Risk Assessment Mitigation Phase

(Chapter SDG&E-8)

High Pressure Gas Pipeline Incident (Excluding Dig-in)

November 27, 2019

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Risk: High Pressure Gas Pipeline Incident

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation plan for San Diego Gas and Electric Company's (SDG&E or Company) High Pressure Gas Pipeline Incident risk. Each chapter in the 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 SA Decision).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter 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, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SDG&E anticipates requesting recovery in its Test Year (TY) 2022 GRC. SDG&E's TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report, activities are delineated between controls and mitigations, which is

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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").

consistent with the definitions adopted in the SA 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 Gas Pipeline Incident risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VI 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 California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

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[3] *Id.* at 16.

[4] *Id. at 17.*

SDG&E and Southern California Gas Company (SoCalGas), collectively the "Companies," own and operate an integrated natural gas system. The Companies collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SoCalGas and SDG&E territory to maintain consistency. However, execution of such policies and procedures are the responsibility of the employees at respective geographically delineated operating unit headquarters. Accordingly, there are similar mitigation plans presented in the 2019 RAMP Report across the Companies' gas pipeline incident related chapters.[5]

A. Risk Definition

For purposes of this RAMP Report, the High Pressure Gas Pipeline Incident risk is the risk of damage, caused by a high pressure pipeline (maximum allowable operating pressure – Maximum Allowable Operating Pressure (MAOP), greater than 60 psig) failure event, which results in serious injuries or fatalities. For purposes of this testimony, the failure event is when a high-pressure pipe ruptures as a 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 psig and less are included in the RAMP chapter for incidents involving medium pressure pipelines. Similarly, events caused by third party damage are included in their own RAMP chapters.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[6] for each control and mitigation presented herein, SDG&E has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

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5 The other gas pipeline incident related chapters in the 2019 RAMP Report include: SCG-5 – High Pressure Gas Pipeline Incident; SDG&E-6 – Medium Pressure Gas Pipeline Incident; and SCG-1- Medium Pressure Gas Pipeline Incident.

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

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger or Potential Consequence
DT.1	External corrosion
DT.2	Internal corrosion
DT.3	Stress corrosion cracking
DT.4	Manufacturing defects
DT.5	Construction and fabrication
DT.6	Outside forces (natural disaster, fire, earthquake)
DT.7	Incorrect operations
DT.8	Equipment failure
DT.9	Third party damage (except for underground damages)
DT.10	Incorrect /inadequate asset records
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

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[7] SDG&E has performed a detailed pre- and post-mitigation analysis of controls and mitigations for the risks included in RAMP. SDG&E's baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SDG&E-8-C1	Cathodic Protection
SDG&E-8-C2	Valve Maintenance
SDG&E-8-C3-T1	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1A
SDG&E-8-C3-T2	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1B
SDG&E-8-C4	Transmission Integrity Management Program (TIMP)
SDG&E-8-C5	Pipeline Maintenance
SDG&E-8-C6-T1	Pipeline Safety Enhancement Plan – Pressure Testing

7 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

The drivers/triggers identified for High Pressure Gas Pipeline Incident risk are addressed through the 2018 baseline controls listed in the above table, and SDG&E will continue said regulatory compliance driven controls. Although SDG&E has considered alternatives to these controls, no new mitigations are forecasted to be implemented. The Commission's focus in addressing pipeline safety risk has resulted in robust regulations that guide SDG&E's efforts in addressing the safety of gas pipeline infrastructure. Although no new mitigations are forecasted, SDG&E is forecasting to increase annual activity levels within existing controls.

Finally, pursuant to the SA Decision,[8] SDG&E presents in Section VIII alternatives to the described mitigations for this risk and summarizes the reasons that the alternatives were not included in the mitigation plan in Section VII.

II. RISK OVERVIEW

The SDG&E transmission and distribution system spans from the California-Mexico border to the Pacific Ocean and to the SoCalGas territory border. In total, SDG&E operates 518 miles of high pressure pipelines in its service territory, which includes the 232 miles of transmission defined pipelines.

The number of miles operated by operating unit is listed in the table below:[9]

Table 3: SDG&E Assets

Operating Unit	Total High Pressure Miles (>60psig)	Number of High Consequence Area (HCA) Miles
Transmission	232	192
Distribution	286	4
Total	518	196

The U.S. Department of Transportation Pipeline and Hazardous Materials and Safety Administration (PHMSA) and American Society of Mechanical Engineers (ASME) B31.8S,

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8 *Id.* at 34.

9 The miles are based on DOTs definition of "transmission" whereas the table defines miles by department operating pipelines.

“Managing System Integrity of Gas Pipelines” categorizes eight types of threats that could lead to a high-pressure pipeline incident. They 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 SDG&E’ 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.[10]

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

[10] American Society of Mechanical Engineering standard B31.8S: Managing System Integrity of Gas Pipelines. 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 verses 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 is 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 the pipeline right-of-way.

The presence of HCA miles in a transmission system provides an indication of the potential consequences of an incident to the public because HCA's 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 gas pipeline risk is similar to the SoCalGas gas pipeline incident since the threats are the same and the system is managed in an integrated manner. The chapter is also similar in nature to the Medium Pressure Gas Pipeline Incident risk because the threats are comparable. The biggest differences are the threats of plastic pipeline since plastic is only used in medium pressure systems and high pressure has an increased potential for injuries and fatalities due to its operating pressure and defined potential impact areas. Since the high pressure gas pipeline asset 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 are primarily related to the Transmission Operations department.

