

Risk Assessment and Mitigation Phase Risk Mitigation Plan

Catastrophic Damage Involving Medium-Pressure Pipeline Failure (SDG&E-16)

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Executive Summary

The Catastrophic Damage Involving a Medium-Pressure Pipeline Failure (Medium-Pressure Pipeline Failure) risk relates to the public safety and property impacts that can result from failure of medium-pressure and non-Department of Transportation (DOT) pipelines.

To assess this risk, SDG&E first identified a reasonable worst case scenario, and scored the scenario against five residual impact categories (e.g., Health, Safety, Environmental; Operational & Reliability, etc., discussed in Section 4). Then, SDG&E considered as a baseline, the SDG&E mitigation in place as of 2015 (in Section 5) and estimated the costs (baseline mitigations are summarized in Section 7) SDG&E identified the 2015 controls that comply with Code of Federal Regulation Part 192 and General Order 112:

1. Maintenance
2. Qualifications of Pipeline Personnel
3. Requirements for Corrosion Control
4. Operations
5. Gas Distribution Pipeline Integrity Management

These 2015 controls focus on safety-related impacts (e.g., Health, Safety, and Environment) per guidance provided by the Commission in Decision 16-08-018 as well as controls and mitigations that may address reliability.

Based on the foregoing assessment, SDG&E proposed future mitigations (discussed in Section 6). SDG&E will continue to apply these 2015 controls and proposes to expand and enhance aspects of the Distribution Integrity Management Program (DIMP) and the DIMP Distribution Risk Evaluation and Monitoring System (DREAMS) program as well as add new activities, such as a Cathodic Protection Reliability program.

Finally, SDG&E developed the risk spend efficiency. The risk spend efficiency is a new tool that SDG&E developed to attempt to quantify how the proposed mitigations will incrementally reduce risk. SDG&E's mitigations in its proposed plan were grouped for risk spend efficiency purposes into four categories. The metric used to determine the risk spend efficiency of the mitigations was based on data relating to medium pressure pipelines, including data from PHMSA and asset data. Based on a benefit-cost assessment (i.e. risk spend efficiency), the four mitigations for this risk can be prioritized as follows, from highest risk spend efficiency to lowest:

1. DIMP/Distribution integrity (current controls)
2. Regulatory compliance activities (current controls)
3. Expanded integrity activities (incremental mitigations)
4. Technical training (current controls)



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Next, SDG&E developed the risk spend efficiency (sometimes referred to as RSE). The risk spend efficiency is a new tool that SDG&E developed to attempt to quantify how the proposed mitigations will incrementally reduce risk. The RSE was determined using the proposed mitigations and resulted in prioritizing mitigation activities.

Finally, SDG&E considered two alternatives to the proposed mitigations for the Medium-Pressure Pipeline Failure risk, and summarizes the reasons that the two alternatives were not selected as a proposed mitigation.

Risk: Catastrophic Damage Involving Medium Pressure Pipeline Failure

1 Purpose

The purpose of this chapter is to present the mitigation plan of San Diego Gas & Electric Company (SDG&E or Company) for the risk of damage caused by a medium-pressure pipeline (Maximum Allowable Operating Pressure [MAOP] at or lower than 60 psig) failure event with catastrophic consequences (referred to herein as Medium-Pressure Pipeline Failure). This risk concerns a gas public safety event on a medium-pressure distribution pipeline or gas facility, and focuses on routine maintenance and pipeline replacement mitigations consistent with industry standard medium pressure pipeline operations of state of the art polyethylene pipelines and cathodically protected steel pipelines.¹

This risk is a product of SDG&E's September 2015 annual risk registry assessment cycle. Any events that occurred after that time were not considered in determining the 2015 risk assessment, in preparation for this Report. Note that while 2015 is used as base year for mitigation planning, risk management has been occurring, successfully, for many years within the Company. SDG&E and Southern California Gas Company (SoCalGas) (collectively, the utilities) take compliance and managing risks seriously, as can be seen by the number of actions taken to mitigate each risk. This is the first time, however, that the utilities have presented a Risk Assessment Mitigation Phase (RAMP) Report, so it is important to consider the data presented in this plan in that context. The baseline mitigations are determined based on the relative expenditures during 2015; however, the utilities do not currently track expenditures in this way, so the baseline amounts are the best effort of each utility to benchmark both capital and operations and maintenance (O&M) costs during that year. The level of precision in process and outcomes is expected to evolve through work with the California Public Utilities Commission (Commission or CPUC) and other stakeholders over the next several General Rate Case (GRC) cycles.

The Commission has ordered that RAMP be focused on safety related risks and mitigating those risks.² In many risks, safety and reliability are inherently related and cannot be separated, and the mitigations reflect that fact. Compliance with laws and regulations is also inherently tied to safety and the utilities take those activities very seriously. In all cases, the 2015 baseline mitigations include activities and amounts necessary to comply with the laws in place at that time. Laws rapidly evolve, however, the RAMP baseline has not taken into account any new laws that have been passed since September 2015. Some proposed mitigations, however, do take into account those new laws.

¹ Mitigation activities addressing damage to gas infrastructure caused by third parties, also referred to as dig-ins, is not addressed in this chapter, but rather discussed in the Risk Assessment Mitigation Phase (RAMP) chapter of Catastrophic Damage Involving Gas Infrastructure (Dig-Ins).

² Commission Decision (D.) 14-12-025 at p. 31.



The purpose of RAMP is not to request funding. Any funding requests will be made in the GRC. The forecasts for mitigation are not for funding purposes, but are rather to provide a range for the future GRC filing. This range will be refined with supporting testimony in the GRC. Although some risks have overlapping costs, the utilities have made efforts to identify those costs.

