Risk Assessment and Mitigation Phase

(Chapter SDG&E Risk-3)

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

May 17, 2021

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

I. INTRODUCTION

The purpose of this chapter is to present San Diego Gas & Electric Company's (SDG&E or Company) risk control and mitigation plan for the Incident Related to the High Pressure System (Excluding Dig-In) (High Pressure 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]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter SDG&E-RAMP-B of this RAMP Report. On an annual basis, SDG&E'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 SDG&E's General Rate Case (GRC) application. The costs presented in this 2021 RAMP Report are those costs for which SDG&E anticipates requesting recovery in its Test Year (TY) 2024 GRC. SDG&E'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 SDG&E'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 address each risk are

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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 SDG&E's High Pressure Incident risk; however, many of the activities presented herein also help mitigate other areas.

As discussed in Chapters SCG/SDG&E RAMP-A and SCG/SDG&E RAMP-C, SDG&E has endeavored to calculate a Risk Spend Efficiencies (RSE) for all controls and mitigations presented in this risk chapter. However, for controls and mitigations where no meaningful data or SME opinion exists to calculate the RSE, SDG&E 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.

SDG&E 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 Section III and/or IV.

A. Risk Overview

The SDG&E transmission and distribution system spans from the California-Mexico border to the Pacific Ocean and to the Southern California Gas Company (SoCalGas) territory border. In total, SDG&E operates 524 miles of high-pressure pipelines in its service territory, which includes the 218 miles of transmission defined pipelines.

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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.").

The U.S. Department of Transportation Pipeline and Hazardous Materials and Safety Administration (PHMSA) and 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. The Third Party Damage threat is addressed in the Excavation Damage (Dig-In) on the Gas System 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 SDGE's leak indication 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

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6 American Society of Mechanical Engineering standard B31.8S: Managing System Integrity of Gas Pipelines. 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.

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 a high consequence area (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 SDG&E High Pressure Incident risk is similar to the SoCalGas High Pressure 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, SDG&E's High Pressure Incident risk is defined as the risk of failure of a high-pressure pipeline,[7] which results in serious injuries, or fatalities,

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

and/or damages to the infrastructure. For purposes of this chapter, the failure event would be the result of eight threats identified by the Department of Transportation Pipeline and Hazardous Materials and Safety Administration. The medium pressure assets operating at a pressure of 60 pounds per square inch gauge (psig) and less are included in the Risk Assessment Mitigation Phase (RAMP) chapter for incidents involving medium pressure pipelines. Similarly, 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 High Pressure 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:	SDG&E 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 SDG&E 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 High Pressure Incident risk.

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

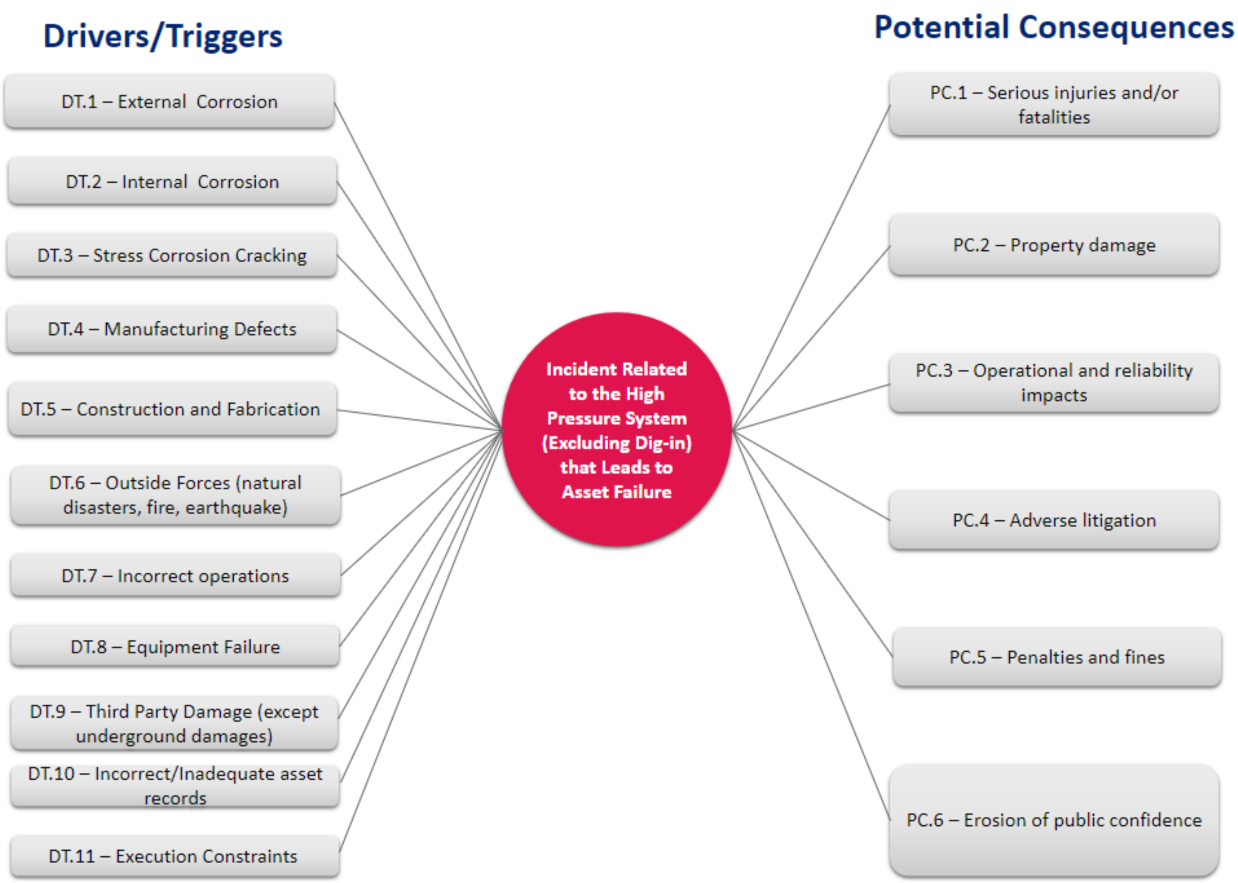
The risk bow tie is a commonly used tool for risk analysis, and the Settlement Decision[9] instructs the utility to include a risk bow tie illustration for each risk included in RAMP. As