Additionally, although not included in this RAMP filing, SDG&E is currently in the very preliminary stages of organizing and modeling a Facilities Integrity Management Program (FIMP) based on principles developed by the Canadian Energy Pipeline Association (CEPA) and the Pipeline Research Council International (PRCI). The FIMP is not intended to duplicate any systems, processes, or information that may already exist, but rather to supplement the already existing programs to enhance the safety and integrity of the integrated gas pipeline system.[11] FIMP will be a documented program, specific to the facilities portion of a pipeline system,[12] that identifies the practices used by the operator for purposes of "safe, environmentally responsible, and reliable service."[13] While SDG&E is currently in the preliminary stages of organizing and modeling a FIMP approach based on the principles of CEPA, FIMP is anticipated to be included in the next GRC. Although this concept of an overarching program is still maturing in the industry, SDG&E's intention of a FIMP is to better identify and reduce risks of facility assets, extend the life of assets, and achieve operational excellence, in alignment with both the principles of RAMP and the Company's existing Transmission and Distribution, Integrity Management Programs (TIMP, DIMP respectively).[14] Consistent with the SA

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11 SDG&E notes that there are certain facilities management systems and processes in place, for example Pipeline Research Council International (PRCI) – Facility Integrity Management Program Guidelines – PRCI IM-2-1 Contract PR-186-113718.

12 "Pipeline system" is defined by Pipeline Research Council International (PRCI) - Facility Integrity Management Program Guidelines – PRCI IM-2-1 Contract PR-186-113718 as "*Pipeline System is comprised of pipelines, stations, and other facilities required for the measurement, processing, gathering, transportations, and distribution of oil or gas industry fluids*."

13 Canadian Energy Pipeline Association (CEPA), Facilities Integrity Management Program, Recommended Practice, 1st Edition (May 2013) at 7-8.

14 Based on industry definitions, there are a variety of types of facilities; facilities are highly complex; a variety of equipment/asset types exist within facilities; and in this context facilities are not considered building structures.

Decision, a supplemental analysis will be conducted in the GRC for FIMP if it ultimately meets the criteria for inclusion in that proceeding.

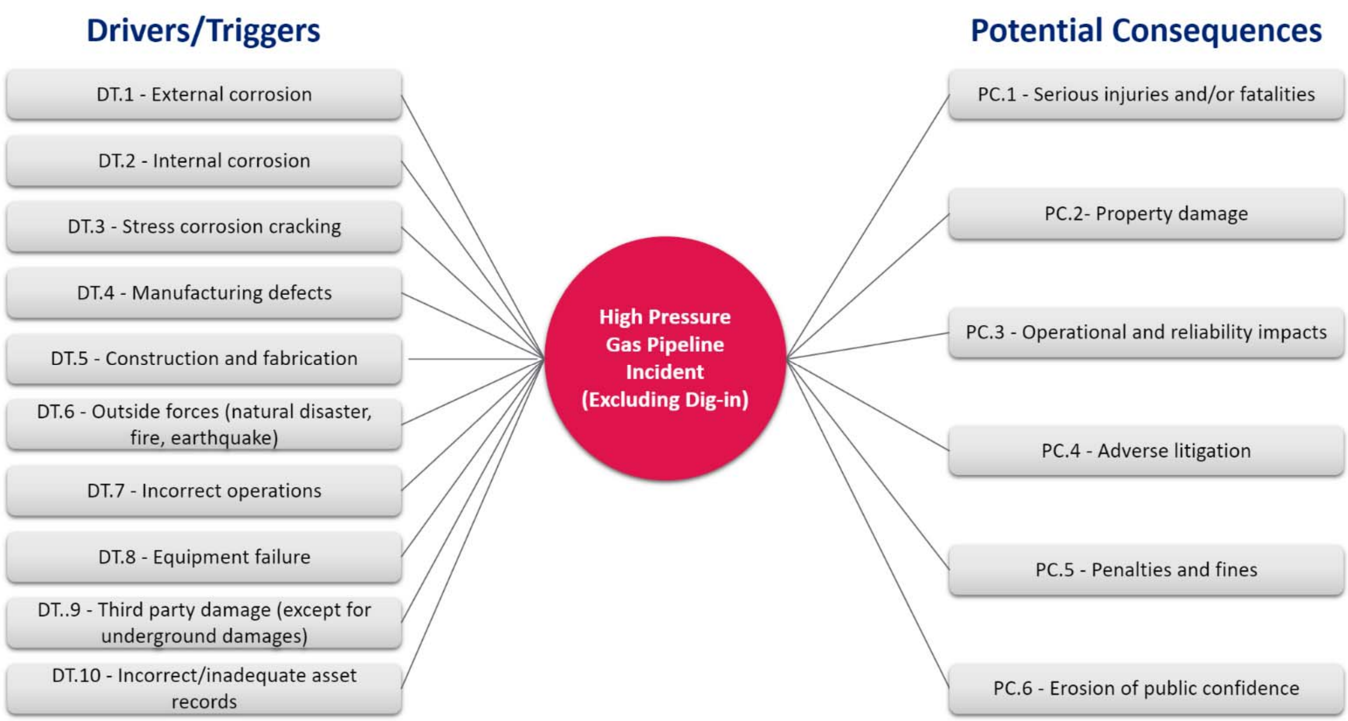
III. RISK ASSESSMENT

In accordance with the SA Decision,[15] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the High Pressure Gas Pipeline Incident risk.