2 Background

Typically, medium-pressure distribution systems use a series of mains, larger diameter pipe, to feed service lines. The service lines are smaller diameter pipes which feed customer homes, businesses, and some commercial applications. Medium-pressure pipelines are comprised of steel or plastic material.

For safety and compliance purposes, the Code of Federal Regulations (CFR) Part 192 and General Order (GO) 112 are the leading sources, among other legal and regulatory provisions, of requirements for SDG&E's medium-pressure pipeline. CFR Part 192 prescribes minimum safety requirements for pipeline facilities and the transportation of gas and GO 112 complements and enhances the requirements set forth on a federal level at a state level.

With regard to medium pressure lines, the Company currently operates over 8,000 miles of medium-pressure main with nearly 4,500 miles being plastic and upwards of 3,600 being steel (see Table 1 below). These medium-pressure pipelines serve over 875,000 SDG&E consumers.

Table 1: Medium-Pressure Pipelines

<u>Medium-Pressure Main</u>	<u>SDG&E</u>
Miles of Steel	3,596
Miles of Plastic	4,461
Total Miles Medium-Pressure Main	8,057

Various causes and events can lead to medium pressure pipeline failures. Factors can range from improper installation techniques or material defects, aging/environmental factors such as corrosion and fatigue, and inadequate operations or maintenance of the pipeline infrastructure. However, for the purposes of this chapter, the Medium Pressure Failure risk focuses on the more serious results of failures that lead to a release of natural gas with possibility of hazard to life and property.



3 Risk Information

As stated in the testimony of Jorge M. DaSilva in the Safety Model Assessment Proceeding (S-MAP) Application (A.) 15-05-002, “SDG&E is moving towards a more structured approach to classifying risks and mitigations through the development of its new risk taxonomy. The purpose of the risk taxonomy is to define a rational, logical and common framework that can be used to understand, analyze and categorize risks.”³ The Enterprise Risk Management (ERM) process and lexicon that SDG&E has put in place was built on the internationally-accepted ISO 31000 risk management standard. In the application and evolution of this process, the Company is committed to increasing the use of quantification within its evaluation and prioritization of risks.⁴ This includes identifying leading indicators of risk. Sections 3 – 9 of this plan describe the key outputs of the ERM process and resultant risk mitigations.

In accordance with the ERM process, this section describes the risk classification, potential drivers and potential consequences of the Medium-Pressure Pipeline Incident risk.

3.1 Risk Classification

Consistent with the taxonomy presented by SDG&E and SoCalGas in A.15-05-002, SDG&E classifies this risk as a gas, operational risk as shown in Table 2.

Table 2: Risk Classification per Taxonomy

Risk Type	Asset/Function Category	Asset/Function Type
OPERATIONAL	GAS	MEDIUM AND LOW-PRESSURE (<=60 PSI)

3.2 Potential Drivers⁵

When performing the risk assessment for Medium-Pressure Pipeline Incident, SDG&E identified potential indicators of risk, referred to as potential drivers. The potential drivers for this risk are derived from the listing of cause categories from the Pipeline and Hazardous Materials Safety Administration (PHMSA) database, along with historical events and credible scenarios developed by Subject Matter Experts (SMEs). The potential drivers include, but are not limited to:

³ A.15-05-002, filed May 1, 2015, at p. JMD-7.

⁴ Testimony of Diana Day, Risk Management and Policy (SDG&E-02), submitted on November 14, 2014 in A.14-11-003.

⁵ An indication that a risk could occur. It does not reflect actual or threatened conditions.



1. **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.⁶
2. **Natural Forces** attributable to causes not involving humans, such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, high winds.
3. **Other Outside Force Damage** is attributable to outside force damage other than excavation damage or natural forces such as damage by car, truck or motorized equipment not engaged in excavation, etc.
4. **Pipe, Weld or Joint Failure** is attributable to material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects, or in-service stresses such as vibration, fatigue and environmental cracking.
5. **Equipment Failure** is attributable to malfunction of component including but not limited to regulators, valves, meters, flanges, gaskets, collars, couples, etc.

Incorrect Operations can include a pipeline incident attributed to insufficient or incorrect operating procedures or the failure to follow a procedure.

In accordance with the taxonomy of SDG&E, the potential drivers above can be classified as an asset failure, employee incident, contractor incident, public incident, or force of nature. Table 3 below maps the specific potential risk drivers of Medium-Pressure Pipeline Failure to SDG&E’s taxonomy.

Table 3: Potential Operational Risk Drivers

Potential Driver Category	Potential Medium-Pressure Pipeline Failure Driver(s)
Asset Failure	<ul style="list-style-type: none"> • Corrosion • Pipe, Weld, or Joint Failure • Equipment Failure
Asset-Related Information Technology Failure	Not applicable
Employee Incident	<ul style="list-style-type: none"> • Other Outside Forces • Incorrect Operation • Pipe, Weld, or Joint Failure
Contractor Incident	<ul style="list-style-type: none"> • Other Outside Forces • Incorrect Operation
Public Incident	<ul style="list-style-type: none"> • Other Outside Forces

⁶ Corrosion Basics, An Introduction, L.S. Van Delinder, ed. (Houston, TX: NACE, 1984).

