2025 Risk Assessment Mitigation Phase

(Chapter SDG&E-Risk-2)
High Pressure Gas System

May 15, 2025

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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 High Pressure Gas System risk (HP System Risk). This chapter contains information and analysis for this risk that meet the requirements of the California Public Utilities Commission's (Commission or CPUC) Risk-Based Decision-Making Framework (RDF),[1] including the requirements adopted in Decision (D.) 22-12-027 (Phase 2 Decision) and D.24-05-064 (Phase 3 Decision). HP System Risk is included in the 2025 RAMP Report based on a safety risk assessment, further informed by its reliability and financial consequence attributes, consistent with RDF guidance. This risk chapter describes the basis for selection of HP System Risk, the controls and/or mitigations put forth to reduce the likelihood or consequence of this risk, a discussion of alternative mitigations considered but not selected, and a graphic to show historical progress. This chapter presents cost and unit forecasts for the risk-mitigating activities, but it does not request funding. Any funding requests for this risk will be made through the Company's Test Year (TY) 2028 General Rate Case (GRC) application. Finally, this chapter describes the methods applied to estimate the risk's monetized, pre-mitigated risk, the estimated risk-reduction benefits of each included control and mitigation, and the calculation of Cost-Benefit Ratios (CBRs) for each control and mitigation consistent with the method and process prescribed in the RDF.

A. Risk Definition and Overview

1. Risk Definition

For the purposes of this RAMP Report, SDG&E's HP System Risk is defined as the risk of failure of a high-pressure pipeline[2] (including non-line pipe, appurtenances, and facilities) that results in serious injuries, fatalities, and/or damages to the infrastructure. As discussed further below, the failure event would be a result of one or more of the risk's eleven Drivers/Triggers depicted in its Bow Tie analysis, which include eight threat categories identified by the United

1 As discussed in Volume 1, Chapter RAMP-1, the RDF Framework broadly refers to the recent modifications to the Commission's Rate Case Plan adopted in Rulemaking (R.) 13-11-006, Safety Model Assessment Proceeding A.15-05-002 et al. (cons.), and R.20-07-013 (the Risk OIR), including D.24-05-064, Appendix A.

2 Maximum Allowable Operating Pressure (MAOP) at higher than 60 psig. Hereinafter references in this chapter to "pipelines," "transmission," and "distribution" refer to high-pressure unless otherwise noted.

States Department of Transportation (DOT) Pipeline and Hazardous Materials and Safety Administration (PHMSA). Medium pressure assets operating at a pressure of 60 psig or less are included in the Medium Pressure Gas System Risk chapter (SDG&E-Risk-3). Events caused by third-party dig-in damage are included in the Excavation Damage Risk chapter (SDG&E-Risk-1).

Certain controls and mitigations presented in this chapter are subject to compliance mandates beyond RDF requirements, such as those from the CPUC's General Order (GO) 112-F and PHMSA, including but not limited to, subparts of Rule 49 Code of Federal Regulation (CFR). A list of compliance requirements applicable to high pressure gas system is provided in Attachment A. Certain mitigation programs have value beyond the estimated risk reduction calculated under the RDF, such as addressing catastrophic (*i.e.*, tail) risk, targeting high risk assets, enhancement of operations, and/or preparing for future capacity needs (such as driven by electrification or climate impacts).

2. Risk Overview

The SDG&E natural gas transmission[3] and distribution[4] 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 nearly 550 miles of high-pressure pipelines in its service territory, which includes 219 miles of transmission-defined pipelines.

Title 49 Part 192 of PHMSA's CFR and American Society of Mechanical Engineers (ASME) pipeline integrity standard B31.8S, "Managing System Integrity of Gas Pipelines," categorizes types of threats that could lead to a high-pressure pipeline incident. Eight of those threat types are discussed in this Chapter:

1) External Corrosion
2) Internal Corrosion
3) Stress Corrosion Cracking
4) Manufacturing Defect
5) Construction & Fabrication
6) Outside Forces

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[3] As defined in 49 C.F.R. § 192.3 (2024).

[4] *Id.*

7) Incorrect Operation

8) Equipment Threat

These threat types, as well as three additional threats categories identified by SDG&E, together comprise the eleven Drivers/Triggers in the Risk Bow Tie presented in Section II.B. These threat types can work independently and/or interactively together and can lead to leaks or ruptures on the pipeline system.

Leaks, which are defined by PHMSA as unintentional releases of gas and can range from non-hazardous leaks – which can usually be resolved by lubrication, adjustment, or tightening – to more severe instances where more extensive and long-term modifications (*e.g.*, welded repair bands, segment removal/replacement) to the pipe or equipment are required.

The presence of a leak alone may not necessarily represent a risk of serious injury or fatality. The risk to the public and employees can increase; however, when leaks are in close proximity to an ignition source and/or where there is a potential for gas to migrate to and accumulate in a confined space. SDG&E addresses the safety concerns of leaks through its leak indication and repair prioritization and scheduling procedures as discussed in Section III of this chapter.

Instances of a pipeline rupturing, however, are considered an elevated risk since this type of failure[5] has the potential to rapidly release a high volume of combustible energy, which could ignite, resulting in damage to the surrounding area, injury, and/or loss of life.

Whether a pipeline fails by leak versus rupture is dependent on several factors, including the stress on the pipe, the pipe material properties, and the geometry of the pipeline flaw/defect. Pipelines operating at stress levels above 20% Specified Minimum Yield Strength (SMYS), and especially above 30% SMYS, are at greater risk of rupture (sometimes referred to as a propagating fracture), as compared to pipelines operated at stress levels below 20% SMYS.[6]

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5 As defined in ASME B31.8S.

6 *See* B.N. Leis et al., Leak Versus Rupture Considerations for Steel Low-Stress Pipelines, Battelle Final Report GRI-00/0232 at 32 (January 2001): Given the results generated, the leak to rupture transition for corrosion defects in the low-wall-stress pipeline system can be taken as 30 percent of SMYS, a value that is conservative in comparison with in-service incidents. Thresholds for the transition from leak to rupture also were evaluated for immediate as well as delayed mechanical damage incidents with reference to full-scale test data, incident data, and mechanics and fracture analysis. Full-scale test data indicated this threshold was in excess of 30 percent of SMYS, the lowest threshold identified for rupture due to corrosion, whereas the steels represented in reportable incidents

B. Risk Scope

SDG&E's HP System Risk analysis considers risk events associated with failure of a high-pressure pipeline (*i.e.*, pipeline with a maximum allowable operating pressure (MAOP) greater than 60 psig), including non-line pipe, appurtenances, and facilities, which result in consequences such as injuries, fatalities, and/or damages to infrastructure.

The SDG&E HP System Risk is substantially similar to the SoCalGas HP System Risk because the threats are the same, and the SoCalGas/SDG&E high pressure transmission system is managed in an integrated manner.

C. Data Sources Used to Quantify Risk Estimates[7]

SDG&E utilized internal data sources to determine an HP System Risk Pre-Mitigation Risk Value and calculate risk reduction estimates for mitigation activities (which enables estimation of Post Mitigation Monetized Risk Values and Cost Benefit Ratios). Where internal data is deemed insufficient, supplemental industry or national data is used, as appropriate, and adjusted to account for the risk characteristics associated with the Company's specific operating locations and service territory. For example, certain types of incident events have not occurred within the SoCalGas and SDG&E service territories (*i.e.*, a transmission pipeline rupture in an HCA). Expanding the quantitative data sources to include industry data where such incidents have been recorded is appropriate to establish a baseline of risk and risk addressed by mitigative activities. Attachment B provides additional information regarding these data resources.

The probability of failure component of the quantitative risk models for high pressure gas assets is primarily derived from failure rates sourced from SoCalGas, SDG&E, and broader industry data. Time-dependent phenomena such as material degradation (*e.g.*, corrosion), are accounted for using an exponential model to characterize changes in failure likelihood over time. This approach has not yet been implemented across all threat categories. Where time-dependent modeling is not yet available, the absence of explicit time-dependent modeling should not be interpreted as indicating these assets are unaffected by time-dependent trends.

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possess toughness [sic] indicated a threshold on order of 25 percent of SMYS.

[7] Copies and/or links to these data resources are provided in the workpapers served with this Report on May 15, 2025.

II. RISK ASSESSMENT

In accordance with Commission guidance, this section provides a qualitative description of the HP System Risk, including a risk Bow Tie, which delineates potential Drivers/Triggers and potential Consequences, followed by a description of the Tranches determined for this risk.

A. Risk Selection

HP System Risk was included as a risk in SDG&E's 2021 RAMP and was included in the 2022, 2023, and 2024 Enterprise Risk Registries (ERR).[8] SDG&E's ERR evaluation and selection process is summarized in Chapter RAMP-2, Enterprise Risk Management Framework and in Chapter RAMP-3 Risk Quantification Framework.

SDG&E selected this risk in accordance with the RDF Row 9.[9] Specifically, SDG&E assessed the top risks from the Company's 2024 ERR based on the Consequence of a Risk Event (CoRE) Safety attribute. The HP System Risk was among the risks presented in SDG&E's list of Preliminary 2025 RAMP Risks on December 17, 2024 at a Pre-Filing Workshop. HP System Risk was selected based on the qualification of its Safety risk attribute, as required under the RDF. At the pre-filing workshop, no party expressed opposition to the inclusion of this risk in SDG&E's 2025 RAMP Report.