A. Risk Bow-Tie

The Risk Bow Tie shown in Figure 1 below is a commonly-used tool for risk analysis. The left side of the Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

Figure 1: Risk Bow Tie



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

B. Asset Groups or Systems Subject to the Risk

The SA Decision[16] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. SDG&E' High Pressure Incident risk impacts all of SDG&E' high pressure natural gas infrastructure and assets.

Natural Gas Pipeline Distribution System - SDG&E's medium and high-pressure distribution pipeline system is comprised of plastic and steel pipelines and their appurtenances (e.g., meters, regulators, risers). The aforementioned portions operating over 60 psig comprise the high-pressure portion of the system. Some Distribution pipelines operate at over 20% of the pipeline's Specified Minimum Yield Strength (SMYS), and they are considered to be transmission pipelines. By definition, however, these assets are operated by Distribution Operations.

Natural Gas Pipeline Transmission System – SDG&E's high-pressure transmission pipeline system is comprised of steel pipelines and its appurtenances (e.g., meters, regulators, risers) operating over 20% of the pipeline's SMYS.

C. Risk Event Associated with the Risk

The SA Decision[17] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the bow tie) is a pipeline failure event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

D. Potential Drivers/Triggers[18]

The SA Decision[19] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for High Pressure Gas

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16 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

17 *Id.* at Attachment A, A-11 ("Bow Tie").

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

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

Pipeline Incident, SDG&E identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **D.T1 – 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.[20]
- **D.T2 – Internal Corrosion:** Corrosion is the deterioration of metal that results from an electrochemical reaction with its immediate surroundings. This reaction causes the iron in the steel pipe or other pipeline appurtenances to oxidize (rust). Corrosion results in metal loss in the pipe. Over time, corrosion, if left unmitigated, can cause the steel to lose its strength and possibly render it unable to contain the fluid in the pipeline at its operating pressure. The loss of material from corrosion can eventually result in "pinhole" leakage, or a crack, split, or rupture of the pipeline unless the corrosion is repaired, the affected pipe section is replaced, or the operating pressure of the pipeline is reduced.[21]
- **DT.3 – Stress Corrosion Cracking:** A form of corrosion that produces a marked loss of pipeline strength with little metal loss. 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.[22]
- **DT.4 – Manufacturing defects:** Attributable to material defect within the pipe, component or joint due to faulty manufacturing procedures, design

[20] L.S. Van Delinder, *Corrosion Basics, An Introduction* (1984); *see also* U.S. Dept. of Transportation, *Fact Sheet: Internal Corrosion*, *available at* https://primis.phmsa.dot.gov/comm/FactSheets/FSInternalCorrosion.htm.

[21] *Id.*

[22] *Id.*

defects, or in-service stresses such as vibration, fatigue and environmental cracking.

- **DT.5 – Construction and fabrication:** Attributable to the construction mythology applied during the installation of pipeline components specifically based on the vintage of the construction standards, fabrication technics (welding, bending, etc.) and overall guiding regulations.
- **DT.6 – Outside forces (natural disaster, fire, earthquake):** 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 component including but not limited to regulators, valves, meters, flanges, gaskets, collars, couples, etc.
- **DT.9 – Third party damages (except for underground damages):** 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.
- **D.T10 – 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.

E. Potential Consequences

Potential Consequences are listed to the right side of the 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; and

PC.6 – Erosion of public confidence.

These potential consequences were used in the scoring of the High Pressure Gas Pipeline Incident risk that occurred during the development of SDG&E's 2018 enterprise risk registry.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[23] including enhancements to the Interim Decision 16-08-018.[24] SDG&E used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter 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 4: Pre-Mitigation Analysis Risk Quantification Scores[25]

High Pressure Gas Pipeline Incident (Excluding Dig-in)	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	4	**31**	77
LoRE		**0.3**	
CoRE	12	**97**	238

23 D.18-12-014 at Attachment A.

24 *Id.* at 2-3.

25 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[26] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Scope

In-Scope for purposes of risk quantification:	The risk of damage, caused by a high pressure pipeline (maximum allowable operating pressure - MAOP greater than 60 psig) failure event, which results in consequences such as injuries or fatalities or outages.
Out-of-Scope for purposes of risk quantification:	The risk of damage caused by a non-high-pressure pipeline failure event or third-party dig-ins which results in consequences such as injuries or fatalities or outages.

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results and available and appropriate data (*e.g.*, Pipeline and Hazardous Materials Safety Administration (PHMSA) data).[27]

Historical PHMSA data and internal SME input was used to estimate the frequency of incidents. To determine the incident rate per year for SDG&E, the national average incident rate per mile per year was applied to the high-pressure pipeline miles at SDG&E.

The safety risk assessment primarily utilized data from the PHMSA, the reliability risk assessment was based on internal data, and the financial risk assessment was estimated based on both PHMSA and internal data. Internal SME input, based on recent damage repair costs, was used to estimate the financial consequence of incidents. Historical PHMSA high-pressure gas incidents were also used in estimating financial and safety consequences. The reliability incident rate per year was estimated using internal data. Additionally, Monte Carlo simulation was performed to understand the range of possible consequences.

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

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

B. Sources of Input

The SA Decision[28] 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 (PHMSA)
  - Link: https://cms.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 (PHMSA)
  - Link: https://cms.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 (PHMSA)
  - Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data
- SDG&E high-pressure pipeline miles are from 2017 internal SME data
- Gas industry sales customers
  - Agency: AGA (2016Y)
  - Link: https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf

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[28] *Id.* at Attachment A, A-8-A-9 ("Identification of the Frequency of the Risk Event").

