non-HCA)	$8,210	$20,709	$74,845	$90,601	$181,374	$219,558
C22-T4.3	PSEP: Valve Enhancement (GRC base, HCA)	$37,902	N/A	$27,253	$32,990	N/A	N/A
C22-T4.4	PSEP: Valve Enhancement (GRC base, non-HCA)	$3,837	N/A	$5,166	$6,253	N/A	N/A
C23-T2	Ventura Compressor Station Modernization	$3,231	N/A	$169,728	$205,459	N/A	N/A
M1-T1	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA)	N/A	N/A	$43,843	$140,296	$28,755	$92,016
M1-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (Non-HCA)	N/A	N/A	$17,908	$57,304	$11,745	$37,584
M2-T1	Gas Transmission Safety Rule – Material Verification (HCA)	N/A	N/A	$82	$261	$72	$230
M2-T2	Gas Transmission Safety Rule – Material Verification (Non-HCA)	N/A	N/A	$167	$533	$147	$469

Table 5: Risk Control & Mitigation Plan - Units Summary

ID	Control/Mitigation Name	Units Description		Recorded Units		Forecast Units			
		Capital	O&M	2020 Capital	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 (Low) O&M	TY 2024 (High) O&M
C1-T1	Cathodic Protection – Capital (HCA)	# of Projects		18	-	60	76	-	-
C1-T2	Cathodic Protection – Capital (non-HCA)	# of Projects		37	-	127	158	-	-
C2-T1	Cathodic Protection – Maintenance (HCA)	# of CP and follow up reads		-	584	-	-	555	709
C2-T2	Cathodic Protection – Maintenance (non-HCA)	# of CP and follow up reads		-	1,185	-	-	1,062	1,358
C3-T1	Leak Repair (HCA)	# of Projects		14	-	31	40	-	-
C3-T2	Leak Repair (non-HCA)	# of Projects		29	-	68	85	-	-
C4-T1	Leak Survey & Patrol (HCA)	Miles of Pipeline Surveyed & Patrolled		-	2234	-	-	2,011	2,569
C4-T2	Leak Survey & Patrol (non-HCA)	Miles of Pipeline Surveyed & Patrolled		-	4536	-	-	4,082	5,216
C5-T1	Pipeline Relocation/Replacement (HCA)	# of Projects		15	-	41	53	-	-
C5-T2	Pipeline Relocation/Replacement (non-HCA)	# of Projects		31	-	87	108	-	-
C6-T1	Shallow/Exposed Pipe Remediations (HCA)	# of Projects		7	-	15	22	-	-
C6-T2	Shallow/Exposed Pipe Remediations (non-HCA)	# of Projects		17	-	38	49	-	-
C7-T1	Pipeline Maintenance (HCA)	# of pipeline orders		-	311	-	-	285	364

ID	Control/Mitigation Name	Units Description		Recorded Units		Forecast Units			
		Capital	O&M	2020 Capital	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 (Low) O&M	TY 2024 (High) O&M
C7-T2	Pipeline Maintenance (non-HCA)	# of pipeline orders		-	630	-	-	579	740
C8-T1	Right of Way (HCA)	# of Projects		-	8	-	-	7	9
C8-T2	Right of Way (non-HCA)	# of Projects		-	16	-	-	14	18
C9-T1	Class Location – Hydrotest (HCA)	Miles of Pipeline Hydrotested		-	0	-	-	4	6
C9-T2	Class Location – Hydrotest (non-HCA)	Miles of Pipeline Hydrotested		-	0	-	-	9	12
C10	Compressor Stations - Capital	# of Projects		66	-	226	275	-	-
C11	Compressor Stations - Maintenance	# of Compliance and Preventative maintenance work orders		-	3,843	-	-	3,651	4,419
C12-T1	Measurement & Regulation – Capital (HCA)	# of Projects		22	-	68	86	-	-
C12-T2	Measurement & Regulation – Capital (non-HCA)	# of Projects		47	-	148	181	-	-
C13-T1	Measurement & Regulation Station – Maintenance (HCA)	# of compliance and preventative work orders		-	1,030	-	-	978	1,184
C13-T2	Measurement & Regulation Station – Maintenance (non-HCA)	# of compliance and preventative work orders		-	2,090	-	-	1,986	2,404

