Risk Assessment and Mitigation Phase

(Chapter SDG&E-Risk-9)

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

May 17, 2021

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

I. INTRODUCTION

The purpose of this chapter is to present SDG&E's risk control and mitigation plan for the Incident Related to the Medium Pressure System (Excluding Dig-in) risk, (Medium Pressure Incident risk). Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014 and the Settlement Agreement included therein (the Settlement Decision).[1]

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

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

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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").

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

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

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

A. Risk Overview

Typically, the medium pressure distribution system uses a series of mains (pipes with larger diameter) to feed service lines, regulator stations, meters, and other appurtenance piping. Service lines are smaller diameter pipes which feed customer homes, businesses, and some commercial applications. Medium pressure pipelines are made of steel or plastic material.

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[3] *Id*. at 16.

[4] *Id.* at 17.

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

For safety and compliance, Title 49 of the Code of Federal Regulations (CFR) Part 192, General Order (GO) 58, and GO 112-F are the leading sources of requirements for SDG&E's gas distribution system pipelines (among other legal and regulatory provisions). Title 49 CFR Part 192 prescribes safety requirements for pipeline facilities and the transportation of gas at the federal level. GO 112-F and GO 58 complement and enhance the requirements of 49 CFR 192 at the state level.

With regard to medium pressure pipelines, SDG&E currently operates approximately 14,900 miles of medium mains and services with approximately 5,900 miles being steel and 9,000 miles being plastic. The medium-pressure pipelines serve over 890,000 SDG&E consumers.

Various causes and events can lead to medium pressure pipeline incidents. Drivers can range from natural forces (such as natural disasters, fires, earthquakes), improper installation techniques, material defects, aging/environmental factors such as corrosion and material fatigue, improper operations, and inadequate maintenance of the pipeline infrastructure. For the purposes of this chapter, the Medium Pressure Incident risk focuses on risk events that result in serious injuries, fatalities, or impact to the infrastructure.

SDG&E notes that 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's leak indication prioritization and repair schedule procedures. In most cases, a pipe with a leak will continue to transport gas, and therefore is not considered a pipeline "failure" using the definition in American Society of Mechanical Engineering B31.8S.[6]

SDG&E's many risk mitigating activities focus on the safety of employees, customers, and the public. This is driven by a safety-first culture stemming from the Company's core values

6 American Society of Mechanical Engineering standard B31.8S: Managing System Integrity of Gas Pipelines. AMSE B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes. Recorded costs and forecast ranges are rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

of customer and public safety. An example of SDG&E's focus on safety are the safety-related customer communications that are an integral part of after-the-meter incident prevention in a customer's home, regardless of whether or not an SDG&E employee visits the premises. These communications are a proactive approach to inform our customers and the public how to detect possible safety issues within their homes, how to identify potential hazards, and how to avoid hazards that may result from damage occurring during a risk event. Gas public safety communications and field and public safety are two customer and public safety related controls that will be discussed in greater detail within this Chapter.[7]

B. Risk Definition

For purposes of this RAMP Application, SDG&E's Medium Pressure Incident risk is defined as the risk of asset failure caused by a medium pressure pipeline system[8] event which results in serious injuries or fatalities and/or damages to the infrastructure. This risk concerns a gas public safety event on a medium pressure distribution plastic or steel pipeline and/or its appurtenances (*e.g.*, valves, meters, regulators, risers) as well as on and beyond the customer meter.

In the 2019 RAMP Report SDG&E presented a stand-alone risk chapter associated with Customer & Public Safety that contained Customer Services type mitigations, *e.g.*, call center services, advanced meter activities, meter set assemblies, and beyond the meter activities, among others. For this report, the definition of the Medium Pressure Incident risk has been expanded to include all aspects of the medium pressure system and may include incidents downstream of the customer's meter. Therefore, certain customer and public safety related mitigations are presented within scope for this chapter.

C. Scope

Table 1 below provides what is considered in and out of scope for the Medium Pressure Incident risk in this RAMP Application.

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[7] The customer and public safety mitigations were previously included as part of the customer and public safety risk chapter in SDG&E's 2019 RAMP filing.

[8] Maximum Allowable Operating Pressure (MAOP) at lower than 60 psig.

Table 1: Risk Scope

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

II. RISK ASSESSMENT

In accordance with the Settlement Decision,[9] this section describes the risk bow tie, possible drivers, potential consequences, and the risk score for the Medium Pressure Incident risk.

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

The risk bow tie is a commonly used tool for risk analysis, and the Settlement Decision[10] instructs the utility to include a risk bow tie illustration for each risk included in RAMP. As illustrated in the risk bow tie shown below in Figure 1, the risk event is that related to a Medium Pressure Incident risk leading to asset failure (center of the bow tie). The left side of the bow tie illustrates drivers/triggers that lead to the risk event occurring, and the right side shows the potential consequences of the risk event occurring. SDG&E applied this framework to identify and summarize the information provided in Figure 1. A mapping of each mitigation to the element(s) of the risk bow tie addressed is provided in Appendix A.

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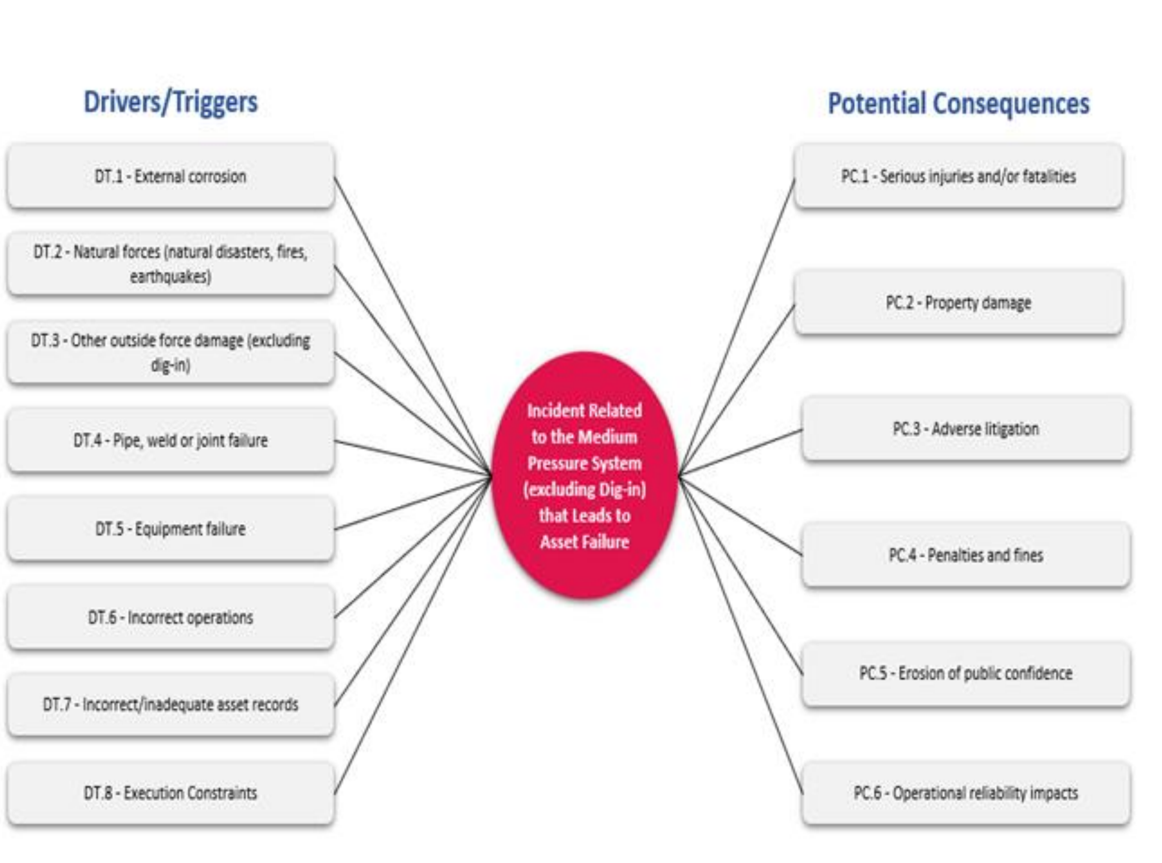
9 D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

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

Figure 1: Risk Bow Tie



B. Cross-Functional Factors

The following cross-functional factors (CFF) have programs and/or projects that affect this risk chapter: Climate Change Adaptation, Energy System Resilience, and GHG Emissions; Emergency Preparedness and Response and Pandemic; Foundational Technology Systems; Physical Security; Records Management; Safety Management Systems; and Workforce Planning/Quality Workforce. As an example, regarding the Workforce Planning/Quality Workforce CFF, all the RAMP O&M core activities include training to maintain and strengthen a qualified workforce. Safety is rooted in all phases of training pertaining to the medium pressure system. SDG&E is taking proactive action to enhance employee training, qualification, and work quality. An integral component of overall workforce proficiency is the Operator Qualification (Op Qual) program. As part of Op Qual compliance, employees are trained, either formally or informally, whenever significant changes occur in a work task or as required per SDG&E's Gas Standards, state pipeline safety standards in GO 112-F, and/or federal pipeline safety standards under the Department of Transportation's (DOT) Pipeline Safety and Hazardous Materials Administration's (PHMSA) 49 C.F.R. § 192.

The work environment surrounding the medium pressure system is increasingly influenced and evolves by multiple training drivers. These drivers focus the training on the following core activities:

- Adoption of new regulations
- The need to maintain a trained and qualified workforce
- The need to support new field technologies and to facilitate the integration of these tools within the field and overall management practices.
- Increased workforce turnover: Workforce turnover presents issues of knowledge transfer, skills development, and overall proficiency of the replacement workforce.
- Introduction of new construction and maintenance methods into office and field functions.

C. Potential Drivers/Triggers[11]

The Settlement Decision[12] instructs the utility to identify which element(s) of the associated risk bow tie each mitigation addresses. When performing the risk assessment for the Medium Pressure Incident risk, SDG&E identified potential leading indicators, referred to as drivers or triggers. These include, but are not limited to:

- **DT.1 – Corrosion:** External corrosion is 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. Internal corrosion is the deterioration of the interior of an asset as a result of the environmental conditions on the inside of the pipeline.[13] In pipelines, corrosion can occur internally and/or externally, both potentially resulting in a pipeline incident; therefore, both internal and external corrosion will be referred to as "corrosion" in the remainder of this chapter, unless otherwise needed.