- SDG&E end user natural gas customers
  - Source: SNL (2016Y, from the FERC From 2/2-F, 3/3-A or EIA 176)
  - Link: https://platform.mi.spglobal.com/web/client?auth=inherit&newdomainredirect=1&#company/report?id=4057146&keypage=325311

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[29] This section describes SDG&E's Risk Mitigation Plan by each selected Control for this risk, including the rationale supporting each selected Control.

As stated above, the High Pressure Gas Pipeline Incident risk is the risk of damage, caused by a high pressure pipeline failure event, which results in serious injury or fatalities. The Risk Mitigation Plan discussed below includes current controls that are expected to continue for the period of SDG&E's Test Year 2022 General Rate Case (GRC) cycle.[30] While there are no mitigations identified SDG&E is forecasting to expand the level of activity for certain controls as further described below.

The controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with compliance requirements that were in effect at that time. This section describes SDG&E's Risk Mitigation Plan by each selected control for this risk, including the rationale supporting each selected control.

This section describes SDG&E's Risk Mitigation Plan by each selected control for this risk, including the rationale supporting each selected control. Overall the compliance requirements set forth within the regulations (although considered minimum requirements) are robust in that they provide prescriptive preventative and maintenance guidance to the high

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29 *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

30 *Id* at 16 and 17. A "Control" is defined as a "[c]urrently established measure that is modifying risk." 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."

pressure assets. In addition, the Transmission Integrity Management Program (TIMP) regulations guide operators in completing enhanced assessment of transmission pipelines in high consequence areas. More recently, Public Utility Code 957 and 958 have been an additional layer to evaluate construction and manufacturing related threats through pressure testing and mitigation of additional threats through full replacement. To date, PSEP has pressure tested over 111 miles, replaced over 105 miles and completed 306 valve project bundles for SDG&E and SoCalGas. Within the RAMP chapter, the makeup of the portfolio is a healthy mix of compliance requirements and additional programs implemented by TIMP and PSEP within the last 7 years. The TIMP is continually evaluating the system threats and risk to determine if additional mitigations are required like the introduction of the Damage Program Analyst specifically covered within the Third Party Dig-In on a High Pressure Pipeline chapter.

These controls focus on safety-related impacts per guidance provided by the Commission in Decision (D.) 16-08-018 as well as controls and mitigations that may address reliability. SDG&E will continue its 2018 baseline controls. In addition, based on the foregoing assessment, SDG&E projects to expand its current/existing control activities to survey and maintain the Company's Right of Way (ROW) to increase span painting, pipeline maintenance, storm damage repair, removal of previously abandoned pipelines, vegetation removal, and ROW maintenance.

A. SDG&E-8-C1 - Cathodic Protection

Corrosion threat is a natural process that can deteriorate metal assets and potentially lead to leaks or damages. Cathodic Protection, coating and monitoring is key to protecting and extending the life of a steel asset by keeping corrosion at bay. The on-going compliance controls for the threat of corrosion are prescribed by 49 CFR 192 Subpart I – Requirements for Corrosion Control Operations. The requirements include monitoring of cathodic protection areas, remediation of CP areas that are out of tolerance and preventative installations to avoid areas out of tolerance. These activities are intended to address threats as identified by PHMSA specifically external corrosion. These preventive measures provide an opportunity to address issues that otherwise could lead to a serious incident or a failure. The following section details the required intervals for completing these preventative measures as prescribed in 49 CFR 192 Subpart I:

- 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.

In addition to meeting these federal and state requirements, based on feedback from the Commission's Safety and Enforcement Division (SED) during a 2018 Safety Audit, and upon further review, SDG&E issued new guidelines requiring the re-evaluation of existing 100 mV polarization shift areas[31] at least every 10 years to verify their effectiveness as a measurement for adequate cathodic protection of an area. A pipeline utilizing the 100 mV polarization shift criteria must achieve a minimum of 100 mV of polarization along its entirety through the application of Cathodic Protection.

B. SDG&E-8-C2/C5 – Transmission Operations Maintenance (Valve Maintenance and Pipeline Maintenance)

Gas Transmission is responsible for the safe day-to-day operation and maintenance of gas transmission pipeline facilities and related infrastructure. Their responsibilities include gas measurement, pressure regulation, non-core customer equipment and facilities, instrumentation, cathodic protection, locate-and-mark activities, standby, patrol, leakage survey, class location survey, bridge and span inspections and valve inspections. In addition, pipeline and valve maintenance validates that the pipelines within the system operate appropriately which enhances public safety. Valve inspections may include flushing, repair or replacement, function test, and other activities (and should the valve be inoperable it needs to be addressed promptly.) The valve inspections are to be conducted once a year and not to exceed 15 months. Both valve and pipeline maintenance control activities have costs that are tracked separately and provide similar risk reduction profiles within each asset group. However, for ease of review and because both

[31] 49 CFR 192 at Appendix D – Criteria for Cathodic Protection and Determination of Measurements.

O&M activities are done under the same operating umbrella, the activities are grouped together here.

