# Risk Assessment and Mitigation Phase

# (Chapter SCG-Risk-3)

# 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 SoCalGas'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]

SoCalGas 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, SoCalGas's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process. The ERR process influenced how risks were selected for inclusion in this 2021 RAMP Report, consistent with the Settlement Decision's directives, as discussed in Chapter RAMP-C.

The RAMP Report's purpose is to present a current assessment of key safety risks and the proposed activities for mitigating those risks. The RAMP Report does not request funding. Any funding requests will be made in SoCalGas's General Rate Case (GRC) application. The costs presented in this 2021 RAMP Report are those costs for which SoCalGas anticipates requesting recovery in its Test Year (TY) 2024 GRC. SoCalGas's TY 2024 GRC presentation will integrate developed and updated funding requests from the 2021 RAMP Report, supported by witness testimony.[2] This 2021 RAMP Report is presented consistent with SoCalGas's GRC presentation, in that the last year of recorded data (2020) provides baseline costs and cost estimates are provided for years 2022-2024, as further discussed in Chapter 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 SoCalGas'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, SoCalGas 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 subject matter expert (SME) opinion exists to calculate the Risk Spend Efficiency (RSE), SoCalGas has included an explanation why no RSE can be provided, in accordance with California Public Utilities Commission (CPUC or Commission) Safety Policy Division (SPD) staff guidance.[5] Activities with no RSE value presented in this 2021 RAMP Report are identified in Section VII below.

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

### A. Risk Overview

Typically, medium pressure systems use 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 that 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 are the leading sources of requirements for SoCalGas's distribution 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 and GO 58 complement and enhance the requirements of 49 CFR 192 at the state level.

SoCalGas currently operates approximately 100,000 miles of medium pressure mains and services, with over 22,000 miles of steel mains and approximately 25,000 miles of plastic mains. These medium pressure pipelines serve over 21.8 million SoCalGas consumers.

Various causes and events can lead to incidents related to the medium pressure pipeline system. 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 degradation, 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 significant impact to the infrastructure.

SoCalGas 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 caused by the leak is addressed by SoCalGas'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 (ASME) Code section B31.8S.[6]

SoCalGas'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 of customer and public safety. An example of SoCalGas's focus on safety as related to this risk is the safety-related customer communications that are an integral part of after the meter incident

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6 American Society of Mechanical Engineering standard B31.8S: Managing System Integrity of Gas Pipelines. AMSE B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes.

prevention in a customer's home, whether or not a SoCalGas employee visits the premises. These communications are a proactive approach to inform 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 baseline controls that will be discussed in greater detail within this chapter.

### B. Risk Definition

For purposes of this RAMP Report, SoCalGas's Medium Pressure Incident risk is defined as the risk of asset failure, caused by a medium pressure pipeline system[7] event, which results in serious injuries or fatalities. 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 SoCalGas's 2019 RAMP report SoCalGas 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. In this RAMP 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 gas meter. Therefore, certain customer and public safety related mitigations are presented within scope to this chapter.

### C. Scope

Table 1 below provides what is considered in and out of scope for the Incident Related to the Medium Pressure System (Excluding Dig-in) risk in this RAMP Application.

**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 serious consequences such as injuries, fatalities, or outages and includes consequences beyond the customer meter. |
| **Data Quantification Sources:** | SoCalGas 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 SoCalGas |

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

| | |
|---|---|
| | 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.<br><br>See Appendix B for additional information. |

## II. RISK ASSESSMENT

In accordance with the Settlement Decision,[8] this section describes the risk bow tie, possible drivers, potential consequences, and the risk score for the 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[9] instructs the utility to include a risk bow tie illustration for each risk included in RAMP. As illustrated in the risk bow tie shown below in Figure 1, the risk event (center of the risk bow tie) is Medium Pressure Incident that Leads to Asset Failure, the left side of the risk bow tie illustrates drivers/triggers that lead to a Medium Pressure Incident Asset Failure, and the right side shows the potential consequences of a Medium Pressure Incident Asset Failure. SoCalGas applied this framework to identify and summarize the information provided in Figure 1. A mapping of each mitigation to the element(s) of the risk bow tie addressed is provided in Appendix A.

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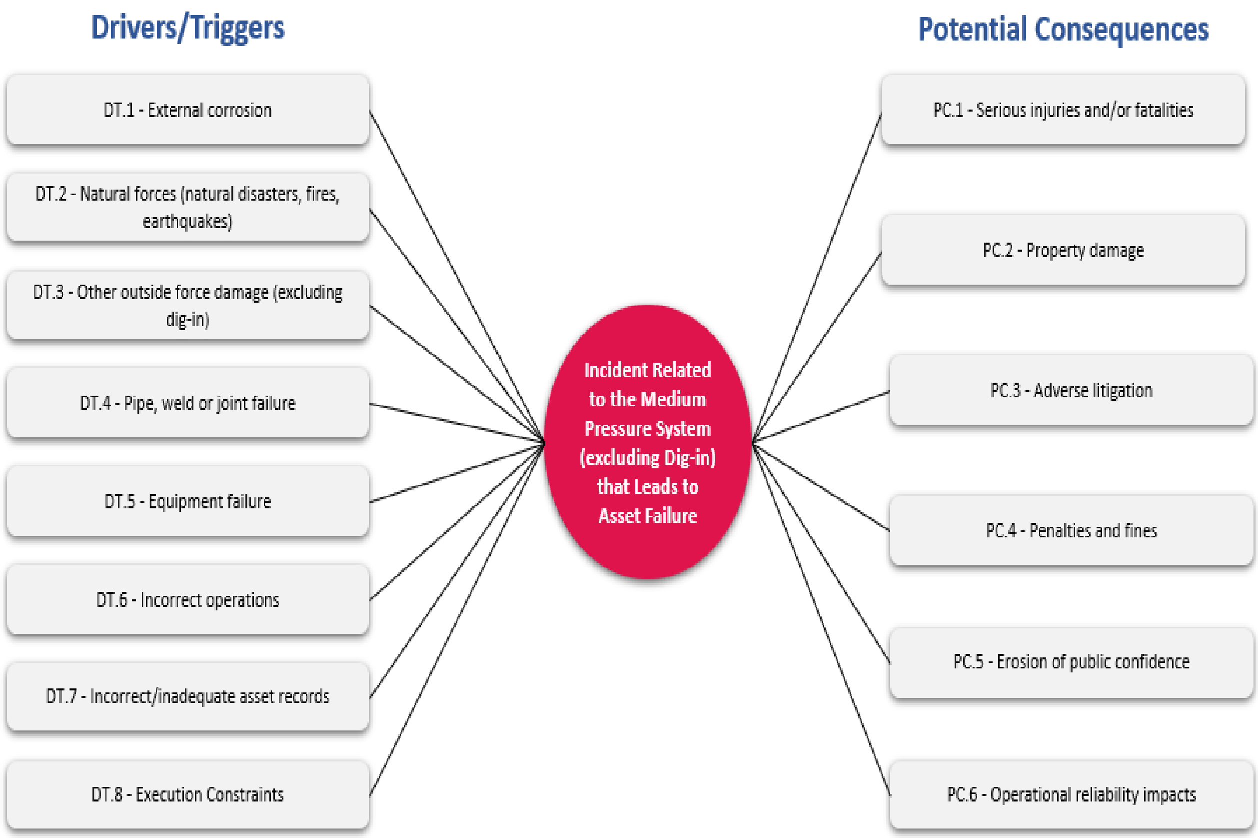
8 D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

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

**Figure 1: Risk Bow Tie**




## B. Cross-Functional Factors

The following CFFs have programs and/or projects that affect this risk chapter: Asset and Records Management, Energy Resilience, Emergency Preparedness and Response and Pandemic, Foundational Technology Solutions, Physical Security, Safety Management Systems (SMS), and Workforce Planning / Quality Workforce. As an example, the training of SoCalGas emergency response personnel and activation of SoCalGas's emergency operations control center, as discussed in the Emergency Preparedness and Response and Pandemic CFF addresses some of the potential consequences of this risk. Another example is the customer service-based quality assurance activities discussed in the SMS CFF. Additional information is provided in the narratives for the referenced CFFs.

### C. Potential Drivers/Triggers[10]

The Settlement Decision[11] instructs the utility to identify which element(s) of the associated risk bow tie each mitigation addresses. When performing the risk assessment for the Medium Pressure Incident risk, SoCalGas 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.[12] 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.
- **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,

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

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

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

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 SoCalGas'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[13] 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 of the Medium Pressure Incident that occurred during the development of SoCalGas's 2020 Enterprise Risk Registry.

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

## E. Risk Score

The Settlement Decision requires a pre- and post-mitigation risk calculation.[14] 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**[15]

| | LoRE | CoRE | Risk Score |
|---|---|---|---|
| Incident Related to the Medium Pressure System | 544.99 | 5.63 | 3,071 |

Pursuant to Step 2A of the Settlement Decision, the utility is instructed to use actual results, as well as available and appropriate data (*e.g.,* Pipeline and Hazardous Materials Safety Administration data).[16]

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

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 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.

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

15 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.