Force of Nature

- Natural Forces

3.1 Potential Consequences

If one of the potential risk drivers listed above were to occur, resulting in an incident, the potential consequences, in a reasonable worst case scenario, may include:

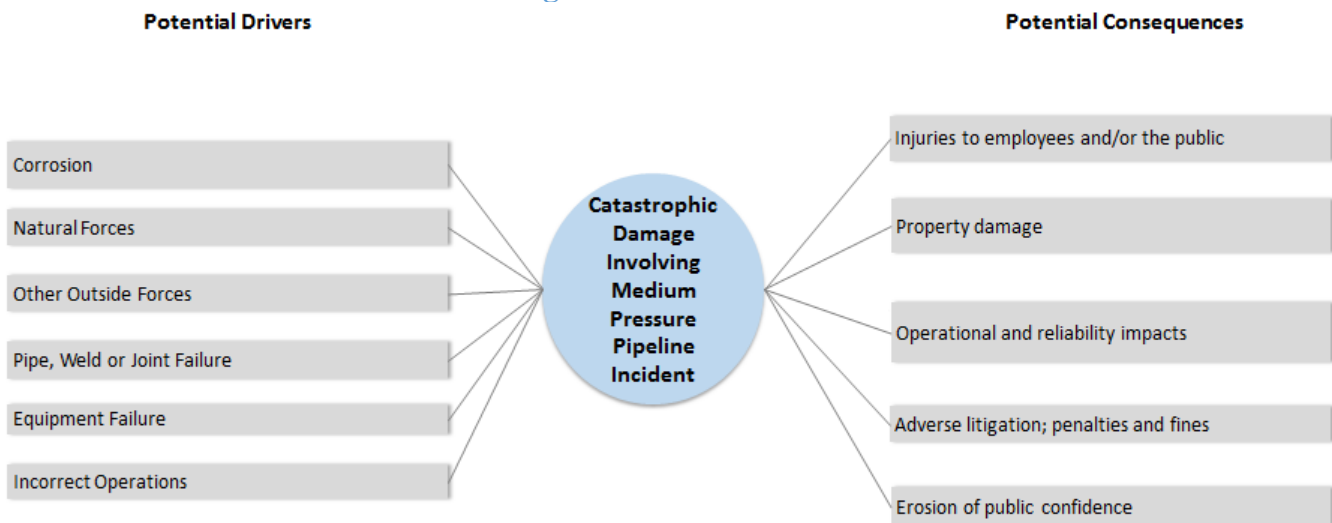
- Injuries to employees and/or the public.
- Property damage.
- Operational and reliability impacts.
- Adverse litigation and resulting financial consequences.
- Increased regulatory scrutiny.
- Erosion of public confidence.

These potential consequences were used in the scoring of Medium-Pressure Pipeline Incident that occurred during the SDG&E’s 2015 risk registry process. See Section 4 for more detail.

3.2 Risk Bow Tie

The risk “bow tie,” shown in Figure 1, is a commonly-used tool for risk analysis. The left side of the bow tie illustrates potential drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above.

Figure 1: Risk Bow Tie



4 Risk Score

The SDG&E and SoCalGas ERM organization facilitated the 2015 risk registry process, which resulted in the inclusion of Medium-Pressure Pipeline Incident as one of the enterprise risks. During the development of the risk register, subject matter experts assigned a score to this risk, based on empirical



data to the extent it is available and/or using their expertise, following the process discussed in this section.

4.1 Risk Scenario – Reasonable Worst Case

For purposes of scoring this risk, subject matter experts used a reasonable worst case scenario to assess the impact and frequency. The scenario represented a situation that could happen, within a reasonable timeframe, and lead to a relatively significant adverse outcome. These types of scenarios are sometimes referred to as low frequency, high consequence events. The subject matter experts selected a reasonable worst case scenario to develop a risk score for Medium-Pressure Pipeline Incident:

- A medium pressure pipeline failure due to a control device malfunction, which results in uncontrolled gas release causing injuries to employees and the public, and/or results in over 1,000 customers without gas supply for at least 24 hours.

Note that the following narrative and scores are based on this reasonable worst case risk scenario; they do not address all consequences that may happen if the risk occurs.

4.2 2015 Risk Assessment

Using this scenario, subject matter experts then evaluated the frequency of occurrence and potential impact of the risk using SDG&E’s 7X7 Risk Evaluation Framework (REF). The framework (also called a matrix) includes criteria to assess levels of impact ranging from Insignificant to Catastrophic and levels of frequency ranging from Remote to Common. The 7X7 framework includes one or more criteria to distinguish one level from another. The Commission adopted the REF as a valid method to assess risks for purposes of this RAMP.⁷ Using the levels defined in the REF, the subject matter experts applied empirical data to the extent it is available and/or their expertise to determine a score for each of four residual impact areas and the frequency of occurrence of the risk.

Table 4 provides a summary of the Medium-Pressure Pipeline Failure risk score in 2015. This risk has a score of 4 or above in the Health, Safety, and Environmental impact area and, therefore, was included in the RAMP. These are residual scores because they reflect the risk remaining after existing controls are in place. For additional information regarding the REF, please refer to the RAMP Risk Management Framework chapter within this Report.

Table 4: Risk Score

Residual Impact				Residual Frequency	Residual Risk Score
Health, Safety, Environmental (40%)	Operational & Reliability (20%)	Regulatory, Legal, Compliance (20%)	Financial (20%)		
5	3	3	3	3	2,344

⁷ D.16-08-018 Ordering Paragraph 9.



4.3 Explanation of Health, Safety, and Environmental Score

The Company scored this risk a 5 (extensive) in the Health, Safety, and Environmental impact area due to the potential of an event resulting in serious injuries to the public or employees, as well as environmental impacts. For example, from 2010-2016 there have been 37 material failure/weld/fitting incidents in the United States on distribution mains, causing two fatalities and approximately 40 injuries.⁸ On the other hand, fatalities are rare for these types of incidents compared to other risk events such as dig-ins or failures on high-pressure pipelines. Accordingly, SDG&E determined that a score of 6 (severe) was not appropriate.