ID	Control/Mitigation Name	Units Description		Recorded Units		Forecast Units			
		Capital	O&M	2020 Capital	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 (Low) O&M	TY 2024 (High) O&M
C14	Odorization	LBS of Odorant		-	146,341	-	-	139,024	168,292
C15	Security and Auxiliary Equipment	# of Projects		46	-	103	127	-	-
C16	SCADA Operation	A measurable unit for the SCADA Operations department is not practical given the multiple assets that are remotely monitored for different departments. The SCADA system provides for remote monitoring and operation of valves, compressors, pressure regulation equipment, and gas flow across the system.							
C17	Control Room Monitoring, Operation and Fatigue Management	A measurable unit is not practical given the multiple means of communications and operations used to address this risk.							
C18	Gas Transmission Planning	A measurable unit is not practical given the various types of requests the Department analyzes using different analytical tools.							
C19	Engineering, Oversight and Compliance Review	A measurable unit is not practical given the charges are coded against multiple cost elements like Labor, Material, and Purchased Services							
C20	Facility Integrity Management Plan	Number of compressor stations		-	10	-	-	1	10
C21-T1	Integrity Assessments & Remediation (HCA)	# of Miles		N/A	207	N/A	N/A	155	198
C21-T2	Integrity Assessments & Remediation (Non-HCA)	# of Miles		N/A	258	N/A	N/A	300	383
C22-T4.3	PSEP: Valve Enhancement (GRC base, HCA)	# of valve bundles		19	N/A	13	16	N/A	N/A
C22-T4.4	PSEP: Valve Enhancement (GRC base, non-HCA)	# of valve bundles		8	N/A	2	2	N/A	N/A

ID	Control/Mitigation Name	Units Description		Recorded Units		Forecast Units			
		Capital	O&M	2020 Capital	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 (Low) O&M	TY 2024 (High) O&M
C22-T2.4	PSEP: Pipeline Replacement (Phase 1B, GRC base, non-HCA)	# of miles		4	N/A	19	23	N/A	N/A
C22-T3.2	PSEP: Pipeline Replacement (Phase 2A, GRC base, non-HCA)	# of miles		0.03	N/A	28	33	N/A	N/A
C22-T3.4	PSEP: Hydrotesting (Phase 2A, GRC base, non-HCA)	# of miles		N/A	20	N/A	N/A	357	433
C23-T2	Ventura Compressor Station Modernization	# of facilities being modernized		N/A	N/A	1	1	N/A	N/A
M1-T1	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA)	# of Miles		N/A	N/A	4	14	17	59
M1-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (Non-HCA)	# of Miles		N/A	N/A	2	6	7	24
M2-T1	Gas Transmission Safety Rule – Material Verification (HCA)	The Material Verification program is currently being developed and due to it being opportunistic, the number and types of samples are unclear at this point in time.							
M2-T2	Gas Transmission Safety Rule – Material Verification (Non-HCA)	The Material Verification program is currently being developed and due to it being opportunistic, the number and types of samples are unclear at this point in time.							

Table 6: Risk Control & Mitigation Plan - Quantitative Analysis Summary

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Post Mitigation Risk Score	RSE
C1-T1	Cathodic Protection – Capital (HCA)	8.56	538	4,603	76.9
C1-T2	Cathodic Protection – Capital (non-HCA)	8.54	538	4,589	50.7
C2-T1	Cathodic Protection – Maintenance (HCA)	8.44	538	4,536	276.4
C2-T2	Cathodic Protection – Maintenance (non-HCA)	8.38	538	4,503	177.2
C3-T1	Leak Repair (HCA)	8.63	538	4,640	10.0
C3-T2	Leak Repair (non-HCA)	8.63	538	4,638	6.8
C4-T1	Leak Survey & Patrol (HCA)	8.15	538	4,384	901.3
C4-T2	Leak Survey & Patrol (non-HCA)	8.01	538	4,306	577.1
C5-T1	Pipeline Relocation/Replacement (HCA)	8.59	538	4,616	36.3
C5-T2	Pipeline Relocation/Replacement (non-HCA)	8.57	538	4,607	23.2
C6-T1	Shallow/Exposed Pipe Remediations (HCA)	8.63	538	4,639	32.0
C6-T2	Shallow/Exposed Pipe Remediations (non-HCA)	8.63	538	4,638	20.1
C7-T1	Pipeline Maintenance (HCA)	8.07	538	4,338	1,336.3
C7-T2	Pipeline Maintenance (non-HCA)	7.90	538	4,246	855.7
C8-T1	Right of Way (HCA)	8.64	538	4,643	1.7
C8-T2	Right of Way (non-HCA)	8.63	538	4,641	1.7
C9-T1	Class Location – Hydrotest (HCA)	8.64	538	4,644	0.3