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

## III. 2020 CONTROLS

This section "[d]escribe[s] the controls or mitigations currently in place" as required by the Settlement Decision.[17] The activities in this section were in place as of December 31, 2020. Controls that will continue as part of the control & mitigation plan are identified in Section IV.

As stated above, the Medium Pressure Incident risk is the risk of asset failure, caused by a medium pressure system event, which could result in serious injuries and/or fatalities. The risk mitigation plan includes both controls that are expected to continue and projected mitigations for the period of SoCalGas's TY 2024 GRC cycle. The controls are those activities that were in place as of 2021, 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. SoCalGas's mitigation plan for this risk consists of controls based on compliance with 42 CFR Part 192, GO 58, GO 112-F, and forecasted enhancements within existing controls.

For this RAMP chapter, the makeup of the portfolio of controls is a combination of compliance requirements and additional programs implemented by the DIMP. The DIMP is continually evaluating system threats and risk to determine if additional mitigations are appropriate. The threat and risk evaluation leverages leak repair, incident data, and 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, 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

[17] *Id.* at 33.

master-metered gas systems.  The MHP is not included in this mitigation plan because MHP costs are not anticipated to be forecasted in SoCalGas's next GRC.[18]

### A. C1: Cathodic Protection Base Activities

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 SoCalGas 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 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 at anodic sites. Cathodic protection can be achieved by the installation of sacrificial anodes or impressed current systems.[19]  Each cathodic protection rectifier 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.[20]  SoCalGas plans to continue this schedule for these cathodic protection base activities.

The directives prescribed by 49 CFR 192 Subpart I, and followed by SoCalGas, include the monitoring of CP areas, remediation of CP areas that are out of tolerance,[21] and preventative installations to avoid out of tolerance areas.

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[18] 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.

[19] SoCalGas utilizes both impressed current and magnesium anode (galvanic) systems to provide CP to existing pipelines.  Impressed current systems utilize rectifiers 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.

[20] 49 CFR § 192.465(a) and (b).

[21] Out of tolerance areas are defined as areas where CP reads are outside of pre-determined read tolerances, and if left unaddressed, CP measures may not effectively mitigate the effect of the corrosive environment on steel assets.

### B. C2: Cathodic Protection- CP10 Activities

SoCalGas also tests each pipeline that is under cathodic protection as prescribed by 49 CFR § 192.465. The following summarizes the required intervals for completing preventative measures, like CP10, as prescribed in 49 CFR § 192.465 External Corrosion Control (Monitoring).

- Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least ten percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different ten percent checked each subsequent year, so that the entire system is tested in each ten-year period.

SoCalGas plans to continue these CP10 activities according to this schedule.

### C. C3: Cathodic Protection- 100mV Requalification

In addition to meeting federal and state requirements, based on feedback from the Commission's Safety and Policy Division[22] during a 2018 safety audit, SoCalGas issued new guidelines requiring the re-evaluation of existing 100 mV polarization shift areas[23] at least once every ten years to verify their effectiveness as a measurement for adequate Cathodic Protection of an area. A pipeline utilizing the 100 mV polarization shift criteria must achieve a minimum of 100 mV of polarization along its entirety through the application of Cathodic Protection. This activity supports the safety and integrity of the system and mitigates risks defined in this RAMP chapter.

### D. C4: Meter & Regulator (M&R) Station and Electronic Pressure Monitors (EPM) Inspection and Maintenance

Regulator stations reduce the pressure of gas entering the distribution system from high-pressure pipelines to provide a lower pressure to be used on the distribution pipeline system. A

[22] At the time, it was called the Safety and Enforcement Division.

[23] 49 CFR Part 192, Appendix D (Criteria for Cathodic Protection and Determination of Measurements).

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 resulting from potential over-pressure events.

Regulator stations are critical pressure control installations in the gas distribution system. Title 49 CFR § 192.739 requires inspections/tests to be conducted annually, not to exceed 15 months to maintain these stations and EPMs in good mechanical condition. Functional tests of regulation and monitoring equipment is performed as part of the annual inspections. If any device does not perform properly, internal maintenance and inspections are conducted. This consists of disassembling, inspecting, and cleaning the internal components of the regulator. Any worn, corroded, or damaged components are repaired/replaced, and the regulator is reassembled and verified to be in working order prior to placing back into service. SoCalGas has an internal program that requires all “soft-parts” to be replaced on a 15-year interval.

As regulator stations age, their parts and equipment can begin to wear and become harder to disassemble, increasing maintenance requirements. Regulator stations are designed to maintain continued safe and reliable operation of the station in the event of a failure within either of the two runs. Annual maintenance and inspections are used to record the condition of each station and EPM and identify items that require immediate and long-term action. The overall inspection of the station includes evaluation of the design, condition of the equipment, valves, vaults and EPMs, and exposure to other outside forces including flooding and traffic conditions.

The following summarizes the requirements, which are followed by SoCalGas, for completing these preventative measures as prescribed within 49 CFR § 192.739 Pressure limiting and regulating stations: Inspection and testing:

- Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is:
  (1) In good mechanical condition;
  (2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed.

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

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

### E. C5: Regulator Station Replacements/Installs

SoCalGas's operating and maintenance 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. SoCalGas has developed a district regulator station (DRS) risk assessment tool to assess prioritizing enhancements and replacements of stations. Concurrent with starting this new risk model, SoCalGas plans to utilize the results of the model more fully by increasing the number of regulator station replacements specifically to reduce safety risks. The new risk model, similar to DIMP DREAMS for pipeline segments, includes likelihood of failure and consequence of failure related data for all regulator stations. Risk reduction is achieved when addressing both equipment failure probability and consequences. Best practices and philosophies have evolved to modernize antiquated stations designs to essentially reduce over/under pressure and outside force risks. SoCalGas will prioritize the replacement of DRSs across operating regions while continuing to enhance the prioritization methodology to validate the number of regulator station replacements performed each year. This regulator station replacement risk assessment effort is an example of modernizing SoCalGas's aging infrastructure and will be used as a model to review other facilities and equipment in a similar fashion.

While stations have been replaced in the past to reduce safety risk, this new risk model allows prioritization and focus of this particular replacement work based solely on safety, and allows for this work to become a multi-year program moving forward.

### F. C6: Meter Set Assembly (MSA) Inspection and Maintenance

Meter and regulator activities include maintaining, inspecting, or replacing approximately ten percent of the total 102,010 medium and large M&R MSAs in the SoCalGas service territory. The MSAs 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 meter set assemblies proactively target the risk of equipment failures, corrosion, and outside force before operation and safety issues arise. In addition, as required by 49 CFR § 192.481, above ground piping facilities such as MSAs must be inspected for atmospheric corrosion no less than once every three calendar years and at intervals not to exceed 39 months.

### G. C7: Electronic Pressure Monitor (EPM) Replacement & Installs

The purpose of Electronic Pressure Monitoring (EPM) is to monitor and record system operating pressures, and generate alarms when pressures exceed or drop below alarm set points, monitoring for maximum allowable operating pressure (MAOP) exceedance or under-pressure conditions as required by 49 CFR 192.741, 192.201(a), 192.739(a)(2), and GO 112F 122.2. Pressure alarms are maintained and evaluated and the appropriate corrective actions such as new installs and replacements are taken to ensure public safety and operation of Company infrastructure. The pressure zones and pressure districts are monitored and reported as part of GO 112-F requirements for Over-MAOP and Under-Pressure events. EPMs are required to indicate the gas pressure in each distribution system supplied by more than one district pressure regulating station. In addition, for distribution systems supplied by a single district pressure regulating station, it is up to the operator to determine the necessity of installing an EPM. EPM installations and replacements are ongoing activities.

### H. C8: Leak Survey

SoCalGas performs leak survey monitoring activities by conducting a thorough search for gas leak indications in an assigned area and reporting all detectable leaks using an approved survey method.

The monitoring and inspections must follow certain prescribed processes included in the Code of Federal Regulations[24] and incorporated into SoCalGas's Gas Standards.

- For medium pressure pipelines operating at 60 psig or less, the following apply:
    - (1) Survey all pipe (including services) in business districts at intervals not exceeding 15 months, but at least once each calendar year.

[24] 49 CFR § 192.721.

(2) Survey Non-State-of-the-Art polyethylene (PE) main pipe and connected services where the main is not located in a business district once every calendar year, at intervals not exceeding 15 months.

(3) Survey cathodically unprotected main pipe and connected services where the main is not located in a business district at least once every three calendar years at intervals not exceeding 39 months.

(4) Survey PE and cathodically protected main pipe and connected services where the main is not located in a business district once everyfive calendar years at intervals not exceeding 63 months.

- High pressure pipelines operating over 60 psig, not including Department of transportation (DOT) transmission pipelines.

  (1) Survey all pipelines and associated taps, cross-over piping, services and other piping every 15-months; but at least once every calendar year for all location classes.