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

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

[13] ASME B31.8S, "Managing System Integrity of Gas Pipelines."

- **DT.2 - Natural forces (natural disasters, fires, earthquakes)**: 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, wildfires, and high winds.
- **DT.3 - Other outside force damage (Excluding dig-in):** 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.
- **DT.4 - Pipe, weld, or joint failure:** Attributable to material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects, improper construction or fabrication, or in-service stresses such as vibration, fatigue, and environmental cracking.
- **DT.5 - Equipment failure:** Similar to DT.4, but unrelated to pipe (main and services). These failures are attributable to the malfunction of a component including, but not limited to, regulators, valves, meters, flanges, gaskets, collars, and couples. This driver/trigger is specific to the material properties related to the manufacturing process or post installation of the equipment.
- **DT.6 - Incorrect operations:** May include a pipeline incident attributed to insufficient or incorrect operating procedures or the failure to follow a procedure.
- **DT.7 - Incorrect/inadequate asset records:** The use of inaccurate or incomplete information that could result in the failure to: (1) construct, operate, and maintain SDG&E's pipeline system safely and prudently; or (2) to satisfy regulatory compliance requirements.
- **DT.8 – Execution Constraints:** Constraints including third-party vendor issues, Quality Assurance/Quality Control issues related to materials and operational oversight, resource constraints (*e.g.*, workforce, material), re-allocation or unexpected maintenance or regulatory requirements or the inability to be able to complete projects initiatives or meet operational compliance.

D. Potential Consequences of Risk Event

Potential consequences[14] are listed to the right side of the risk bow tie illustration provided above. If one or more of the drivers/triggers listed above were to result in an incident, the potential consequences, in a reasonable worst-case scenario, could include:

- **PC.1 - Serious injuries and/or fatalities**
- **PC.2 - Property damage**
- **PC.3 - Adverse litigation**
- **PC.4 - Penalties and fines**
- **PC.5 - Erosion of public confidence**
- **PC.6 - Operational reliability impacts**

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

E. Risk Score

The Settlement Decision requires a pre- and post-mitigation risk calculation.[15] Chapter RAMP-C of this RAMP Application explains the Risk Quantitative Framework that underlies this chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 2: Pre-Mitigation Analysis Risk Quantification Scores[16]

	LoRE	CoRE	Risk Score
Medium Pressure Incident	101.42	5.97	606

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

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

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

Pursuant to Step 2A of the Settlement Decision, the utility is instructed to use actual results, available and appropriate data (*e.g.*, Pipeline and Hazardous Materials Safety Administration data).[17]

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 medium-pressure pipeline miles at SDG&E. The safety risk assessment primarily utilized data from 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 medium-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

III. 2020 CONTROLS

The Settlement 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."[18] This section describes SDG&E's risk control and mitigation plan by each selected mitigation and control for this risk, including the rationale supporting each selected control and mitigation.

As stated above, the Medium Pressure Incident risk is the risk of damage, caused by a medium pressure system event, which could result in serious injuries or fatalities. The risk mitigation plan includes both controls that are expected to continue and projected mitigations for the period of SDG&E's Test Year 2024 General Rate Case (GRC) cycle. The controls are those activities that were in place as of December 30, 2020, most of which are compliance driven and have been implemented over decades, plus the addition of the Distribution Integrity Management Program (DIMP) that has been developed over recent years, to address this risk. SDG&E's mitigation plan for this risk consists of controls based on compliance with 42 CFR Part 192, GO 58, GO 112-F, and planned enhancements within existing controls.

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

[18] *Id.* at Attachment A, A-14 (Mitigation Strategy Presentation in the RAMP and GRC).

For this RAMP chapter, the makeup of the portfolio of controls is a combination of compliance requirements and additional programs implemented by the DIMP within the last 7 years. The DIMP is continually evaluating the system threats and risk to determine if additional mitigations are appropriate. The threat and risk evaluation leverages leak repair, incident data, and subject matter expert (SME) input to evaluate and rank risk. As programs are developed, available data sets are leveraged to develop specific risk ranking, which supports risk-based prioritization of mitigations. For example, the Distribution Risk Evaluation and Monitoring System (DREAMS) steel replacement program utilizes leak rates, condition of the pipe, soil type and condition, and other factors to prioritize medium-pressure and high-pressure segments for replacement.

Not all programs and activities that would mitigate the Medium Pressure Incident risk are included in this risk mitigation plan. For example, the Mobilehome Park Utility Upgrade Program (MHP) is converting master-metered/sub-metered natural gas and/or electric services to direct utility services in mobile home parks and manufactured housing communities to improve the safety and reliability of service for residents of mobile home parks currently served by master-metered gas systems. The MHP is not included in this mitigation plan because MHP costs are not anticipated to be forecasted in SDG&E's next GRC.[19]

A. C1: Cathodic Protection Program – O&M

Corrosion is a natural process that can deteriorate steel assets and potentially lead to leaks or asset failure. If a leak migrates to a confined space and an ignition source is introduced, there is the potential for injuries. Although SDG&E operations groups respond immediately to these leak situations, such conditions have the potential to lead to a pipeline incident. Cathodic protection (CP) coating and monitoring can protect and extend the life of a steel pipeline asset by mitigating corrosion. The application of a CP related low electric current is necessary to overcome local inductive corrosion currents along the pipeline, that left unabated would result in

19 The Mobile Home Park Conversion Program began as a pilot program (authorized by and discussed in D.14-03-021 and Resolutions E-4878 (September 28, 2017) and E-4958 (March 14, 2019) and has evolved into a post-piloted Mobile Home Park Utility Conversion Program per D.20-04-004. Cost recovery is via a balancing account with a reasonableness review occurring in the GRC.

localized corrosion on the pipeline. Cathodic protection can be achieved by the installation of sacrificial anodes or impressed current systems.[20]

The directives prescribed by state and federal pipeline corrosion control standards[21] include the monitoring of CP areas, remediation of CP areas that are out of tolerance,[22] and preventative installations to avoid out of tolerance areas. The CP work in this CP Program constitutes the O&M activities that provide compliance to these regulations, supports the safety and integrity of the gas system, and mitigates risks defined in this RAMP chapter.

B. C2: Cathodic Protection Program – Capital

This project represents the capital expenditures associated with the installation of new and replacement CP infrastructure systems and equipment in accordance with state and federal pipeline corrosion control standards .[23] Examples include the installation of impressed current stations, deep well anode beds, magnesium anode systems, and the purchase of CP instrumentation and monitoring equipment.

CP system shorts and current interference typically occur as SDG&E's pipeline components come into contact with water lines or with third-party grounding systems that can drain current from the pipeline; or near customer meter set assemblies and risers, from improperly grounded customer owned electrical systems and dog or bicycle chains wrapped around risers and meter sets, thus reducing the level of protection and depleting anodes. SDG&E continues to identify necessary modifications to CP systems to shorts and current interference from these factors. Associated work includes the installation of insulating unions separating CP systems, new rectifiers, anode beds, and test points allowing the CP technician to take CP reads.

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20 SDG&E utilizes both impressed current and magnesium anode (galvanic) systems to provide CP to existing pipelines. Impressed current systems utilize a rectifier for the generation of the direct current. Both systems utilize sacrificial anodes as a primary component in the system. Anodes are installed in wells drilled into the surrounding soil by third-party drilling contractors. Each protected pipe segment requires multiple anodes, collectively referred to as an "anode bed." The number of anodes needed to achieve the desired level of protection and the average life of the anode bed can vary based on pipeline length, coating effectiveness, soil conditions and interference that may occur on the system.

21 49 C.F.R. § 192, Subpart I–Requirements for Corrosion Control; GO 112-F.

22 Out of tolerance areas are defined as areas where CP measures are not efficiently mitigating the effect of the corrosive environment on steel assets.

23 49 C.F.R. § 192, Subpart I–Requirements for Corrosion Control; GO 112-F.

Adding to or improving the current CP infrastructure with work activities and expenses will reduce exposure of corrosion to the SDG&E steel pipeline system thus enhancing the integrity of the gas system and mitigating the risks defined in this RAMP chapter.

C. C3: Piping in Vaults Replacement Program

This project is for the replacement of piping located in underground vaults.[24] SDG&E has a number of piping and valves that are surrounded by a concrete vault to provide access to the valve for emergency operations. Any pipe segment, fitting, or valve exposed within a below grade vault is at risk for accelerated atmospheric corrosion due to the potential for water accumulation, pipe coating failure, and decreased cathodic protection effectiveness as these components within the vault are not protected for buried conditions and are exposed to the atmosphere. This on-going control follows the review of existing work orders determining the locations of all vaults containing medium and high-pressure facilities.

Once all vaults with exposed valves and piping are identified, the valve will be replaced with a valve appropriate for buried service, and the vault removed and backfilled so that the valve will be protected by cathodic protection. During this process, the valve continues to be accessible so that it can be used for emergency isolation. It is estimated that approximately 50 locations will require replacement. SDG&E will assess the coating and the condition of the above-ground and below-ground facilities within the vaults and prioritize for complete replacement.

D. C4: Regulator Station, Valve, and Large Meter Set Inspection

This project is for inspections and maintenance to regulator stations, critical valves, and large meter sets. Regulator stations reduce the pressure of gas entering the distribution system from high-pressure pipelines to provide a lower pressure used on the distribution pipeline system. A failure of a regulator station due to mechanical failure, corrosion, contamination, or other cause could result in over-pressurization of the gas distribution system, which may compromise the integrity of medium-pressure pipelines and/or jeopardize public safety as evident by recent over-pressure events in the industry.

Regulator stations are critical control elements in the gas distribution system. Federal regulation 49 CFR § 192.739 requires inspections/tests to be conducted annually, not to exceed

[24] Vaults are rooms that allow for access to piping and piping components.

15 months to maintain these devices in good mechanical condition. Functional tests of regulator stations are performed as part of inspections. The pressure checks are done to verify that the station's pressure protection devices perform as designed. If a station does not perform properly, internal maintenance and inspections are conducted. This consists of disassembling the regulator devices and inspecting the internal components for worn or damaged parts. The regulator is cleaned and inspected for corrosion and any faulty parts are replaced.