4.4 Explanation of Other Impact Scores

Based on the selected reasonable worst case risk scenario, SDG&E scored the other residual impact areas in the following manner:

- **Operational and Reliability:** SDG&E scored this impact category as a 3 (moderate). A risk score of 3 is defined in the 7x7 matrix as greater than 1,000 customers affected, impacts a single critical location or customer, or disruption of service for one day. Based on the risk scenario, it a significant customer disruption may occur in which a whole street, several homes, or a whole block loses gas service depending if the damages involved medium pressure gas main or service lines.
- **Regulatory, Legal, and Compliance:** SDG&E scored this impact category as a 3 (moderate). SDG&E scored in this manner because of the potential lawsuits and financial impacts. The most common legal issue associated with this risk scenario typically involves lawsuits.
- **Financial:** The Company could suffer financial repercussions as a result of the other risk areas. Potential litigation and penalties from the CPUC and PHMSA are prime examples of the costs associated with the medium-pressure pipeline system failing. Though the exact cost of litigation and other potential financial consequences can vary depending on the type of incident, if a failure were to occur, the potential financial loss could be between \$1 million and \$10 million. The risk score of a 3 (moderate) was assigned due to the fact that all incidents are collateral damages of the first risk area, health, safety, and environment assigning it a secondary type of risk.

4.5 Explanation of Frequency Score

The frequency of an event occurring was assumed to be once every 10-30 years; a score of 3 (infrequent). According to PHMSA, between 1996-2015, there have been nine (9) fatalities in California due to medium-pressure failures. See below.



PHMSA Pipeline Incidents: (1996-2015)
Incident Type: Serious **System Type:** GAS DISTRIBUTION **State:** CALIFORNIA

Calendar Year	Number	Fatalities	Injuries
1996	1	0	3
1997	1	1	2
1998	3	0	4
1999	3	0	3
2000	2	0	2
2001			
2002	1	1	0
2003	3	1	2
2004			
2005	1	0	1
2006	1	0	1
2007	4	0	5
2008	4	1	5
2009			
2010			
2011			
2012	2	3	1
2013			
2014	2	2	1
2015	1	0	2
Grand Total	29	9	32

Therefore, the risk score is a reasonable estimate of how frequently these types of events happen.

5 Baseline Risk Mitigation Plan

As stated above, Medium-Pressure Pipeline Failure risk potentially impacts the public and/or property damage. The 2015 baseline mitigations discussed below includes the current evolution of the utilities’ risk management of this risk. The baseline mitigations have been developed over many years to address this risk and they include activities to comply with laws that were in effect at that time. SDG&E’s baseline mitigation plan for this risk consists of controls based on CFR Part 192 and GO 112-E.

The primary areas highlighted in the risk registry are:

1. CFR 192 Subpart M – Maintenance
2. CFR 192 Subpart N – Qualifications of Pipeline Personnel
3. CFR 192 Subpart I – Requirements for Corrosion Control
4. CFR 192 Subpart L – Operations
5. CFR 192 Subpart P – Gas Distribution Pipeline Integrity Management

These controls focus on safety-related impacts⁹ (i.e., Health, Safety, and Environment) per guidance provided by the Commission in D.16-08-018¹⁰ as well as controls and mitigations that may address reliability.¹¹ Accordingly, the controls and mitigations described in this section and in Section 6 address safety-related impacts primarily. Note that the controls and mitigations in the baseline and proposed risk mitigation plans are intended to address various events related to Medium-Pressure Pipeline Failure and are not limited to the reasonable worst case risk scenario used for the Risk Score.

1. CFR 49 Part 192 Subpart M – Maintenance

Federally mandated activities to provide the minimum safety requirements for medium-pressure pipelines. These activities include performing pipeline patrols; bridge and span, meter set assemblies, valve and regulator inspections; and maintenance on a regular basis throughout the year. These activities are intended to address threats as identified by PHMSA, specifically outside forces (vandalism, fault lines, liquefaction, etc.), equipment failure (pipeline facilities and components) and corrosion. The activities include but are not limited to:

- Inspections of natural gas pipeline over bridges and land crossings at least once every two calendar years, but with intervals not exceeding 27 months
- Each pressure limiting station, relief device, signaling device, and pressure regulating station and its equipment must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year.
- Each valve must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year. (CFR 192.747).
 - Prompt remedial action must be taken to repair an inoperable valve unless an alternative valve is used to divert gas.
- Region operations may perform tests and inspections at times other than the compliance period but cannot be substituted for federally mandated valve inspection in CFR 192.747.

2. CFR 49 Part 192 Subpart N – Qualifications of Pipeline Personnel

The training, set forth in Subpart N, requires a qualification program on covered tasks, recordkeeping, and evaluation. Each covered task is attached to a gas standard which contains a full description of what

⁹ The Baseline and Proposed Risk Mitigation Plans may include mandated, compliance-driven mitigations.

¹⁰ D.16-08-018 at p. 146 states “Overall, the utility should show how it will use its expertise and budget to improve its safety record” and the goal is to “make California safer by identifying the mitigations that can optimize safety.”

¹¹ Reliability typically has an impact on safety. Accordingly, it is difficult to separate reliability and safety.



the employee/contractor will have to perform. For distribution programs, the following training subsets are the most prominent:

- Distribution construction technician training
- Distribution lead construction technician
- Distribution system protection specialist
- Distribution valve tech training
- Distribution welder training
- Distribution instrument tech training
- Distribution regulator tech training

By properly training employees and contractors through the distribution technician training, the frequency of potential accidents can be lowered because the training educates the employees and contractors on proper safety techniques and standards. After a prescribed amount of years, SDG&E's employees are evaluated and requalified to reflect any changes in Company or federal standards.