- Special Survey

  Special leak surveys are one-time, additional surveys to the routine scheduled survey that is driven by a specific circumstance. Perform special leak survey:

  (1) Upon discovery that the MAOP of a pipeline is exceeded by 10% or more at any time during the life of the pipeline;

  (2) After the occurrence of any significant incident (*e.g.*, train derailment, explosion, earthquake, flooding, landslides, etc.) over or adjacent to high pressure pipelines or related facilities;

  (3) There is the danger of public exposure to leaking gas; the special survey is performed using the appropriate leak detection method. Document the reason, location, limits, and results of all special leak surveys on the appropriate Company inspection record;

  (4) When increasing the MAOP of a pipeline;

  (5) When the routine scheduled survey frequency is not considered adequate because of pipe condition, limited opportunity for gas to vent safely, or other reasons. When the special surveys will be ongoing and scheduled,

efforts shall be made to identify the segment of pipe to be at the greater frequency in SAP and EGIS, and be scheduled as routine;

(6) There is a need to monitor pipe condition for special situations, such as: material evaluations, proposed street improvement projects, as a mitigated measure for the Integrity Management Program; and

(7) Special leak survey may also be considered in conjunction with major underground construction projects.

### I. C9/C10/C11: Pipeline Monitoring (Pipeline Patrol, Bridge & Span Inspections, Unstable Earth Inspection)

SoCalGas conducts pipeline monitoring and inspection activities to proactively target risk factors before operation and safety issues arise. These monitoring activities include pipeline patrols (C9), bridge and span inspections (C10), and unstable earth inspections (C11) to observe surface conditions on and adjacent to the pipeline right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation to comply with 49 CFR §§ 192.705, 192.721. Pipeline patrols are conducted by trained personnel familiar with the location and operation of the pipeline. Qualified distribution Field Employees are responsible for using Pipeline Patrol Maps that depict the location of pipe and the frequency in which the pipe should be patrolled, to aid in pipeline patrol activities.

Distribution pipeline spans, pipe supported on bridges, above ground (or jacketed) pipelines, and all other exposed pipeline (as installed) are inspected for atmospheric corrosion. As-found conditions that are corrected upon discovery are identified and reported, and the remedial action taken are also noted. For all transmission pipeline and distribution main additional (special) patrols are conducted as deemed necessary immediately after events that could cause pipeline movement or loading conditions to change. These events may include earthquakes, heavy rain, flooding, sinkholes, landslides, or indications of earth movement, surface subsidence or cracking, that would result in unstable earth conditions.

Pipeline monitoring activities are preventative in nature and should reduce or eliminate conditions that might lead to an incident by detecting and addressing emergent issues. Pipeline monitoring activities also increase public and employee safety by mitigating various risk sources, including corrosion and degradation, for example. Safety risks will be proactively reduced on a regular basis as result of the continual, ongoing nature of pipeline monitoring activities.

Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability. 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.

### J. C12: Valve Inspection & Maintenance

Valve maintenance is a program that validates that the valves within the system operate at optimum effectiveness, enhancing public safety by providing SoCalGas with the ability to control the pressure and flow of gas in the system. The maintenance activities vary by type of valve, and 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: fire valves at 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 incident, these valves will operate as intended and fully isolate the area. A second example, which occurs more frequently, when excavation damage occurs, these valves can be operated to allow for a safe environment to complete the repairs and minimize the risk of furthering the incident.

The following summarizes the requirements for completing these preventative measures as prescribed within the 49 CFR § 192.747 and followed by SoCalGas:

- Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.
- Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

### K. C13: Valve Installs and Replacements

Each "critical" valve, the use of which may be necessary for the safe operation of a distribution system must be inspected, serviced, lubricated and/or flushed (when required) and partially operated at intervals not exceeding 15 months, but at least once each calendar year. Each operator must take prompt remedial action to correct any "critical" valve found inoperable unless the operator designates an alternate valve.

"Critical" valves are open valves considered necessary for the safe operation of the distribution system. Examples may include but are not limited to:

- Sectionalizing valves in supply lines.
- "Shut-off" valves upstream and downstream of regulator stations. This may be completed as part of the Regulator Station Inspection.
- Isolation area valves.
- Bridge approach valves.
- All other valves, as determined by Distribution Engineering to be critical to the safe operation of the distribution system.

After scheduled inspections, if the conditions of valves that are identified as "hard to operate," "inaccessible," "inoperable," or "sanded-in are not resolved, Distribution Planning and Engineering personnel must be informed to create an alternate shutdown procedure in addition to working with Distribution Planning on a possible valve replacement or new valve installation plan.

### L. C14: Cathodic Protection – Install/Replace Impressed Current Systems

Buried steel pipelines will revert back to their natural state as an iron oxide (corrode) without proper intervention. Corrosion on pipelines increases the risk for leaks and may reduce the useful life of the pipelines. In addition to the application of coating and electrical isolation, cathodic protection (CP) is a method for mitigating external corrosion on steel pipelines. CP combats corrosion by imposing an electric current flow toward the surface of the pipeline, which means keeping the pipeline negatively charged (cathodic) with respect to the surrounding soil. This results in reduced corrosion on the pipeline system. Title 49 C.F.R. § 192, Subpart I, and GO 112-F set forth the regulatory standards that govern pipeline corrosion control. SoCalGas utilizes impressed current systems to provide CP to existing pipelines. Impressed current systems utilize a rectifier for the generation of the direct current and sacrificial anodes as primary components 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 rectifiers and 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. Impressed current cathodic protection system maintenance, installation, and replacement are all ongoing activities.

### M. C15: Inspection of Company and Contractor Work on Gas Pipelines.

Company Authorized Representatives (CAR) shall inspect and score construction work performed by SoCalGas and contractors to ensure Company quality standards are met. The inspection is documented on Form Number 2849 Construction Inspection Report (CIR) and made available electronically from Company databases. SoCalGas manages all aspects of gas pipeline construction projects daily and oversees contractor work at construction sites to ensure that the project is built to Company Gas Standards. SoCalGas personnel physically inspect gas pipeline construction projects and preside over high- and medium-pressure control operations and inspect all welding, materials, testing, coating, excavating, backfilling, paving, and repairs on pipeline projects. All work performed by contractors and subcontractors is subject to the inspection and approval of the Company at all times, but such right of inspection of the work by the Company does not relieve the contractor of responsibility for the proper performance of the work. The CAR acts as the Company representative on-site and the liaison between the Company and contractors for submittals, schedules, material requirements, change orders, environmental issues, operator qualifications, invoices, engineering designs, etc.

Supervisors and SoCalGas representatives conduct documented job-site safety inspections of contractors working at a facility, property, or worksite owned, operated, or managed by the Company (including leased premises and rights-of-ways) on SoCalGas projects at a frequency of once per week per contractor. When there are multiple crews for a specific contractor working on similar projects, one safety inspection per contractor per week meets this requirement. The CIR, built in ISNetworld, a vendor platform for contractor management services, must be used for documenting such inspections and the Report of Contractor's Performance, Form Number 6350, also built in ISNetworld, must be used for documenting the contractor's performance.

Qualified Company personnel must perform inspections of contractor crews performing work under blanket contractor agreements and document the observations on Form Number 2849 CIR at least two times each week over a minimum of two days or (more), as needed. Observations of Company crews and the contractors' work, tools, equipment, and materials used, employee qualifications, and procedural adherence all provide opportunity to identify, assess, and resolve potential hazards.

### N. C16: Capital CP 10 Service Replacement

Service Replacements are for routine replacement of isolated medium pressure distribution service pipelines to maintain system reliability. One of the main drivers for Service Replacements is corrosion, which also involves underground (UG) shorts, and/or ineffective coating, for example if a -1.0 Volt direct current minimum pipe-to-soil (P/S) potential cannot be achieved, the service should be replaced. Service Replacement costs associated with main replacements are captured in the forecast for main replacements.

SoCalGas has a total of 320,065 CP10 services that will continue to be monitored, inspected, and maintained on a ten-year cycle. CP10 services are separately protected service lines that are surveyed on a sampling basis where at least ten percent of system inventory is sampled each year, so that the entire system is tested in a ten-year period.

### O. C17: Main & Service Leak Repair

This control establishes guidelines and requirements for assessing the degree of hazard and coding of leaks or leak indications found on the Company's below ground piping system, and actions required to provide for public safety and repair of the leak as required by SoCalGas' Gas Standards. Leak indications on Company facilities are classified by trained and qualified employees according to location, spread, concentration of gas, possibility for accumulation of gas, possible sources of ignition, potential migration, and imminence of hazard to people or property. Classifications of leaks or leak indications are based on the relative degree of hazard and examples listed are intended only as a guide. The judgment of the person evaluating the leak or leak indication, after consideration of all factors involved, is the primary criterion for classification and mitigation. Hazardous indications of underground leaks are reported, and action is taken according to the applicable Gas Standard until the hazard has been eliminated and the leak has been either temporarily or permanently repaired; or until it is determined that the leak is from a source other than the Company piping system. Existing leaks are verified using the “Shop Papers” under the “Attachments” tab within the Leak Survey Order. Once verified, existing leaks are identified with the Equipment number. Existing Code 2 and Code 3 (Steel and Plastic) leak indications are displayed on the Leak Survey Map and identified with the Equipment number. Leak indications detected over existing leaks within the path of survey are recorded.