SDG&E's O&M practices allow the useful lives of regulator stations to be extended. However, it is prudent to proactively replace regulator stations prior to the end of their useful life to reduce overall system risk. This risk reduction is achieved through improved station design of dual-run regulators which will reduce the risk of over-pressure and the stations location can be evaluated to reduce the risk of vehicular damage (outside force) or vandalism.

Valve maintenance allows the opportunity to validate that the valves within the system operate at optimum effectiveness which enhances public safety by providing SDG&E with the ability to control the pressure and flow of gas in the system. The maintenance activities may include flushing, lubrication, parts replacement, cleaning, and testing of operability. Valves are installed for control of pressure and flow of gas. Their location and purpose determine their criticality: inlet (aka "fire") valves to regulator stations isolate the high- and medium-pressure systems; emergency valves isolate segments of pipelines in case of pipe damage or for operational purposes; and isolation valves segment portions of the system in the event of a widespread emergency, such as an earthquake and reduce the impact of resulting pipeline damage.

A valve that is operating at its optimum effectiveness means that, for example, in the case of an earthquake or fire where an area needs to be isolated to reduce the risk of the incident, these valves will operate as intended and fully isolate the area. A second example, which occurs more frequently, is when a pipeline is hit caused by third-party damage, releasing the uncontrolled escape of gas, these valves can be operated to allow for a safe environment, allow completion of the repairs to the pipeline, and minimize the risk of furthering the incident.

The meter set assemblies (MSA) reduce the pressure of natural gas and measure the volume of natural gas delivered to the customer. General Order 58-A requires that meters, regulators, and other components be maintained, repaired, and tested periodically to meet customers' capacity requirements, measure gas volume accurately, and deliver natural gas at an adequate pressure for the houseline and home appliances. Additionally, if MSAs are housed in vaults, the vaults must be inspected and repaired, if necessary, to protect the MSA. Should the regulators fail a household could potentially see a much higher pressure of natural gas which could lead to an incident. Scheduled inspections of MSAs proactively target and reduce the risk of equipment failures, corrosion, and outside force before operation and safety issues arise.

As required by 49 CFR § 192.481, above ground piping facilities must be inspected for atmospheric corrosion no less than once every three calendar years and at intervals not to exceed 39 months. If severe corrosion is found, the piping is replaced. This additional activity reduces the risk of consequent leakage due to the atmospheric corrosion.

E. C5: Regulator Station Replacements

Regulator stations reduce the pressure of gas entering the distribution system from high-pressure supply pipelines to the lower pressures used in the distribution pipeline network. SDG&E has approximately 472 regulator stations. SDG&E's O&M practices allow the useful lives of regulator stations to be extended through annual inspection and maintenance, however, it is prudent to proactively replace regulator stations prior to the end of their useful life in order to reduce overall system risk. This risk reduction is achieved through improved replacement station design, including the addition of dual-run regulators providing redundancy which will reduce the risk of over-pressure. In addition, the stations' location can be evaluated to reduce the risk of vehicular damage (outside force), vandalism, and risk to employee safety during maintenance due to high traffic levels near the station.

Regulator stations are critical control elements in the gas distribution system. Failure of a regulator station could result in under- or over-pressurization of the gas distribution system, resulting in reduced service to customers and/or jeopardizing public safety. Regulator stations are part of SDG&E's aging infrastructure. Presently over 70 percent of the Company's operating regulator stations are 24 years or older. SDG&E prioritizes its older regulator stations for replacement based on risk criteria, some of which are described above. Approximately 3 to 5 stations are replaced on an annual basis. In this manner, risks to employee and public safety can be mitigated.

F. C6: Leak Repair

SDG&E proactively surveys its gas distribution system for leakage at frequencies determined based on the pipe material involved, the operating pressure, whether the pipe is under cathodic protection, and the proximity of the pipe to various population densities as prescribed within 49 CFR § 192.723. A routine leak survey consists of surveys at intervals of one or three years for steel mains and plastic. The frequency of this survey is determined by the pipe material and date of installation involved. Annual surveys are scheduled in business districts, and near public service establishments, such as schools, churches, hospitals, pre-1950 steel and pre-1986 plastic (Aldyl-A). Three-year survey cycles are typically used for plastic and cathodically protected steel mains and services installed in residential areas.

If a leak is found during a survey of the gas distribution system, SDG&E takes steps to either remediate or monitor the situation depending on the type of leak classification. A leak will be remediated immediately if there is a hazardous condition. If the leak does not create a hazardous situation, SDG&E will monitor the leak. SDG&E has shortened the prescribed timeframe for which leaks will be monitored and scheduled for remediation. The leak survey program has accelerated due to the increased footage to align with SB1371 based requirements.

G. C7: Pipeline Monitoring (Leak Mitigation, Bridge & Span, Unstable Earth and Pipeline Patrol)

SDG&E conducts pipeline monitoring and inspection activities to proactively target risk factors before operation and safety issues arise. These monitoring activities include pipeline patrols, leak surveys, bridge and span inspections, and unstable earth inspections. These inspections are critical since they are intended to observe assets over time to determine if abnormal conditions exist prior to becoming a concern. For example, a span that is no longer coated appropriately due to recent weather conditions can be identified for re-coating before corrosion that could lead to a leak begins. The leak survey monitoring identifies leaks that require repair.

The monitoring and inspections must follow certain prescribed processes included in Title 49 of the CFR Part 192, and GO 112-F. [36]

H. C8: Underperforming Steel Replacement Program

The steel replacement program mitigates risk on underperforming CP protected steel pipelines that were installed using construction practices that are no longer considered best practices. The determination of where and when to implement mitigation measures is based on pipe attributes, operational conditions, and potential impacts on populations in the event of an incident. The Underperforming Steel Replacement Program proactively identifies the risk factors for remediation before operational and safety issues arise. As this program continues to be evaluated, activity may vary between the tranches. SDG&E's early vintage program (pipeline) consists of the following elements: underperforming steel replacement program – threaded main (pre-1933 vintage), underperforming steel replacement program 1934-1965, and underperforming steel replacement program – other steel (post 1965). Each control is further described below:

1. C8-T1: Underperforming Steel Replacement Program – Threaded Main (pre-1933 vintage).

Prior to 1933, piping in the gas distribution system was joined by threaded couplings. This project aims to proactively remove a total of 165 miles of threaded main pipe over a 10-year period as well as associated services (it is estimated this also involves 218 miles of services). This is approximately a 10-year program which on average would require 15 miles of pipe per year, however mileage can vary slightly from year-to-year. Threaded pipe has a greater susceptibility to leaks at the joint connections and higher potential for joint failure during a seismic event. This is due to the thinning of the wall thickness from the cutting of the threads into the pipe.

This program mitigates the potential for gas leakage due to the replacement of vintage threaded steel mains and services.

2. C8-T2: Underperforming Steel Replacement Program (1934-1965 vintage).

The early vintage steel replacement program focuses on the replacement of poor performing steel. In early vintage steel mains, cold tar asphaltic wrap was used as the first layer of corrosion protection. Over time, the early generation pipe wrap degrades and disbonds from the pipe, causing cathodic protection current to leave the pipe around the disbonded coating thereby not providing adequate protection. Ultimately, this lack of corrosion protection will lead to increased leakage. SDG&E anticipates continuing this program while monitoring performance thereby continually reviewing the benefits and risk reduction accomplished. Examples of early vintage steel replacement indicators reviewed include leak repairs and incident leak rates related to the steel pipelines.

3. C8-T3: Underperforming Steel Replacement Program – Other Steel (Post 1965 vintage).

The process for selecting pipelines requiring replacement due to a recurring leak history involves an evaluation tool or scoring system that considers various replacement elements, including but not limited to, leakage history, age of the pipe, main pressure, and location of the pipe relative to population density. These planned pipeline replacements processed in this manner, will therefore result in a list among all pipeline replacement candidates, of recommended pipeline replacements in priority order. Pipeline replacements can then be planned, with strong emphasis on a recurring leak history, from this list resulting in removal of the highest risk to the public from pipeline leakage.

I. C9: Early Vintage Program (Pipeline Component Removal)

The early vintage programs mitigate risk on certain early vintage pipeline components in the pipeline system. The determination of where and when to implement mitigation measures is based on pipeline component attributes, operational conditions, and impact on populations in the event of an incident. The early vintage program proactively identifies the risk factors for remediation before operational and safety issues arise. SDG&E's early vintage program (pipeline component removal) consists of oil-drip piping removal, Dresser mechanical coupling removal, and removal of valves separating high and medium pressure zones in the gas systems. Each mitigation is further described below:

1. C9-T1: Early Vintage Program (Components) - Oil Drip Piping Removal.

Pipeline oil drips were installed in low point high volume areas of the gas system to collect and purge unwanted liquids from gas mains. These systems were installed in the early days in the downtown areas when coal gasification was used and liquids were traditionally found in the system. Since liquids are no longer an issue for the SDG&E pipeline system, oil drips are obsolete. The buried oil drip piping facilities are at risk of excavation damage as their location and configuration historically were not captured with enough detail to identify them with precision on facility maps. These facilities often were symbolized by a "teardrop" on the maps. Because the feature lengths and attributes were not mapped in detail, it has led to difficulties in marking out as part of locate and mark requests. In recent history, a facility was damaged and caused an uncontrollable release of gas until the pipeline could be shut down. This incident caused a major freeway that serves southern San Diego County to temporarily be shut down for safety. Gas Distribution has gathered partial historical oil drip location data and sites and marked the approximate location of these facilities in GIS; however, this effort needs additional validation.

This project will follow the review work orders and field validation of above ground and buried oil drip lines and containers. Additionally, this capital expenditure will be associated with the validated oil drip line locations and containers that are no longer necessary and will be removed from the system thus improving the safety and reliability of the system.

2. C9-T2: Early Vintage Program (Components) - Dresser Mechanical Coupling Removal.

The Dresser mechanical coupling joins two pipes together without the need for welding. This type of coupling cannot resist lateral movement, and over time the rubber pressure containing seal degrades. Dresser mechanical couplings require lateral support and are not as strong as modern mechanical couplings which have rubber mechanical seals. In the event of land movement, pipe separation/rupture may occur and create an incident. These types of incidents are low frequency, but potentially high consequence events because the Dresser mechanical couplings are primarily located in high population density areas. They exist in both the medium and high-pressure systems.