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

9 *Id.* at Attachment A, A-11 (“Bow Tie”).

illustrated in the risk bow tie shown below in Figure 1, the risk event (center of the bow tie) is a High Pressure Incident that Leads to Asset Failure, the left side of the bow tie illustrates drivers/triggers that lead to the High Pressure Incident that Leads to Asset Failure, and the right side shows the potential consequences of the High Pressure Incident that Leads to Asset Failure, SDG&E 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



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: Climate Change Adaptation, Energy Systems Resilience, and GHG Emissions; Emergency Preparedness and Response and Pandemic; Foundational Technology Systems; Physical Security; Records Management; Safety Management Systems; and Workforce Planning / Quality Workforce.

C. Potential Drivers/Triggers[10]

The Settlement Decision[11] instructs the utility to identify which element(s) of the associated risk Bow Tie each mitigation addresses. When performing the risk assessment for the HP Incident risk, SDG&E identified potential leading indicators, referred to as drivers or triggers. These include, but are not limited to:

- **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 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.

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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 *See* AMSE B31.8S.

14 *See* AMSE B31.8S.

- **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[9]):** 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 SDG&E'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.

D. Potential Consequences of Risk Event

Potential consequences[15] 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

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

These potential consequences were used in the scoring of the High Pressure Incident risk that occurred during the development of SDG&E's 2020 Enterprise Risk Registry.

E. Risk Score

The Settlement Decision requires a pre- and post-mitigation risk calculation.[16] Chapter SCG/SDG&E RAMP-C of this RAMP Report explains the Risk Quantitative Framework which 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[17]

	LoRE	CoRE	Risk Score
Incident Related to the High Pressure System	0.88	2,301	2,029

Pursuant to Step 2A of the Settlement Decision, the utility is instructed to use actual results, where available, as well as available and appropriate data (*e.g.*, Pipeline and Hazardous Materials Safety Administration data).[18] Historical PHMSA data and internal SME 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.[19] 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 49 CFR 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

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[16] D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

[17] 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.

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

[19] Settlement Decision at 33.

institutes a different risk profile associated with HCA pipe as compared to high pressure pipe not located in an HCA. Therefore, SDG&E set out to appropriately tranche controls and mitigations, where feasible, for the determination of costs and activity scope. 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 SDG&E 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 versus in non-HCAs) was applied to costs and scope for activities within these two tranches, unless otherwise noted. SDG&E 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 reaction required for cathodic protection via an impressed current system along SDG&E pipelines. The utilization of remote power allows SDG&E 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 SDG&E 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, and 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 – External Corrosion Control: Monitoring Section 192.465:

- 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.
- 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 ensure 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 Part 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: Pipeline Relocation/Replacement

- **C4-T1: HCA; C4-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.

E. C5: Shallow/Exposed Pipe Remediations

- **C5-T1: HCA; C5-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.

F. C6: Pipeline Maintenance

- **C6-T1: HCA; C6-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 valves, inspecting & 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 Part 192 Subpart M – Maintenance Sections 192.745 and 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.

G. C7: Compressor Station Physical Security

Compressor Station Physical Security activity consists of a security guard shack located at the Moreno Compressor Station. This activity is necessary to harden the security at the Moreno Compressor Station, resulting in increased personnel safety and reduction of potential system damage.

H. C8: 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 on transmission pipeline systems. These activities are necessary to maintain or improve system reliability, extend equipment and system life, and uphold public safety.

I. C9: Compressor Station - Maintenance

Compressor Station Maintenance activities consist of compressor unit inspections, primary and backup power generators 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 involves 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, operating valves, inspecting & servicing actuators, lubricating valves, check for atmospheric corrosion, test for combustible gas, test/record set points and/or verify rupture disc rating, check supply regulators for proper operation, check for leakage, blow/inspect supply filters, check hydraulic fluid levels, check controller for proper operation, and test/record set points. These activities are necessary to maintain or improve the pipeline system, extend the life of the pipeline, maintain pipeline and station compliance prescribed by 49 CFR Part 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.