3. CFR 49 Part 192 Subpart I –Requirements for Corrosion Control Operations

As prescribed by CFR 192 Subpart I –Requirements for Corrosion Control Operations, the minimum safety requirements include monitoring of cathodic protection (CP) areas, remediation of CP areas that are out of tolerance, and preventative installations to avoid areas out of tolerance. These activities are intended to address threats as identified by PHMSA specifically corrosion both external and internal. The following summarizes the required intervals for completing these preventative measures:

- Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463.
- Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding two and a half months, to insure that it is operating.

4. CFR 49 Part 192 Subpart L – Operations

The minimum safety requirements prescribed by CFR 192 Subpart L – Operations include locate and mark, emergency preparedness and odorization. These activities are intended to address threats as identified by PHMSA. Locate and mark activities are specific to third party damage while emergency preparedness and odorization are intended to address all threats. The following provides the required intervals for completing these preventative measures as prescribed in Subpart L and SDG&E complies with these requirements:



- To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable

5. CFR 49 Part 192 Subpart P – Gas Distribution Pipeline Integrity Management

PHMSA established DIMP requirements to enhance pipeline safety by having operators identify and reduce pipeline integrity risks for distribution pipelines, as required under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006.

- (a) SDG&E has implemented certain Programs and Activities to Address Risk (PAARs) and DREAMS PAAR prioritizes certain early-vintage steel (pre-1960) and plastic (pre-1986), including Aldyl-A, for replacement. With regard to plastic, PHMSA Advisory Bulletin ADB-07-01 states that “the number and similarity of plastic pipe accident and non-accident failures indicate past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking for much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s.” The DREAMS risk evaluation therefore considers the cause of the leak, the leakage history, cathodic protection (for steel), vintage of the pipe and the location using E-GIS.

(b) *EPOCH*

Projects are generated from field crew field observations concerning the condition of the pipe. Generally, Epoch projects start with a single coded leak repair. The section of pipe to be replaced is added to the Epoch list and risk-ranked. The scores are reevaluated when another leak occurs in the same area of an identified Epoch project; which could result in the project moving up the list.

6 Proposed Risk Mitigation Plan

SDG&E will continue with its baseline activities described in Section 5 above. In addition, SDG&E is proposing to expand and add new mitigations to further address the risk of medium pressure pipeline failure. The proposed activities and costs for the mitigations are primarily based on the Code of Federal Regulation Part 192 and General Order 112-F state requirements.

It should be noted that the proposed activities do not account for the Notice of Proposed Rule Making (NPRM) issued by PHMSA on Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines which may expand the integrity requirements beyond HCAs, require the verification of Maximum Allowable Operating Pressure (MAOP), and records requirements among other items.

SDG&E proposes to expand the Gas Distribution Pipeline Integrity Management mitigation as well as add new projects and programs included in a mitigation labeled Improvements. These incremental activities are described below.

1. Expansion of DIMP

SDG&E proposes to expand the DREAMS program. For DREAMS, SDG&E proposes to accelerate this program in order to replace certain mains and services at a faster rate. As part of the DREAMS program, SDG&E primarily replaces Aldyl-A pipe. Currently, SDG&E replaces approximately 17 miles of pipe per year in the DREAMS program of which Aldyl-A pipe is 16.5 miles. SDG&E is proposing to accelerate the replacement of Aldyl-A pipe in the SDG&E gas system by replacing an additional 17 miles per year to total 34 miles per year.

2. Improvements

Further, SDG&E proposes to implement new projects and programs. Examples of these new projects and programs are:

- Dresser Mechanical Couplings – This program consists of evaluating the coupling field location, excavating, and assessing the weld housing to encapsulate the dresser mechanical couplings main in and near downtown San Diego. In the event of a strong earthquake or exposure of 12” pipeline, leaking or failure may occur if not addressed properly.
- Oil Drip Piping – This project is designed to verify the location of above ground and buried oil drip lines and containers. As part of the process, SDG&E consults with Pipeline Operations and Region Engineering to determine and remove facilities that are not necessary. The buried facilities are at risk of excavation damage because certain maps showing their size and location are not available.
- Buried Piping in Vaults – SDG&E has pipeline buried in vaults that may be corroded by above ground facilities and pitting of below ground piping. This activity will determine the locations vaults containing medium and high pressure facilities. SDG&E will assess the coating and the condition of the above-ground and below-ground facilities within the vaults.
- CP Reliability Program – This is a region specific program which will perform a detailed cathodic protection evaluation that will include the development of a relative risk algorithm to assess the “health” of the CP system. The information would feed into a relative risk ranking tool for DIMP segments that are under CP protection. The CP system analysis would include enhanced documentation and expanded analysis of the system’s routine maintenance records collected per 49 CFR 192 Subpart I – Requirements for corrosion control. The end result of the CP reliability analysis should be a health ranking and project list that could be used to prioritize such projects. The CP reliability project will assess 520 CP areas to determine the research required to generate the risk algorithm. The timing of implementing this program is currently uncertain as SDG&E may commence this program in a year other than the test year (2019). Accordingly, a larger range of costs for O&M is provided in Table 6 for the Improvements mitigation.
- Closed Valves between High and Medium Pressure Piping – SDG&E has identified valves for remediation. Currently, the valves are closed and locked; however, the valves need to be removed because an inadvertent opening would overpressure medium pressure pipelines. This



proposed activity involves verifying the valve location, excavating, and removing the closed and locked valves which connect high pressure piping to medium pressure piping.

- Early Vintage Steel Replacement - This program is intended to remove pre-1947, non-piggable high pressure pipeline as well as pre-1955 medium pressure steel mains. In the years prior to 1955, cold tar asphaltic wrap was used as the primary protection against corrosion with cathodic protection supplementing as secondary protection. Over time, the cold tar asphaltic wrap can degrade and dis-bond from the pipe. This program is intended to remove early-vintage pipe. This would be a 10 year program to remove 15 miles of pipe per year of poor performing pipe.
- Threaded Piping Removal – Prior to 1933, piping in the gas distribution system was joined by treaded couplings. This project aims to proactively remove a total of 152 miles of threaded pipe over a 10-year period. This would be a 10-year program to remove 15 miles of pipe per year.