This project consists of evaluating locations where Dresser mechanical couplings exist, excavating, removing the Dresser mechanical couplings, and welding pipes back together. This mitigates the risk of an incident caused by the leakage of gas from these couplings.

3. C9-T3: Early Vintage Program (Components) - Removal of Closed Valves between High/Medium Pressure Zones.

SDG&E has identified 130 valves which separate high-pressure from medium-pressure systems. These valves are permanently locked out and tagged out in the closed position to serve as a physical barrier between high pressure and medium pressure. This condition is a result of a MAOP uprating of a pipeline which was previously interconnected to a distribution system and operated at a lower MAOP. Simply closing and locking the valve between high- and medium pressure systems is no longer an acceptable practice as there is inherent risk should the valve be operated in error, operated in an act of sabotage, or the valve leak pressure downstream to the lower MAOP system potentially causing an overpressure condition of the downstream system.

This project will verify valve locations in the field, excavate, and remove the closed and locked valves currently connecting high-pressure piping to medium pressure piping thus improving the safety and reliability of the system.

J. C10: Code Compliance Mitigation.

This project consists of upgrades or additions to facilities to maintain compliance with minimum federal safety standards for gas pipelines in 49 C.F.R. § 192 and state safety standards in GO 112-F.

One component of this activity is installing barricades to protect meter set assemblies (MSA) from vehicular damage. Barricades are installed to protect the MSA from vehicular traffic at existing customer locations in accordance with 49 C.F.R. § 192.353(a) and GO 112-F. The installation of meter barricades creates a more secure environment at the MSA location, which in addition to increasing public safety, results in increased longevity and performance of the MSA equipment. Furthermore, the increased growth in the SDG&E service territory brings increased population density, creating a higher probability for conflicts with vehicular traffic at MSA locations. Recent trends in architecture to maximize saleable square footage have resulted in less room for MSAs, increasing the demand for meter barricades to protect MSAs.

Another component of this activity (budget code 507) is the removal of inoperable valves. When a valve has been discovered inoperable through normal maintenance and inspections, it will be reported replaced with an operable valve. A valve that is operating properly can be used to mitigate several safety risks. For example, in the case of an earthquake or fire, valves can provide isolation of an area to reduce the risk of the incident. A second more frequently occurring example is when a pipeline incurs damaged caused by third-party contact, causing the uncontrolled escape of gas. Valves can be operated to allow for a safe environment, allowing completion of repairs to the pipeline, and minimize the risk of furthering the incident.

K. C11: Gas Distribution Emergency Department.

When SDG&E is notified of a gas emergency it is critical to respond immediately and take measures to control escaping gas to ensure public safety. To improve gas emergency response time SDG&E established the Gas Distribution Emergency Department (GED), which is an organization consisting of two person crews dedicated to responding to gas emergencies. The GED operates 24/7 in overlapping shifts to provide ample coverage during peak periods of gas emergencies and rapid response regardless of the time or day, which allows them to control escaping gas quickly making the scene safe. These dedicated "specialist" crews responding to gas emergencies reduce the risk of injuries and property damage to both the public and crew responding to the incident.

L. C12: Cathodic Protection System Enhancements

The CP system enhancement tracks projects specifically associated with creating dedicated high-pressure and medium-pressure distribution pipeline CP systems. SDG&E's existing CP station coverage areas often include a mixture of high-pressure and medium-pressure pipelines. Typically, CP systems protecting medium-pressure pipelines are more susceptible to shorts compromising CP protection levels. SDG&E has initiated creating dedicated CP systems for high-pressure pipelines where any adverse conditions due to corrosion pose a higher risk. This Cathodic Protection System Enhancement control was created to track projects specifically dedicated to separating high-pressure and medium-pressure CP systems and other specialty CP system improvement surveys above and beyond the typical activities normally performed as part of the CP Program – Capital (SDG&E-9-C2). Since the inception, SDG&E has identified an increasing number of areas that need dedicated CP systems or CP system improvements.

In addition, SDGE has about 19,700 services, referred to as CP10s that will continue to be monitored, inspected, and maintained on a ten-year cycle as required in 49 CFR § 192.465. CP10s are separately protected service lines that are surveyed on a sampling basis where at least ten percent of these services are sampled each year, thus ensuring that the entire group of CP10s are tested in a ten year period. These inspection activities are covered under control C1. However, as the CP10s go beyond their useful life and protection levels are reduced, they will be evaluated for replacement and the replacement will occur as part of this CP system enhancement project area.

This control also installs the isolation joints that provide the separation of the CP systems between pressure districts. CP isolation of high and medium pressure systems, as well as conducting specialty CP surveys and appropriate replacement of CP10 service lines will reduce the risk of corrosion and subsequent corrosion caused leaks in the distribution pipeline system.

M. C13: Human Factors Mitigations – Gas Handling Plans.

A series of structure fires and explosions occurred in Massachusetts in 2018 after high-pressure natural gas was released into a low-pressure natural gas distribution system resulting in multiple fatalities and injuries. Within their final report[25], the National Transportation Safety Board (NTSB) found there was "…weak engineering management that did not adequately plan, review, sequence, and oversee the construction project…", and recommended that the local utility should:

> …Revise the engineering plan and constructability review process across all of your subsidiaries to ensure that all applicable departments review construction documents for accuracy, completeness, and correctness…

After reviewing this accident and its application to SDG&E, SDG&E management decided that a gas handling plan (GHP) shall be required for all high-pressure mains and mains operating at or less than 60 psig and services using any fitting larger than a 2" service tee at the service-to-main connection, The GHP is developed, reviewed and signed by design, engineering, and construction supervisory personnel and is a site specific document with detailed procedures and graphical flow depictions describing the step-by-step processes, to "handle" the diversion of gas flow internal to the piping system. A GHP provided for the applicable gas system pipeline construction projects can reduce the risk of an incident occurring due to a miscommunication or human error.

N. C14: Human Factors Mitigations - Operator Qualification Training and Certification

All gas pipeline operators are required to create and maintain a written Op Qual program to establish compliance policies for the Department of Transportation (DOT) Operator Qualification Program as required by 49 CFR Subpart N – Qualification of Pipeline Personnel. All employees and contractors performing DOT-covered tasks are required to be pre-qualified per this Op Qual program. Such programs are reviewed by the Operator Qualification department prior to performing work on pipelines or pipeline facilities. The Op Qual program requires that employees are trained, initially qualified and subsequently re-qualified every three or five years depending on the task. SDG&E's training frequency conforms to these requirements and the results of the evaluations are recorded, demonstrating employees' knowledge, skills, and abilities of the job requirements and that they are qualified to perform the required tasks. Qualification ensures adherence to proper company policy and procedures and

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[25] NTSB Report Number PAR-19-01, Over-pressurization of Natural Gas Distribution System, Explosions, and Fires in Merrimack Valley, Massachusetts.

therefore mitigates the risk of hazardous conditions developing and increases the overall awareness and response to unsafe activities.

O. C15: Human Factors Mitigations - QA/QC Program – Mandated Compliance Activities

In addition to SDG&E's Operator Qualification program to ensure operations are performed in a safe and proficient manner, SDG&E performs quality control checks for various pipeline operational activities as mandated by 49 CFR § 192.605 (b8) (c4). During these quality control checks; internal assessors review the work performed by gas pipeline personnel to determine the effectiveness and adequacy of the procedures used in normal operations and maintenance. In addition, the assessors validate the conformance of employees to these policies and procedures. The assessors identify if abnormal operating conditions (AOCs) are present and ensure that the employees respond to the AOCs and take appropriate corrective actions.

SDG&E performs quality control assessments on the Company's regulator station, valve, and large meter set inspection and maintenance activities, as well as on pipeline monitoring activities, and cathodic protection activities. These assessments are tracked and recorded to communicate lessons learned and to help develop refresher training. Adherence to proper company policy and procedures mitigates the risk of hazardous conditions developing and increases the overall awareness and response to unsafe activities.

P. C16: Distribution Integrity Management Program (DIMP)

DIMP Programs/Projects Addressing Risk (PAARs) enhance pipeline safety by continually assessing, mitigating, and reducing risk for distribution pipelines through threat identification and risk analysis, management and the development of specific programs/projects, and other activities to address risk.

As these DIMP programs continue to be evaluated, activities may vary. SDG&E's DIMP currently consists of the following elements: 1. DREAMS – The vintage integrity plastic plan and 2. replace balance of CP daisy chained services. Each control is further described below:

1. C16-T1: Distribution Integrity Management Program (DIMP).

The vintage integrity plastic plan (VIPP) falls within the umbrella of the Distribution Risk Evaluation and Monitoring System (DREAMS). Plastic pipe manufactured and used for gas service from the 1960s through the early 1980s (SDG&E has over 1,500 miles of this type of pipe) can exhibit a brittle-like cracking characteristic that could cause a leak to grow and release natural gas, increasing the risk of natural gas gathering and igniting causing injuries and/or fatalities. Given the higher potential for a release of gas, the frequency of performing leak surveys has been increased to yearly versus every five years for plastic pipelines within this vintage. The initial focus of the VIPP is early vintage plastic manufactured pre-1973. This vintage of plastic exhibits the brittle-like cracking characteristics discussed, but also exhibits a sow ductile inner wall issue that further exacerbates the brittle-like cracking issues when external loads are applied. The manufacturers of this pipe have issued notices informing of the issues. The initial focus of SDG&E's VIPP will be a wholesale replacement of pre-1973 plastic pipe, with a priority given to poor performing segments by utilizing a relative risk model and dynamic segmentation. A secondary focus will be to leverage the same relative risk model and dynamic segmentation to continue to focus on the replacement of poor performing early vintage plastic for pre-1986 plastic pipe. As SDG&E's infrastructure continues to age and more leak data is accumulated through annual inspections, SDG&E anticipates continuing to increase the level of replacement over the next 6-8 years while monitoring performance to continually review the benefits and risk reduction accomplished through VIPP through indicators such as leak repair and incident rates related to early vintage plastic.