B. Risk Bow Tie

In accordance with Commission requirements, this section describes the risk Bow Tie, possible Drivers, potential Consequences, and a mapping of the elements in the Bow Tie to the mitigation(s) that address them.[10] As illustrated in the risk Bow Tie shown below in Figure 1, the risk event (center of the Bow Tie) is an HP System Risk that leads to failure of an high pressure asset, the left side of the Bow Tie illustrates Drivers/Triggers that could lead to the HP System Risk that may cause a HP System Risk event asset failure, and the right side shows the Potential Consequences of the HP System Risk event. SDG&E applies this framework to identify and summarize the information provided in Figure 1. A mapping of each mitigation to

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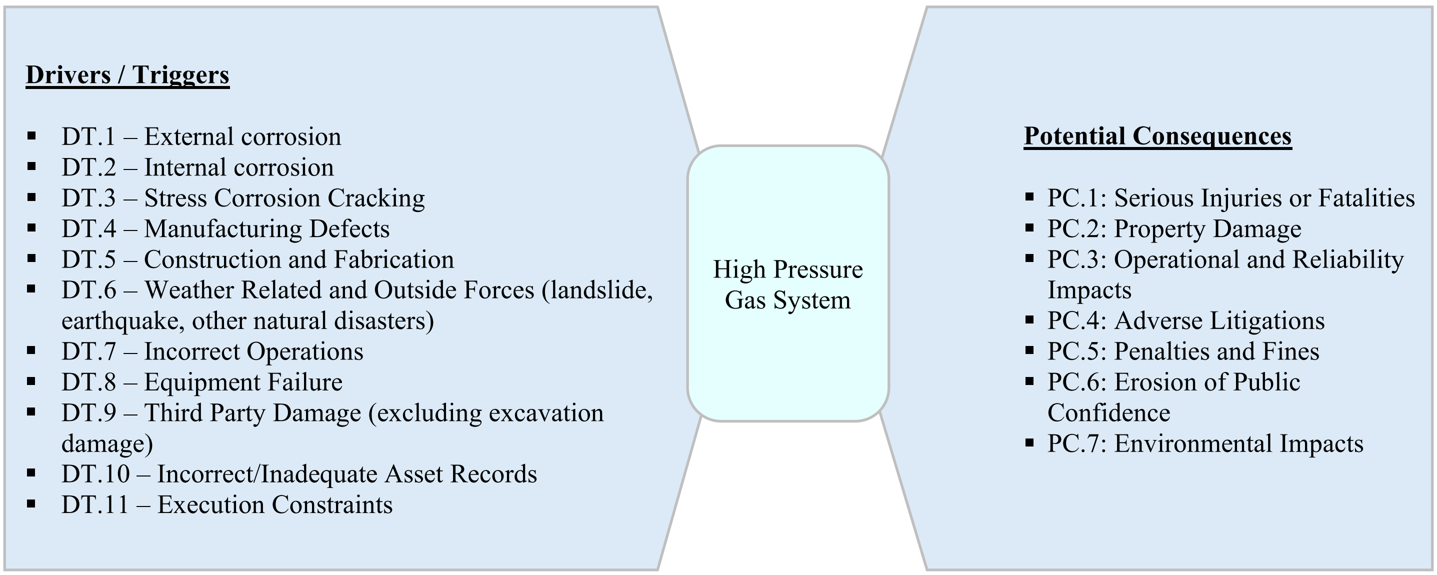
[8] In the 2021 RAMP Report this risk was called Incident Related to the High Pressure System. For 2025, the following was added to the risk definition, to further define high-pressure pipeline: "(including non-line pipe, appurtenances, and facilities) that…"

[9] D.24-05-064, RDF Row 9 states that risks to be included in the RAMP Report, at minimum, are those identified in the Company's ERR comprising "the top 40% of ERR risks with a Safety Risk Value greater than zero dollars".

[10] D.24-05-064, RDF Row 15.

the addressed elements of the risk Bow Tie is provided in Attachment C.

Figure 1
High Pressure Gas System: Risk Bow Tie



C. Potential Risk Event Drivers/Triggers[11]

When performing a risk assessment for the HP System Risk, SDG&E identifies potential leading causes, referred to as Drivers or Triggers, that reflect current and/or forecasted conditions and may include both external actions as well as characteristics inherent to the asset.[12] These Bow Tie Drivers/Triggers inform the Likelihood of a Risk Event (LoRE) component of the risk value. These include:

- **DT.1 – External corrosion:** A naturally occurring phenomenon commonly defined as the deterioration of a material (usually a metal) that results from a chemical or electrochemical reaction with its environment.[13] This risk driver is based on the potential for corrosion on the external surface of assets, such as steel tubing, casing, and pipelines exposed to corrosive environments.
- **DT.2 – Internal corrosion:** Deterioration of the interior of a pipeline attributable

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

[12] D.24-05-064, RDF Rows 10-11.

[13] *See* ASME B31.8S.

to environmental conditions inside the asset.[14]

- **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 pipe that together reduce the pressure-carrying capability of the pipe.[15]
- **DT.4 – Manufacturing Defects:** This risk driver is based on the potential for failure due to defects introduced during the manufacturing process. It is attributable to material defects 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:** This risk driver is attributable to the construction methodology applied during the installation of pipeline components typically based on the vintage of the construction standards, fabrication techniques (welding, bending, etc.), and overall guiding regulations.
- **DT.6 – Weather Related and Outside Forces (landslide, earthquake, other natural disasters):** This risk driver is attributable to causes not involving humans, and includes the effects of climate change. This driver includes events such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, and high winds.
- **DT.7 – Incorrect Operations:** This risk driver may include a pipeline incident attributed to insufficient or incorrect operating procedures or the failure to follow a procedure.
- **DT.8 – Equipment Failure:** This risk driver is attributable to malfunction of a component, including but not limited to, regulators, valves, meters, flanges, gaskets, collars, and couples.
- **DT.9 – Third-Party Damage (excluding excavation damage):[16]** This risk driver is attributable to outside force damage other than excavation damage or natural

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14 *Id.*

15 *Id.*

16 Excavation damage is addressed in a separate risk chapter.

forces, such as damage by car, truck, or motorized equipment not engaged in excavation.

- **DT.10 – Incorrect/Inadequate Asset Records:** This risk driver is attributable to the use of inaccurate or incomplete information that could result in the failure to: (1) construct, operate, or maintain SDG&E's pipeline system safely and prudently; or (2) to satisfy regulatory compliance requirements.
- **DT.11 – Execution Constraints:** This risk driver refers to events (excluding those covered by outside force damages) that impact the Company's ability to perform as planned. Examples include, but are not limited to, reduced availability of materials or 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 (CoRE)

Potential Consequences are listed on the right side of the risk Bow Tie. SDG&E identifies the Potential Consequences of this Risk by analyzing internal data sources where available, industry data, and subject matter expertise (SME).[17] These Bow Tie Consequences inform the CoRE component of the risk value. If one or more of the Drivers listed above were to result in an incident, the Potential Consequences, in a plausible worst-case scenario, could include:

- **PC.1: Serious Injuries 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**
- **PC.7: Environmental Impacts**

These potential consequences were used by SDG&E to assess HP System Risk during the development of its 2024 ERR.

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[17] D.24-05-064, Row 10.

E. Evolution Of Risk Drivers and Consequences

As specified in the Phase 3 Decision,[18] the following changes to the previous ERR and/or the 2021 RAMP include:

- The title of *High Pressure Gas System* was changed from *Incident Related to the High Pressure System (Excluding Dig-In)* to align with the updated terminology for 2025.

1. Changes to Drivers/Triggers of the Risk Bow Tie

- DT.6 – "Outside Forces (natural disasters, fire, earthquake)" in the 2021 RAMP was changed to "Natural Forces (natural disasters, fire, earthquake)" in the 2024 ERR, and "Weather Related and Outside Forces (landslide, earthquake, other natural disasters)" for the 2025 RAMP.
- DT.9 – "Third Party Damage (except underground damages)" in the 2021 RAMP was changed to "Third Party Damage (excluding excavation damage)."

2. Changes to Potential Consequences of the Risk Bow Tie

- PC.7 – Added "Environmental Impacts."

F. Summary of Tranches

To determine groups of assets or systems with similar risk profiles, or Tranches, and in accordance with Row 14 of the RDF, SDG&E applied the Homogeneous Tranching Methodology (HTM) as outlined in Chapter RAMP - 3: Risk Quantification Framework. As a result, the following classes, LoRE-CoRE pairs, and resulting number of Tranches were determined:

Table 1: High Pressure Gas System Risk Tranche Identification

Class	Number of LoRE-CoRE Pairs	Number of Resulting Tranches
HP Pipe	313	23
Facilities	3	1
TOTAL	**316**	**24**

[18] D.24-05-064, RDF Row 8.

Attachment D illustrates the derivation of the Tranches, as shown in Table 1 above, in accordance with the HTM. The classes were identified by SDG&E subject matter experts as logical groups of assets and systems based on the Company's operations. These classes also align risk treatments with asset risk profiles reflective of SDG&E's operations. More detailed Tranche information, including risk quantification by LoRE-CoRE pair, Tranche names, and mitigation associations (*i.e.*, cost mapping and risk reduction) to Tranches is provided in workpapers.

III. PRE-MITIGATION RISK VALUE

In accordance with RDF Row 19, the table below provides the pre-mitigation risk values for the HP System Risk. Further details, including pre-mitigation risk values by Tranche are provided in workpapers. Explanations of the risk quantification methodology and other higher-level assumptions are provided in Chapter RAMP-3 Risk Quantification Framework.

Table 2: High Pressure Gas System Risk
Monetized Risk Values
(Direct, in 2024 $ millions)

LoRE	CoRE [Risk-Adjusted Attribute Values]			Total CoRE	Total Risk [LoRE x Total CoRE]
	Safety	Reliability	Financial		
7.15	$1.25	$0.58	$0.29	$2.11	$15.11

A. Risk Value Methodology

SDG&E's risk modeling for the HP System Risk follows RDF guidance[19] for implementing a Cost Benefit Approach, as described below:

1. **Cost Benefit Approach Principle 1 – Attribute Hierarchy (RDF Row 2):** HP System Risk is quantified in a combined attribute hierarchy as shown in the table above, such that Safety, Reliability, and Financial are presented based on available, observable, and measurable data.
2. **Cost Benefit Approach Principle 2 – Measured Observations (RDF Row 3):** SDG&E uses observable and measurable data to estimate CoRE values for HP System Risk. SDG&E utilized a combination of internal data and external data to estimate consequences in terms of natural units, (*e.g.*, fatalities, serious injuries,

[19] D.24-05-064, Rows 2-7.

and meters out) that occur as the result of a risk event that could occur on the HP System.