J. C10: Measurement & Regulation – Capital

- **C10-T1: HCA; C10-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 assembly's and control valve stations on transmission pipeline systems. These activities are necessary to maintain or improve system reliability, extend equipment and system life, and uphold public safety.

K. C11: Measurement & Regulation – Maintenance

- **C11-T1: HCA; C11-T2: non-HCA**

Measurement & Regulation Stations 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 & servicing actuators, lubricating valves, check for atmospheric corrosion, test for combustible gas, inspect covers, ventilation systems, structural condition of vaults, vault ladders, steps, handrails, test/record set points and/or verify rupture disc rating, check supply regulators for proper operation, check for leakage, blow/inspect supply filters, check hydraulic fluid levels, inspect mummy cage, check controller for proper operation and test/record set points. These activities are necessary to maintain or improve the pipeline system, extend the life of the pipeline, maintain pipeline compliance prescribed by 49 CFR Part 192 Subpart M – Maintenance Section 192.739:

- 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:
    - In good mechanical condition;
    - Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;
    - 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
    - Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.
- 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.

L. C12: Odorization

Odorization activities consist of monthly odor intensity testing on transmission pipelines. The mentioned activity involves the following: testing gas to verify a recognizable amount of gas odor is detectable, test for any harmful components and calibrate appropriate equipment intervals. These activities are necessary to uphold public safety, maintain system reliability, meet regulatory requirements prescribed by 49 CFR Part 192 Subpart L – Operations Section 192.625:

- 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.
- 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:
  - Receiving written verification from their gas source that the gas has the proper concentration of odorant; and
  - Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.

M. C13: 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 SCADAs on transmission pipeline facilities. These activities are necessary to harden the security at pressure limiting stations, valve stations, compressor stations, increase personnel safety and reduce the potential of system damage.

N. C14: 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. 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 Part 192, complying to company issued standards, extend the life of the pipeline, uphold public safety, and maintain system reliability.

O. C15: Integrity Assessments & Remediation

- **C15-T1: Transmission Integrity Management Program (TIMP)**

Through the TIMP, per 49 CFR Part 192 Subpart O, SDG&E 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 have 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, SDG&E 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 preclude 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 185 miles out of 218 miles of SDG&E's transmission pipelines are located in HCA areas.

- **C15-T2: Outside of High Consequence Area Assessments**

Because a pipeline may consist of segments located inside and outside of HCAs, SDG&E also assesses incidental non-HCA pipeline segments. Since SDG&E 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, SDG&E is newly required 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, External Corrosion Direct Assessment (ECDA), and pressure testing. As with TIMP assessment, 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 replacement are intended to increase public and employee safety by reducing or eliminating conditions that might lead to an incident. When a threat is identified, SDG&E 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 safety and preclude pipeline failures.

The numbers and types of activities will vary from year to year and approximately 6 miles out of 218 miles of SDG&E's transmission pipelines are located in MCAs or non-HCA Class 3 and 4 locations.

P. C16: Pipeline Safety Enhancement Plan

The 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 Commission in D.11-06-017 and later codified in California Public Utilities Code Sections 957 and 958. Separate from the testing or replacing of pipeline, PSEP also includes a valve enhancement plan, as required by the Commission in D.11-06-017.[20]

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. The PSEP is divided into two phases and each phase is further subdivided into two parts resulting in four separate phases, Phase 1A, Phase 1B, Phase 2A, and Phase 2B.

PSEP Phase 1A and Phase 1B both include projects that had recorded costs in 2020 and these phases are discussed below in this Section and denoted with a control ID. SDG&E's PSEP does not include any mileage for Phase 2A projects – those for 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, and therefore Phase 2A is not discussed in this RAMP Report. SDG&E plans to initiate the implementation of Phase 2B projects during the TY 2024 GRC forecast period, and as such that phase is discussed below in Section IV and denoted with a mitigation ID (M1).

SDG&E'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 SDG&E 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 SDG&E 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. C-16-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

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

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 majority of the pipeline mileage that has thus far been addressed falls within the Phase 1A category. Phase 1A projects are classified as refundable and are tranched to reflect pipeline replacement and hydrotesting projects.

- C-16-T1.1: Pipeline Replacement (Phase 1A, refundable, HCA)
- C-16-T1.2: Hydrotesting (Phase 1A, refundable, HCA)

2. C-16-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. For SDG&E, this control also addresses Phase 1B pipe through hydrotesting and replacement pursuant to the Line 1600 Test and Replace Plan. SDG&E began construction in 2020 pursuant to D.20-02-024 on replacement of certain sections of pipe and anticipates that substantial investments will be made in both the replacement and pressure testing of existing Line 1600 mileage during the 2022-2024 forecast period. The Line 1600 project is classified as refundable and is tranched to reflect pipeline replacement and hydrotesting projects and that projects may occur in both HCA and non-HCA areas.