If indications are still present and additional leakage is suspected, the Company issues a Recheck Leak Order when conditions are non-hazardous and current leak investigation procedures can no longer be performed, or it is impractical to continue. Recheck Leak orders are dispatched at or after 60 days and must be completed within 90 days from the completion of the original Leak Repair Order. Recheck Leak orders must not be revaluated.

The taking of below ground leak samples with an approved combustible gas indicator is conducted to the extent that the belowground leak spread is determined or to ensure that the belowground area is free from concentrations of natural gas. Leak investigations where leakage is not readily detected must include at a minimum, but is not limited to, all belowground gas facilities for 150’ ft in all directions (both sides of street/alley way) over the main and services from the initial location where the leak or odor was reported.

Each segment of pipeline that becomes unsafe must be repaired, altered, or removed from service. Each imperfection or damage that would impair the serviceability of PE pipe or fittings must be repaired or removed. Appropriate temporary repairs such as plugging, or clamping shall be made if permanent repairs are not possible at the time of discovery.

### P. C18: Residential Meter Protection Project

The Residential Meter Protection Project (RMPP) addresses the prevention of potential vehicular damage associated with above-ground distribution facilities at residential properties. This control minimizes the potential for vehicular damage for above ground gas equipment (*e.g.*, the meter set assembly, or MSA) by placing various forms of physical devices or barriers to mitigate damage in case of a potential collision. Barriers are intended to be a visual, not a structural, deterrent and are not intended or capable of stopping all vehicular traffic, particularly large vehicles. Where adequate mitigation cannot be achieved, gas equipment can be relocated or removed. Additionally, RMPP addresses the concerns PHMSA expressed under its regulations that require operators to address identified threats of low frequency but potentially high consequence events.

RMPP anticipates there are as many as 300,000 locations where need for mitigation from vehicular damage is warranted. RMPP is expected to last as a project for approximately 10-12 years.

### Q. C19: Main Replacements- Leakage, Abnormal Op. Conditions, CP Related

Activities under Main Replacements include installation of new mains to replace existing ones, main replacements in advance of public infrastructure projects, and service line replacements, existing service line tie-overs, and meter set rebuilds in connection with newly installed replacement mains. Replacements are due to leakage and anticipated leakages, defects, corrosion, deterioration of pipes, and to meet cathodic protection mandates.

Leakage is often the driving factor for pipeline replacements; however, there are other considerations. Other criteria taken into consideration are whether the steel pipe meets cathodic protection mandates, or the main is found to have active corrosion. In addition, the pipeline may be deemed unsafe or unfit for service under pressure due to manufacturing or other defects. Leak history and pending leaks on individual segments are the primary factors in identifying the majority of SoCalGas's main replacements. These replacements are critical to sustain operational reliability and public safety.

### R. C20: Distribution Integrity Management Program - Distribution Riser Inspection Program (DRIP)

The Distribution Riser Inspection Project (DRIP) is one of the Programs/Projects and Activities to Address Risk (PAAR) under the DIMP and addresses the threat of failure of anodeless risers due to corrosion. Anodeless risers (ALRs) are service line components that have shown a propensity to fail before the end of their useful lives. ALRs were first introduced in the 1970s as a new technology replacing steel risers to transition from the underground plastic pipe to the above ground steel meter set. When an ALR was originally installed, it was set at a height where the gas carrying portion of the ALR was above ground. However, as grade conditions change due to landscaping and hardscaping, this gas carrying portion may no longer be at the proper height above the ground. When the gas carrying portion of the ALR is buried or set too low it can potentially corrode due to contact with the soil. The consequence of this component failing can be significant in that risers are attached to the meter set assembly, which is usually located next to a residence.

SoCalGas's research-based efforts to develop an effective means of mitigating above-ground and ground level corrosion on anodeless risers has led to the implementation of the epoxy composite wrap, which provides a protective barrier for the above-ground section of the riser under the environmental conditions that are typical of riser installations, in lieu of replacement of the riser. Where the threat of failure of an ALR is present, SoCalGas will remediate the issue by implementing an epoxy composite wrap to provide a protective barrier for the above-ground section of the ALR.

### S. C21: Distribution Integrity Management Program - Distribution Risk Evaluation and Monitoring System (DREAMS)

The DREAMS program is an additional control developed and managed as part of the DIMP. Within DIMP, the DREAMS tool is used to prioritize risk mitigation on early vintage plastic and steel pipeline segments. The risk algorithm includes pipe attributes, operational conditions, and potential impact on population. The results of the analysis determine appropriate action to address risk for each segment and prioritize replacement investments based on a failure analysis.

As SoCalGas's infrastructure continues to age and more leak data is accumulated through annual inspections, SoCalGas plans to continue increasing the level of replacement while monitoring performance to continually review the benefits and risk reduction accomplished through the replacement program through indicators such as leak repair and incident rates related to early vintage plastic as part of DIMP regulations. Although the initial outlook is for a continued increase in scope for DREAMS (as previously stated), program metrics will be monitored on a continual basis to determine increased or decreased levels in scope.

#### 1. C21-T1: Vintage Integrity Plastic Plan (VIPP)

The Vintage Integrity Plastic Plan (VIPP) falls within the umbrella of DREAMS. Plastic pipe manufactured and used for gas service from the 1960s through the early 1980s exhibit a brittle-like cracking characteristic that could cause a leak to grow and release additional natural gas than would otherwise be released, increasing the risk of natural gas gathering and igniting, and potentially causing injuries and/or fatalities. Given the potential for a higher release of gas, the leak survey frequency 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 Low Ductile Inner Wall (LDIW) issue that further exacerbates the brittle-like cracking issues since it expedites crack initiation when external loads are applied. This issue in the manufacturing practice has been the focus of earlier notices as issued by the manufacturer DuPont and PHMSA. Therefore, the focus is on wholesale replacement of pre-1973 plastic pipe, with priority given to poor performing segments, by utilizing a relative risk model and dynamic segmentation. The secondary focus is to leverage the same relative risk model and dynamic segmentation to continue to focus on the replacement of poor performing early vintage plastic for all pre-1986 plastic pipe.

As mentioned, SoCalGas anticipates continuing to increase the level of replacement 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. C21-T2: Bare Steel Replacement Program (BSRP)

The Bare Steel Replacement Plan (BSRP) falls within the umbrella of DREAMS and will continue to focus on the replacement of bare steel with the highest leak rates. SoCalGas plans to target 35 miles of steel mains and associated services in 2021 for replacement above and beyond routine replacements. SoCalGas continues monitoring performance to review the benefits and risk reduction accomplished through BSRP through indicators such as leak repair and incident rates related to bare steel. The lack of protective coating makes bare steel a high-risk family of pipe and has been identified by DOT and PHMSA as a family of pipe that should be evaluated for an accelerated replacement program.

### T. C22: Distribution Integrity Management Program - Gas Infrastructure Protection Program (GIPP)

The Gas Infrastructure Protection Project (GIPP) addresses prevention of potential third-party vehicular damage associated with above-ground pressurized natural gas facilities. An incident involving vehicular damage of a distribution facility can cause serious injuries or fatalities due to the possibility of ignition. The GIPP is an additional control developed and managed as part of the DIMP. This program is responsive to PHMSA guidance indicating that operators should address low frequency, but potentially high consequence, events through the

DIMP.[25] Although the DIMP guidelines do not prescribe what programs operators should implement, the prescriptive sections result in the need to take action to reduce system risk.

GIPP identifies, evaluates, recommends, and implements damage prevention solutions for at risk above-ground pressurized gas facilities that are exposed to vehicular impacts. The solutions reduce the number of incidents to pressurized piping and/or reduce the potential consequences caused from escaping natural gas after vehicular collisions. Major actions include investigating historical claims data and developing risk assessment algorithms, conducting record reviews and physical inspections of facilities, developing risk exposure categories, identifying and implementing mitigation measures, updating policies/practices/procedures, and developing performance measures and program tracking.

GIPP remediation measures include the construction of barriers between facilities and vehicular traffic (bollards or block wall), relocation of a facility, or installation of an excess flow valve. Barriers are intended to be a visual, not a structural deterrent and are not intended or capable of stopping all vehicular traffic, particularly large vehicles. The installation of excess flow valves can aid in the reduction of unrestrained gas flows. Considerations for the relocation of a facility include the type of road nearby, the volume of traffic, and the type of area (*e.g.*, commercial or residential). The prioritization of GIPP inspections and remediations is based on field assessments.

Among MSAs, which is the largest population of facility type, the most vulnerable are high pressure residential first stage regulation meter sets and commercial and industrial MSAs. GIPP is focusing on these meter sets and MSAs, which account for approximately 500,000 facilities in the SoCalGas territory. Since the development and implementation of the program in 2011, approximately 475,000 sites with above-ground distribution facilities have been inspected and over 45,000 sites have been remediated.