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Post Mitigation Risk Score	RSE
C9-T2	Class Location – Hydrotest (non-HCA)	8.64	538	4,643	0.3
C10	Compressor Stations - Capital	8.34	538	4,485	67.1
C11	Compressor Stations - Maintenance	4.51	538	2,426	261.4
C12-T1	Measurement & Regulation – Capital (HCA)	8.63	538	4,639	4.7
C12-T2	Measurement & Regulation – Capital (non-HCA)	8.62	538	4,637	3.2
C13-T1	Measurement & Regulation Station – Maintenance (non-HCA)	8.61	538	4,626	129.3
C13-T2	Measurement & Regulation Station – Maintenance (non-HCA)	8.60	538	4,621	82.6
C14	Odorization	8.63	538	4,642	2.6
C15	Security and Auxiliary Equipment	8.64	538	4,642	1.0
C16	SCADA Operation	N/A	N/A	N/A	N/A
C17	Control Room Monitoring, Operation and Fatigue Management	N/A	N/A	N/A	N/A
C18	Gas Transmission Planning	N/A	N/A	N/A	N/A
C19	Engineering, Oversight and Compliance Review	N/A	N/A	N/A	N/A
C20	Facility Integrity Management Plan	N/A	N/A	N/A	N/A
C21-T1	Integrity Assessments & Remediation (HCA)	2.51	538	1,351	83.1
C21-T2	Integrity Assessments & Remediation (Non-HCA)	0.67	538	359	85.5
C22-T4.3	PSEP: Valve Enhancement (GRC base, HCA)	8.04	538	4,324	276.4
C22-T4.4	PSEP: Valve Enhancement (GRC base, non-HCA)	8.33	538	4,481	743.2
C22-T2.4	PSEP: Pipeline Replacement (Phase 1B, GRC base, non-HCA)	8.61	538	4,630	5.7

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Post Mitigation Risk Score	RSE
C22-T3.2	PSEP: Pipeline Replacement (Phase 2A, GRC base, non-HCA)	7.28	538	3,915	220.3
C22-T3.4	PSEP: Hydrotesting (Phase 2A, GRC base, non-HCA)	7.28	538	3,915	23.6
C23-T2	Ventura Compressor Station Modernization	4.18	538	2,248	344.6
M1-T1	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA)	8.59	538	4,617	2.7
M1-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (Non-HCA)	8.62	538	4,637	1.8
M2-T1	Gas Transmission Safety Rule – Material Verification (HCA)	8.64	538	4,644	0.7
M2-T2	Gas Transmission Safety Rule – Material Verification (Non-HCA)	8.64	538	4,644	0.4

Table 7-SCG HP: Risk Control & Mitigation Plan - Quantitative Analysis Summary for RSE Exclusions

ID	Control/Mitigation Name	RSE Exclusion Rationale
C17	Control Room Monitoring & Operation - O&M	Control Room activities are vital to the safety and reliability of operating the high pressure gas system. This control captures the operating and maintenance activities associated with the control room thereof. While SoCalGas possesses data regarding the control room, these metrics are associated with the operation of facility and personnel not directly tied to the potential reduction in likelihood or consequence of a high pressure system event. SoCalGas has utilized a central control for decades and no data exists to trend what the incident rates on the system might be without this activity. Likewise, no SME data could be utilized to draw conclusions about the risk addressed or reduced for this activity.

ID	Control/Mitigation Name	RSE Exclusion Rationale
C18	Gas Transmission Planning - O&M	Gas Transmission Planning is a key function to ensure the reliability and safety of the high pressure system. This activity establishes the design criteria of the system. Although the Company possesses data, such as capacity and system throughput, no data exists that directly relates the existence of Gas Transmission Planning to change in the likelihood or consequence of a high pressure system incident. Likewise, no SME input can be established to directly link this activity to risk reduced or addressed.
C19	Engineering, Oversight and Compliance Review - O&M	Engineering, Oversight and Compliance review is a prudent safety and reliability activity conducted by a utility. Although SoCalGas tracks data surrounding engineering approvals, compliance goals and the establishment of overall health to the pipeline design process, no data exists internally or externally, to directly relate this activity to a reduction in incident rate or the consequences thereof. Additionally, no SME could establish a quantifiable value for risk addressed by possessing proper engineering, oversight and compliance protocol.
C16	SCADA Operations - O&M	Possessing the ability to monitor and control the natural gas system is prudent for maintaining safety and reliability. SCADA facilitates that control and monitor and helps operators respond to issues or incidents that may arise. Although the Company has a vast array of telemetric data around the gas system, no data set exists to quantify the relation a SCADA system may have to increasing or decreasing the likelihood or consequence of a high pressure system incident. Likewise no SME input could be used to craft this value to risk reduction SCADA provides in this risk area.