3. **Cost Benefit Approach Principle 3-Comparison (RDF Row 4):** HP System Risk quantification does not include any attributes that are not directly measurable, so proxy data, as described in this RDF, is not necessary.

4. **Cost Benefit Approach Principle 4-Risk Assessment (RDF Row 5):** The data sources used for the HP System Risk, as described in the preceding paragraphs, are sufficient to model probability distributions for use in estimating risk values.

5. **Cost Benefit Approach Principle 5-Monetized Levels of Attributes (RDF Row 6:** In accordance with D.22-12-027 and D.24-05-064, RDF Row 6, SoCalGas and SDG&E used a California-adjusted Department of Transportation monetized equivalent to calculate the Safety CoRE attribute at a monetized equivalent of $16.2 million per fatality, and $4.1 million per serious injury;[20] the Gas Reliability CoRE attribute is valued at a monetized equivalent of $3,868 per gas meter outage; and the Financial CoRE attribute is valued at $1 per dollar.[21]

Further information regarding SDG&E's quantitative risk analyses, including raw data, calculations, and technical references is provided in workpapers.

6. **Cost Benefit Approach Principle 6-Adjusted Attribute Level (Row 7):**

Table 3: High Pressure Gas System Risk
Risk Scaled vs Unscaled Value by CoRE Attribute (Direct, in 2024 $ millions)

	Safety	Reliability	Financial	Total
Unscaled Risk Value	$1.2	$0.46	$1.92	$3.58
Scaled Risk Value	$8.94	$4.12	$2.05	$15.11

The values in the table above are the result of SDG&E applying the risk scaling methodology described in Chapter RAMP-3 to the CoRE attributes for HP System Risk. Like all SDG&E RAMP risks, a convex risk-averse scaling function is applied to the monetized levels of each CoRE attribute for high potential events, resulting in risk-adjusted attribute levels. The

20 *See* D.22-12-027 at 35 ("We adopt Staff's recommendation to require a dollar valuation of the Safety Attribute in the Cost Benefit Approach in the RDF using the DOT VSL as the standard value.").

21 *See* Chapter RAMP-3: Risk Quantification Framework, Section II.

societal risk-averse scaled values reflect a wide range of possible outcomes, including multiple fatalities and serious injuries from a single event, such as a rupture with ignition in HCAs, such as Class 3 or 4 locations. Consequently, the risk adjustment is more significant than compared to medium pressure pipes, where the range of possible outcomes from one event is narrower.

Further information regarding the risk scaling function, including the risk scaling factor and the loss threshold at which the risk scaling factor begins to apply, is provided in Chapter-RAMP-3.

IV. 2024-2031 CONTROL & MITIGATION PLAN

This section identifies and describes the controls and mitigations comprising the portfolio of mitigations for HP System Risk and reflects any changes to the portfolio expected to occur from the last year of recorded costs at the time of filing this RAMP Report (2024) through the 2028 GRC cycle (2031). For clarity, a current activity that is included in the plan may be referred to as either a control and/or a mitigation. Table 4 below shows which control activities are in place in 2024, which are expected to be ongoing, completed, or new during the 2025-2031 time periods. Because the TY 2024 GRC proceeding established rates through 2027,[22] information through 2027 is calculated as part of the baseline risk, in accordance with D.21-11-009.[23] For the TY 2028 GRC, SDG&E calculated CBRs beginning with TY 2028 and for each Post-Test Year (2029, 2030, and 2031).[24]

Since the high-pressure pipeline system is managed by two operating departments (Gas Transmission and Gas Distribution), it is difficult to identify costs solely dedicated to high-pressure pipelines managed by Gas Distribution Operations. Therefore, the costs in this risk Chapter are primarily related to the Gas Transmission Operations department, and activities and costs for high pressure pipelines managed by the Gas Distribution Operations department are included in the Medium Pressure Gas System Risk chapter.

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22 *See* D.24-12-074.

23 *See,* D.21-11-009 at 136 (Conclusion of Law (COL) 7) (providing a definition for "baselines" and "baseline risk").

24 In the TY 2028 GRC, the last year of recorded costs, or base year, will be 2025. SoCalGas and SDG&E will forecast information for 2026 through 2031, in accordance with the Rate Case Plan.

Table 4: High Pressure Gas System Risk
2024-2031 Control and Mitigation Plan Summary

ID[25]	Control/Mitigation Description	2024 Control	2025-2031 Plan
C010	Pipeline Monitoring Technologies	X	Ongoing
C013	Gas Transmission Safety Rule – MAOP Reconfirmation	X	Ongoing
C104	Cathodic Protection – Capital	X	Ongoing
C108	Cathodic Protection – Maintenance	X	Ongoing
C113	Leak Repair	X	Ongoing
C118	Rupture Mitigation Valve Installation – Valve Rule	X	Ongoing
C125	Pipeline Relocation/Replacement	X	Ongoing
C126	Shallow/Exposed Pipe Remediations	X	Ongoing
C132	Pipeline Maintenance	X	Ongoing
C136	Compressor Stations – Capital	X	Ongoing
C142	Compressor Station – Maintenance	X	Ongoing
C151	Measurement & Regulation Station – Capital	X	Ongoing
C155	Measurement & Instrumentation – Maintenance	X	Ongoing
C171	Integrity Assessments & Remediations: Transmission Integrity Management Program (TIMP)	X	Ongoing

A. Control Programs

In accordance with Commission guidance, this section "[d]escribe[s] the controls or mitigations currently in place"[26] (*i.e.*, the activities in this section were in place as of December 31, 2024). Controls that will continue as part of the risk mitigation plan are identified in Table 4 above.

- **C010 – Pipeline Monitoring Technologies:** The Control Center Modernization (CCM) organization has begun deploying new field pipeline monitoring technologies along existing high-consequence and evacuation-challenged areas and new and replaced transmission pipelines. These field monitoring assets (*i.e.*,

25 The order of Control Programs is based on logical groupings of similar controls rather than numerical.

26 D.18-12-014 at 33.

fiber optics, methane sensors) allow Gas Control to better monitor pipelines to more quickly identify and respond to abnormal operating or emergency conditions resulting from risk drivers. These new field pipeline technologies provide multiple safety and reliability benefits, including, but not limited to:

  - Faster response times to incidents and the reduction of severity of incidents due to the ability to monitor and respond to unfolding incidents in real-time.
  - Centralized and modernized technology, increasing operational efficiency and improving the speed and ability to manage incidents, enhancing public, infrastructure, and employee safety.

- **C013 – Gas Transmission Safety Rule – MAOP Reconfirmation:** Pursuant to 49 CFR section 192.624(a), which was initially published in October 2019 as part of PHMSA's Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments Final Rule (GTSR Part 1), SDG&E is required to reconfirm, by July 2035, the Maximum Allowable Operating Pressure (MAOP) of transmission lines that meet the applicability requirements of 49 CFR section 192.624(a). Separate from the State-mandated Pipeline Safety Enhancement Plan (PSEP), which has also been leveraged to comply with 49 CFR § 192.624, SDG&E has identified approximately 22 miles out of 219 miles of SDG&E's transmission pipelines that currently fall within the scope of MAOP Reconfirmation. For these pipelines, reconfirmation must be performed using one of six prescribed methods: pressure testing, replacement, pressure reduction, engineering critical assessment (ECA), pressure reduction for lines with a small Potential Impact Radius (PIR), and/or an alternative technology approved by PHMSA.

  The MAOP reconfirmation program, which is incorporated in SDG&E's Integrated Safety Enhancement Plan,[27] reduces the risk of failure on the high

[27] As presented by SDG&E in its TY 2024 GRC application, the Integrated Safety Enhancement Plan combines federal requirements (49 C.F.R. § 192.624 (2020)) and state requirements (D.19.09-051 at 779-780 (Ordering Paragraph (OP) 15)) for the development of traceable, verifiable, and complete pressure test records where applicable.

pressure gas system through the re-evaluation of a pipeline's MAOP and, when necessary, repair/remediation of each pipeline that is within the scope of the program. SDG&E has begun this work and plans to continue it beyond 2031 until pipelines subject to this requirement have been reconfirmed in accordance with the deadlines established by PHMSA in 49 CFR section 192.624(b). With ongoing work on pipelines that may result in changes to records, SDG&E continues to review and refine the total miles of pipe that require MAOP reconfirmation.

This control also includes a variety of activities related to supporting the MAOP reconfirmation program and other emergent activities resulting from new federal safety regulations (*e.g.*, data analysis and management, reporting, planning, process development, and quality assurance). Because this program includes a variety of activities to comply with GTSR Part 1, a single unit of measure was not identified to reflect the breadth of work. SDG&E monitors and evaluates federal regulatory and industry activity to identify and, where applicable, adopt best practices and compliance measures to enhance the safety of its pipeline system.

- **C104 – Cathodic Protection – Capital:** Cathodic protection (CP) activities consist of the planning, installation, construction, and closeout of rectifiers/deep well anode beds, remote power, and pipeline coating replacements on transmission pipelines. Corrosion on pipelines increases the risk of leaks and may reduce the useful life of the pipelines. In addition to applying coating and electrical isolation, CP is a method for mitigating external corrosion on steel pipelines. CP combats corrosion by imposing an electric current flow toward the surface of the pipeline, which means keeping the pipeline negatively charged (cathodic) with respect to the surrounding soil. This results in reduced corrosion on the pipeline system. Rectifiers/deep well anode beds 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 reduce the amount of CP current needed to protect the newly recoated portion of the pipeline. These activities are necessary to maintain or improve the pipeline CP system, extend the life of pipeline assets, and maintain compliance with 49 CFR section 192.463. The variety of work activities in this category makes it infeasible to identify a single unit of measurement.