2. C16 -T2: DIMP –Replace Balance of CP Daisy Chained Services.

The daisy chain riser remediation program was implemented to improve the risk profile of gas pipeline risers constructed in a daisy chain configuration. A daisy chain configuration uses buried plastic pipe's tracer wire to connect multiple steel risers to a central anode in order to provide cathodic protection. However, the bond wire is at risk of being inadvertently disconnected as a result of various activities such as maintenance or homeowner excavation. The disconnection of the wire would lead to an increased risk of having unprotected steel risers in the system.

Mitigation strategies to manage the risk of failure include eliminating the daisy-chained tracer wire, installing a new anode that is consistent with current CP standards, replacing mains and services with state-of-the-art polyethylene piping, and/or increasing the frequency of CP reads.

Remediating daisy-chained systems will decrease the likelihood of failure due to corrosion. SDG&E is currently in the last phase of this program and expects it to be completed by the end of 2021.

Q. C17: Control Center Modernization (CCM) Distribution Field Asset Real Time Monitoring and Control Site Installations/Upgrades & New Control Room Technologies

The Control Center Modernization organization will enhance distribution field assets by installing control and real time pressure monitoring capabilities. Increased operational awareness through the implementation of a centralized data management system and real time monitoring capabilities will help Gas Control personnel to quickly identify abnormal operating pressures within the system and will provide Gas Control personnel with remote control functionality to help prevent an overpressure. With the introduction of these new field assets and capabilities, the CCM will introduce new processes, training, and increase workforce. Additionally, these field assets will be supported by the implementation of new control room and IT system and network technologies.

The new control room technology features will focus on employee safety, security, ergonomics, training, and decision making while the CCM IT functionality will integrate both new and existing IT platforms to provide system-wide viewing of daily health and alarm information from the Company's new field pipeline technologies. Operators and region personnel will be able to leverage these new systems and data analytics to troubleshoot issues and/or perform proactive mitigations to prevent abnormal operating conditions. The installation and deployment of these CCM field assets and technology will ramp up in 2020 and be on-going throughout the next GRC cycle and beyond.

R. C18: Gas Public Safety Communications

SDG&E conducts public awareness efforts to enhance the safety of its customers and the general public. These efforts are designed to engage with the Company's customers and the public to inform them about the shared safety responsibilities. Without adequate communication and education programs, the public may not know how to safely dig on their property or how to keep themselves safe around company facilities that may be damaged during an event. Communication with the public also allows customers to be able to detect possible safety issues within and around their homes. Without adequate communications and education programs, a customer or member of the general public may not know how to identify a hazardous situation and subsequently report it or how to prevent one. Customer outreach, communication, and education are a few of the methods SDG&E uses to mitigate customer and public safety gas risk. The activities to mitigate this risk include safety-related messages delivered through multiple communication channels. Communication channels include bill inserts, print media, radio, web, and social media. Messages include, but are not limited to, Carbon Monoxide safety, fumigation, and furnace safety.

S. C19: Field and Public Safety

SDG&E Customer Services' primary goal is providing safe, reliable, and efficient gas and electric service to customers, while complying with applicable federal, state, and local regulations. SDG&E has formal procedures, processes, and standards it adheres to and makes accessible to field personnel so they can adequately and safely do their jobs. Until SDG&E field employees are fully trained to do their jobs adequately and safely, they cannot perform work orders on their own. SDG&E Customer Service Field Dept. representatives have access to the Company's procedures and standards through their mobile data terminal (MDT). These reference materials instruct the employee on how work should be performed, how to perform procedures safely, and provide overall direction to employees. Below, are Call Center and Field activities managed by SDG&E related to safety:

<u>Customer Service Field (CSF) orders related to public safety include:</u>

- <u>Carbon Monoxide</u> - CSF employees respond to orders created for a customer experiencing carbon monoxide illness, a customer whose carbon monoxide alarm has sounded, or a "courtesy test" for a customer who is concerned about the possibility of their gas appliance producing carbon monoxide. Upon arrival, if carbon monoxide is detected the CSF employee will evacuate the premises, shut off the gas meter for safety, and call for medical attention if necessary. A carbon monoxide investigation on all gas appliances is performed.
- <u>Gas Purge Orders</u> - Purge orders are issued to ensure customer safety by confirming customer owned gas house lines are safe and leak-free and odorant is readily detectable. Purge orders usually involve large gas meter installations and customer owned gas systems for commercial and industrial customers. These jobs usually relate to new construction projects where Gas Distribution Pipeline Operations sets a large gas meter and the Company schedules a date to test and purge the houseline. The steps are below:

- Once the meter is set by Pipeline Operations Dept. personnel, CSF energizes and tests the houseline to make sure there are no leaks in the system.
- Once it is determined that the complete houseline has been pressure tested and it's leak free, SDG&E continues to purge gas out of the farthest point(s) of the houseline. When purging gas, the goal is to displace all of the air from the system. Purging continues until SDG&E no longer register gas indications using combustible gas indicators from the farthest point(s) of the houseline. This is important from a customer safety aspect because it makes sure that the system is safe and ready for use when gas equipment is fired off. During purging and once there are no longer gas indications, an odorant test is performed to confirm odorant is readily detectable. There have been instances when odorant is detected at the meter/riser location, but it is not detected on the customers houseline when purging. In situations when SDG&E is unsuccessful with odorant breakthrough, an odorant injection will be scheduled through SoCalGas.
- Last, SDG&E fires off all gas equipment that is connected at the request of the customer or contractor to make sure each piece of equipment is operating safely. There are many times that industrial or commercial gas equipment is involved, and SDG&E's customers prefer to have the vendor fire off their equipment initially.

- <u>High Gas Consumption Order</u> – Smart meter technology captures daily gas consumption data. Using a newly developed algorithm SDG&E can detect a "spike" or unusual gas consumption based on historical or recent gas usage. When this occurs, a high gas consumption order is created for a CSF employee to investigate. Findings vary, as a customer that has simply added a new gas appliance, such as a gas pool heater, would cause a spike in gas usage; however, sometimes a gas leak on the customer's houseline or appliance is discovered (*e.g.*, appliance burner left on, fireplace or BBQ gas valve left on, but not in use).

- Turn On Orders with Safety Checks – CSF employees are responsible for turning on service valves for metering installations with capacities of 1,500 standard cubic feet per hour (SCFH) and below with delivery pressure of 2 PSI and below. When turning service valves on to restore gas, the customer's system is tested for safety purposes. Additionally, CSF employees adjust, inspect, communicate appropriate referrals, plus provide advisory service on energy efficiency and the safe utilization of gas appliances. Employees remain alert for hazardous or unsatisfactory appliance conditions and take appropriate corrective action for customer safety and protection of property.
- Soft Shut Off Gas Orders – To eliminate the need for a new tenant to provide access for a gas turn-on, the Energy Service Specialist (ESS) may issue a Soft Shut-Off (SSO) gas order. Based on safety considerations, CSF employees are to use their judgment as to whether an SSO should be converted to a regular shut-off when fielding this type of order. CSF personnel go out to the premises and perform a registration check at the meter to ensure that gas registration is within safe and allowable limits when considering whether to leave the gas on. If the registration check passes the test, the CSF employee will leave the gas meter on and also leave a "Gas is on" Form (SD6552) on the door of the premises. The purpose of this form is to notify a new occupant the gas has been left on, temporarily. Instructions are provided to prevent gas service interruption, and how to shut off the gas meter in an emergency.
- Read/Verify – Read and verify the meter number for Billing purposes. During this process, CSF employees will verify the read and meter number to ensure meter matches the account's address, then document the meter read. During this process, the CSF employee ensures the read still

indicates the gas is off and if not, ensures a follow up order to turn the gas off for safety purposes.

- Seasonal Checks and Appliance Checks – CSF conducts ongoing and seasonal appliance checks to perform appliance inspections, lighting pilots/turning-on appliances, and adjusting to ensure appliances are safe to use by SDG&E customers. Additionally, CSF communicates appropriate referrals, plus provides advisory service on energy efficiency and the safe utilization of gas appliances. Field employees remain alert for hazardous or unsatisfactory appliance conditions and take appropriate corrective action for customer safety and the protection of property.
- Fumigation - Prior to the "tenting" of a home or business CSF employees inspect the gas riser and properly shut off and secure the gas meter to avoid gas accumulating within the tent during fumigation. Upon completion of fumigation, a CSF employee will return to turn gas service back on and perform appliance checks on gas appliances.
- Hazardous and non-hazardous gas leaks - CSF employee will respond to all calls of gas leaks or gas odors and perform a gas leak investigation.

T. C20: Natural Gas Appliance Testing (NGAT) or Carbon Monoxide Testing

This is a safety-related program for Energy Savings Assistance (ESA) Program participants. The purpose is to test in-home equipment for carbon monoxide hazards. SDG&E conducts Carbon Monoxide testing on homes weatherized through the ESA Program in accordance with the Statewide Energy Savings Assistance Program Installation Standards and the Statewide Energy Savings Assistance Program Policy and Procedures Manual. CPUC directives order SDG&E to charge the costs for the NGAT program to base rates rather than to the public purpose funds.

U. C21: CSF Quality Assurance (QA) Program

SDG&E field employees are trained to address safety hazards on customer premises. Public safety orders include carbon monoxide, fumigation, and hazardous and nonhazardous gas leaks. The QA Program is designed to verify the field employees are completing field orders according to established policy and procedures and to see that customers are receiving safe and reliable service. The program provides a snapshot of the quality of work being performed by the

CSF Employees on customer premises. QA Specialists (Inspectors) take a random sampling of field orders completed by field employees and inspect the work performed on the customer premises. Inspectors record all findings of each individual order onto an inspection form. That information is then utilized to develop refresher training and to provide feedback to the CSF employees.

IV. 2022-2024 CONTROL & MITIGATION PLAN

This section contains a table identifying the controls and mitigations comprising the portfolio of mitigations for this risk.[26]

All of the activities discussed in Section III above, except for DIMP – Replace Balance of CP Daisy Chained Services (C16 -T2) are expected to continue during the TY 2024 GRC time period. For clarity, a current activity that is included in the plan may be referred to as either a control and/or a mitigation. For purposes of this RAMP, a control that will continue as a mitigation will retains its control ID unless that the size and/or scope of that activity will be modified, in which case that activity's control ID will be replaced with a mitigation ID. The table below shows which activities are expected to continue.