### U. C23: Distribution Integrity Management Program - Sewer Lateral Inspection Project (SLIP)

The SLIP project is an additional control developed and managed as part of the DIMP. SLIP addresses the concerns PHMSA expressed under the DIMP regulations that require operators to address identified threats of low frequency, but potentially high consequence events

[25] U.S. Department of Transportation PHMSA, DIMP Enforcement Guide (Dec. 7, 2015), *available at* *https://www.phmsa.dot.gov/pipeline/enforcement/dimp-enforcement-guidance*.

concerning pipeline damage within sewer laterals. Threats to pipeline integrity can occur if the trenchless installation inadvertently crosses a sewer line (or "lateral") and penetrates, or bores, through the sewer line, creating what is referred to as a "cross bore." For instance, through the SLIP, SoCalGas is proactively inspecting gas services for points of intrusion into house sewer lines. Should an intrusion be found, the service is remediated, which mitigates the potential of an incident due to a homeowner or plumber attempting to clear a house sewer line when a clog is present. For example, a plumber or the property owner may unknowingly uses a cleanout technology, such as a sewer-line auger, to clean out what is seemingly normal sewer debris and blockage. Following this work, the sewer line appears to be unclogged, but in reality, the sewer-line auger has pierced the gas line. Depending on how extensive the damage caused by the sewer-line auger, the gas line, which has now been breached, will leak gas into the sewer line and elsewhere. This unwanted gas migration can pose significant risks of bodily injury and damage to property.

Since the start of the program in 2010, approximately three million services have been reviewed and over 450,000 services inspected in the field. The SLIP forecast for remaining records review is about two million services; the number of remaining services to be inspected depends on the findings of the records review, but is anticipated to add another 300,000-350,000 services, based on current estimates. At the present rate, SLIP records research is anticipated to be completed by 2025.

## V. C24: 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 Information Technology (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 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.

### W. C25: Field Employee Skills Training

Training is an integral part of how SoCalGas mitigates the Medium Pressure Incident risk. All field service technicians must complete and pass mandatory training. This training includes classroom and situational field exercises to educate employees on safety processes and procedures to perform work in a manner that meets all applicable rules, regulations, and SoCalGas internal policies and procedures. Formal skills training reduces the likelihood of employees deviating from Company policy or procedure because field service technicians do not work customer orders on their own until they are fully trained to do their jobs adequately and safely. Once the field service employees successfully pass formal training, they are permitted to work customer orders on their own.

### X. C26: Staff Employee Skills Training

Field instructors within the Customer Services staff area conduct the mandatory training for field service technicians based on safety process and procedures to perform work in a manner that meets all applicable rules, regulations, and SoCalGas internal policies and procedures. A follow-on quality assurance assessment is then performed by Field Instructors to confirm that the field service technicians have retained the training knowledge and skills required to safely perform their duties.

### Y. C27: Emergency Calls

Customers call SoCalGas's Customer Contact Center (CCC) to request service for many different reasons, including potential gas leaks and other emergency orders. As it is often the first point of Company contact for emergencies; the CCC provides a critical support role in the safety of the SoCalGas system and the public's well-being. Gas leak calls are given top priority, and customer service representatives are trained to identify the different types of emergencies and manage calls to see that appropriate field personnel are sent in an order prioritizing the necessary response in accordance with 49 Part § 192.615.

These types of requests include, but are not limited to:

- General Leaks – at appliances, at gas meters, inside structures-source unknown, ignited leaks;
- Outside Leaks- damaged gas lines or meter, dying vegetation;
- Carbon Monoxide (CO) – customer experiencing symptoms or not, CO safety checks, CO alarm/Detectors activated or not;
- Miscellaneous Safety-Related issues – Odor Fade, appliance recalls; and
- Other Urgent Situations – water heater not cycling off (water steaming), bomb threats.

The CCC also helps to mitigate risk related to the medium pressure system during non-emergency situations by issuing customer requested appliance inspection and maintenance orders.

### Z. C28: Quality Assurance Program

As referenced in C26, SoCalGas performs regular Quality Assurance (QA) assessment of the quality of work of its field personnel. The QA function regularly includes in-field sampling of completed customer service field orders to assess employee work quality and compliance with Company policies and procedures. QA Specialists receive random orders previously completed by customer service field representatives and make in-home visits. The purpose of the QA program is to have QA Specialists verify that customer service field representatives recognize and address safety issues with customer-owned appliances and Company-owned equipment. The efforts of the QA program promote improved consistency while adhering to Company policies and processes and a reduction in work errors that may pose a risk to customer and public safety.

### AA. C29: DCU/Pole Inspections

SoCalGas conducts cyclical inspections of Data Collector Units (DCUs) and poles to identify structural problems and/or hazards in support of public safety and a reliable network communication. Although SoCalGas is only mandated to inspect SoCalGas-owned poles, SoCalGas goes above and beyond and inspects all DCU units on an annual basis, including third party poles. The pole inspection process identifies structural problems and/or hazards in support of public safety and system reliability.

Qualified SoCalGas field resources perform this work in accordance with the CPUC's General Order 165. The purpose of this General Order is to establish requirements for electric distribution and transmission facilities (excluding those facilities contained in a substation) regarding inspections in order to ensure safe and high-quality electrical service. Inspection results are logged and maintained by the Network Maintenance & Construction team for compliance reporting.

**BB. C30: Meter Set Assembly (MSA) Inspection Program**

As required by the Department of Transportation CFR Title 49 §192.481 regarding inspections of above-ground piping facilities for atmospheric corrosion, Meter Set Assemblies (MSAs) and exposed above ground piping must be inspected no less than once every three calendar years and at intervals not exceeding 39 months. In addition to atmospheric corrosion, SoCalGas has proactively expanded the inspection criteria to include other physical conditions at the MSA that may pose the potential risk to safety and reliability. All remedial activities are conducted within required timelines and/or prioritization based on conditions found at the time of the inspection or in an abundance of caution.

**CC. C31: Personal Protective Equipment (PPE)**

The purpose of SoCalGas's PPE Program is to protect employees from the risk of injury by creating a barrier against workplace hazards. The PPE Program addresses eye, face, head, foot, and hand protection. OSHA standards require employers to conduct and certify workplace hazard assessments for the use of PPE at facility locations that are representative of the types of ongoing work operations. SoCalGas does not have to perform a hazard assessment at each location, but if a hazard assessment is performed, for example, at a transmission facility, then that assessment is representative of other similar transmission facilities and would also apply to those locations. SoCalGas provides its employees with the PPE required to safely perform work (*e.g.*, flame-retardant suits, eye protection, and gloves). The Company maintains processes and procedures so that employee hearing and respiratory functions are not impaired due to exposure to harmful environmental conditions. When work is performed that could expose customers or the public to injury, controls are implemented to mitigate the risk. The costs associated with protective equipment and specific occupational safety programs are included in this category.

### DD. C32: Safety Related Field Orders

Field service technicians respond to the customer orders taken by the CCC, described above in C25 Emergency Calls. They are trained to rectify safety hazards on customer premises in order to maintain safe operations of Company facilities. Some of these customer requests are safety related, such as checking appliances upon move in. However, any customer call about a gas leak, both hazardous and non-hazardous, is dispatched to a field service technician to perform a gas leak investigation. SoCalGas requires that all hazardous and non-hazardous leak orders are responded to by a field technician within the same day of receiving the customer call, with the response to the highest priority gas leak orders within 30 minutes.

## 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]

As reflected in the Table below, all the activities discussed in Section III above are expected to continue during the TY 2024 GRC. For clarity, a current activity that is included in the plan may be referred to as either a control and/or a mitigation. For purposes of this RAMP, a control that will continue as a mitigation will retain its control ID unless the size and/or scope of that activity will be modified, in which case that activity's control ID will be replaced with a mitigation ID. The table below shows which activities are expected to continue.

**Table 3: Control and Mitigation Plan Summary**

| Line No. | Control/ Mitigation ID | Control/Mitigation Description | 2020 Controls | 2022-2024 Plan |
|---|---|---|---|---|
| 1 | C1 | Cathodic Protection Base Activities | X | X |
| 2 | C2 | Cathodic Protection - CP10 Activities | X | X |
| 3 | C3 | Cathodic Protection - 100mV Requalification | X | X |
| 4 | C4 | Meter & Regulator Station Inspection and Electronic Pressure Monitors (EMP) Inspection and Maintenance | X | X |
| 5 | C5 | Regulator Station Replacements/Installs | X | X |
| 6 | C6 | Meter Set Assembly (MSA) Inspection and Maintenance | X | X |
| 7 | C7 | EPM Maintenance & Installs | X | X |