- C-16-T2.1: L1600 Pipeline Replacement (Phase 1B, refundable, HCA)
- C-16-T2.2: L1600 Pipeline Replacement (Phase 1B, refundable, non-HCA)
- C-16-T2.3: L1600 Hydrotesting (Phase 1B, refundable, non-HCAs)

3. C-16-T3: 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. Valve enhancement projects are classified as refundable and are tranched to reflect that projects may occur in both HCA and non-HCA areas.

- C-16-T3.1: Valve enhancement (refundable, HCA)

- C-16-T3.2: Valve enhancement (refundable, non-HCA)

IV. 2022-2024 CONTROL & MITIGATION PLAN

This section contains a table identifying the controls and mitigations comprising the portfolio of mitigations for this risk.[21]

All of the activities discussed above in Section III, except for the PSEP related activities with cost recovery via a mechanism outside of the GRC, are expected to continue during the TY 2024 GRC. 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 will retain 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.

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	Pipeline Relocation/Replacement	X	X
5	C5	Shallow/Exposed Pipe Remediation	X	X
6	C6	Pipeline Maintenance	X	X
7	C7	Compressor Station Physical Security	X	X
8	C8	Compressor Stations – Capital	X	X
9	C9	Compressor Stations – Maintenance	X	X
10	C10	Measurement & Regulation - Capital	X	X
11	C11	Measurement & Regulation – Maintenance	X	X
12	C12	Odorization	X	X
13	C13	Security and Auxiliary Equipment	X	X
14	C14	Engineering, Oversight and Compliance Review	X	X
15	C15	Integrity Assessments & Remediation	X	X
16	C16-T1.1 C16-T1.2	PSEP, Phase 1A - Refundable	X	No
17	C16-T2.1 C16-T2.2 C16-T.2.3	PSEP, Phase 1B – Refundable	X	No
18	C16-T3.1	PSEP, Valve Enhancements - Refundable	X	No

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

Line No.	Control/ Mitigation ID	Control/Mitigation Description	2020 Controls	2022-2024 Plan
	C16-T3.1			
19	M1-T1.1 M1-T1.2	PSEP, Phase 2B – Pipeline Replacement	X	X
20	M1-T1.3 M1-T1.4	PSEP, Phase 2B – Hydrotesting	X	X
21	M2	Gas Transmission Safety Rule – MAOP Reconfirmation	No	X
22	M3	Gas Transmission Safety Rule – Material Verification	No	X
23	M4	Adobe Falls Relocation Project	No	X
24	M5	Moreno Compressor Station Modernization	No	No

For activities SDG&E plans to perform that remain unchanged, refer to the description 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

- **C15-T2: Integrity Assessments & Remediation**

As described above in Section III, the Integrity Assessments & Remediation mitigation has been expanded beyond the Transmission Integrity Management Program 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 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, SDG&E has incorporated approximately 6 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, SDG&E has tranched the Integrity Assessments & Remediation control accordingly.

B. 2022 – 2024 Mitigations

- **M1: PSEP Phase 2B**

Phase 2B pipelines are pipelines 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. Because SDG&E’s PSEP does not include any Phase 2A scoped work that must precede Phase 2B work, SDG&E is planning to begin implementing standalone Phase 2B projects during the TY 2024 GRC forecast period. In its TY 2019 GRC proceeding (A.17-10-007), SoCalGas had sought clarification from the Commission for both utilities as to whether work to test or replace Phase 2B qualifying pipelines was required to be undertaken and completed as a part of PSEP. The Commission concluded in D.19-09-051 that Phase 2B was within the scope of PSEP, stating "D.11-06-017 requires that all in-service natural gas transmission pipeline be tested in accordance with 49 CFR 192.619"[22] and "pipeline projects under Phase 2B of SoCalGas' Implementation Plan must comply with D.11-06-017…."[23] The Decision also required that SoCalGas file a proposed implementation plan for the pipelines that may be re-tested as part of Phase 2B. [24,25] Consistent with the D.19-09-051, SoCalGas and SDG&E are currently performing an evaluation of Phase 2B pipeline mileage and plans to include certain components of its Phase 2 implementation plan, such as 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.[26] Phase 2B projects are classified as GRC based and are tranched to reflect both pipeline replacement and hydrotesting projects and projects may occur in both HCA and non-HCA areas.

- M1-T1.1: Pipeline Replacement (Phase 2B, GRC base, HCA)
- M1-T1.2: Pipeline Replacement (Phase 2B, GRC base, non-HCA)
- M1-T1.3: Hydrotesting (Phase 2B, GRC base, HCA)
- M1-T1.4: Hydrotesting (Phase 2B, GRC base, non-HCA)

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

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22 D.19-09-051 at 220.

23 D.19.09-051, Conclusion of Law 47 at 767.

24 SDG&E's Phase 2B projects will be coordinated with the Phase 2B implementation plan prepared by SoCalGas.

25 D19.09-051, Ordering Paragraph 15 at 779-780.

26 SoCalGas requested and received an extension to file the Phase 2B implementation plan as part of its next GRC Application. *See* Letter from Alice Stebbins, Executive Director, CPUC to Chuck Manzuk, Director, GRC Revenue Requirements, Sempra Energy Utilities (November 14, 2019).

of 49 CFR 191 and 192 and federally mandates gas operators to update or implement procedures accordingly.