ID	Control/Mitigation Name	RSE Exclusion Rationale
T20	Facilities Integrity Management Program	Due to the program still being in a development stage, the activities that will be included in the program are still being identified. When program scoping is completed, activities that have been included will be tracked and risk mitigations will be defined and subsequently quantified.

VI. ALTERNATIVES

Pursuant to D.14-12-025 and D.16-08-018, SoCalGas considered alternatives to the Risk Mitigation Plan for the Incident Related to the High Pressure System (Excluding Dig-In) risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. A1: Proactive Soil Sampling

SoCalGas collects soil samples during TIMP-related excavations along its pipelines. These soil samples are analyzed for chemical composition and characteristics that determine the corrosivity of the soil in the vicinity of the pipeline. Expanding this soil sampling program to include collecting soil samples at regular intervals, such as every mile, along pipelines with a history of corrosive activity may allow SoCalGas to anticipate segments of pipeline that may be susceptible to accelerated corrosion between inspection events. The results of the soil sampling would be integrated into the SoCalGas pipeline GIS system and be used in a comprehensive evaluation of the SoCalGas pipeline system. Soil sample data (*i.e.*, resistivity and pipe-to-soil reads) would be used to determine corrosion rates, which is critical information in developing a mature risk assessment of corrosion threat. SoCalGas has not initiated an expanded soil sampling program since the potential benefit is related to the maturing of the risk assessment. As the risk assessment continues to mature from a relative risk model to a deterministic risk model for the corrosion threat, the benefit of additional information can be better understood. In the interim, SoCalGas will be researching available data sets and determining the benefit of additional soil property information.

B. A2: Expanding Geotechnical Analysis

SoCalGas considered expanding its geotechnical analysis of pipelines potentially exposed to landslide and debris flow hazards. This analysis includes slope stability of terrain surrounding the pipelines and evaluating the likelihood and consequence of landslides and the resulting debris flow on the pipeline. SoCalGas has performed extensive analysis and evaluation of the slope stability, landslide, and debris flow conditions of pipelines that have been impacted by severe weather events. The results of this analysis and evaluation have been used to mitigate the potential impact of future severe weather events on these pipelines. SoCalGas has considered identifying additional pipelines with potential exposure to severe weather events to perform analysis regarding slope stability, landslide, and debris flow. SoCalGas has not initiated an expanded geotechnical analysis program since the potential benefit is related to the maturing of the risk assessment. As the risk assessment continues to mature from a relative risk model to a deterministic risk model the benefit of additional information can be better understood.

Table 8: Alternate Mitigation Plan - Forecast Dollars Summary[32]
(Direct After Allocations, In 2020 $000)

ID	Control/Mitigation Name	Forecast Dollars			
		2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
A1	Proactive Soil Sampling	$0	$0	$1,692	$2,160
A2	Expanding Geotechnical Analysis	$0	$0	$419	$535

Table 9: Alternative Mitigation Plan - Units Summary

ID	Control/Mitigation Name	Units Description		Forecast Units			
		Capital	O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 (Low) O&M	TY 2024 (High) O&M
A1	Proactive Soil Sampling	# of Samples		0	0	2,023	2,585
A2	Expanding Geotechnical Analysis	# of Miles		0	0	95	121

32 Recorded costs and forecast ranges are rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding. The figures provided are direct charges and do not include Company loaders, with the exception of vacation and sick. The costs are also in 2020 dollar and have not been escalated to 2021 amounts. The capital presented is the sum of the years 2022, 2023, and 2024, or a three-year total. Years 2022, 2023 and 2024 are the forecast years for SoCalGas's Test Year 2024 GRC Application.