- **C108 – Cathodic Protection – Maintenance:** Cathodic protection maintenance activities consist of annual electrical test station (ETS) reads, bi-monthly current source inspections, and annual rectifier maintenance on transmission pipelines. These activities involve the following: read/record voltage and verify compliance, inspect ETS for signs of damage, verifying ID tags and test leads for correct information and good condition, verify rectifier proper operation, read/record voltage and amperage across rectifier, clean and tighten current carrying connections on rectifier, clean ventilating screens on rectifier units, calibrate voltage and amperage meters on rectifier, repair damaged wires, check fuses/circuit breakers, clean off rectifier unit, replace rectifier ID tags, diagnose and troubleshoot substandard conditions or out of tolerance reads. These activities are necessary to maintain or improve the pipeline CP system, extend the life of the pipeline, and maintain CP compliance prescribed by 49 CFR Part 192 Subpart I – Requirements for Corrosion Control. The variety of work activities in this category makes it infeasible to identify a single unit of measurement.
- **C113 – Leak Repair:** 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 the 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 support public safety system reliability, as well as meet regulatory requirements prescribed by 49 CFR section 192.717. The variety of work activities in this category makes it infeasible to identify a single unit of measurement, as the scope of work is project-specific and varies significantly from project to project.

- **C118 – Rupture Mitigation Valve Installation – Valve Rule:** On April 8, 2022, PHMSA amended 49 CFR Parts 192 and 195 through the publication of the Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards Final Rule (Valve Rule), which became effective on October 5, 2022. The rule requires operators to install rupture mitigation valves (RMVs) on newly constructed or "entirely replaced"[28] transmission pipeline segments with six inches or greater diameters and perform risk analyses annually to identify RMV installation opportunities.

  This control captures valve installations planned in compliance with the Valve Rule. The activities of this control mitigate the risk of pipeline ruptures and enable a faster response time should a failure occur due to natural forces (*e.g.*, natural disasters, fires, earthquakes, landslides), third-party damage, vandalism, or other causes. SDG&E completed its first annual risk analysis in 2023 to identify areas where RMV installations are appropriate, and the forecast of activities is an initial estimate based on this analysis.
- **C125 – Pipeline Relocation/Replacement:** Pipeline relocation and replacement activities consist of planning, installation, construction, and closeout of pipeline reroutes triggered by weather-related external forces, municipality requests, right-of-way agreements, or class location changes. Pipeline replacements due to changes in operating class are time-sensitive and must be completed within 24 months of the class location change.[29] These relocation and replacement activities are necessary to reduce the potential for pipeline damage, support public safety, and maintain pipeline access. The variety of work activities in this category makes it infeasible to identify a single unit of measurement, as project costs and scopes in this category vary significantly from project to project.
- **C126 – Shallow/Exposed Pipe Remediations:** Shallow or exposed pipe

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[28] 49 CFR § 192.3 provides that "Entirely replaced onshore transmission pipeline segments means, for the purposes of §§ 192.179 and 192.634, where 2 or more miles, in the aggregate, of onshore transmission pipeline have been replaced within any 5 contiguous miles of pipeline within any 24-month period. This definition does not apply to any gathering line."

[29] 49 CFR § 192.611(d).

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), installation of a drop section, and/or additional earth coverage are installed to prevent damage to exposed/shallow pipes caused by corrosion, third-party damages, erosion, or other external forces. These activities are necessary to support public safety, reduce the potential for pipeline damage, and extend the life of pipeline assets. The variety of work activities in this category makes it infeasible to identify a single unit of measurement.

- **C132 – Pipeline Maintenance:** 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 changes in population density, verifying ID tags for correct information and good condition, partially operating valves (*i.e.*, open/close) to confirm good working condition, inspecting and servicing actuators, lubricating valves, checking for atmospheric corrosion, testing for combustible gas, inspecting covers, ventilation systems, the structural condition of vaults, vault ladders, steps, and handrails. These activities are necessary to maintain or improve the pipeline system, extend the life of pipeline assets, and maintain compliance with 49 CFR 192 sections 192.745 and 192.749. The variety of work activities in this category makes it infeasible to identify a single unit of measurement.
- **C136 – Compressor Stations – Capital:** Compressor station activities consist of the planning, installation, construction, and closeout of compressor upgrades, pipe replacements, valve replacements, and equipment upgrades, including water, oil, and air systems at the compressor station. These upgrades are required over time due to the normal wear and tear of compressor station equipment. These activities are necessary to maintain or improve system reliability, extend equipment and system life, and support public safety. The variety of work activities in this category makes it infeasible to identify a single unit of measurement.

- **C142 – Compressor Station – Maintenance:** Compressor Station Maintenance activities consist of compressor unit inspections, primary and backup power generator inspections, fire water system and emergency system inspections, programable logic controllers (PLC) and instrumentation inspections, valve inspections, vessel inspections, tank inspections, scrubber inspections, relief valve inspections, actuator/controller and regulator inspections, and leak surveys on compressor station equipment and pipeline systems. The above-mentioned activities involve the following: complete periodic performance analysis and time-based overhauls on main compressor units and generators; function test 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, odorant sensing equipment and gas moisture monitoring systems; verify ID tag information and good condition; examine operating valves, inspect and service actuators, and lubricate 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 pipeline and compressor assets, and maintain compliance with 49 CFR sections 192.731. The variety of work activities in this category makes it infeasible to identify a single unit of measurement.
- **C151 – Measurement & Regulation Station – Capital:** Measurement & Regulation Station – Capital activities consist of the planning, installation, construction, and closeout of redesigns/upgrades for producer vessels, meters, stations, Company-owned facilities at customer meter set assemblies, and control valve stations on transmission pipeline systems. These upgrades are required to replace aging equipment with new equipment to enhance functionality. The safety and reliability of SDG&E's transmission system depends on the meter and regulator equipment used to control the flow of natural gas in transmission pipelines using valves and regulator stations. These activities are necessary to

maintain or improve system reliability, extend equipment and system life, and support public safety. The variety of work activities in this category makes it infeasible to identify a single unit of measurement, as project costs and scopes vary significantly from project to project in this category.

- **C155 – Measurement & Instrumentation – Maintenance:** Measurement & Instrumentation Station activities consist of valve inspections, vault inspections, producer station inspections, pressure limiting station inspections, relief valve inspections, and actuator/controller and regulator inspections on transmission pipelines. These activities involve the following: verifying ID tags for correct information and good condition; partially operating valves to confirm good working condition; inspecting and servicing actuators; lubricating valves; checking for atmospheric corrosion; testing for combustible gas; inspecting covers, ventilation systems, structural condition of vaults, vault ladders, and test/record set points; verifying rupture disc rating; checking supply regulators for proper operation; checking for leakage; blowing/inspecting supply filters; checking hydraulic fluid levels; checking controller for proper operation; and testing/recording set points. These activities are necessary to identify or remediate any developing system deficiencies during the performed activities, to maintain or improve the pipeline system, extend the life of the pipeline, and maintain compliance with 49 CFR 192 section 192.739. The variety of work activities in this category makes it infeasible to identify a single unit of measurement.
- **C165 – Security & Auxiliary Equipment:** Security & auxiliary equipment activities include planning, installing, constructing, and closing security cameras, lighting, gates, locks, and equipment upgrades such as pipe supports, analyzers, and Supervisory Control and Data Acquisitions (SCADA) on transmission pipeline facilities. These activities harden the security at pressure limiting stations, valve stations, and compressor stations, increase personnel safety, and reduce the potential of system damage. The variety of work activities in this category makes it infeasible to identify a single unit of measurement.

- **C171 – Integrity Assessments & Remediations: Transmission Integrity Management Program (TIMP):** Through the TIMP, SDG&E continuously manages the integrity and safety of its transmission pipeline system, conducting a robust set of federally mandated activities.[30] SDG&E identifies threats to transmission pipelines in high consequence areas (HCAs), Class 3 and Class 4 locations not in HCAs, and moderate consequence areas (MCAs); determines the risk posed by these threats; schedules prescribed assessments to evaluate these threats; collects information about the condition of pipelines; and takes actions to minimize applicable threat and integrity concerns to reduce the risk of a pipeline failure.

  The TIMP Threat and Risk Assessment process includes an evaluation of the Likelihood of Failure (LOF), using threat categories such as those discussed in Section I.A. (External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing, Construction, Equipment, Third Party Damage, Incorrect Operations, and Weather Related and Outside Force), and the Consequence of Failure (COF), using pipeline operational parameters and information about the area near the pipeline. The LOF multiplied by the COF produces the pipeline's Relative Risk Score, which is then used to inform assessment scope and methods. Information about the physical condition of transmission pipelines is collected regularly through integrity assessments.

  At a minimum of every seven years for pipeline segments in HCAs and every ten years for other pipeline segments, transmission pipelines within the scope of TIMP are assessed using methods such as In-Line-Inspection (ILI), Direct Assessment, or Pressure Test, and remediated as needed. Generally, ILI is the preferred assessment method to identify potential pipeline integrity threats due to the amount of data that can be collected on the pipeline during this process. During an ILI, intelligent pipeline inspection devices are inserted into pipelines to collect pipeline condition data via sensors; such data includes but is not limited to wall thickness measurements, geographical positioning of features, as well as

[30] 49 C.F.R. Part 192, Subpart O and 49 C.F.R. § 192.710 (2023).

measurements and locations of anomalies such as dents and cracks. Assessment method selection depends on factors such as the threats that require assessment,[31] pipeline characteristics, and operational considerations.