There are three new sections with which SDG&E must comply that require new risk mitigating programs: Outside-of-HCA Assessments (49 CFR § 192.710) – which has been addressed under C20, MAOP Reconfirmation (49 CFR § 192.624), and Material Properties and Attributes Verification (49 CFR § 192.607).

a. M2: Gas Transmission Safety Rule - MAOP Reconfirmation

- **M2-T1: HCA; M2-T2: non-HCA**

Pursuant to 49 CFR § 192.624, SDG&E is required to reconfirm – by July 2035 – the MAOP of transmission lines that either: (1) do not have traceable, verifiable, or complete pressure test records 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 SDG&E is in the process of developing its MAOP Reconfirmation program in accordance with the final rule. Separate from the state mandated PSEP, SDG&E has preliminarily identified approximately 130 miles out of 218 miles of SDG&E'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.

b. M3: Gas Transmission Safety Rule – Material Properties and Attributes Verification

- **M3-T1: HCA; M3-T2: non-HCA**

Pursuant to 49 CFR § 192.607, SDG&E 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"[27] records. Procedures will address nondestructive or destructive tests, examinations, and assessments, as well as sampling requirements established by 49 CFR § 192.607. If SDG&E should find materials that are not consistent with existing information or expectations, SDG&E will address these findings in accordance with 49 CFR § 192.607 and may re-evaluate a pipeline's MAOP to reduce the risk of failure of a transmission pipeline.

The material verification plan and program are currently in development and SDG&E's preliminary forecast of activities and costs are an estimate. Because the program is based on opportunistic verification, actual costs will be influenced by SDG&E's ongoing portfolio of projects.

2. M4: Adobe Falls Pipeline Relocation Project

The current Adobe Falls pipeline is a 6-inch, 400 psig steel line, 2000 feet in length, that runs from north of the San Diego State University (SDSU), across a deep valley, to serve 3 Meter Set Assemblies including a cogeneration facility on the SDSU campus. On the north side of the valley, the pipeline drops 260 feet, nearly vertical, and then southward under Interstate 8 to serve the SDSU facilities. This northside valley route, due to its steep drop, presents a dangerous path for mandated periodic leak surveys by Company personnel as well as nearly impossible access should the pipeline require other maintenance or response for emergency repairs.

This RAMP project relocates this pipeline to a new route, thus eliminating the risk to personnel involved in periodic surveys and other pipeline maintenance while still serving the SDSU campus. In addition, the new route eliminates the current route's position under Interstate 8 freeway, and environmentally it eliminates ground disturbance caused when periodic mandated surveys are completed in the natural area portion of the current pipeline route.

The relocated pipeline is 6000 feet of 400 psig 6-inch steel line, running from a position east of the campus to serve the same SDSU services and cogeneration facility.

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[27] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (October 1, 2019) at 52218-52219, available at *https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf*.

3. M5: Moreno Compressor Station Modernization Project

The primary objective of the Moreno Compressor Modernization project is to replace and modernize existing compressors and associated infrastructure to comply with air quality regulations while prioritizing reliability, capacity, and system resilience. In D.19-09-051[28] 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 system. The Commission encouraged SDG&E to place a high priority on critical projects with aging compressors because of key risks that need to be mitigated.

The Moreno Compressor Station is an SDG&E-owned facility located in Moreno Valley, approximately 35 miles north of the San Diego County line, and is operated and maintained by SDG&E (and managed by shared SoCalGas employees). The station is currently comprised of three compressor plants with supporting auxiliary equipment and buildings which are used to flow and compress gas into San Diego County.

The existing configuration of the Moreno Compressor Station includes:

- Clark Plant: Three Clark HSRA-8LEC reciprocating compressors
- Solar Plant: Four Solar Saturn turbine-driven centrifugal compressors
- Cooper Plant: Two Cooper "Quad" reciprocating compressors and one Cooper 8V-275 reciprocating compressor

The Moreno Compressor Modernization Project's scope includes the retirement of the existing Clark, Solar, and two Cooper units and replacing with new compression equipment. The compression plant will be known as Plant 4 and will include two modern gas turbine driven centrifugal compressors including post combustion NOx and CO reduction systems, two

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28 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.").

emission-free electric motor driven reciprocating compressors, a new compressor building, and additional infrastructure and appurtenances to support Plant 4 operations.

This project has a planned in-service date after the 2024 test year of the upcoming GRC and as such it is not part of the risk control and mitigation plan. It is included in this RAMP Report for the Commission's and stakeholders' awareness of safety risk activities being pursued by SDG&E.

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. SDG&E does not account for and track costs by activity or tranche; rather, SDG&E accounts for and tracks costs by cost center and capital budget code. The costs shown were estimated using assumptions provided by Subject Matter Experts (SMEs) and available accounting data.