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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 |
|---|---|---|---|---|
| 8 | C8 | Leak Survey | X | X |
| 9 | C9/C10/C11 | Pipeline Monitoring (Pipeline Patrol, Bridge & Span Inspections, Unstable Earth Inspection) | X | X |
| 10 | C12 | Valve Inspection & Maintenance | X | X |
| 11 | C13 | Valve Installs and Replacements | X | X |
| 12 | C14 | Cathodic Protection – Install/Replace Impressed Current Systems | X | X |
| 13 | C15 | Company and Contractor Inspections on Gas Pipelines | X | X |
| 14 | C16 | Capital CP 10 Service Replacement | X | X |
| 15 | C17 | Main & Service Leak Repair | X | X |
| 16 | C18 | Residential Meter Protection | X | X |
| 17 | C19 | Main Replacements- Leakage, Abnormal Op. Conditions, CP Related | X | X |
| 18 | C20 | Distribution Integrity Management Program (DIMP) - Distribution Riser Inspection Program (DRIP) | X | X |
| 19 | C21-T1 | DIMP - Distribution Risk Evaluation and Monitoring System (DREAMS): Vintage Integrity Plastic Plan (VIPP) | X | X |
| 20 | C21-T2 | DIMP – DREAMS: Bare Steel Replacement Program (BSRP) | X | X |
| 21 | C22 | Distribution Integrity Management Program - Gas Infrastructure Protection Program (GIPP) | X | X |
| 22 | C23 | Distribution Integrity Management Program - Sewer Lateral Inspection Project (SLIP) | X | X |
| 23 | C24 | CCM Distribution Field Asset Real Time Monitoring and Control Site Installations / Upgrades & New Control Room Technologies | X | X |
| 24 | C25 | Field Employee Skills Training | X | X |
| 25 | C26 | Staff Employee Skills Training | X | X |
| 26 | C27 | Emergency Calls | X | X |
| 27 | C28 | Quality Assurance Program | X | X |
| 28 | C29 | DCU/Pole Inspections | X | X |
| 29 | C30 | Meter Set Assembly (MSA) Inspection Program | X | X |
| 30 | C31 | Personal Protective Equipment (PPE) | X | X |

| Line No. | Control/ Mitigation ID | Control/Mitigation Description | 2020 Controls | 2022-2024 Plan |
|---|---|---|---|---|
| 31 | C32 | Safety Related Field Orders | X | X |

For activities SoCalGas 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 the section below.

### EE. Changes to 2020 Controls

SoCalGas plans to continue each of the existing mitigations discussed above in Section III through the 2022 – 2024 period without any significant changes.

### FF. 2022 – 2024 Mitigations

SoCalGas is currently not planning any new mitigations during the 2022 – 2024 period.

## 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. SoCalGas does not account for and track costs by activity or tranche; rather, SoCalGas accounts for and tracks costs by cost center and capital budget code. The costs shown were estimated using assumptions provided by SMEs and available accounting data.

**Table 4: Risk Control and Mitigation Plan - Recorded and Forecast Dollars Summary[27]**
**(Direct After Allocations, In 2020 $000)**

| ID | Control/Mitigation Name | Recorded Dollars | | Forecast Dollars | | | |
|---|---|---|---|---|---|---|---|
| | | 2020 Capital[28] | 2020 O&M | 2022-2024 Capital (Low) | 2022-2024 Capital (High) | TY 2024 O&M (Low) | TY 2024 O&M (High) |
| C1 | Cathodic Protection Base Activities | - | 11800 | - | - | 10850 | 13130 |
| C2 | Cathodic Protection- CP10 Activities | - | 1225 | - | - | 875 | 1160 |
| C3 | Cathodic Protection- 100mV Requalification | - | 5 | - | - | 1105 | 1335 |
| C4 | Meter & Regulator (M&R) Station and Electronic Pressure Monitors (EPM) Inspection and Maintenance | - | 3047 | - | - | 3395 | 4150 |
| C5 | Regulator Station Replacements/Installs | 1750 | - | 8215 | 10870 | - | - |
| C6 | Meter Set Assembly (MSA) Inspection and Maintenance | - | 1620 | | | 1455 | 1780 |
| C7 | Electronic Pressure Monitor (EPM) Replacement & Installs | 190 | - | 1270 | 1680 | - | - |
| C8 | Leak Survey | - | 8400 | - | - | 7180 | 8690 |

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

28 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/C10 /C11 | Pipeline Monitoring (Pipeline Patrol, Bridge & Span Inspections, Unstable Earth Inspection) | - | 160 | - | - | 160 | 195 |
| C12 | Valve Inspection & Maintenance | - | 1005 | | | 1215 | 1475 |
| C13 | Valve Installs and Replacements | 1000 | - | 2440 | 2980 | - | - |
| C14 | Cathodic Protection – Install/Replace Impressed Current Systems | 5855 | - | 17695 | 23400 | - | - |
| C15 | Company and Contractor Inspection on Gas Pipelines | 1670 | 350 | 4380 | 5795 | 305 | 405 |
| C16 | Capital CP 10 Service Replacement | 13400 | - | 36545 | 44220 | - | - |
| C17 | Main & Service Leak Repair | | 17300 | - | - | 12840 | 15695 |
| C18 | Residential Meter Protection Project | 4760 | - | 23745 | 31405 | - | - |
| C19 | Main Replacements- Leakage, Abnormal Op. Conditions, CP Related | 23000 | - | 63000 | 83320 | - | - |
| C20 | Distribution Integrity Management Program - Distribution Riser Inspection Program (DRIP) | - | 19820 | - | - | 22260 | 28445 |
| C21-T1 | DIMP – DREAMS: Vintage Integrity Plastic Plan (VIPP) | 106945 | 4095 | 501070 | 606560 | 45515 | 55100 |

[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[30] | 2020 O&M | 2022-2024 Capital (Low) | 2022-2024 Capital (High) | TY 2024 O&M (Low) | TY 2024 O&M (High) |
| C21-T2 | DIMP – DREAMS: Bare Steel Replacement Program (BSRP) | 73630 | 3055 | 214745 | 259955 | 19505 | 23615 |
| C22 | DIMP: Gas Infrastructure Protection Program (GIPP) | 13575 | 2110 | 49145 | 62800 | 10430 | 13325 |
| C23 | DIMP: Sewer Lateral Inspection Project (SLIP) | - | 15970 | - | - | 22260 | 28445 |
| C24 | CCM Distribution Field Asset Real Time Monitoring and Control Site Installations/Upgrades & New Control Room Technologies | 5805 | 46 | 49675 | 71755 | 3870 | 5590 |
| C25 | Field Employee Skills Training | - | 5710 | - | - | 9904 | 11989 |
| C26 | Staff Employee Skills Training | - | 3070 | - | - | 2432 | 2944 |
| C27 | Emergency Calls | - | 3664 | - | - | 3396 | 4112 |
| C28 | Quality Assurance Program | - | 763 | - | - | 771 | 933 |
| C29 | DCU/Pole Inspections | - | 257 | - | - | 251 | 304 |
| C30 | Meter Set Assembly (MSA) Inspection Program | - | 24650 | - | - | 21065 | 25499 |
| C31 | Personal Protective Equipment (PPE) | - | 113 | - | - | 160 | 193 |
| C32 | Safety Related Field Orders | 4878 | 61126 | 16965 | 20540 | 90198 | 109187 |

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

**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 Base Activities | No. of Base CP orders | | - | 43718 | - | - | 41378 | 50068 |
| C2 | Cathodic Protection- CP10 Activities | No. of CP 10 orders | | - | 13977 | - | - | 9999 | 13224 |
| C3 | Cathodic Protection- 100mV Requalification | No. of 100mV Requalification areas | | - | 10 | - | - | 230 | 282 |
| C4 | Meter & Regulator (M&R) Station and Electronic Pressure Monitors (EPM) Inspection and Maintenance | No. of M&R inspections and maintenance orders | | - | 10410 | - | - | 9830 | 12015 |
| C5 | Regulator Station Replacements/Installs | No. of replacements and/or installations | | - | 5 | 23 | 31 | - | - |
| C6 | Meter Set Assembly (MSA) Inspection and Maintenance | No. of MSA inspections and maintenance orders. | | - | 8388 | - | - | 7549 | 9227 |
| C7 | Electronic Pressure Monitor (EPM) Replacement & Installs | No. of replacements/installs | | 62 | | 413 | 546 | - | - |
| C8 | Leak Survey | Leak survey mileage | | - | 31529 | - | - | 27095 | 32786 |
| C9/ C10/ C11 | Pipeline Monitoring (Pipeline Patrol, Bridge & Span Inspections, Unstable Earth Inspection) | No. of inspection orders | | - | 1404 | - | - | 1439 | 1759 |

| 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 |
| C12 | Valve Inspection & Maintenance | No. of Valve inspection & maintenance orders. | | - | 7126 | - | - | 6830 | 8264 |
| C13 | Valve Installs and Replacements | No. of replacements and installations | | 21 | - | 51 | 60 | - | - |

| ID | Control/Mitigation Name | Units Description | | Recorded Units | | Forecast Units | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Capital | O&M | 2020 Capital | 2020 O&M | 2022-2024 Capital (Low) | 2022-2024 Capital (High) | TY 2024 (Low) O&M | TY 2024 (High) O&M |
| C14 | Cathodic Protection – Install/Replace Impressed Current Systems | No. of deep well installations and replacements | | 43 | - | 130 | 171 | - | - |
| C15 | Company and Contractor Inspection on Gas Pipelines | No. of inspections on pipeline | | 18039 | 7811 | 47058 | 62235 | 6792 | 8983 |
| C16 | Capital CP 10 Service Replacement | No. of replacements | | 2186 | | 5962 | 7214 | - | - |
| C17 | Main & Service Leak Repair | No. of main & service leak repairs orders | | - | 34689 | | | 30022 | 36694 |
| C18 | Residential Meter Protection Project | No. of meter guard installations projects | | 10420 | - | 47491 | 62807 | - | - |
| C19 | Main Replacements- Leakage, Abnormal Op. Conditions, CP Related | Footage replaced | | 71429 | - | 157500 | 208294 | - | - |
| C20 | DIMP - DRIP | Inspections | | | 184881 | - | - | 153000 | 195500 |
| C21-T1 | DIMP – **DREAMS: VIPP** | Miles replaced | | 83 | - | 270 | 327 | - | - |