Upon detection during pipeline assessments, anomalies are classified and addressed based on severity, with the most severe requiring immediate action. Actions are then taken to address applicable threats and integrity concerns to increase safety and prevent pipeline failures. SDG&E may remediate pipe to reduce risk where corrosion, welding joint failure, or other forces are occurring or have occurred. When appropriate, post-assessment pipeline repairs or replacements are intended to increase public and employee safety by reducing or eliminating conditions that might lead to an incident.

The number and types of TIMP activities vary year to year and are based on the timing of previous assessments performed in the same locations. The TIMP consists of both O&M and capital activities, which are primarily driven by the number of assessments completed and the results of those assessments. Capital activities consist of data application improvements and a variety of remedial actions, dependent upon the O&M assessment activities, which cannot be unitized.

The TIMP reduces the risk of failure to the transmission system, and, on a continual basis, the Integrity Management department evaluates the effectiveness of the program and scheduled assessments.

B. Changes from 2024 Controls

SDG&E plans to continue each of the existing controls discussed above, and reflected in Table 2, through the 2025-2031 period without significant changes.

C. Mitigation Programs

SDG&E does not currently foresee implementing new mitigations not described above during the 2025-2031 period beyond the mitigations described in this Chapter.

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[31] 49 CFR §§ 192.921(a) & 192.937(c).

D. Climate Change Adaptation

Pursuant to Commission decisions in the Climate Adaptation OIR (R.18-04-019),[32] SDG&E performed a Climate Adaptation Vulnerability Assessment (CAVA) focused on years 2030, 2050, and 2070, with the aim of identifying asset and operational vulnerabilities to climate hazards across the SDG&E system. SDG&E recognizes the need to address climate vulnerabilities to promote the safety and reliability of its services and mitigate the increasing climate-related hazards through innovative and community-centric approaches. Some of the climate hazards that will have short- and long-term ramifications in the San Diego region include extreme temperatures, wildfire, inland flooding, coastal flooding and erosion, and landslides. Climate change is recognized as a factor that can drive, trigger, or exacerbate multiple RAMP risks. Implementing climate change adaptation measures and integrating climate vulnerability considerations into RAMP controls and mitigations can enhance system infrastructure longevity and reduce the severity of long-term negative climate impacts. The controls and mitigations described in further detail in this chapter, as shown below, align with the goal of increasing SDG&E's physical and operational resilience to the increasing frequency and intensity of climate hazards. Additional information on the CAVA and a list of climate-relevant controls and mitigations included in RAMP, are provided in Chapter RAMP-5: Climate Change Adaptation.

Table 5: High Pressure Gas System Risk
Controls and Mitigations that Align with Increasing Resilience to Climate Hazards

ID	Relevant Control/Mitigation	Potential Climate Hazard(s)
C010	Pipeline Monitoring Technologies	Inland Flooding and Landslides
C013	Gas Transmission Safety Rule – Maximum Allowable Operating Pressure (MAOP) Reconfirmation	Inland Flooding and Landslides
C104	Cathodic Protection - Capital	Inland Flooding and Landslides
C113	Leak Repair	Inland Flooding and Landslides
C125	Pipeline Relocation/Replacement	Inland Flooding and Landslides
C126	Shallow/Exposed Pipe Remediations	Inland Flooding and Landslides
C171	Integrity Assessments & Remediation	Inland Flooding and Landslides

E. Foundational Programs

Foundational Programs are "[i]nitiatives that support or enable two or more Mitigation

32 D.19-10-054; D.20-08-046.

programs or two or more Risks but do not directly reduce the Consequences or reduce the Likelihood of safety Risk Events."[33]

This risk chapter does not have any foundational programs.

F. Estimates of Costs, Units, and Cost-Benefit Ratios (CBRs)

The tables in this section provide a quantitative summary of the risk control and mitigation plan for the High Pressure Gas System, including the associated costs, units, and CBRs. Additional information by Tranche is provided in workpapers. The costs shown are estimated using assumptions provided by SMEs and available data. In compliance with the Phase 3 Decision,[34] for each enterprise risk, SDG&E uses actual results and industry data and when that is not available, supplements the data with SME input. Additional details regarding the data and expertise relied upon in developing these estimates are provided in Attachment B.

Table 6: High Pressure Gas System Risk
Control and Mitigation Plan –Recorded and Forecast Costs Summary
(Direct, in 2024 $ thousands)

Control/Mitigation		Recorded Costs		Forecast Costs			
ID	Name	2024 Capital	2024 O&M	2028 O&M	2025-2028 Capital	PTY Capital	PTY O&M
C010	Pipeline Monitoring Technologies	324	0	336	4,116	1,605	1,249
C013	Gas Transmission Safety Rule - MAOP Reconfirmation	11,423	0	18	45,937	64,862	54
C104	Cathodic Protection - Capital	58	0	0	232	174	0
C108	Cathodic Protection - Maintenance	0	135	134	0	0	402
C113	Leak Repair	0	0	0	4,032	3,024	0
C118	Rupture Mitigation Valve Installation - Valve Rule	0	0	0	4,051	20,255	0
C125	Pipeline Relocation/Replacement	200	0	0	800	600	0
C126	Shallow/Exposed Pipe Remediations	2,230	0	0	8,916	6,687	0
C132	Pipeline Maintenance	0	933	933	0	0	2,799

[33] D.24-05-064, Appendix A at A-4.

[34] D.24-05-064, RDF Row 10.

Control/Mitigation		Recorded Costs			Forecast Costs		
ID	**Name**	**2024 Capital**	**2024 O&M**	**2028 O&M**	**2025-2028 Capital**	**PTY Capital**	**PTY O&M**
C136	Compressor Stations - Capital	4,761	0	0	19,044	14,283	0
C142	Compressor Station - Maintenance	0	5,598	5,072	0	0	15,215
C151	Measurement & Regulation Station Capital	2,686	0	0	10,744	8,058	0
C155	Measurement & Instrumentation Maintenance	0	364	364	0	0	1,092
C171	Integrity Assessments & Remediation	31,938	31,072	29,031	73,391	57,108	118,748
Total		**53,620**	**38,102**	**35,888**	**171,263**	**176,656**	**139,559**

Table 7: High Pressure Gas System Risk
Control & Mitigation Plan – Units Summary

Control/Mitigation			Recorded Units		Estimated Units			
ID	**Name**	**Units**	**2024 Capital**	**2024 O&M**	**2028 O&M**	**2025-2028 Capital**	**PTY Capital**	**PTY O&M**
C010	Pipeline Monitoring Technologies	HCA Methane Sensors	0	0	1	87	60	3
C013	Gas Transmission Safety Rule - MAOP Reconfirmation	Miles	0	0	0	5	17	0
C104	Cathodic Protection - Capital	N/A	0	0	0	0	0	0
C108	Cathodic Protection - Maintenance	N/A	0	0	0	0	0	0
C113	Leak Repair	N/A	0	0	0	0	0	0
C118	Rupture Mitigation Valve Installation - Valve Rule	Valves	0	0	0	1	5	0
C125	Pipeline Relocation/Replacement	N/A	0	0	0	0	0	0
C126	Shallow/Exposed Pipe Remediations	N/A	0	0	0	0	0	0
C132	Pipeline Maintenance	N/A	0	0	0	0	0	0
C136	Compressor Stations - Capital	N/A	0	0	0	0	0	0
C142	Compressor Station – Maintenance	N/A	0	0	0	0	0	0

Control/Mitigation			Recorded Units		Estimated Units			
ID	**Name**	**Units**	**2024 Capital**	**2024 O&M**	**2028 O&M**	**2025-2028 Capital**	**PTY Capital**	**PTY O&M**
C151	Measurement & Regulation Station Capital	N/A	0	0	0	0	0	0
C155	Measurement & Instrumentation Maintenance	N/A	0	0	0	0	0	0
C171	Integrity Assessments & Remediation	Miles	0	11	8	0	0	112

In the table below, CBRs are presented in summary at the mitigation or control level for the Test Year 2028 GRC cycle. CBRs are calculated based on scaled, expected values unless otherwise noted, and are calculated for each of the three required discount rates[35] in each year of the GRC cycle and for the post-test years in aggregate (2029-2031). Costs and CBRs for each year of the GRC cycle and the aggregated years are provided in workpapers.

Table 8: High Pressure Gas System Risk
Cost Benefit Ratio Results Summary
(Direct, in 2024 $ millions)

ID	Control/Mitigation Name	Capital (2028 – 2031)	O&M (2028 – 2031)	CBR (Societal)	CBR (Hybrid)	CBR (WACC)
C010	Pipeline Monitoring Technologies	2,536	1,585	1.09	0.80	0.67
C013	**Gas Transmission Safety Rule - MAOP Reconfirmation**	66,810	72	0.77	0.26	0.19

35 *See* Chapter RAMP-3: for definitions of discount rates, as ordered in the Phase 3 Decision.

ID	Control/Mitigation Name	Capital (2028 – 2031)	O&M (2028 – 2031)	CBR (Societal)	CBR (Hybrid)	CBR (WACC)
C104	**Cathodic Protection – Capital**	233	0	141.55	151.67	141.75
C108	**Cathodic Protection - Maintenance**	0	540	21.47	23.01	21.50
C113	**Leak Repair**	4,032	0	2.21	2.36	2.21
C118	**Rupture Mitigation Valve Installation - Valve Rule**	24,306	0	0.10	0.04	0.04
C125	**Pipeline Relocation/Replacement**	802	0	1.41	0.53	0.39
C126	**Shallow/Exposed Pipe Remediations**	8,920	0	0.35	0.08	0.05
C132	**Pipeline Maintenance**	0	3,733	24.34	25.93	24.35
C136	**Compressor Stations – Capital**	19,045	0	12.24	5.48	4.26
C142	**Compressor Station – Maintenance**	20,286	0	0.30	0.32	0.30
C151	**Measurement & Regulation Station Capital**	10,744	0	0.35	0.16	0.12
C155	**Measurement & Instrumentation Maintenance**	0	1,457	1.11	1.19	1.11
C171	**Integrity Assessments & Remediation**	71,018	147,782	1.33	1.25	1.12

Bold *indicates this control/mitigation includes mandated programs/activities.*

Tranche-level CBRs by year and in aggregate for each mitigation are provided in workpapers.