C. SDG&E-8-C3/-C6 – Pipeline Safety Enhancement Plan (PSEP) – Pipe Replacement/Pressure Testing

The primary objectives of the Pipeline Safety Enhancement Plan (PSEP) are to enhance public safety, comply with Commission directives, maximize cost effectiveness, and minimize customer impacts from safety investments. PSEP comprises Pipeline Replacement and Pressure Testing components. 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:

1. Phase 1A

Phase 1A encompasses replacing or pressure testing pipelines located in Class 3 and 4 locations and Class 1 and 2 locations in HCA's that do not have sufficient documentation of a pressure test to achieve at least 125% of the maximum allowable operating pressure (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.

2. Phase 1B

The scope of Phase 1B, is to replace pipelines incapable of being assessed via inline smart inspection tools (non-piggable pipelines), installed prior to 1946, with new pipe constructed using state-of-the-art methods and to modern standards, including current pressure test standards.

3. Phase 2A

Phase 2A replaces transmission 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-HCA's.

4. 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. There are no standalone Phase 2B projects[32] anticipated to begin within the next GRC cycle, and therefore none are associated with this control.

The primary focus of PSEP will be the replacement and pressure testing of Line 1600.[33] Line 1600 is a 16-inch outside diameter (OD) transmission pipeline installed in 1949 and historically operated at 800 psig. The pipeline runs approximately 50 miles from the Rainbow Metering Station in northern San Diego County into the city of San Diego. The pipeline primarily consists of flash welded seam pipe meeting API 5LX Grade X52. SDG&E has no documentary evidence that Line 1600 was hydrostatically pressure tested. In fact, Line 1600 was installed several years before the State of California required pressure testing as part of the pipeline commissioning process (in 1961), and before such practices were adopted in the gas pipeline industry. In addition, the pipe manufacturing process utilized by A.O. Smith company to produce flash welded seam pipe has been known to have deficiencies which create manufacturing defects/flaws. For example, SDG&E has observed seam flaws in the form of hook cracks on Line 1600 associated with the manufacturing process. PSEP provides a vehicle to address this type of pipelines as intended by the regulation. The replacements areas will eliminate the manufacturing threat and pressure testing will provide an assessment of the pipeline at the time of the pressure test.

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32 To date, SoCalGas and SDG&E have solely addressed Phase 2B segments within the scope of Phase 1 or Phase 2A projects for constructability and/or cost efficiency reasons. This is referred to as "accelerated" Phase 2B pipeline segments.

33 As of the date of this RAMP report, the Commission is considering modifications to D.18-06-028. If adopted, the Decision would reopen the Pipeline Safety & Reliability Project (PSRP) proceeding (A.15-09-013) for a Phase 2 that will consider a cost forecast pertaining to SDG&E's and SoCalGas' Line 1600 PSEP. As such, it is uncertain whether the reasonableness of Line 1600 PSEP forecasted costs will be litigated in the next GRC.

D. SDG&E-8-C4 – Transmission Integrity Management Program (TIMP)

Through the TIMP, per 49 C.F.R. 192, Subpart O, SDG&E is federally mandated to identify threats to transmission pipelines in HCA's, determine the risk posed by these threats, schedule prescribed assessments to evaluate these threats, collect information about the condition of the pipelines, take actions to minimize applicable threat and integrity concerns to reduce the risk of a pipeline failure. At a minimum of every seven years transmission pipelines located within HCAs are assessed using 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 actions. 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, the SDG&E might take immediate action to reduce risk until a repair is completed. These actions involve removing a pipeline from service or reducing operating pressure. In cases where the assessment involves a pressure test, 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 pipeline 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 a 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 numbers 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 132 miles out of 232 miles of SDG&E's transmission pipelines are located in HCA areas.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

As described in Chapter RAMP-D, SDG&E has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. Unless otherwise specified, all elements of the Bow Tie concerning Potential Consequences are assumed to be addressed by the below mentioned controls. SDG&E has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[34] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SDG&E's rationale for the determination of Tranches is presented below.

SDG&E's comprehensive integrity and maintenance programs consist of policies, programs, and efforts designed to reduce the probability of a pipeline incident. The extensive activities SDG&E performs to mitigate pipeline risks have been grouped into the controls presented herein based on the similarity of their risk profiles.

SDG&E does differentiate some programs by asset type (*e.g.* steel vs plastic); however, as discussed in RAMP-G, costs are not tracked at a level of detail to allow for the logical disaggregation of assets or systems at a more granular level than the controls described in the mitigation plan.

PSEP is an established, phased, program to which tranches reflecting said phases was logically discernable and maintained within this control.

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34 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Table 6: Summary of Tranches

ID	Control	Tranche	Tranche ID
SDG&E-8-C3	Pipeline Safety Enhancement Plan – Pipeline Replacement	Phase 1A	SDG&E-8-C3-T1
		Phase 1B	SDG&E-8-C3-T2
SDG&E-8-C6	Pipeline Safety Enhancement Plan – Pressure Testing	Phase 1B	SDG&E-8-C6-T1

B. Post-Mitigation/Control Analysis Results

As described in RAMP-D and Section 4 above, SDG&E utilized both internal data/modeling as well as PHMSA data to build RSEs for the pipeline incident risk areas. In the determination of inputs for the RSE calculations, SMEs were heavily utilized to confirm and provide data including the effectiveness of each control. The effectiveness percentages shown below are the result of discussions with SMEs whose knowledge of the control heavily dictated the values selected.

The below sections detail the Risk Reduction Benefits of each control/mitigation as well as specifically outline the data used in conjunction with said SME input to develop the RSE values.