| 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 |
| C21-T2 | DIMP – DREAMS: BSRP | Miles replaced | | 33 | - | 115 | 139 | - | - |
| C22 | DIMP - GIPP | Mitigations | Inspections | 4377 | 5096 | 2970 | 3795 | 1800 | 2300 |
| C23 | DIMP - SLIP | No. of inspections | | - | 73122 | - | - | 54000 | 69000 |
| C24 | CCM Distribution Field Asset Real Time Monitoring and Control Site Installations/Upgrades & New Control Room Technologies | Control: No. of sites installed/inspected<br>Real-time: No. of sites installed/inspected | | - | - | Control: 55<br>Real-time: 137 | Control: 78<br>Real-time: 197 | Control: 40<br>Real-time: 79 | Control: 57<br>Real-time: 114 |
| C25 | Field Employee Skills Training | FTE | | - | 63 | - | - | 110 | 133 |

| 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 |
| C26 | Staff Employee Skills Training | FTE | | - | 29 | - | - | 26 | 31 |
| C27 | Emergency Calls | Calls | | - | 460768 | - | - | 449517 | 544152 |
| C28 | Quality Assurance Program | FTE | | - | 7 | - | - | 9 | 10 |
| C29 | DCU/Pole Inspections | Inspections | | - | 4416 | - | - | 4478 | 5421 |
| C30 | Meter Set Assembly (MSA) Inspection Program | Orders | | - | 3186617 | - | - | 2611887 | 3161758 |
| C31 | Personal Protective Equipment (PPE) | FTE | | - | 1370 | - | - | 1879 | 2275 |
| C32 | Safety Related Field Orders | Orders | | 38281 | 1082800 | 132417 | 160295 | 1514143 | 1832910 |

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

| ID | Control/Mitigation Name | Forecast | | | |
|---|---|---|---|---|---|
| | | LoRE | CoRE | Post Mitigation Risk Score | RSE |
| C1 | Cathodic Protection Base Activities | 470 | 5.63 | 2,648 | 34.4 |
| C2 | Cathodic Protection-CP10 Activities | 537 | 5.63 | 3,028 | 115.2 |
| C3 | Cathodic Protection-100mV Requalification | 541 | 5.63 | 3,050 | 50.8 |
| C4 | Meter & Regulator (M&R) Station and Electronic Pressure Monitors (EPM) Inspection and Maintenance | 485 | 5.63 | 2,731 | 92.5 |
| C5 | Regulator Station Replacements/Installs | 545 | 5.63 | 3,069 | 4.7 |
| C6 | Meter Set Assembly (MSA) Inspection and Maintenance | 518 | 5.63 | 2,918 | 80.7 |
| C7 | Electronic Pressure Monitor (EPM) Replacement & Installs | 542 | 5.63 | 3,052 | 106.6 |
| C8 | Leak Survey | See C8/C17 below | | | |
| C9[31] | Pipeline Monitoring (Pipeline Patrol, Bridge & Span Inspections, Unstable Earth Inspection) | 544.63 | 5.63 | 3069 | 21.3 |
| C10 | | 544.92 | 5.63 | 3,071 | 5.2 |
| C11 | | 544.88 | 5.63 | 3,070 | 91.5 |
| C12 | Valve Inspection & Maintenance | 530 | 5.63 | 2,989 | 63.9 |
| C13 | Valve Installs and Replacements | 545 | 5.63 | 3,071 | 3.4 |

[31] There are three different types of pipeline monitoring activities, each with a different cycle. The activities are treated as a single event for dollar and unit purposes but separately for RSE purposes to align with the different cycles.

| ID | Control/Mitigation Name | Forecast | | | |
|---|---|---|---|---|---|
| | | LoRE | CoRE | Post Mitigation Risk Score | RSE |
| C14 | Cathodic Protection – Install/Replace Impressed Current Systems | 538 | 5.63 | 3,033 | 28.1 |
| C15 | Company and Contractor Inspection on Gas Pipelines | See Table 7 | | | |
| C16 | Capital CP 10 Service Replacement | 543 | 5.63 | 3,062 | 1.9 |
| C8/C17 | Leak Survey[32] and Main & Service Leak Repair | 459 | 5.63 | 2,585 | 23.2 |
| C18 | Residential Meter Protection Project | 526 | 5.63 | 2,963 | 91.4 |
| C19 | Main Replacements-Leakage, Abnormal Op. Conditions, CP Related | 545 | 5.63 | 3,070 | 0.3 |
| C20 | Distribution Integrity Management Program - Distribution Riser Inspection Program (DRIP) | 535 | 5.63 | 3,017 | 21.2 |
| C21-T1 | DIMP – DREAMS: Vintage Integrity Plastic Plan (VIPP) | 540 | 5.63 | 3,045 | 1.2 |
| C21-T2 | DIMP – DREAMS: Bare Steel Replacement Program (BSRP) | 543 | 5.63 | 3,063 | 0.9 |
| C22 | DIMP: Gas Infrastructure | 401 | 5.63 | 2,258 | 221.0 |

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

| ID | Control/Mitigation Name | Forecast | | | |
|---|---|---|---|---|---|
| | | LoRE | CoRE | Post Mitigation Risk Score | RSE |
| | Protection Program (GIPP) | | | | |
| C23 | DIMP: Sewer Lateral Inspection Project (SLIP) | 540 | 5.63 | 3,044 | 10.7 |
| C24 | CCM Distribution Field Asset Real Time Monitoring and Control Site Installations/Upgrades & New Control Room Technologies | See Table 7 | | | |
| C25 | Field Employee Skills Training | 545 | 5.63 | 3,068 | 0.4 |
| C26 | Staff Employee Skills Training | See Table 7 | | | |
| C27 | Emergency Calls | See Table 7 | | | |
| C28 | Quality Assurance Program | 544 | 5.63 | 3,064 | 7.6 |
| C29 | DCU/Pole Inspections | See Table 7 | | | |
| C30 | Meter Set Assembly (MSA) Inspection Program | 495 | 5.63 | 2,790 | 11.9 |
| C31 | Personal Protective Equipment (PPE) | See Table 7 | | | |
| C32 | Safety Related Field Orders | 381 | 5.63 | 2,147 | 3.0 |

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

| ID | Control/Mitigation Name | RSE Exclusion Rationale |
|---|---|---|
| C15 | Inspection of Company & Contractor Work on Gas Pipelines | Quality assurance and control of pipeline construction jobs 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 inspections exist to determine compliance with construction 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 of a risk thereof; hence, an RSE could not be calculated. |

| ID | Control/Mitigation Name | RSE Exclusion Rationale |
|---|---|---|
| C24 | 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 a prudent 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 SoCalGas 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 be used to quantify partial aspects of the CCM, like 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. |

| ID | Control/Mitigation Name | RSE Exclusion Rationale |
|---|---|---|
| C26 | Staff Employee Skills Training | Training employees on how to receive, direct, and resolve customer service calls is a standard safety procedure for the Company. Metrics exist internally on how many employees are trained or refreshed annually as well as types of calls received and resoled. There does not exist data, however, that ties the cause of a medium pressure incident to the lack of training or improper direction given by an employee to a customer which led to an incident. Additionally, there is no data, internally or externally, that ties an increase in consequence due to the improper training of an employee during a medium pressure incident. SoCalGas employees are trained to ensure the safety of the public if they receive a call that could be a potential incident, *i.e.* customer odor complaints or notification of excavation damage. Likewise, no SME input could be used to determine an explicit quantification of an increase in likelihood or consequence due to discontinuing training Customer Services Staff. |
| C27 | Emergency Calls | The Company receives thousands of emergency calls annually as described above. The Customer Contact Center is a critical safety component of the Company's interaction with the public. Reporting leaks, odors, or faulty appliances are just some of the critical safety functions the Contact Center handles and while data exists around types of calls received and orders issued for dispatching Company crews, no data exists to determine the increase in likelihood or consequence of a medium pressure pipeline incident if the Contact Center was not active. No viable assumptions could be made of the data present (*i.e.* number of calls attributed to a pipeline leak) to provide an explicit value associated with a cause or result of an incident. Additionally, the activity associated with this mitigation solely relates to receiving and responding to emergency calls. Any measurable risk reduction would occur when a leak is remediated, or appliance |