7 Summary of Mitigations

Table 5 summarizes the 2015 baseline risk mitigation plan, the risk driver(s) addressed the 2015 baseline costs for Medium-Pressure Pipeline Incident. While control or mitigation activities may address both potential risk drivers and potential consequences, potential risk drivers link to the likelihood of a risk event. Thus, potential risk drivers are specifically highlighted in the summary tables.

SDG&E does not account for or track costs by activity, but rather, by cost center and capital budget code. So, the costs shown in Table 5 were estimated using assumptions provided by SMEs and available accounting data.



Table 5: Baseline Risk Mitigation Plan¹²
(Direct 2015 \$000)¹³

ID	Control	Potential Risk Drivers Addressed	Capital ¹⁴	O&M	Control Total ¹⁵	GRC Total ¹⁶
1	Maintenance*	<ul style="list-style-type: none"> Asset Failure Public Incident Force of Nature 	\$1,220	\$5,780	\$7,000	\$7,000
2	Qualifications of Pipeline Personnel*	<ul style="list-style-type: none"> Employee Incident Contractor Incident 	200	500	700	700
3	Requirements for Corrosion Control *	<ul style="list-style-type: none"> Asset Failure Public Incident Force of Nature 	530	1,400	1,930	1,930
4	Operations*	<ul style="list-style-type: none"> Asset Failure Employee Incident Contractor Incident Public Incident 	500	500	1,000	1,000
5	Gas Distribution Pipeline Integrity Management*	<ul style="list-style-type: none"> Asset Failure Public Incident 	6,210	20	6,230	6,230
	TOTAL COST		\$8,660	\$8,200	\$16,860	\$16,860

* Includes one or more mandated activities

¹² Recorded costs were rounded to the nearest \$10,000.

¹³ The figures provided in Tables 5 and 6 are direct charges and do not include Company overhead loaders, with the exception of vacation and sick. The costs are also in 2015 dollars and have not been escalated to 2016 amounts.

¹⁴ Pursuant to D.14-12-025 and D.16-08-018, the Company is providing the “baseline” costs associated with the current controls, which include the 2015 capital amounts. The 2015 mitigation capital amounts are for illustrative purposes only. Because projects generally span several years, considering only one year of capital may not represent the entire mitigation.

¹⁵ The Control Total column includes GRC items as well as any applicable non-GRC jurisdictional items. Non-GRC items may include those addressed in separate regulatory filings or under the jurisdiction of the Federal Energy Regulatory Commission (FERC).

¹⁶ The GRC Total column shows costs typically presented in a GRC.



Specifically as it relates to training, SDG&E does not track its employees’ and contractors’ labor in a manner that distinguishes when and how long an employee or contractor attended training compared to when they were performing their “typical” job function. Accordingly, for training, assumptions were used based on the known number of students that attended the safety-related distribution training, the duration of the training and a derived labor rate. Training materials and instructor costs were also included in the cost of the Qualifications of Pipeline Personnel control.

Table 6 summarizes SDG&E’s proposed mitigation plan, associated projected ranges of estimated O&M expenses for 2019, and projected ranges of estimated capital costs for the years 2017-2019. It is important to note that SDG&E is identifying potential ranges of costs in this plan, and is not requesting funding approval. SDG&E will request approval of funding, in its next GRC. As set forth in Table 6, the utilities are using a 2019 forecast provided in ranges based on 2015 dollars.

Table 6: Proposed Risk Mitigation Plan¹⁷
(Direct 2015 \$000)

ID	Mitigation	Potential Risk Drivers Addressed	2017-2019 Capital ¹⁸	2019 O&M	Mitigation Total ¹⁹	GRC Total ²⁰
1	Maintenance*	<ul style="list-style-type: none"> Asset Failure Public Incident Force of Nature 	\$2,980 - 3,300	\$5,870-6,490	\$8,850 - 9,790	\$8,850 - 9,790
2	Qualifications of Pipeline Personnel*	<ul style="list-style-type: none"> Employee Incident Contractor Incident 	1,420 - 1,730	790 - 960	2,210 - 2,690	2,210 - 2,690
3	Requirements for Corrosion Control *	<ul style="list-style-type: none"> Asset Failure Public Incident Force of Nature 	6,070 - 6,710	1,460 - 1,620	7,530 - 8,330	7,530 - 8,330
4	Operations*	<ul style="list-style-type: none"> Asset 	1,410 -	470 - 520	1,880 - 2,080	1,880 - 2,080

¹⁷ Ranges of costs were rounded to the nearest \$10,000.

¹⁸ The capital presented is the sum of the years 2017, 2018, and 2019 or a three-year total. Years 2017, 2018 and 2019 are the forecast years for SDG&E’s Test Year 2019 GRC Application.

¹⁹ The Mitigation Total column includes GRC items as well as any applicable non-GRC items.

²⁰ The GRC Total column shows costs typically represented in a GRC.