1. SDG&E-8-C1: Cathodic Protection (CP)

a. Qualitative Description of Risk Reduction Benefits

A steel pipeline can corrode externally and experience a degradation process that can lead to a structural incident. Corrosion control activities like Cathodic Protection (CP) are meant to manage or arrest structural changes. CP is a method to mitigate external corrosion on steel pipelines thereby extending the life of a steel asset. The activities associated with CP include installation, monitoring, and remediation. SDG&E has installed CP on all of its 3,571 miles of gas mains and 266,806 gas services. Given the mandated requirement to continuously monitor and evaluate the CP areas, the management of this control is cyclical in nature. Gas Transmission manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

CP reduces safety risks by controlling pipeline corrosion rates thus reducing the frequency of corrosion-related incidents. Minimizing corrosion has the additional benefits of reducing reconstruction costs from pipeline incidents, reducing risk to property, and the potential benefit of improved service reliability. SDG&E exceeds the minimum safety requirements for CP prescribed by 49 CFR 191 Subpart I, which includes monitoring of CP areas, remediation of CP areas that are out of tolerance, and preventative installations to avoid areas out of tolerance.

b. Elements of the Bow Tie Addressed

Cathodic protection addresses the following elements of the bow tie:

i. [DT.1] – External Corrosion

ii. [DT.3] – Stress corrosion cracking

iii. [DT.4] – Manufacturing defects

iv. [DT.5] – Construction and fabrication

c. RSE Inputs and Basis

Scope	The cathodically protected transmission system running at a pressure over 60 psi.
Effectiveness	Per internal SME assessment, the effectiveness is 95%.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 7 natural gas incidents occurred at SoCalGas and SDG&E starting in 2010. 1 out of the 7 SoCalGas and SDG&E incident samples was corrosion-related (14%). Using these assumptions, this mitigation could improve safety risk by up to 10% of the current residual risk. **Reliability**: Using these assumptions, this control tranche could improve reliability risk by up to 10% of the current residual risk. **Financial**: Using these assumptions, this control tranche could improve financial risk by up to 10% of the current residual risk.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	LoRE		**0.35**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	4.29	**34.27**	84.23
	RSE	11.40	**91.00**	223.66

2. SDG&E-8-C2/C5: Transmission Operations Maintenance (Valve Maintenance and Pipeline Maintenance)

a. Qualitative Description of Risk Reduction Benefits

Transmission Operations Maintenance supports the effective operation of gas transmission pipeline facilities and related infrastructure, which enhances public safety. Transmission Operations Maintenance activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident by mitigating various risk sources, primarily corrosion and degradation. Given the mandated requirement to conduct Transmission Operations Maintenance, the management of this control is cyclical in nature. Valve inspections and maintenance, pipeline patrols, and pipeline maintenance increase public and employee safety. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Transmission Operations Maintenance addresses the following elements of the bow tie:

i. ***[DT.1] – External corrosion***

ii. ***[DT.2] – Internal corrosion***

iii. ***[DT.3] – Stress corrosion cracking***

iv. ***[DT.4] – Manufacturing defects***

v. ***[DT.5] – Construction and fabrication*** *vi. [DT.6] – Outside forces*

vii. [DT.7] – Incorrect operations [DT.8] – Equipment failure

viii. [DT.9] – Third party damage (except for underground damages)

3. SDG&E-8-C3/-C6 – Pipeline Safety Enhancement Plan – Pipe Replacement/Pressure Testing

a. Qualitative Description of Risk Reduction Benefits

SDG&E's Pipeline Safety Enhancement Plan (PSEP) program 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. SDG&E is dividing the work to complete pressure testing on all pipelines without a record of a pressure test and complete pipeline replacements into three phases (Phase 1A, Phase 1B, and Phase 2A) The work is prioritized such that testing is completed in more populated areas first, HCA's, followed by less populated areas, non-HCAs.

Pressure testing is a pipeline integrity assessment tool. A pressure test can reveal weakened spots on a pipeline. A failed test requires immediate remediation. As part of the PSEP, SDG&E is conducting pressure tests on segments of pipelines where no records of pressure testing exist (pressure testing has been previously completed in these areas, but it was not recorded). Once segments are tested remediations, including pipeline replacement, are completed, and records are updated. PSEP projects are coordinated to reduce capability issues and customer impacts. Once the PSEP projects are completed, SDG&E will follow TIMP inspection protocols on these pipeline segments in the future.

The principal benefit of PSEP is the substantial reduction in the likelihood of a pipeline incident, which thereby increases public and employee safety. PSEP reduces risk to public and employee safety, as well as risk to property. Additionally, the PSEP improves service reliability and maximizes cost effectiveness by reducing the potential reconstruction costs from potential incidents.

b. Elements of the Bow Tie Addressed

Pipeline Safety Enhancement Plan – Pipe Replacement and Pressure Testing addresses the following elements of the bow tie:

i. *[DT.1] – External corrosion*

ii. *[DT.2] – Internal corrosion*

iii. *[DT.3] – Stress corrosion cracking*

iv. *[DT.4] – Manufacturing Defects*

v. *[DT.5] – Construction and fabrication*

vi. *[DT.6] – Outside forces*

vii. *[DT.9] – Third party damage (except for underground damages)*

viii. *[DT.10] – Incorrect /inadequate asset records*

c. RSE Inputs and Basis

i. SDG&E-8-C3-T2: Pipeline Replacement: Phase 1B

Scope	Replacing 39 miles of pipe out of 42 miles (93%).
Effectiveness	Per SME estimate, we assume 100% effectiveness. These segments are also assumed to be 3.4 times more likely for an incident to occur than their replacements.
Risk Reduction	**Safety**: 2 out of 7 historical, significant incidents are due to corrosion and natural forces according to SoCalGas and SDG&E data reported to PHMSA since year 2010. 83% of the risk is assumed to be HCA, with 17% non-HCA. Phase 1B is located within non-HCAs. Using these assumptions, this tranche could improve safety risk by up to 15%. **Reliability:** Using these assumptions, this control for this tranche could improve SDG&E HP Gas Incident reliability risk by up to 15%. **Financial:** Financial risk multiplied by 3 given the one incident causing a similar proportion of total property damage. Using these assumptions, this tranche could improve SDG&E High Pressure Gas Incident financial risk by up to 46%.