Table 4: Risk Control and Mitigation Plan - Recorded and Forecast Dollars Summary[29]
(Direct After Allocations, In 2020 $000)

ID	Control/Mitigation Name	Recorded Dollars		Forecast Dollars			
		2020 Capital[30]	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)	$64	-	$192	$234	-	-
C1-T2	Cathodic Protection – Capital (non-HCA)	$130	-	$391	$475	-	-
C2-T1	Cathodic Protection – Maintenance (HCA)	-	$30	-	-	$23	$29
C2-T2	Cathodic Protection – Maintenance (non-HCA)	-	$60	-	-	$47	$60
C3-T1	Leak Repair (HCA)	$0	-	$1,943	$2,353	-	-
C3-T2	Leak Repair (non-HCA)	$0	-	$3,946	$4,777	-	-

[29] 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 SDG&E's Test Year 2024 GRC Application.

[30] 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 [30]	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
C4-T1	Pipeline Relocation/Replacement (HCA)	$148	-	$1,815	$2,195	-	-
C4-T2	Pipeline Relocation/Replacement (non-HCA)	$301	-	$3,683	$4,459	-	-
C5-T1	Shallow/Exposed Pipe Remediations (HCA)	$81	-	$2,797	$3,385	-	-
C5-T2	Shallow/Exposed Pipe Remediations (non-HCA)	$165	-	$5,678	$6,874	-	-
C6-T1	Pipeline Maintenance (HCA)	-	$194	-	-	$182	$232
C6-T2	Pipeline Maintenance (non-HCA)	-	$393	-	-	$369	$472
C7	Compressor Station Physical Security	-	$248	-	-	$202	$258
C8	Compressor Station – Capital	$7,779	-	$30,131	$36,474	-	-
C9	Compressor Station - Maintenance	-	$2,501	-	-	$2,099	$2,683
C10-T1	Measurement & Regulation – Capital (HCA)	$186	-	$634	$768	-	-
C10-T2	Measurement & Regulation – Capital (non-HCA)	$378	-	$1,288	$1,560	-	-
C11-T1	Measurement & Regulation Station – Maintenance (non-HCA)	-	$140	-	-	$105	$134
C11-T2	Measurement & Regulation Station – Maintenance (non-HCA)	-	$285	-	-	$213	$272
C12	Odorization	-	$9	-	-	$8	$10
C13	Security and Auxiliary Equipment	$730	-	$2,095	$2,536	-	-
C14	Engineering, Oversight and Compliance Review	-	$229	-	-	$195	$249
C15-T1	Integrity Assessments & Remediations (HCA)	$3,302	$7,955	$15,228	$19,458	$5,030	$6,427
C15-T2	Integrity Assessments & Remediations (Non-HCA)	$516	$1,243	$3,572	$4,564	$1,180	$1,508

ID	Control/Mitigation Name	Recorded Dollars		Forecast Dollars			
		2020 Capital [30]	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
M1-T1.1	PSEP: Pipeline Replacement (Phase 2B, HCA)	-	-	9,500	$11,500	-	-
M1-T1.2	PSEP: Pipeline Replacement (Phase 2B, non-HCA)	-	-	$9,500	$11,500	-	-
M1-T1.3	PSEP: Hydrotesting (Phase 2B, HCA)	-	-	$2,850	$3,450	$6,650	$8,050
M1-T1.4	PSEP: Hydrotesting (Phase 2B, non-HCA)	-	-	$2,850	$3,450	$6,650	$8,050
M2-T1	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA)	-	-	$9,360	$29,952	$6,480	$20,736
M2-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (Non-HCA)	-	-	$390	$1,248	$270	$864
M3-T1	Gas Transmission Safety Rule – Material Verification (HCA)	-	-	$23	$74	$18	$56
M3-T2	Gas Transmission Safety Rule – Material Verification (Non-HCA)	-	-	$6	$15	$4	$11
M4	Adobe Falls Relocation Project	-	-	$1,900	$2,300	-	-

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		3	-	4	9	-	-
C1-T2	Cathodic Protection – Capital (non-HCA)	# of Projects		3	-	12	15	-	-
C2-T1	Cathodic Protection – Maintenance (HCA)	# of CP and follow up reads		-	51	-	-	61	78
C2-T2	Cathodic Protection – Maintenance (non-HCA)	# of CP and follow up reads		-	105	-	-	125	160
C3-T1	Leak Repair (HCA)	# of Projects		0	-	2	2	-	-
C3-T2	Leak Repair (non-HCA)	# of Projects		0	-	4	5	-	-
C4-T1	Pipeline Relocation/Replacement (HCA)	# of Projects		1	-	4	8	-	-
C4-T2	Pipeline Relocation/Replacement (non-HCA)	# of Projects		3	-	7	12	-	-
C5-T1	Shallow/Exposed Pipe Remediations (HCA)	# of Projects		1	-	6	6	-	-
C5-T2	Shallow/Exposed Pipe Remediations (non-HCA)	# of Projects		4	-	12	15	-	-
C6-T1	Pipeline Maintenance (HCA)	# of Miles Patrolled & Maintained		-	146	-	-	131	168
C6-T2	Pipeline Maintenance (non-HCA)	# of Miles Patrolled & Maintained		-	296	-	-	266	340
C7	Compressor Station Physical Security	# of Labor Hours		-	8,760	-	-	7,884	10,074
C8	Compressor Stations - Capital	# of Projects		23	-	73	88	-	-