Table 3: Control and Mitigation Plan Summary

Line No.	Control/ Mitigation ID	Control/Mitigation Description	2020 Controls	2022-2024 Plan
1	C1	Cathodic Protection Program – O&M	X	X
2	C2	Cathodic Protection Program – Capital	X	X
3	C3	Piping in Vaults Replacement Program	X	X
4	C4	Regulator Station, Valve, and Large Meter Set Inspection	X	X
5	C5	Regulator Station Replacements	X	X
6	C6	Leak Repair	X	X
7	C7	Pipeline Monitoring (Leak Mitigation, Bridge & Span, Unstable Earth and Pipeline Patrol)	X	X
8	C8	Underperforming Steel Replacement Program	X	X
9	C8-T1	Underperforming Steel Replacement Program – Threaded Main (pre-1933 vintage	X	X

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

Line No.	Control/ Mitigation ID	Control/Mitigation Description	2020 Controls	2022-2024 Plan
10	C8-T2	Underperforming Steel Replacement Program (1934-1965 vintage).	X	X
11	C8-T3	Underperforming Steel Replacement Program – Other Steel (Post 1965 vintage).	X	X
12	C9	Early Vintage Program (Pipeline Component Removal)	X	X
13	C9-T1	Early Vintage Program (Components) - Oil Drip Piping Removal	X	X
14	C9-T2	Early Vintage Program (Components) - Dresser Mechanical Coupling Removal	X	X
15	C9-T3	Early Vintage Program (Components) - Removal of Closed Valves between High/Medium Pressure Zones	X	X
16	C10	Code Compliance Mitigation	X	X
17	C11	Gas Distribution Emergency Department	X	X
18	C12	Cathodic Protection System Enhancements - Base	X	X
19	C13	Human Factors Mitigations – Gas Handling Plans	X	X
20	C14	Human Factors Mitigations – Operator Qualification Training and Certification	X	X
21	C15	Human Factors Mitigations - QA/QC Program – Mandated Compliance Activities	X	X
22	C16-T1	DIMP – DREAMS – Vintage Integrity Plastic Plan (VIPP)	X	X
23	C16-T2	DIMP –Replace Balance of CP Daisy Chained Services.	X	-
24	C17	CCM Distribution Field Asset Real Time Monitoring and Control Site Installations/Upgrades & New Control Room Technologies	X	X
25	C18	Gas Public Safety Communications	X	X
26	C19	Field and Public Safety	X	X
27	C20	Natural Gas Appliance Testing (NGAT) or Carbon Monoxide Testing	X	X
28	C21	CSF Quality Assurance (QA) Program	X	X
29	M1	Safety Control Valves	-	X
30	M2	Cathodic Protection System Enhancements – Real Time Monitoring	-	X

Line No.	Control/ Mitigation ID	Control/Mitigation Description	2020 Controls	2022-2024 Plan
31	M3	Replace Curb Valves with EFV's	-	X

For activities SDG&E plans to perform that remain unchanged, please refer to the description in Section III. If changes to the various activities are anticipated, such modifications are further described in this section below.

A. Changes to 2020 Controls

SDG&E does not anticipate any significant changes to the scope of the existing controls that are anticipated to continue into years 2022-2024.

B. 2022 – 2024 Mitigations

1. M1: Safety Control Valves.

Block valves and/or control valves are a critical part of a medium pressure system. Valves provide the operator with a means of maintaining the pipeline system through creating temporary unconnected sections of the system and provide alternative choices in how the operator will operate a pipeline system. Importantly, valves also provide the ability to stop the unintended escape of gas from the pipeline system in an emergency. When properly located, valves can greatly reduce the response time to control the escaping gas, thus minimizing the risk to Company employees and the public from the consequences of exposure to the uncontrolled escape of gas.

Valves, specified in the design process, are installed in the gas pipeline system in new segments of pipe added over time as a result of customer growth. Each segment of added pipeline is analyzed for the best placement of valves with consideration for the need for valves as described above.

However, as a gas distribution system grows over time with multiple added segments, not often is the larger integrated gas system analyzed with a "big picture" look at the need for additional valves required for emergency response. This analysis should also include the consideration for additional valving to enhance the operator's ability to maintain the pipeline system with a minimum interruption to customers.

This project is an analysis of SDG&E's gas system using current system maps and modelling tools to identify potential locations for added valves. This would provide additional safety by reducing the response time to control and isolate gas flow in an emergency with the added benefit of improved flexibility for pipeline maintenance.

Elements of the analysis to be included, but not limited to, are size and pressure of the pipeline, pipeline network considerations such as back-ties and single feeds, long existing back-ties between stranded areas, possible reduction in the number of customers affected, and valve access considerations.

2. M2: Cathodic Protection System Enhancements – Real Time Monitoring.

Cathodic Protection coating and monitoring can protect and extend the life of a steel asset by mitigating corrosion. The application of a CP current is necessary to overcome local corrosion currents along the pipeline, that left unabated would result in localized corrosion on the steel pipeline. Cathodic Protection can be achieved by the installation of sacrificial anodes or impressed current systems (rectifier stations).

Each cathodic protection rectifier station or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 1/2 months, to ensure that it is operating.[27] Currently this is done manually by CP electricians who visit and inspect these rectifier installations every two months. This means that during the two months in-between inspections, if the rectifier becomes inoperable, the CP system could be off for the local area, increasing the likelihood of accelerated corrosion and the risk of leakage.

This project involves the installation of remote monitoring units (RMUs) to monitor the level of CP provided by rectifier stations to the steel pipeline system. These units would electronically monitor the rectifier stations on a continuous real-time basis to verify that the level of current from the rectifiers is adequately protecting steel pipelines. The RMUs send alarm notifications through landline or wireless communication to the department monitoring these devices when key parameters such as current levels are below or above a pre-set tolerance. In this way, CP protection can be monitored continuously rather than manually on a bi-monthly basis by employees under the current mandated periodic inspection program. This significantly improves the mitigation of the risk of corrosion of the steel pipeline system through the loss of the CP protection system.

[27] 49 CFR § 192.465.

3. M3: Replace Curb Valves with EFVs.

All newly installed or replaced service lines with installed meter capacity exceeding 1000 SCFH, must have installed either a manual service line shut-off valve (a "curb" valve or other manually operated valve) or an excess flow valve (EFV). This mitigation project will survey the gas system for installed curb valves, prioritize their replacement based on inaccessibility issues and schedule the replacement of these valves with EFVs.

In the past, if a curb valve was chosen, requirements for these manually operated valves from 49 CFR 192.385, include that they "be located near the service that is safely accessible to operator personnel or other personnel authorized to manually shut off gas flow to the service line, if needed." In addition, if a manual curb valve was chosen to comply with the service line shut off requirement, 49 CFR 192.385 also requires that it must be "installed in such a way to allow accessibility during emergencies." "…[they are]..subject to regular scheduled maintenance." If an EFV was chosen as the shut off device, it is buried as near as practical to the service to main connection. The EFV has an advantage over a curb valve (which requires periodic inspection and maintenance) in that it is designed to automatically shut off the service if a high flow is detected (such as that associated with a broken service line).

When there is a broken service line incident, based on the location requirements discussed above, the EFV (with automatic response) will protect the majority of the service line to the customer as opposed to the curb valve (requiring manual operation) located closer to the customers property will protect only a smaller portion of the service line. The EFV also does not have the location accessibility constraints that manually operated curb valves have in order to be operated.

Prior to the mandate to install EFVs in services, manually operated curb valves were installed in services for various reasons to remotely shut off a service line. Some of these valves, accessible from inside a curb valve box, may still be inaccessible due to their location in a parking strip where they could be covered with a parked vehicle, or located within high traffic areas. In addition, these curb valve boxes, which have not required inspection in the past, may have filled with street sand, or have been covered with street paving or sidewalk construction limiting access to the valve.

Because EFVs are automated and do not require manual operation, the response time to shut off a curb valve is much longer than the auto-shut off response time of an EFV. In addition, EFVs are not subject to street and sidewalk location inaccessibility issues. This will significantly mitigate risk to the public and the affected customer by decreasing the response time to shut down a customer service, when required, due to damage of the service line from outside forces.

V. COST, UNITS, AND QUANTITATIVE SUMMARY TABLES

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

Table 4: Risk Control and Mitigation Plan - Recorded and Forecast Dollars Summary[28]
(Direct After Allocations, In 2020 $000)

ID	Control/Mitigation Name	Recorded Dollars		Forecast Dollars			
		2020 Capital[29]	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
C1	Cathodic Protection Program - O&M	-	1,965	-	-	1,853	2,245
C2	Cathodic Protection Program - Capital	3,670	-	17,795	21,540	-	-
C3	Piping in Vaults Replacement Program	190	-	8,605	10,420	-	-
C4	Regulator Station, Valve, and Large Meter Set Inspection	-	4,500	-	-	4,240	5,130
C5	Regulator Station Replacement	-	-	5,400	6,900	-	-
C6	Leak Repair	9,500	1,400	26,865	32,525	1,330	1,610
C7	Pipeline Monitoring (Leak Mitigation, Bridge & Span, Unstable Earth, and Pipeline Patrol	-	2900	-		2755	3335
C8-T1	Underperforming Steel Replacement Program -Threaded Main (pre- 1933 vintage)	1665	-	26270	31800	-	-
C8-T2	Underperforming Steel Replacement Program (1934 - 1965 vintage)	3755	-	20805	25185	-	-
C8-T3	Underperforming Steel Replacement Program - Other Steel (Post 1965 vintage)	1040	-	10165	12305	-	-