V. ALTERNATIVE MITIGATIONS

Pursuant to D.14-12-025, D.16-08-018, and D.18-12-014,[36] SDG&E considered two alternatives to the risk mitigation plan for HP System 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 considers changes in risk reduction, cost, reasonableness, current conditions, modifications to the plan and constraints, such as budget and resources.

Table 9: High Pressure Gas System Risk
Alternative Mitigation Plan –Forecast Costs Summary
(Direct, in 2024 $ millions)

ID	Alternative Mitigation Name	Forecast Costs			
		2025-2028 Capital	PTY Capital	2025-2028 O&M	PTY O&M
A125	Pipeline Rerouting to Mitigate Landslide Impacts	14,380	10,785	0	0
A171	DIMP - High Pressure Pipeline In-Line Inspections	8,064	6,048	16,410	12,307
Total		**22,444**	**16,833**	**26,664**	**19,998**

Table 10: High Pressure Gas System Risk
Alternative Mitigation Cost Benefit Ratio Results Summary
(Direct, in 2024 $ millions)

ID	Alternative Mitigation Name	Capital TY 2028	O&M TY 2028	CBR (Societal)	CBR (Hybrid)	CBR (WACC)
A125	Pipeline Rerouting to Mitigating Landslide Impacts	3,595	0	~0.00	~0.00	~0.00
A171	DIMP – High Pressure Pipeline In-Line Inspections	2,016	6,666	0.07	0.06	0.06

A. Alternative 1: Pipeline Rerouting to Mitigate Landslide Impacts

The Pipeline Rerouting – Landslide Exposure alternative consists of identifying

[36] D.18-12-014 at 33-35.

transmission pipelines currently in areas susceptible to landslides and rerouting them to more desirable locations. In recent years, SDG&E has experienced an increase in extreme weather events throughout its service territory that have resulted in landslides that have impacted high-pressure pipelines. This alternative would mitigate the likelihood of failure associated with landslide-driven pipeline damages and support public safety and operational reliability.

Proposed work for this mitigation includes surveying, planning, construction, and closeouts of identified pipeline reroutes. At this time, SDG&E estimates approximately 41 miles of transmission pipelines are in high landslide risk areas. This proposal estimates that one mile of pipeline would be identified and replaced each year. SDG&E currently replaces pipeline segments on an as-needed basis following extreme weather events. While replacements under this rerouting program would subsume such replacements, the cost to execute this alternative is estimated to be higher, and there is uncertainty about whether all identified pipeline segments would benefit from rerouting.

Before pursuing the mitigation, a more in-depth analysis of the benefits and costs associated with this alternative is required. This work would require additional resources or redirection of existing resources.

B. Alternative 2: DIMP – High Pressure Pipeline In-Line Inspections

Through the DIMP, SDG&E is federally mandated to demonstrate an understanding of its gas distribution system; identify threats to its gas distribution system; determine the risk posed by these threats; and take actions to minimize applicable threat and integrity concerns to reduce the risk of a pipeline failure. These actions include identifying and implementing risk reduction measures, monitoring the results of these measures, and evaluating their effectiveness.

The alternative mitigation of conducting ILI assessments on high pressure distribution pipeline segments installed in more populated areas would enhance SDG&E's evaluation and management of the integrity of high-pressure pipe, which is associated with a higher consequence of failure. This activity would enable SDG&E to collect additional information about the physical condition of high-pressure pipelines that are not within the scope of TIMP regulations. SDG&E would evaluate collected data and detect conditions that are validated and addressed based on severity. Risk reduction measures would be taken to address applicable threats and integrity concerns to reduce the likelihood of failure and increase the safety of the pipeline.

SDG&E does not propose at this time to adopt this alternative as a programmatic risk reduction measure for two primary reasons. As discussed in PHMSA's 2024 report on *Integrity Assessment of Distribution Pipelines*, which was mandated by Section 122 of the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020" (PIPES Act of 2020), ILI technology is not readily available for all distribution pipe configurations.[37] A more in-depth evaluation of SDG&E's distribution pipelines and available technology is necessary to determine the actual scope of a high pressure distribution in-line inspection program. This would then require an updated evaluation of costs, risk reduction, and overall benefits. Additionally, there is not currently a set of ILI assessment policies within the industry that apply to this category of assets.

Currently, SDG&E continuously assesses risks on its distribution pipeline system through the DIMP and manages those associated with high pressure distribution pipe through activities such as pipeline repair and replacement, which are included in forecasts for C007 (Underperforming Mains and Services) in the Medium Pressure Risk chapter (SDGE-Risk-3). SoCalGas is currently conducting a pilot project to evaluate technology and inform a set of policies and practices that can be applied to a high pressure distribution ILI assessment program, which may also inform a possible program for SDG&E. Until then, SDG&E will continue to execute its current work plan to address high pressure risk.

VI. HISTORICAL GRAPHICS

As directed by the Commission in the Phase 2 Decision, this section illustrates the accomplishments in safety work and the progress in mitigating safety risks over the two immediately preceding RAMP cycles. A bar chart graphic is employed to depict historical progress. This graphic uses a TIMP metric that aligns with Company safety goals to illustrate trends in historical progress and identify remaining tasks necessary to continue mitigating risks. It presents completed assessment mileage and total assessment plan (AP) mileage.

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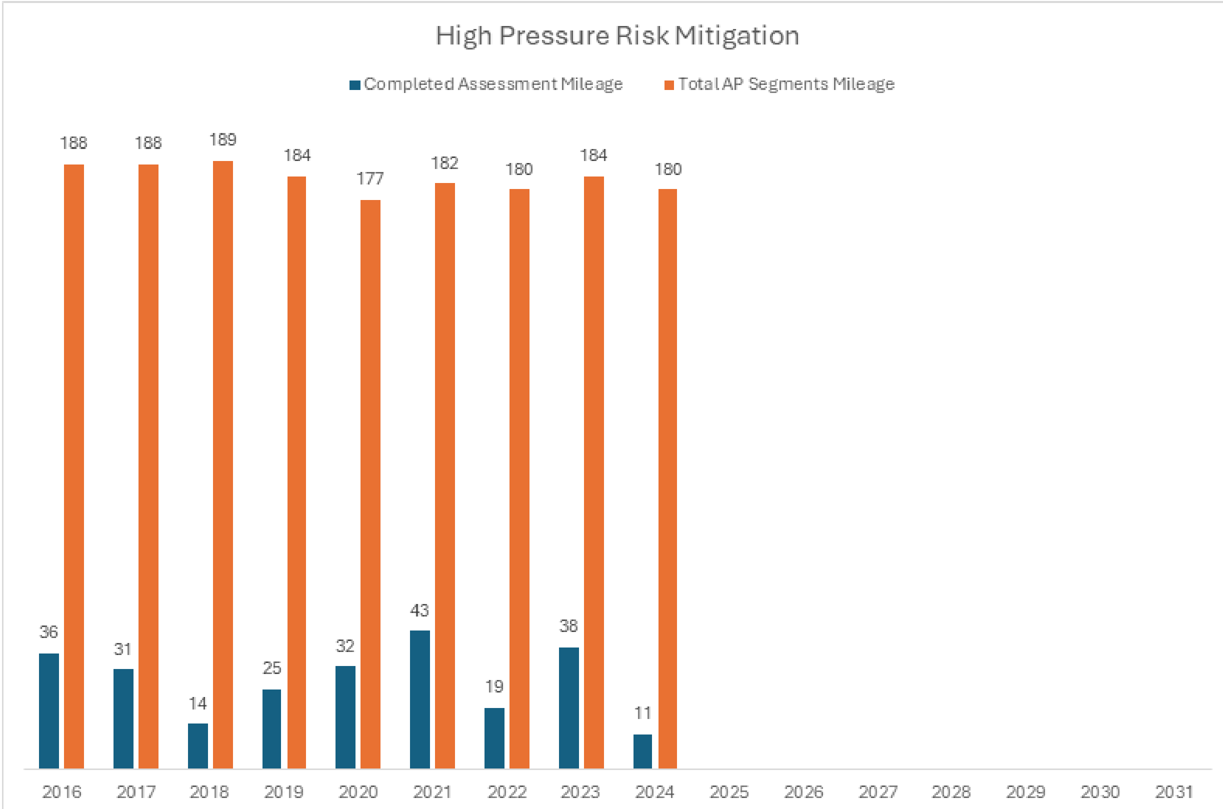
[37] PHMSA, *Integrity Assessments of Distribution Pipelines* (January 2024) at Section 6, *available at:* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2024-09/Report%20to%20Congress%20-%20Integrity%20Assessments%20of%20Distribution%20Pipelines.pdf.



As described in Section III.A., the TIMP (C171 – Integrity Assessments & Remediations: Transmission Integrity Management Program) is a prescriptive program that includes continuous cycles of assessments and remediations to manage pipeline integrity. Regular evaluations are conducted at intervals no less than every seven years for HCAs and every ten years for other segments, using methods such as ILI, Direct Assessment, or Pressure Testing.

From 2016 to 2024, SDG&E successfully conducted regular pipeline assessments, improved data integration, and completed necessary remediations to enhance pipeline safety through the TIMP. In the forecast years, continuous improvements in threat and risk analyses, the expansion of assessments with advanced technologies, and evaluations and applications of preventive measures will continue to enhance the integrity and safety of the high-pressure gas pipeline system.