		Failure • Employee Incident	1,560			
<input type="checkbox"/> Status quo is maintained <input checked="" type="checkbox"/> Expanded or new activity * Includes one or more mandated activities						
5	Gas Distribution Integrity Management Programs*	<ul style="list-style-type: none"> • Asset Failure • Public Incident 	64,480 - 89,160	220 - 300	64,700 - 89,460	64,700 - 89,460
6	Improvements	<ul style="list-style-type: none"> • Asset Failure • Public Incident 	129,270 - 142,870	0 - 6,700	129,270 - 149,570	129,270 - 149,570
	TOTAL COST		\$205,630 - \$245,330	\$8,810 - 16,590	\$214,440 - 261,920	\$214,440 - 261,920

While all the mitigations and costs presented in Tables 5 and 6 mitigate the Medium-Pressure Pipeline Failure risk, some of the activities also mitigate other risks presented in this RAMP Report, including: Catastrophic Damage Involving Third Party Dig-Ins (Dig-Ins) and Employee, Contractor and Public Safety. Because these activities mitigate Medium-Pressure Pipeline Failure as well as these aforementioned risks, both the costs and risk reduction benefits are included in all applicable RAMP chapters.



8 Risk Spend Efficiency

Pursuant to D.16-08-018, the utilities are required in this Report to “explicitly include a calculation of risk reduction and a ranking of mitigations based on risk reduction per dollar spent.”²¹ For the purposes of this Section, Risk Spend Efficiency (RSE) is a ratio developed to quantify and compare the effectiveness of a mitigation at reducing risk to other mitigations for the same risk. It is synonymous with “risk reduction per dollar spent” required in D.16-08-018.²²

As discussed in greater detail in the RAMP Approach chapter within this Report, to calculate the RSE the Company first quantified the amount of Risk Reduction attributable to a mitigation, then applied the Risk Reduction to the Mitigation Costs (discussed in Section 7). The Company applied this calculation to each of the mitigations or mitigation groupings, then ranked the proposed mitigations in accordance with the RSE result.

8.1 General Overview of Risk Spend Efficiency Methodology

This subsection describes, in general terms, the methods used to quantify the *Risk Reduction*. The quantification process was intended to accommodate the variety of mitigations and accessibility to applicable data pertinent to calculating risk reductions. Importantly, it should be noted that the analysis described in this chapter uses ranges of estimates of costs, risk scores and RSE. Given the newness of RAMP and its associated requirements, the level of precision in the numbers and figures cannot and should not be assumed.

8.1.1 Calculating Risk Reduction

The Company’s SMEs followed these steps to calculate the Risk Reduction for each mitigation:

1. **Group mitigations for analysis:** The Company “grouped” the proposed mitigations in one of three ways in order to determine the risk reduction: (1) Use the same groupings as shown in the Proposed Risk Mitigation Plan; (2) Group the mitigations by current controls or future mitigations, and similarities in potential drivers, potential consequences, assets, or dependencies (e.g., purchase of software and training on the software); or (3) Analyze the proposed mitigations as one group (i.e., to cover a range of activities associated with the risk).
2. **Identify mitigation groupings as either current controls or incremental mitigations:** The Company identified the groupings by either current controls, which refer to controls that are already in place, or incremental mitigations, which refer to significantly new or expanded mitigations.
3. **Identify a methodology to quantify the impact of each mitigation grouping:** The Company identified the most pertinent methodology to quantify the potential risk reduction resulting from a mitigation grouping’s impact by considering a spectrum of data, including empirical data to the

²¹ D.16-08-018 Ordering Paragraph 8.

²² D.14-12-025 also refers to this as “estimated mitigation costs in relation to risk mitigation benefits.”

extent available, supplemented with the knowledge and experience of subject matter experts. Sources of data included existing Company data and studies, outputs from data modeling, industry studies, and other third-party data and research.

4. **Calculate the risk reduction (change in the risk score):** Using the methodology in Step 3, the Company determined the change in the risk score by using one of the following two approaches to calculate a Potential Risk Score: (1) for current controls, a Potential Risk Score was calculated that represents the increased risk score if the current control was not in place; (2) for incremental mitigations, a Potential Risk Score was calculated that represents the new risk score if the incremental mitigation is put into place. Next, the Company calculated the risk reduction by taking the residual risk score (See Table 4 in this chapter.) and subtracting the Potential Risk Score. For current controls, the analysis assesses how much the risk might increase (i.e., what the potential risk score would be) if that control was removed.²³ For incremental mitigations, the analysis assesses the anticipated reduction of the risk if the new mitigations are implemented. The change in risk score is the risk reduction attributable to each mitigation.

8.1.2 Calculating Risk Spend Efficiency

The Company SMEs then incorporated the mitigation costs from Section 7. They multiplied the risk reduction developed in subsection 8.1.1 by the number of years of risk reduction expected to be realized by the expenditure, and divided it by the total expenditure on the mitigation (capital and O&M). The result is a ratio of risk reduction per dollar, or RSE. This number can be used to measure the relative efficiency of each mitigation to another. Figure 2 shows the RSE calculation.

Figure 2: Formula for Calculating RSE

$$\text{Risk Spend Efficiency} = \frac{\text{Risk Reduction} * \text{Number of Years of Expected Risk Reduction}}{\text{Total Mitigation Cost (in thousands)}}$$

The RSE is presented in this Report as a range, bounded by the low and high cost estimates shown in Table 6 of this chapter. The resulting RSE scores, in units of risk reduction per dollar, can be used to compare mitigations within a risk, as is shown for each risk in this Report.

8.2 Risk Spend Efficiency Applied to This Risk

SDG&E analysts used the general approach discussed in Section 8.1, above, in order to assess the RSE for the Medium Pressure Pipeline Incident risk. The RAMP Approach chapter in this Report, provides a more detailed example of the calculation used by the Company.

To calculate the RSE, SDG&E began with the six mitigations in its proposed plan:

1. Maintenance

²³ For purposes of this analysis, the risk event used is the reasonable worst case scenario, described in the Risk Information section of this chapter.