Table 10: Risk Control & Mitigation Plan - Quantitative Analysis Summary (Direct After Allocations, In 2020 $000)

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Post Mitigation Risk Score	RSE
A1	Proactive Soil Sampling	8.63	538	4,639	0.8
A2	Expanding Geotechnical Analysis	8.64	538	4,644	0.2

APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE

APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE

Incident Related to the High Pressure System (Excluding Dig-In): Summary of Elements of the Risk Bow Tie

ID	Control/Mitigation Name	Elements of the Risk Bow Tie Addressed
C1	Cathodic Protection – Capital	DT.1, DT.2, DT.8, DT.4, DT.6, PC.3, PC.1
C2	Cathodic Protection - Maintenance	DT.1, DT.2, DT.4, DT.8, PC.1, PC.3
C3	Leak Repair	DT.6, DT.9, PC.3
C4	Leak Survey & Patrol	DT.1, DT.2, DT.4, DT.8, DT.9, PC.1, PC.2, PC.3
C5	Pipeline Relocation/Replacement	DT.5, DT.4, DT.6, DT.9, DT.10, PC.3, PC.4, PC.5
C6	Shallow/Exposed Pipe Remediation	DT.6, DT.5, PC.3, PC.4, PC.5
C7	Pipeline Maintenance	DT.7, DT.8, PC.3
C8	Right of Way	DT.5, DT.6, PC.3, PC.5, PC.6
C9	Class Location - Hydrotest	DT.10, PC.3
C10	Compressor Stations – Capital	DT.8, DT.4, DT.5, DT.3, PC.3, PC.1, PC.5
C11	Compressor Stations - Maintenance	DT.3, DT.4, DT.5, DT.10, PC.1, PC.3, PC.5
C12	Measurement & Regulation – Capital	DT.8, DT.4, DT.7, PC.3, PC.1, PC.5
C13	Measurement & Regulation – Maintenance	DT.4, DT.7, DT.8, DT.10, PC.3, PC.5, PC.1
C14	Odorization	DT.7, DT.8, PC.4, PC.6, PC.5
C15	Security and Auxiliary Equipment	DT.5, DT.8, PC.3, PC.2
C16	SCADA Operation	DT.4, DT.6, DT.7, DT.8, PC.1, PC.2, PC.3
C17	Control Room Monitoring, Operation and Fatigue Management	DT.6, DT.7, DT.8, DT.9, PC.1, PC.2, PC.3
C18	Gas Transmission Planning	DT.4, DT.7, DT.8, PC.1, PC.2, PC.3
C19	Engineering, Oversight and Compliance Review	DT.4, DT.7, DT.6, DT.9, DT.11 PC.2, PC.3, PC.4
C20	Facilities Integrity Management Program	DT1, DT2, DT3, DT 4, DT 5, DT 6, DT 7, DT 8, DT 9, DT 10, DT 11 PC 1, PC 2, PC 3, PC 4, PC 5, PC 6

ID	Control/Mitigation Name	Elements of the Risk Bow Tie Addressed
C21	Integrity Assessments & Remediation	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9, DT.10 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C22-T1; C-22-T2; C22-T3	PSEP: Phase 1A, Phase 1B, Phase 2A (Replacement or Hydrotesting)	DT.1, DT. 2, DT. 3, DT. 4, DT.5, DT. 6, DT. 9, DT. 10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C22-T4	PSEP: Valve Enhancement Plan	DT.1, DT. 2, DT. 3, DT. 4, DT.5, DT. 6, DT. 9, DT. 10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C23-T2	Ventura Compressor Station Modernization	DT.8 PC.1, PC. 3, PC. 4, PC. 5, PC. 6
M1	Gas Transmission Safety Rule - MAOP Reconfirmation	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9, DT.10 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
M2	Gas Transmission Safety Rule – Material Verification	DT.10 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6

APPENDIX B: REFERENCE MATERIAL FOR QUANTITATIVE ANALYSES

APPENDIX B: REFERENCE MATERIAL FOR QUANTITATIVE ANALYSES

The Settlement Decision directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. Provided below is a listing of the inputs utilized as part of this assessment.

Annual Report Mileage for Natural Gas Transmission & Gathering Systems

- **Agency: Pipeline and Hazardous Materials Safety Administration**
- **Link:** ***https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems***

Annual Report mileage for Gas Distribution Systems

- **Agency: Pipeline and Hazardous Materials Safety Administration**
- **Link:** ***https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems***

Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data

- **Agency: Pipeline and Hazardous Materials Safety Administration**
- **Link:** ***https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data***

SoCalGas high-pressure pipeline miles

- **2020 internal pipeline integrity data**

SoCalGas Probability of Exceedance (PoE) data

- **5 years of anomaly data from in-line-inspections (ILI)**