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

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

ID	Control/Mitigation Name	Recorded Dollars		Forecast Dollars			
		2020 Capital[29]	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
C9-T1	Early Vintage Program (Pipeline Component Removal)- Oil Drip Piping	195	-	6800	8235	-	-
C9-T2	Early Vintage Program (Pipeline Component Removal) - Dresser Mechanical Coupling Removal	1390	-	8825	10685	-	-
C9-T3	Early Vintage Program (Pipeline Component Removal) - Removal of Closed Valves Between High/Medium Zones	450	-	735	890	-	-
C10	Code Compliance Mitigation	1280	-	5900	7140	-	-
C11	Gas Distribution Emergency Department		2710	-	-	2595	3140
C12	Cathodic Protection System Enhancements	1250		2980	3610	-	-
C13	Human Factors Mitigations - Gas Handling Plans	285	-	995	1275	-	-
C14	Human Factors Mitigations - Operator Qualification Training and Certification	580	2115	1255	1520	2345	2840
C15	Human Factors Mitigations - QA/QC Program - Mandated Compliance Activities	-	270	-	-	340	415
C16-T1	DIMP – DREAMS – Vintage Integrity Plastic Plan (VIPP)	40365	2680	157605	182490	2850	3300
C17	CCM Distribution Field Asset Real Time Monitoring and Control Site Installations/Upgrades & New Control Room Technologies	-	-	12420	17940	265	382
C18	Gas Public Safety Communications	-	2661	-	-	2395	3459
C19	Field and Public Safety	568	9,694	1623	1962	9209	11633
C20	Natural Gas Appliance Testing (NGAT) or Carbon Monoxide Testing	-	111	-	-	105	322
C21	CSF Quality Assurance (QA) Program	-	65	-	-	185	224

ID	Control/Mitigation Name	Recorded Dollars		Forecast Dollars			
		2020 Capital[29]	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
M1	Safety Control Valves	-	-	6845	8745	-	-
M2	Cathodic Protection System Enhancements – Real Time Monitoring	-	-	2700	3450	-	-
M3	Replace Curb Valves with EFV's	-	-	7225	8745	-	-

Table 5: Risk Control & Mitigation Plan - Units Summary

ID	Control/Mitigation Name	Units Description		Recorded Units		Forecast Units			
		Capital	O&M	2020 Capital	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 (Low) O&M	TY 2024 (High) O&M
C1	Cathodic Protection Program - O&M	No. of troubles orders		-	1,385	-	-	1,305	1,580
C2	Cathodic Protection Program - Capital	No. of deep well anode beds		39	-	137	166	-	-
C3	Piping in Vaults Replacement Program	No. of projects		2	-	57	69	-	-
C4	Regulator Station, Valve, and Large Meter Set Inspection	No. of inspections and related maintenance		-	1,020	-	-	816	988
C5	Regulator Station Replacement	No. of regulator stations replaced		-	-	11	14	-	-
C6	Leak Repair	No. of projects		564	635	1607	1946	601	728
C7	Pipeline Monitoring (Leak Mitigation, Bridge & Span, Unstable Earth, and Pipeline Patrol	No. of inspections/surveys		-	940	-	-	894	1082
C8-T1	Underperforming Steel Replacement Program -Threaded Main (pre- 1933 vintage)	No. of feet		1584	-	189003	228794	-	-

ID	Control/Mitigation Name	Units Description		Recorded Units		Forecast Units			
		Capital	O&M	2020 Capital	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 (Low) O&M	TY 2024 (High) O&M
C8-T2	Underperforming Steel Replacement Program (1934 - 1965 vintage)	No. of feet		10560	-	149676	181187	-	-
C8-T3	Underperforming Steel Replacement Program - Other Steel (Post 1965 vintage)	No. of feet		1718	-	73137	88534	-	-
C09-T1	Early Vintage Program (Pipeline Component Removal)- Oil Drip Piping	No. of projects		3	-	113	137	-	-
C9-T2	Early Vintage Program (Pipeline Component Removal) - Dresser Mechanical Coupling Removal	No. of projects		11	-	59	71	-	-
C9-T3	Early Vintage Program (Pipeline Component Removal) - Removal of Closed Valves Between High/Medium Zones	No. of projects		4	-	4	5	-	-
C10	Code Compliance Mitigation	No. of projects		1364	-	2836	3433		
C11	Gas Distribution Emergency Department	No. of responses		-	1030	-	-	1216	1472
C12	Cathodic Protection System Enhancements	No. of projects		18	-	137	166	-	-
C13	Human Factors Mitigations - Gas Handling Plans	No. of projects		386	-	1890	2415	-	-
C14	Human Factors Mitigations – Operator Qualification Training and Certification	No. of employees/contractors trained/certified		650	650	2005	2428	712	861

ID	Control/Mitigation Name	Units Description		Recorded Units		Forecast Units			
		Capital	O&M	2020 Capital	2020 O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 (Low) O&M	TY 2024 (High) O&M
C15	Human Factors Mitigations - QA/QC Program – Mandated Compliance Activities	No. of internal QA/QC field audits			240	-	-	227	275
C16-T1	DIMP – DREAMS – Vintage Integrity Plastic Plan (VIPP)	No. of miles		51		140	170		
C17	CCM Distribution Field Asset Real Time Monitoring and Control Site Installations/Upgrades & New Control Room Technologies	No. of control sites installed/inspected No. of real-time monitoring sites installed/inspected		-	-	Control: 13 Real-time:34	Control: 20 Real-time: 50	Control: 10 Real-time:20	Control: 14 Real-time: 29
C18	Gas Public Safety Communications	A measurable unit is not practical given the multiple means of communications used to implement this control.							
C19	Field and Public Safety	No. of orders		6784	123195	19334	23405	117036	160155
C20	Natural Gas Appliance Testing (NGAT) or Carbon Monoxide Testing	No. of natural gas appliance tests		-	2840	-		2696	6953
C21	CSF Quality Assurance (QA) Program	No. of inspections		-	180	-	-	1509	1826
M1	Safety Control Valves	No. of projects		-		51	66	-	-
M2	Cathodic Protection System Enhancements – Real Time Monitoring	No. of upgraded rectifier stations		-	-	1180	1508	-	-
M3	Replace Curb Valves with EFV’s	No. of projects		-	-	361	437	-	-

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

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Risk Score	RSE
C1	Cathodic Protection Program - O&M	97.98	5.97	584.9	13.4
C2	Cathodic Protection Program - Capital	94.95	5.97	566.9	24.6
C3	Piping in Vaults Replacement Program	101.0	5.97	603.0	6.3
C4	Regulator Station, Valve, and Large Meter Set Inspection	57.69	5.97	344.4	56.8
C5	Regulator Station Replacement	101.3	5.97	604.9	2.7
C6/C7	Leak Repair & Pipeline Monitoring (Leak Mitigation, Bridge & Span, Unstable Earth and Pipeline Patrol)[30]	30.0	5.97	179.3	14.9
C8-T1	Underperforming Steel Replacement Program – Threaded Main (pre-1933 vintage	100.5	5.97	600.0	5.7
C8-T2	Underperforming Steel Replacement Program (1934-1965 vintage).	100.6	5.97	600.7	6.3
C8-T3	Underperforming Steel Replacement Program – Other Steel (Post 1965 vintage).	100.9	5.97	602.3	8.6
C9-T1	Early Vintage Program (Components) - Oil Drip Piping Removal	100.9	5.97	602.2	13.5
C9-T2	Early Vintage Program (Components) - Dresser Mechanical Coupling Removal	101.4	5.97	605.3	0.6
C9-T3	Early Vintage Program (Components) - Removal of Closed Valves between High/Medium Pressure Zones	101.4	5.97	605.3	6.2
C10	Code Compliance Mitigation	101.1	5.97	602.8	10.2
C11	Gas Distribution Emergency Department	78.62	5.97	469.3	144.0
C12	Cathodic Protection System Enhancements - Base	101	5.97	603	4.4
C13	Human Factors Mitigations – Gas Handling Plans	See Table 7			
C14	Human Factors Mitigations – Operator Qualification Training and Certification	101.1	5.97	604	0.4

[30] Pipeline Monitoring is a standalone activity with costs and units tracked as such. For purposes of calculating an RSE, Pipeline Monitoring was combined with Leak Repair as Pipeline Monitoring is only the work associated with inspections wherein risk mitigation thereof occurs in the Leak Repair activity.

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Risk Score	RSE
C15	Human Factors Mitigations - QA/QC Program – Mandated Compliance Activities	See Table 7			
C16-T1	DIMP – DREAMS – Vintage Integrity Plastic Plan (VIPP)	98.02	5.97	585.2	3.4
C17	CCM Distribution Field Asset Real Time Monitoring and Control Site Installations/Upgrades & New Control Room Technologies	See Table 7			
C18	Gas Public Safety Communications	See Table 7			
C19	Field and Public Safety	100.3	5.97	598.9	0.2
C20	Natural Gas Appliance Testing (NGAT) or Carbon Monoxide Testing	101.4	5.97	605.3	0.5
C21	CSF Quality Assurance (QA) Program	101.2	5.97	604.2	6.3
M1	Safety Control Valves	101.2	5.97	604.2	4.9
M2	Cathodic Protection System Enhancements – Real Time Monitoring	100.2	5.97	598.3	69.0
M3	Replace Curb Valves with EFVs	98.75	5.97	590	60.6

Table 7-SDG&E MP: Risk Control & Mitigation Plan – Quantitative Analysis Summary for RSE Exclusions

ID	Control/Mitigation Name	RSE Exclusion Rationale
C13	Human Factors Mitigation: Gas Handling Plans	The implementation of Gas Handling procedures is a direct result of lessons learned from the industry at large. SDG&E recognizes this is a prudent safety activity for pipeline operations and therefore is adopting as such. Because this activity is new to the utility, there exists no internal data to determine the decrease in incident rate or consequence of incidents with the implementation of Gas Handling procedures thereof. SoCalGas serves as the closest baseline in this area; however, Gas Handling Procedures have been a long-standing policy of SoCalGas. Since no discernable difference in incident rate between the two companies could be directly tied to a risk reduction associated with the mitigation, an RSE calculation was not performed.