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
C9	Compressor Stations - Maintenance	# of Compressor Station Maintenance orders		-	414	-	-	440	562
C10-T1	Measurement & Regulation – Capital (HCA)	# of Projects		2	-	8	13	-	-
C10-T2	Measurement & Regulation – Capital (non-HCA)	# of Projects		6	-	19	24	-	-
C11-T1	Measurement & Regulation Station – Maintenance (non-HCA)	# of Measurement and Regulation (M&R) repairs and upgrades		-	127	-	-	119	152
C11-T2	Measurement & Regulation Station – Maintenance (non-HCA)	# of Measurement and Regulation (M&R) repairs and upgrades		-	258	-	-	240	307
C12	Odorization	# of Gallons of Odorant used		-	185	-	-	167	213
C13	Security and Auxiliary Equipment	# of Projects		5	-	12	15	-	-
C14	Engineering, Oversight and Compliance Review	# of Labor Hours		-	4,540	-	-	4,111	5,253
C15-T1	Integrity Assessments & Remediations (HCA)	# of miles		N/A	32	N/A	N/A	24	30
C15-T2	Integrity Assessments & Remediations (Non-HCA)	# of miles		N/A	5	N/A	N/A	6	7
M1-T1.1	PSEP: Pipeline Replacement (Phase 2B, HCA)	# of miles		N/A	N/A	1	1	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
M1-T1.2	PSEP: Pipeline Replacement (Phase 2B, non-HCA)	# of miles		N/A	N/A	1	1	N/A	N/A
M1-T1.3	PSEP: Hydrotesting (Phase 2B, HCA)	# of miles		N/A	N/A	N/A	N/A	2	3
M1-T1.4	PSEP: Hydrotesting (Phase 2B, non-HCA)	# of miles		N/A	N/A	N/A	N/A	2	3
M2-T1	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA)	# of Miles		N/A	N/A	1	2	2	8
M2-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (Non-HCA)	# of Miles		N/A	N/A	0.02	0.07	0.1	0.34
M3-T1	Gas Transmission Safety Rule – Material Verification (HCA)	The material verification program is being developed and the number and types of samples are unclear.							
M3-T2	Gas Transmission Safety Rule – Material Verification (Non-HCA)								
M4	Adobe Falls Relocation Project	# of projects		N/A	N/A	1	1	N/A	N/A

Table 6: Risk Control & Mitigation Plan - Quantitative Analysis Summary
(Direct After Allocations, In 2020 $000)

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Risk Score	RSE
C1-T1	Cathodic Protection – Capital (HCA)	0.88	2301	2029	489.2
C1-T2	Cathodic Protection – Capital (non-HCA)	0.88	2301	2027	387.6
C2-T1	Cathodic Protection – Maintenance (HCA)	0.88	2301	2026	1074.6
C2-T2	Cathodic Protection – Maintenance (non-HCA)	0.88	2301	2024	65.5
C3-T1	Leak Repair (HCA)	0.87	2301	2001	5.6

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Risk Score	RSE
C3-T2	Leak Repair (non-HCA)	0.88	2301	2026	5.3
C4-T1	Pipeline Relocation/Replacement (HCA)	0.88	2301	2029	131.3
C4-T2	Pipeline Relocation/Replacement (non-HCA)	0.88	2301	2029	62
C5-T1	Shallow/Exposed Pipe Remediations (HCA)	0.88	2301	2020	8.6
C5-T2	Shallow/Exposed Pipe Remediations (non-HCA)	0.88	2301	2021	5.9
C6-T1	Pipeline Maintenance (HCA)	0.88	2301	2028	1037.9
C6-T2	Pipeline Maintenance (non-HCA)	0.88	2301	2028	62.3
C7	Compressor Station Physical Security	N/A	N/A	N/A	N/A
C8	Compressor Stations - Capital	0.83	2301	1917	91.2
C9	Compressor Stations - Maintenance	0.46	2301	1060	403.4
C10-T1	Measurement & Regulation – Capital (HCA)	0.88	2301	2027	86.0
C10-T2	Measurement & Regulation – Capital (non-HCA)	0.88	2301	2026	57.0
C11-T1	Measurement & Regulation Station – Maintenance (HCA)	0.87	2301	2009	841.4
C11-T2	Measurement & Regulation Station – Maintenance (non-HCA)	0.88	2301	2027	50.6
C12	Odorization	0.88	2301	2029	22.4
C13	Security and Auxiliary Equipment	0.88	2301	2029	0.8
C14	Engineering, Oversight and Compliance Review	N/A	N/A	N/A	N/A
C15-T1	Integrity Assessments & Remediations (HCA)	0.05	2301	108	355.3
C15-T2	Integrity Assessments & Remediations (Non-HCA)	0.76	2301	1751	300.0
M1-T1.1	PSEP: Pipeline Replacement (Phase 2B, HCA)	0.77	2301	1,771	730.5
M1-T1.2	PSEP: Pipeline Replacement (Phase 2B, non-HCA)	0.81	2301	1,864	467.5
M1-T1.3	PSEP: Hydrotesting (Phase 2B, HCA)	0.77	2301	1,771	160.8
M1-T1.4	PSEP: Hydrotesting (Phase 2B, non-HCA)	0.81	2301	1,864	102.9
M2-T1	Gas Transmission Safety Rule - MAOP Reconfirmation (HCA)	0.88	2301	2,014	6.9
M2-T2	Gas Transmission Safety Rule - MAOP Reconfirmation (Non-HCA)	0.88	2301	2029	4.1
M3-T1	Gas Transmission Safety Rule – Material Verification (HCA)	0.88	2301	2029	1.2