Due primarily to the reassessment requirements established in 49 CFR section 192.939, TIMP activity levels vary year to year based on assessment findings and pipeline safety considerations. The planning and execution of assessment projects primarily depend on the timing and intervals of prior assessments and compliance dates, as well as external factors such as applicable risks and threats. The cyclical nature of TIMP results in a somewhat stable scope of work (*i.e.*, pipeline miles) that is not expected to decrease over time. In 2020, there was an increase to the overall miles scoped under the TIMP due to the issuance of the *Pipeline Safety: Safety of Gas Transmission Pipeline: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments* Final Rule, which mandated integrity assessments on pipeline segments in non-HCA Class 3 and Class 4 locations, as well as the newly defined MCAs.

The safety work that remains to be done is addressed in the controls/mitigations detailed above in Section III. 2024-2031 Control and Mitigation Plan.

ATTACHMENTS

ATTACHMENT A

CONTROLS AND MITIGATIONS WITH REQUIRED COMPLIANCE DRIVERS

The table below indicates the compliance Drivers that underpin identified controls and mitigations.

ID	Control/Mitigation Description	Compliance Driver
C013	Gas Transmission Safety Rule – MAOP Reconfirmation	49 CFR § 192.624
C104	Cathodic Protection – Capital	49 CFR 192 Subpart I
C108	Cathodic Protection – Maintenance	49 CFR 192 Subpart I
C113	Leak Repair	49 CFR 192 Subpart M
C118	Rupture Mitigation Valve Installation – Valve Rule	PHMSA "Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards" final rule (49 CFR Parts 192 and 195)
C125	Pipeline Relocation/Replacement	49 CFR 192 Subpart M
C126	Shallow/Exposed Pipe Remediations	49 CFR 192 Subpart M
C132	Pipeline Maintenance	49 CFR 192 Subpart M
C136	Compressor Stations – Capital	49 CFR 192 Subpart M
C142	Compressor Station – Maintenance	49 CFR 192 Subpart M
C151	Measurement & Regulation Station Capital	49 CFR 192 Subpart M
C155	Measurement & Instrumentation - Maintenance	49 CFR 192 Subpart M
C171	Integrity Assessments & Remediation: Transmission Integrity Management Program (TIMP)	49 CFR Part 192, Subpart O 49 CFR § 192.710

ATTACHMENT B

HIGH PRESSURE GAS SYSTEM RISK - REFERENCE MATERIAL FOR QUANTITATIVE ANALYSES

The Phase 3 Decision RDF at Row 10 and Row 29 directs each utility to identify Potential Consequences of a Risk Event using available and appropriate data.[38] Appropriate data may include Company specific data or industry data supplemented by the judgment of subject matter experts. Provided below is a listing of the inputs utilized as part of this assessment and the description of the data.

Risk Data	Source Type	Source Information
Likelihood of failure	Internal Model results	Source: Internal TIMP, HP Distribution and FIMP models Description: A combination of internal and external PHMSA data to model likelihood of failure by outcome and cause for SoCalGas and SDG&E's high pressure pipelines and facilities
Population Density	Internal Data	Source: Results from sliding mile data along SoCalGas and SDG&E's pipelines, and census data. Links: https://data.census.gov/profile/California?g=040XX00US06 https://data.census.gov/table/ACSDT1Y2022.B11016?q=B11016:%20Household%20Type%20by%20Household%20Size Description: SoCalGas and SDG&E population density data used to determine average value and distributions for potential safety consequences per class or zone locations.
National Pipeline Incidents (2010-2024)	External Data	Agency: PHMSA Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data Description: National data was used to estimate the proportion of high pressure pipeline incidents that resulted in customer outages

[38] D.24-05-064, RDF Row 10 and Row 29.

Risk Data	Source Type	Source Information
		because internal data was not available. This source was also used to model serious injuries.
Meter Outages	Internal Data	Source: SME judgment and GIS data Description SME expertise was used to determine scenarios that could result in a significant reliability impact ang GIS data was used to determine the number of meters downstream that would be impacted
National High Pressure Incident Cost data	External Data	Agency: PHMSA Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files Description: National data was used to estimate costs such as property damage in current year (2024) dollars because internal data was not available
Average cost of a fatality	External Data	Agency: National Safety Council (NSC) Link: https://injuryfacts.nsc.org/work/costs/work-injury-costs/ Description: Costs include wage losses, medical expenses, administrative expenses and employer costs, which are not included in the PHMSA costs.
Average Cost of a serious injury	External Data	Agency: CDC Link: https://wisqars.cdc.gov/cost/?y=2022&o=TAR&i=0&m=3000&g=00&s=0&u=TOTAL&u=AVG&t=COMBO&t=MED&t=LIFE&t=WORK&a=5Yr&g1=0&g2=199&a1=0&a2=199&r1=MECH&r2=INTENT&r3=NONE&r4=NONE&c1=NONE&c2=NONE Description: Wage loss and medical costs associated with non-fatal injuries that require hospitalization that are not included in PHMSA costs.

ATTACHMENT C

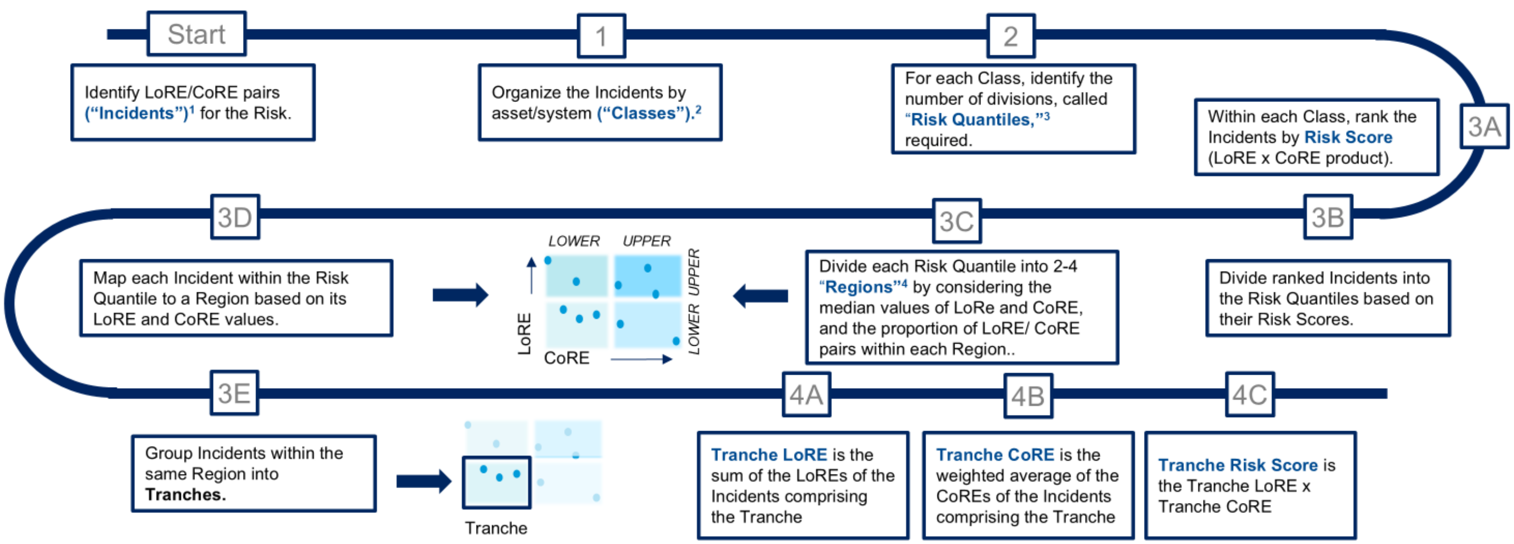
HIGH PRESSURE GAS SYSTEM RISK – SUMMARY OF ELEMENTS OF BOW TIE

SUMMARY OF ELEMENTS OF BOW TIE			
ID	**Control/Mitigation Name**	**Drivers Addressed**	**Consequences Addressed**
C010	Pipeline Monitoring Technologies	DT.6	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6, PC.7
C013	Gas Transmission Safety Rule – MAOP Reconfirmation	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9, D.10	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6, PC.7
C104	Cathodic Protection - Capital	DT.1, DT.2, DT.4, DT.6, DT.8	PC.1, PC.3, PC.7
C108	Cathodic Protection – Maintenance	DT.1, DT.2, DT.4, DT.8	PC.1, PC.3, PC.7
C113	Leak Repair	DT.6, DT.9	PC.3, PC.7
C118	Rupture Mitigation Valve Installation – Valve Rule	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, PC.7
C125	Pipeline Relocation/Replacement	DT.4, DT.5, DT.6, DT.9, DT.10	PC.3, PC.4, PC.5, PC.7
C126	Shallow/Exposed Pipe Remediations	DT.5, DT.6	PC.3, PC.4, PC.5, PC.7
C132	Pipeline Maintenance	DT.7, DT.8	PC.3, PC.7
C136	Compressor Stations – Capital	DT.3, DT.4, DT.5, DT.8	PC.1, PC.3, PC.5, PC.7
C142	Compressor Station – Maintenance	DT.3, DT.4, DT.5, DT.10	PC.1, PC.3, PC.5, PC.7
C151	Measurement & Regulation Station Capital	DT.4, DT.7, DT.8	PC.1, PC.3, PC.5, PC.7
C155	Measurement & Instrumentation Maintenance	DT.4, DT.7, DT.8, DT.10	PC.1, PC.3, PC.5, PC.7
C171	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, PC.7

ATTACHMENT D

APPLICATION OF TRANCHING METHODOLOGY

A sample walkthrough of the Homogeneous Tranching Methodology (HTM) as outlined in Volume 1, Chapter RAMP - 3: Risk Quantification Framework is provided.