ii. SDG&E-8-C6-T1: Pipeline Testing: Phase 1B

Scope	Testing 4 miles of pipe out of 13 miles (31%).
Effectiveness	Per SME estimate, we assume 95% effectiveness.
Risk Reduction	**Safety**: In the absence of pressure testing, incipient failures would not be detected and the rate of pipeline failure might eventually be higher reaching an SME estimated plateau where the pipe is 1.6 times more likely to have an incident occur **Reliability:** Using these assumptions, this mitigation could improve the SDG&E HP Gas Incident reliability risk by up to 133% of the current residual risk.

	Financial: financial risk is multiplied by 3 with one incident causing a similar proportion of property damage. Using these assumptions, this mitigation could improve the SDG&E HP Gas Incident financial risk by up to 400% of the current residual risk.

d. Summary of Results

i. SDG&E-8-C3-T2: Pipeline Replacement: Phase 1B

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	**LoRE**		**0.37**	
	CoRE	12.86	**97.66**	239.00
	Risk Score	4.78	**36.29**	88.81
	RSE	0.20	**1.19**	2.83

ii. SDG&E-8-C6-T1: Pipeline Testing: Phase 1B

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	**LoRE**		**0.75**	
	CoRE	15.20	**100.00**	241.34
	Risk Score	11.43	**75.18**	181.44
	RSE	5.27	**30.84**	73.45

4. SDG&E-8-C4: Transmission Integrity Management Program (TIMP)

a. Qualitative Description of Risk Reduction Benefits

TIMP is a regulatory required program to assess and remediate, as necessary, transmission pipelines within HCA's every seven years using In-Line-Inspection, Direct Assessment or Pressure Test. TIMP supports the effective operation of transmission pipelines, which enhances public safety. TIMP activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident. Given TIMP mandated requirements per 49 C.F.R. § 192, Subpart O, the management of this control is cyclical in nature. The TIMP proactively identifies, evaluates, and reduces pipeline integrity risk thereby improving public and employee safety by reducing the likelihood of a transmission pipeline incident. A secondary activity that aids in the future risk analysis in the collection of data as part of TIMP which may reveal trends in the management of safety risks. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

TIMP addresses the following elements of the bow tie:

i. ***[DT.1] – External corrosion***

ii. ***[DT.2] – Internal corrosion***

iii. ***[DT.3] – Stress corrosion cracking***

iv. ***[DT.4] – Manufacturing defects***

v. ***[DT.5] – Construction and fabrication***

vi. ***[DT.6] – Outside forces***

vii. ***[DT.9] – Third party damage (except for underground damages)***

viii. ***[DT.10] – Incorrect /inadequate asset records***

c. RSE Inputs and Basis

Scope	Approximately 3/7 of the transmission system within the scope of TIMP to be assessed.
Effectiveness	Per internal SME assessment, this mitigation is 95% effective. In the absence of these assessments, risk levels are estimated to be 29 times higher than they would be otherwise.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 7 natural gas incidents occurred at SoCalGas and SDG&E starting in 2010. 2 out of the 7 SoCalGas and SDG&E incident samples are assumed to be in-scope (29%). Using these assumptions, this control tranche could improve safety risk by up to 340% of the current residual risk. **Reliability**: Using these assumptions, this control tranche could improve reliability risk by up to 340% of the current residual risk.

	Financial: Using these assumptions, this control tranche could improve financial risk by up to 340% of the current residual risk.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	**LoRE**		**1.41**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	17.10	**136.53**	335.57
	RSE	2.81	**22.47**	55.22

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

As discussed, the existing controls outlined within this Chapter will continue and certain controls will increase in scope or at an accelerated pace. However, SDG&E, as a diligent operator, will monitor the controls to determine if any adjustments are needed during the implementation period. The programs could be influenced as additional information is gathered or understanding of risk and controls relationship changes. Should controls need to change, consideration will be given to available technology, labor resources, planning and construction lead time, compliance requirements, and operational and execution considerations.

The following table provides a summary of the Risk Mitigation Plan including controls, associated costs, and RSEs by tranche. SDG&E does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in the table were estimated using assumptions provided by SMEs from associated operations, maintenance, and engineering functions within SDG&E and available accounting data.

Table 7: Risk Mitigation Plan Overview[35]
(Direct 2018 $000)[36]

ID	Mitigation /Control	Tranche	2018 Baseline Capital[37]	2018 Baseline O&M	2020-2022 Capital[38]	2022 O&M	Total[39]	RSE[40]
SDG&E-8-C1	Cathodic Protection	T1	290	0	830 – 1,100	0	830 – 1,100	11.40 – 223.66
SDG&E-8-C2	Valve Maintenance	T1	130	0	300 - 390	0	300 - 390	-
SDG&E-8-C3	PSEP – Pipeline Replacement - Phase 1A	T1	0	0	0	0	0	-
SDG&E-8-C3	PSEP – Pipeline Replacement - Phase 1B	T2	7,600	0	100,000 – 130,000	0	100,000 – 130,000	0.2 - 2.83

35 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

36 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

37 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 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.