| ID | Control/Mitigation Name | RSE Exclusion Rationale |
|---|---|---|
| | | fixed, which takes place outside of this control. As such no RSE could be calculated for this activity. |
| C29 | Data Collector Unit (DCU)/Pole Inspections | As described above SoCalGas inspects all poles that have a Data Collection Unit attached as part of a prudent safety and reliability measure. The purpose is twofold, to monitor network reliability of the smart meters and public safety by ensuring the poles remain standing. A medium pressure system incident involving a DCU pole would be in the realm of a pole collapsing onto a member of the public or public/customer property. Although SoCalGas possesses data on the inspections of said poles including any issues that may be found with said units *i.e.*, vandalism, downed poles, etc., there exists no data, internally or externally, to directly relate the inspections to a decrease in likelihood or consequence of a medium pressure system event. Furthermore, SoCalGas SMEs could not explicitly relate the increase in incidents if inspections discontinued. |
| C31 | Personal Protective Equipment (PPE) | Issuing personal protective equipment to employees is a standard safety practice for the Company. SoCalGas would not dispatch employees without the proper PPE and PPE upkeep/replacement is standard procedure. Although internal data exists surrounding employee incidents that may occur due to lack of or failed PPE, there is no data to directly link an employee without PPE, increasing the likelihood or consequence of a medium pressure incident. Further, it can be argued that an employee without PPE may increase the consequence of a medium pressure incident *i.e.* an injury may become a fatality if an employee lacked goggles or a hardhat during a pipeline failure; however, internal or external data does not exist which correlates the risk of a medium pressure incident to not issuing standard PPE to employees. Likewise, no SME input could be used to determine a direct increase in the risk associated with issuing or discontinuing PPE use by employee; therefore, no RSE could be calculated. |

## VI. ALTERNATIVES

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

### A. A1: Technician Refresher Training

SoCalGas considered increasing the frequency of employee refresher training as an alternative to the training program set forth in SoCalGas's Risk Mitigation Plan, above (Field Employee Skills Training, C23). Currently, SoCalGas reviews policies and procedures on a periodic basis, with the time interval being dependent upon the nature of the policy/procedure. When policies and procedures are updated, the updates are shared with gas service technicians, and are accessible to field service technicians on their mobile data terminals.

This alternative proposal considered that all field service technicians complete periodic refresher training sessions at the Company's training facility at Pico Rivera. The refresher training would provide greater reinforcement of the gas service technician job skills. The training would include both classroom and hands-on scenario-based modules reinforcing that policies and procedures are being followed and confirming that updates to policies and procedures are understood.

This alternative proposal is not currently being implemented. The high percentage results seen for the service technician QA program validate the adequacy of the current practice of periodic policy and procedure reviews. Expanding the scope of training by adding periodic refresher training would require additional resources.

### B. A2: Post-Training Follow-up Field Evaluations

Another alternative proposal considered by SoCalGas is for field service technicians to receive a scheduled, formal field evaluation with a QA Specialist six months after graduation from formal training. The QA Specialist would field ride with the employee to observe the employee's adherence to Company policies and procedures following formalized training. Any deficiencies would be addressed with the employee. The findings from the field rides would be compiled to determine if formal training enhancements are needed and/or if the system wide refresher training is needed.

This alternative proposal is not currently being implemented. Like the previous proposal, the high percentage results seen for the service technician QA program validate the adequacy of the current practice of periodic policy and procedure reviews. Implementing the QA Program field rides would require additional resources.

**Table 8: Alternate Mitigation Plan - Forecast Dollars Summary[33]**
**(Direct After Allocations, In 2020 $000)**

| ID | Alternate Mitigation Name | Forecast Dollars | | | |
|---|---|---|---|---|---|
| | | 2022-2024 Capital (Low) | 2022-2024 Capital (High) | TY 2024 O&M (Low) | TY 2024 O&M (High) |
| A1 | Technician Refresher Training | - | - | 315 | 405 |
| A2 | Post-Training Follow-up Field Evaluations | - | - | 194 | 248 |

**Table 9: Alternate Mitigation Plan - Units Summary**

| ID | Control/Mitigation Name | Units Description | | Forecast Units | | | |
|---|---|---|---|---|---|---|---|
| | | Capital | O&M | 2022-2024 Capital (Low) | 2022-2024 Capital (High) | TY 2024 (Low) O&M | TY 2024 (High) O&M |
| A1 | Technical Refresher Training | FTE | | - | - | 135 | 173 |
| A2 | Post-Training Follow-up Field Evaluation | FTE | | - | - | 2 | 2 |

**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 | Technical Refresher Training | 544.99 | 5.63 | 3,071 | 1.3 |
| A2 | Post-Training Follow-up Field Evaluation | 544.90 | 5.63 | 3,071 | 2.1 |

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

# APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE

## APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE

## INCIDENT RELATED TO THE MEDIUM PRESSURE SYSTEM (EXCLUDING DIG-IN): SUMMARY OF ELEMENTS OF THE RISK BOW TIE

| ID | Control/Mitigation Name | Elements of the Risk Bow Tie Addressed |
|---|---|---|
| C1 | Cathodic Protection Base Activities | DT.1, DT.2, DT.3<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C2 | Cathodic Protection - CP10 Activities | DT.1, DT.2, DT.3<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C3 | Cathodic Protection - 100mV Requalification | DT.1, DT.2, DT.3<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C4 | Meter & Regulator (M&R) Station Inspection and Electronic Pressure Monitors (EMP) Inspection and Maintenance | DT.1, DT.2, DT.3, DT.4, DT.5,<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C5 | Regulator Station Replacements/Installs | DT.1, DT.2, DT.3, DT.4, DT.5<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C6 | Meter Set Assembly (MSA) Inspection and Maintenance | DT.1, DT.2, DT.3, DT.4, DT.5,<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C7 | Electronic Pressure Monitor (EPM) Replace & Installs | DT.1, DT.2, DT.3, DT.4, DT.5,<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C8 | Leak Surveys | DT.1, DT.2, DT.3, DT.4, DT.5,<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C9/C10 /C11 | Pipeline Monitoring (Pipeline Patrol, Bridge & Span Inspections, Unstable Earth Inspection) | DT.1, DT.2, DT.3, DT.4, DT.5,<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C12 | Valve Inspection and Maintenance & Replacements | DT.1, DT.2, DT.3, DT.4, DT.5,<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C13 | Valve Installs and Replacements | DT.1, DT.2, DT.3, DT.4, DT.5<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C14 | Cathodic Protection – Install/Replace Impressed Current Systems | DT.1, DT.2, DT.3, DT.5,<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C15 | Company and Contractor Inspections on Gas Pipelines | DT.6, DT.7, DT.8<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C16 | Capital CP10 Service Replacement | DT.1, DT.2, DT.3,<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C17 | Main and Service Leak Repair | DT.1, DT.2, DT.3, DT.4, DT.5,<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C18 | Residential Meter Protection | DT.2, DT.3, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6, |
| C19 | Main Replacements- Leakage, Abnormal Op. Conditions, CP Related | DT.1, DT.2, DT.3, DT.4, DT.5, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C20 | Distribution Integrity Management Program (DIMP) - Distribution Riser Inspection Program (DRIP) | DT.1, DT.2, DT.3, DT.4, DT.5,<br>DT.6, DT.7 |

| ID | Control/Mitigation Name | Elements of the Risk Bow Tie Addressed |
|---|---|---|
| | | PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C21-T1 | DIMP - Distribution Risk Evaluation and Monitoring System (DREAMS): Vintage Integrity Plastic Plan (VIPP) | DT.2, DT.4, DT.6, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C21-T2 | DIMP – DREAMS: Bare Steel Replacement Program (BSRP) | DT.1, DT.4, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C22 | DIMP - Gas Infrastructure Protection Program (GIPP) | DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C23 | DIMP - Sewer Lateral Inspection Project (SLIP) | DT.3, DT.6, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C24 | 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 |
| C25 | Field Employee Skills Training | DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7, DT.8<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C26 | Staff Employee Skills Training | DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7, DT.8<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C27 | Emergency Calls | DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C28 | Quality Assurance Program | DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C29 | DCU/Pole Inspections | DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C30 | Meter Set Assembly (MSA) Inspection Program | DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |
| C29 | Personal Protective Equipment (PPE) | DT.1, DT.2, DT.4, DT.5, DT.6, DT.8<br>PC.1, PC.2, PC.3, PC.5, PC.6 |
| C30 | Safety Related Field Orders | DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7<br>PC.1, PC.2, PC.3, PC.4, PC.5, PC.6 |

# APPENDIX B:  QUANTITATIVE ANALYSIS REFERENCED DATA

## APPENDIX B: QUANTITATIVE ANALYSIS REFERENCED DATA

The Settlement Decision directs the utility to identify potential consequences of a risk event using available and appropriate data.[34] 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*

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*

SoCalGas medium-pressure pipeline miles
2020 internal SME data

SoCalGas annual leakage data
2012-2017 data according to material

SoCalGas overpressure/underpressure data

SoCalGas quality assurance program internal data
5 years aggregated error data

SoCalGas inspection data
Bridge and span inspections
Pipeline patrols
Unstable earth inspections

Gas industry sales customers
Agency: AGA (2016Y)
Link:
*https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf*

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

SoCalGas end user natural gas customers
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=325311https://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*