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Risk Score	RSE
M3-T2	Gas Transmission Safety Rule – Material Verification (Non-HCA)	0.88	2301	2029	6.2
M4	Adobe Falls Relocation Project	0.88	2301	2018	167.1

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

ID	Control/Mitigation Name	RSE Exclusion Rationale
C7	Compressor Station Security – O&M	Compressor stations are key facilities in the gas system marked as cornerstones to the reliability of the gas system. Ensuring the facilities remain in operation and incapable of interacting with the public is a prudent safety and reliability measure by the utility. However, no internal or external data exist that can tie a compressor incident to a lack of security at the stations. Likewise, no SME input could be used to construct a viable measure of the changes to likelihood or consequence of a high-pressure system incident due to station security; therefore, an RSE was not calculated.
C14	Engineering, Oversight and Compliance Review - O&M	Engineering, Oversight and Compliance review is a prudent safety and reliability activity conducted by the utility. Although SoCalGas tracks data surrounding engineering approvals, compliance goals and overall 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 input could establish a quantifiable value for risk addressed by possessing proper engineering, oversight, and compliance protocol.

VI. ALTERNATIVES

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the risk mitigation plan for the High Pressure Incident 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: Soil Sampling

SDG&E 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 SDG&E to anticipate areas of their pipelines that may be susceptible to accelerated corrosion between inspection events. The results of the soil sampling would be integrated into the SDG&E pipeline GIS system and be used in a comprehensive evaluation of the SDG&E 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. SDG&E 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 SDG&E will be researching available data sets and determining the benefit of additional soil property information.

B. A2: Geotechnical Analysis Expansion

SDG&E 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. SDG&E 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. SDG&E has considered identifying additional pipelines with potential exposure to severe weather events to perform analysis regarding slope stability, landslide, and debris flow. SDG&E 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: Alternative Mitigation Plan - Forecast Dollars Summary[31]
(Direct After Allocations, In 2020 $000)

ID	Alternative 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	-	-	$108	$138
A2	Expanding Geotechnical Analysis	-	-	$54	$69

Table 9: Alternative Mitigation Plan - Units Summary

ID	Alternative 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	Miles		-	-	137	175
A2	Expanding Geotechnical Analysis	Miles		-	-	14	17

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

ID	Alternative Mitigation Name	Forecast			
		LoRE	CoRE	Risk Score	RSE
A1	Proactive Soil Sampling	0.88	2,301	2,027	5.7
A2	Expanding Geotechnical Analysis	0.88	2,301	2,029	0.9

31 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 SDG&E's Test Year 2024 GRC Application.

APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE

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	Pipeline Relocation/Replacement	DT.5, DT.4, DT.6, DT.9, DT.10, PC.3, PC.4, PC.5
C5	Shallow/Exposed Pipe Remediations	DT.6, DT.5, PC.3, PC.4, PC.5
C6	Pipeline Maintenance	DT.7, DT.8, PC.3
C7	Compressor Station Physical Security	DT.8, PC.2, PC.3
C8	Compressor Stations - Capital	DT.8, DT.4, DT.5, DT.3, PC.3, PC.1, PC.5
C9	Compressor Stations - Maintenance	DT.3, DT.4, DT.5, DT.10, PC.1, PC.3, PC.5
C10	Measurement & Regulation – Capital	DT.8, DT.4, DT.7, PC.3, PC.1, PC.5
C11	Measurement & Regulation Station – Maintenance	DT.4, DT.7, DT.8, DT.10, PC.3, PC.5, PC.1
C12	Odorization	DT.7, DT.8, PC.4, PC.6, PC.5
C13	Security and Auxiliary Equipment	DT.5, DT.8, PC.3, PC.2
C14	Engineering, Oversight and Compliance Review	DT.4, DT.7, DT.6, DT.8, DT.9; DT.11 PC.2, PC.3, PC.4
C15	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
M1	PSEP: Phase 1A, 1B, 2B (Replacement and 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
M2	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
M3	Gas Transmission Safety Rule – Material Verification	DT.10 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
M4	Adobe Fall Relocation Project	DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6

APPENDIX B: QUANTITATIVE ANALYSIS SOURCE DATA REFERENECES

Appendix B: Quantitative Analysis Source Data References

The SA Decision directs the utility to identify potential consequences of a risk event using available and appropriate data. The below provides 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*

Link: 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*

San Diego Gas & Electric high-pressure pipeline miles

- 2020 internal pipeline integrity data

San Diego Gas & Electric Probability of Exceedance (PoE) Data

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