38 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application. For PSEP capital, it is anticipated that SDG&E will include forecasts for 2022 – 2024 in the TY2022 GRC because prior PSEP capital projects will be recovered through PSEP reasonableness reviews.

39 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

40 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

SDG&E-8-C4	Transmission Integrity Management Program (TIMP)	T1	2,300	6,000	11,000 – 15,000	4,700 – 6,000	16,000 – 21,000	2.81 – 55.22
SDG&E-8-C5	Pipeline Maintenance	T1	0	140	0	110 - 150	110 - 150	-
SDG&E-8-C6-T1	PSEP – Pressure Testing – Phase 1B	T1	6,300	1,000	2,200 – 2,900	5,300 – 6,800	7,500 – 9,700	5.27 – 73.45
		TOTAL COST	**17,000**	**7,000**	**110,000 – 150,000**	**10,000 – 13,000**	**120,000 – 160,000**	**-**

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 8: Summary of RSE Exclusions

ID	Control Name	Reason for No RSE Calculation
SDG&E-8-C2	Valve Maintenance	Mandated activity per 49 CFR 192 Subpart M § 192.745
SDG&E-8-C3-T1	Pipeline Replacement: Phase 1A	No costs are anticipated for the TY2022 GRC cycle for Phase 1A projects.
SDG&E-8-C5	Pipeline Maintenance	Mandated activity per 49 CFR 192 Subpart M

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the described mitigations for the High Pressure Gas Pipeline 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 Risk Mitigation Plan also took into account modifications to the plan and constraints, including but not limited to operational, compliance and resource constraints.

A. SDG&E-8-A1 - Proactive Soil Sampling

1. Description of Risk Reduction Benefits

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 cost estimate of sampling the 228 miles of transmission pipe is $355 thousand over the course of three years; on average, 14 samples per day will be tested at intervals of 2 samples per mile. The results of the soil sampling would be integrated into the SDG&E's 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 rate, 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.

a. RSE Inputs and Basis

Scope	Assuming 100% of soil would be sampled, as a one-time effort: once the soil is sampled, it does not need to be resampled.
Effectiveness	Per internal SME assessment, effectiveness of having additional data for making better decisions for pipe replacements will be minimal, at 1%.[41]
Risk Reduction	Risk addressed is 14%, due to 1 out of 7 corrosion-related significant events in company history since year 2010. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.1%.

b. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	**LoRE**		**0.32**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.17**	76.62
	RSE	0.02	**0.12**	0.31

B. SDG&E-8-A2 – Expanding Geotechnical Analysis

1. Description of Risk Reduction Benefits

SDG&E considered expanding its geotechnical analysis of pipelines potentially exposed to landslide, flood, and debris flow hazards. This analysis includes slope stability analysis and flood evaluation of terrain surrounding the pipelines and evaluating the likelihood and consequence of landslides and the resulting debris flow on the pipeline. SDG&E looks at areas susceptible to landslide, flooding, and debris flows using satellite monitoring, drones, light detection and ranging (LiDAR), strain gauges, inclinometers, and fiber optic cables. 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 by running models based off collected field data. The results of this analysis and evaluation have been used to

41 Given the need for more mature data for this alternative, the RSEs calculated here are particularly speculative.

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.

a. RSE Inputs and Basis

Scope	Per SME input, very few of the potential sites are to be remediated, the scope was set at 1%.
Effectiveness	Per internal SME assessment, the effectiveness of this mitigation is 50%.[42]
Risk Reduction	Risk addressed is assumed to be a fraction of the historical experience or 60% of 1 out of 7 significant events, for risk addressed of 9%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.04%.

b. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	**LoRE**		**0.32**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.20**	76.70
	RSE	0.00	**0.04**	0.09

42 Given the need for more mature data for this alternative, the RSEs calculated here are particularly speculative.

Table 9: Alternative Mitigation Summary
(Direct 2018 $000)[43]

ID	Mitigation	2020-2022 Capital[44]	2022 O&M	Total[45]	RSE[46]
SDG&E-8-A1	Proactive Soil Sampling	0	110 - 140	110 - 140	0.02 – 0.31
SDG&E-8-A2	Expanding Geotechnical Analysis	0	150 - 200	150 - 200	0.00 – 0.09

43 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

44 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

45 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

46 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control Name	Drivers/Triggers/Potential Consequences Addressed
SDG&E-8-C1	Cathodic Protection	DT.1, DT.3, DT.4, DT. 5
SDG&E-8-C2	Valve Maintenance	DT.1, DT.2, DT.4, DT.5, DT.6, DT.7, DT.8, DT.9
SDG&E-8-C3-T1	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1A	DT.1, DT.2, DT.3, DT.4, DT.5, DT.9, DT.10
SDG&E-8-C3-T2	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1B	DT.1, DT.2, DT.3, DT.4, DT.5, DT.9, DT.10
SDG&E-8-C4	Transmission Integrity Management Program (TIMP)	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9, DT.10
SDG&E-8-C5	Pipeline Maintenance	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9
SDG&E-8-C6-T1	Pipeline Safety Enhancement Plan – Pressure Testing	DT.1, DT.2, DT.3, DT.4, DT.5, DT.9, DT.10