ID	Control/Mitigation Name	RSE Exclusion Rationale
C15	Human Factors Mitigations - QA/QC Program – Mandated Compliance Activities	Quality assurance and control of pipeline activities like CP repairs/inspections, M&R inspections, Leak Mitigation, etc. is a crucial safety activity conducted by the Company; however, there is insufficient internal data to tie the risk addressed by this mitigation to the drivers described in the bow tie. The Company possess metrics around inspections completed and forecasted as well as when issues may be found (*e.g.*, when construction is not completed to company standards); however, the data to specifically tie incident causes to the lack of inspections or insufficient inspections does not exist. Likewise, there is no data, internal or external, to explicitly state a consequence would decrease by a quantifiable amount due to the implementation of inspections. The QA/QC program exists to determine compliance with Company standards or to determine if work was not completed. As such, no quantifiable means exists to determine the increase in likelihood or consequence due to inspecting pipeline construction projects. Similarly, no SME input exists that can explicitly tie the increase or decrease thereof; hence, an RSE could not be calculated.
C17	CCM SCG Distribution Field Asset Real Time Monitoring and Control Site-Installations/Upgrades & New Control Room Technologies	Increasing the ability to monitor and control the natural gas system is an important safety and reliability measure for California's energy grid. The CCM will enable SoCalGas to control or isolate the faster in the event of a system incident. Likewise, the CCM will enable SDG&E to identify potential issues in the system sooner, as compared to patrols or a system with fewer monitor points, and potentially resolve those issues before they become an incident. This can include dig-in detection and response, over/under pressure awareness and response, as well as increased flexibility to respond to the varying demands on the system throughout the year. Increased remote control also alleviates employee exposure to operating equipment prior to, during, or after an incident. The CCM overall decreases the consequences of system incidents by allowing the gas system to react faster to incidents with fewer human asset involvement in potentially hazardous conditions. SoCalGas tracks many sets of data that could

ID	Control/Mitigation Name	RSE Exclusion Rationale
		be used to quantify partial aspects of the CCM, such as response time to incidents, valve closure times, over/under pressure events, dig-in responses, SCADA installations/repairs, capacity analysis, etc.; however, in terms of an RSE, no singular data set or combination thereof can be used to appropriately and accurately quantify the decrease in the likelihood or consequence of a medium pressure system incident due to the CCM. Likewise, no SME input could be determined that could quantify a decrease in the number of system incidents attributable to the installation of the CCM.
C18	Gas Public Safety Communications	Educating the public regarding identification of potentially hazardous conditions involving the gas system is a prudent safety measure taken by the Company. It shows responsibility and high ethical value to customers and the public that exists around the gas infrastructure. SDG&E possesses data and metrics around these programs such as the number of communications issued annually, the likelihood or consequence of a medium pressure system event to the public and by what means; however, no data exists, internally or externally, to explicitly tie the reduction in likelihood and consequence of a medium pressure system incident. Additionally, no SME input exists to quantitatively frame the effect to medium pressure incidents from educating the public about the infrastructure and appliances.

VI. ALTERNATIVES

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the risk control and mitigation plan for the Medium Pressure Incident risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this risk control and mitigation plan also took into account modifications to the plan and constraints, such as budget and resources.

A. A1: Post-training Follow-up Field Evaluation

SDG&E considered an alternative that would provide new field Service Technicians and Meter Service Persons with a follow up field evaluation six months after being released from formal training. This evaluation would determine whether these new employees continue to follow the safety policies and procedures established during their formalized training. Any deficiencies in an employee's performance would be addressed on an individual basis and follow up training would be scheduled to remediate any issues. This alternative was not implemented because employees currently participate in annual reviews of safety- and risk-related policies and procedures (*e.g.,* Gas standards, monthly defensive driving training, ergonomic training, bi-weekly safety meetings, etc.). SDG&E employees attend week-long compliance/refresher training that covers pertinent policies, addresses Field QA findings and review recent incidents to help mitigate risk. At SDG&E, there is also no set time period to start QA inspections on new employees. When issues are found they are coached by the direct supervisor, which can lead to field rides by the Supervisor, Appliance Mechanic, Field Instructor, Instructor or QA Inspector. Thus, this alternative seemed unnecessary and would also result in additional costs.

B. A2: Soil Sampling Program

SDG&E considered expanding its collection of soil property information. SDG&E collects soil properties (rocky, clay, sandy) during excavations and repairs along its pipelines. These soil properties are an element within the relative risk models used for prioritization process of the vintage replacement program for plastic. Expanding the collection of soil properties beyond leak repair excavations may allow SDG&E to further refine its replacement efforts. The cost estimate of sampling the over 5,900 miles of medium pressure distribution pipe is $12.2 million; on average, 14 samples per day would be tested at intervals of two samples per mile. SDG&E decided to not include this mitigation as part of the control and mitigation plan because the overall assessment of the risk it would address is ongoing. As the risk assessment continues to mature for the corrosion threat, the benefit of additional information will enable this potential mitigation to be better understood. In the interim SDG&E will be researching available data sets and determining the benefit of additional granularity.

Table 8: Alternate Mitigation Plan - Recorded and Forecast Dollars Summary[31]
(Direct After Allocations, In 2020 $000)

ID	Control/Mitigation Name	Forecast Dollars			
		2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 O&M (Low)	TY 2024 O&M (High)
A1	Post-training Follow-up Field Evaluation	-	-	14	20
A2	Soil Sampling Program	-	-	3,690	5,330

Table 9: Alternate Mitigation Plan - Units Summary

ID	Alternative Mitigation Name	Units Description		Forecast Units			
		Capital	O&M	2022-2024 Capital (Low)	2022-2024 Capital (High)	TY 2024 (Low) O&M	TY 2024 (High) O&M
A1	Post training follow-up field evaluations	No. of evaluations		-	-	32	46
A2	Soil Sampling Program	No. of soil samples		-	-	3,544	5,119

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

ID	Control/Mitigation Name	Forecast			
		LoRE	CoRE	Risk Score	RSE
A1	Post Training Follow-up Field Evaluations	101.42	5.97	606	1.1
A2	Soil Sampling Program	101.38	5.97	606	0.019

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

APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE

Appendix A: Summary of Elements of the Risk Bow Tie

Medium Pressure Incident: Summary of Elements of the Risk Bow Tie

ID	Control/Mitigation Name	Elements of the Risk Bow Tie Addressed
C1	Cathodic Protection Program – O&M	DT.1, DT.4, DT.5 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C2	Cathodic Protection Program – Capital	DT.1, DT.4, DT.5 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C3	Piping in Vaults Replacement Program	DT.1, DT.2, DT.3, DT.4 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C4	Regulator station, Valve, and Large Meter Set Inspections	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C5	Regulator Station Replacements	DT.1, DT.2, DT.3, DT.4, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C6	Leak Repair	DT.1, DT.2, DT.3, DT.5, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C7	Pipeline Monitoring (Leak Mitigation, Bridge & Span, Unstable Earth and Pipeline Patrol	DT.1, DT.2, DT.3, DT.5, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C8-T1	Underperforming Steel Replacement Program – Threaded Main (pre-1933 vintage)	DT.1, DT.2, DT.4, DT.5, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C8-T2	Underperforming Steel Replacement Program (1934-1965 vintage).	DT.1, DT.2, DT.4, DT.5, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C8-T3	Underperforming Steel Replacement Program – Other Steel (Post 1965 vintage).	DT.1, DT.2, DT.4, DT.5, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C9-T1	Early Vintage Program (Components) - Oil Drip Piping Removal	DT.1, DT.2, DT.3, DT.4, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C9-T2	Early Vintage Program (Components) - Dresser Mechanical Coupling Removal	DT.1, DT.2, DT.3, DT.5, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C9-T3	Early Vintage Program (Components) - Removal of Closed Valves between High/Medium Pressure Zones.	DT.1, DT.2, DT.5, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C10	Code Compliance Mitigation	DT.1, DT.2, DT.3, DT.5, DT.6 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C11	Gas Distribution Emergency Department	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C12	Cathodic Protection System Enhancements	DT.1, DT.4, DT.5 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C13	Human Factors Mitigation – Gas Handling	DT.1, DT.4, DT.5, DT.6, DT.7 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C14	Human Factors Mitigation – Operator Qualification Training and Certification	DT.1, DT.4, DT.5, DT.6, DT.7; DT.8 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C15	Human Factors Mitigation – QA/QC Program - Mandated Compliance Activities	DT.1, DT.4, DT.5, DT.6, DT.7 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C16-T1	DIMP – DREAMS – Vintage Integrity Plastic Plan (VIPP)	DT.2, DT.4, DT.6, DT.7 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6

ID	Control/Mitigation Name	Elements of the Risk Bow Tie Addressed
C16-T2	DIMP –Replace Balance of CP Daisy Chained Services.	DT.1, DT.4 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C17	CCM Distribution Field Asset Real Time Monitoring and Control Site Installations / Upgrades & New Control Room Technologies	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6 PC.1, PC.2, PC.4, PC.5, PC.6
C18	Gas Public Safety Communications	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C19	Field and Public Safety	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C20	Natural Gas Appliance Testing (NGAT) or Carbon Monoxide Testing	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
C21	CSF Quality Assurance (QA) Program	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
M1	Safety Control Valves	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
M2	Cathodic Protection System Enhancements – Real Time Monitoring	DT.1, DT.4, DT.5 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
M3	Replace Curb Valves with EFVs	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6

APPENDIX B: QUANTITATIVE ANALYSIS SOURCE DATA REFERENCES

Appendix B: Quantitative Analysis Source Data References

The Settlement Decision directs the utility to identify potential consequences of a risk event using available and appropriate data.[32] The list below provides the inputs used as part of this assessment.

Annual Report Mileage for Natural Gas Transmission & Gathering Systems

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

Link: Annual Report mileage for Gas Distribution Systems

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

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

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

San Diego Gas & Electric Medium-pressure Pipeline miles

- Source: 2020 internal SME data

San Diego Gas & Electric annual leakage data, 2012-2017 data according to material

San Diego Gas & Electric overpressure/underpressure data

San Diego Gas & Electric quality assurance program internal data, 5 years aggregated error data

San Diego Gas & Electric inspection data – Bridge and span inspections, pipeline patrols, unstable earth inspections

United States Census Bureau Quick Facts

- Agency: United States Census Bureau
- Link:*https://www.census.gov/quickfacts/fact/table/US/PST045219*

Gas industry sales customers

- Agency: AGA (2016Y)
- Link: *https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf*

SoCalGas end user natural gas customers

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

- Source: SNL (2016Y, from the FERC Form 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*

Real Estate Property Costs

- Agency: National Association of Realtors
- Link: *https://www.nar.realtor/research-and-statistics/housing-statistics/county-median-home-prices-and-monthly-mortgage-payment*