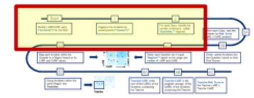
NOTES

*[1]For example, **Incidents (or "Risk Incidents")** for High Pressure are generally modes of failure of High Pressure assets in various environments such as low or high population densities.*

*[2]For example, **Classes (or "Asset Classes")** for High Pressure include Facilities and High Pressure Pipe.*

*[3]**Quantiles** are divisions of equal numbers of incidents (quartiles have 4 divisions, quintiles have 5, etc.) The number of incidents dictates the number of quantiles needed.*

*[4]The four **Regions** are: 1. Lower LoRE-Lower CoRE (LL-LC), 2. Lower LoRE-Upper CoRE (LL-UC), 3. Upper LoRE-Lower CoRE (UL-LC), and 4. Upper LoRE-Upper CoRE (UL-UC).*



Start

Identify LoRE/CoRE pairs **("Incidents")**[1] for the Risk.

1

Organize the Incidents by asset/system **("Classes")**.[2]

2

For each Class, identify the number of divisions, called **"Risk Quantiles,"**[3] required.

Class	LORE / CORE PAIRS	TOTAL # PAIRS
Facilities	Moreno Compressor Mechanical	3
	Moreno Compressor Other	
	Moreno Compressor Piping	
HP Pipe	Transmission (Class 3) HCA installed >=1946. SCC Large_Leak	355
	High_Pressure_Distribution (Zone 1). Equipment Failure Small_Leak	
	Transmission (Class 1) MCA installed >=1946. EXT_CORR Rupture	
	…and 352 more pairs	

$$\min\left(\frac{N}{8}-1,9\right) < K \le \min\left(\frac{N}{8},10\right)$$

Facilities: **1**

HP Pipe: **10**

Step 3 for *HP Pipe*

Within each Class, rank the Incidents by **Risk Score** (LoRE x CoRE product).

3A

3B

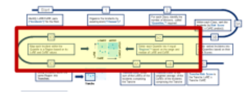
Divide ranked Incidents into the Risk Quantiles based on their Risk Scores.

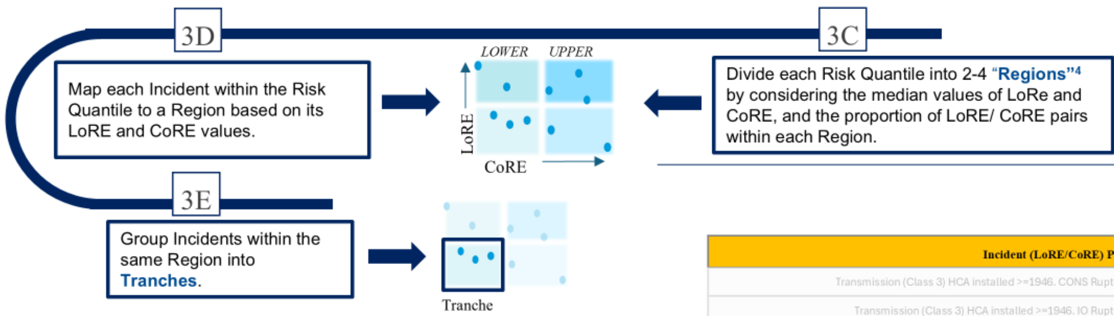
HP Pipe	Transmission (Class 3) HCA installed >=1946. SCC Large_Leak	355
	High_Pressure_Distribution (Zone 1). Equipment Failure Small_Leak	
	Transmission (Class 1) MCA installed >=1946. EXT_CORR Rupture	
	...and 352 more pairs	

10

From Step 2 for *HP Pipe*

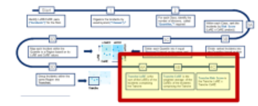
Incident (LoRE/CoRE) Pair	Risk Score	Rank (3A)	Quantile (3B)
Transmission (Class 3) HCA installed >=1946. CONS Rupture	2,229,358	1	#1
Transmission (Class 3) HCA installed >=1946. IO Rupture	1,953,059	2	
Transmission (Class 3) HCA installed >=1946. MFG Rupture	1,915,890	3	
Transmission (Class 3). Equipment Failure Small_Leak	1,461,113	4	
High_Pressure_Distribution (Zone 3) HCA installed >=1946. IO Large_Leak	778,759	5	
Transmission (Class 3) HCA installed >=1946. CONS Large_Leak	627,707	6	
Transmission (Class 3) HCA installed >=1946. EQUIP Large_Leak	532,258	7	
Transmission (Class 3) HCA installed >=1946. EQUIP Rupture	500,613	8	
Transmission (Class 3) HCA installed >=1946. WROF Rupture	450,184	9	
Transmission (Class 3) HCA installed >=1946. EXT_CORR Rupture	358,554	10	
Transmission (Class 3). Corrosion Small_Leak	317,858	11	
High_Pressure_Distribution (Zone 3). Pipe, Weld, or Joint Failure Small_Leak	255,260	12	
High_Pressure_Distribution (Zone 3) HCA installed >=1946. INT_CORR Rupture	192,526	13	
Transmission (Class 3) HCA installed >=1946. CONS Rupture	134,429	14	
Transmission (Class 4) HCA installed >=1946. SCC Rupture	116,831	15	
Transmission (Class 4). Incorrect Operations Small_Leak	110,219	16	
High_Pressure_Distribution (Zone 3) HCA installed >=1946. IO Rupture	97,345	17	
...	...	18-355	





3A 3B 3C 3D

Incident (LoRE/CoRE) Pair	Risk Score	Rank	Quantile	Region	Tranche
Transmission (Class 3) HCA installed >=1946. CONS Rupture	2,229,358	1	#1	UL/UC	HP Pipe-1-1
Transmission (Class 3) HCA installed >=1946. IO Rupture	1,953,059	2		UL/UC	HP Pipe-1-1
Transmission (Class 3) HCA installed >=1946. MFG Rupture	1,915,890	3		UL/UC	HP Pipe-1-1
Transmission (Class 3). Equipment Failure Small_Leak	1,461,113	4		UL/UC	HP Pipe-1-1
High_Pressure_Distribution (Zone 3) HCA installed >=1946. IO Large_Leak	778,759	5		UL/LC	HP Pipe-1-2
Transmission (Class 3) HCA installed >=1946. CONS Large_Leak	627,707	6		UL/LC	HP Pipe-1-2
Transmission (Class 3) HCA installed >=1946. EQUIP Large_Leak	532,258	7		UL/LC	HP Pipe-1-2
Transmission (Class 3) HCA installed >=1946. EQUIP Rupture	500,613	8		UL/UC	HP Pipe-1-1
Transmission (Class 3) HCA installed >=1946. WROF Rupture	450,184	9		LL/UC	HP Pipe-1-3
Transmission (Class 3) HCA installed >=1946. EXT_CORR Rupture	358,554	10		LL/UC	HP Pipe-1-3
Transmission (Class 3). Corrosion Small_Leak	317,858	11		LL/UC	HP Pipe-1-3
High_Pressure_Distribution (Zone 3). Pipe, Weld, or Joint Failure Small_Leak	255,260	12		UL/LC	HP Pipe-1-2
High_Pressure_Distribution (Zone 3) HCA installed >=1946. INT_CORR Rupture	192,526	13		UL/LC	HP Pipe-1-2
Transmission (Class 3) HCA installed >=1946. CONS Rupture	134,429	14		LL/UC	HP Pipe-1-3
Transmission (Class 4) HCA installed >=1946. SCC Rupture	116,831	15		LL/UC	HP Pipe-1-3
Transmission (Class 4). Incorrect Operations Small_Leak	110,219	16		LL/UC	HP Pipe-1-3
High_Pressure_Distribution (Zone 3) HCA installed >=1946. IO Rupture	97,345	17		UL/LC	HP Pipe-1-2
...	...	18-355		...	...



4A

Tranche LoRE is the sum of the LoREs of the Incidents comprising the Tranche

4B

Tranche CoRE is the weighted average of the CoREs of the Incidents comprising the Tranche

4C

Tranche Risk Score is the Tranche LoRE x Tranche CoRE

Incident (LoRE/CoRE) Pair	Tranche	4A Tranche LoRE	4B Tranche CoRE	4C Tranche Risk Score
Transmission (Class 3) HCA installed >=1946. CONS Rupture	HP Pipe-1-1	.0054	1,496,178,140	8,110,092
Transmission (Class 3) HCA installed >=1946. IO Rupture	HP Pipe-1-1			
Transmission (Class 3) HCA installed >=1946. MFG Rupture	HP Pipe-1-1			
Transmission (Class 3) HCA installed >=1946. EQUIP Large_Leak	HP Pipe-1-1			
Transmission (Class 3) None installed None. Equipment Failure Small_Leak	HP Pipe-1-1			
High_Pressure_Distribution (Zone 3) HCA installed >=1946. IO Large_Leak	HP Pipe-1-2	6.322	448,515	2,835,702
Transmission (Class 3) HCA installed >=1946. CONS Large_Leak	HP Pipe-1-2			
Transmission (Class 3) None installed None. Corrosion Small_Leak	HP Pipe-1-2			
High_Pressure_Distribution (Zone 3) None installed None. Pipe, Weld, or Joint Failure Small_Leak	HP Pipe-1-2			
High_Pressure_Distribution (Zone 3) None installed None. Incorrect Operations Small_Leak	HP Pipe-1-2			
High_Pressure_Distribution (Zone 3) HCA installed >=1946. EQUIP Rupture	HP Pipe-1-2			
Transmission (Class 3) HCA installed >=1946. WROF Rupture	HP Pipe-1-3	.0008	2,054,397,679	1,765,645
Transmission (Class 3) HCA installed >=1946. EXT_CORR Rupture	HP Pipe-1-3			
Transmission (Class 3) HCA installed >=1946. INT_CORR Rupture	HP Pipe-1-3			
Transmission (Class 3) HCA installed >=1946. CONS Rupture	HP Pipe-1-3			
Transmission (Class 4) HCA installed >=1946. SCC Rupture	HP Pipe-1-3			
Transmission (Class 4) HCA installed >=1946. IO Rupture	HP Pipe-1-3			