2. Qualifications of Pipeline Personnel
3. Requirements for Corrosion Control
4. Operations
5. Gas Distribution Pipeline Integrity Management
6. Improvements

SDG&E then analyzed and arranged these mitigations into common groupings that addressed similar potential drivers or potential consequences for purposes of the RSE analysis:

- (a) DIMP/Distribution integrity (current controls)
- (b) Technical training (current controls)
- (c) Regulatory compliance activities (current controls)
- (d) Expanded integrity activities (incremental mitigations)

For each of these four mitigation groupings, SDG&E determined the preferred methodology for quantifying the RSE. The primary assumption for the RSE for the Medium-Pressure Pipeline Failure risk was that performance would deteriorate in the absence of the mitigation. Data from the PHMSA and asset data, where applicable, was used to model the deterioration boundaries. The appropriate data is selected based on the judgment of SMEs.

- **DIMP/Distribution Integrity (current control)**

The RSE modeling approach for distribution integrity programs entailed finding the level of possible performance deterioration if these programs did not exist, which would represent the baseline, inherent risk level. It is assumed that should the program not be funded, then performance would deteriorate to at best the incident rate of the worst state in the nation. The term “at best” is used because even the worst-performing states are assumed to have some programs in place.

The potential drivers associated with a medium pressure pipeline incident are material failure of weld or pipe and other. This was compared to the current incident rate due to all potential drivers so as to attain the level of deterioration from current levels should that program not be funded.

Not all targeted assets will be remediated within the time period of interest. To account for this, the risk reduction of the program will be prorated proportionally comparing the number of assets remediated to the total assets.

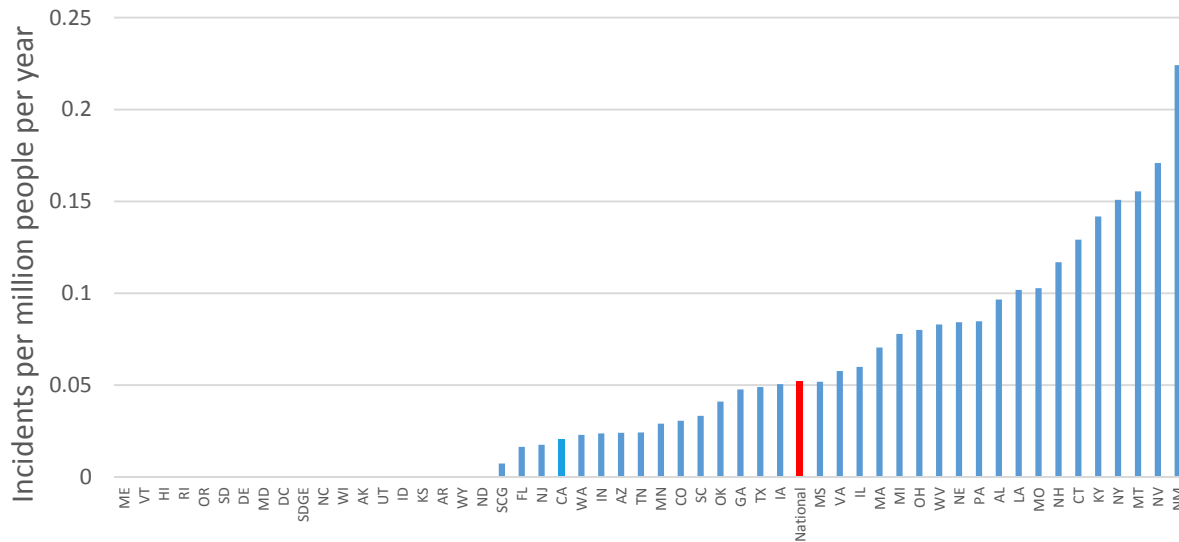
The chart shown below contains the pipeline failure incident rates of all 50 states, in addition to SDG&E and the national average. SDG&E is among the entries with zero incidents per million people per year, and the worst-performing state is New Mexico at 0.224 incidents per million people per year. Using SDG&E’s service population of 3.6 million people, the incident rates can be converted to an incident expectation, given by the following calculation:



A Sempra Energy utility

$$\begin{aligned}
 \text{Expected Incident Rate} &= \Delta(\text{Incident Rate}) * \text{Service Population} \\
 &= (0.224 - 0) \text{ incidents per million people per year} * 3.6 \text{ million people} \\
 &= 0.81 \text{ incidents per year}
 \end{aligned}$$

2010-2016 Significant Incident Rate
Causes: material failure of weld/pipe, other



The average number of SDG&E incidents per year from all causes for the same time period is 0.46²⁴, the proportion of targeted miles being addressed is 100%, and the assumed replacement effectiveness is 1. Putting it all together, the residual risk multiplier is given by the following calculation:

$$\begin{aligned}
 \text{Residual Risk Multiplier} &= \text{Potential deterioration factor} * \text{Proportion of Remediated Assets} \\
 &\quad * \text{Effectiveness} \\
 \text{Residual Risk Multiplier} &= \frac{0.81 \text{ incidents per year}}{0.46 \text{ incidents per year}} * 100\% * 1 \\
 \text{Residual Risk Multiplier} &= 1.7
 \end{aligned}$$

Therefore, if the mitigation is not funded, the projected risk is 1.7 times the current residual risk.

²⁴ Expected Incidents per year for All Causes for SDG&E = Current Incidents per year per million people * Service population
 = 0.1282 incidents per year per million people * 3.6 million people
 = 0.46 incidents per year



- **Technical Training (current control)**

The RSE modeling approach for these programs was the same as that used for distribution integrity programs above with a couple of slight differences. The first difference was that a different set of incident causes is used to establish the worst state performance level. Potential drivers considered applicable to this category are: incorrect operations. The second difference was that there is no secondary adjustment for the percentage of targeted assets and no effectiveness factor. It was assumed that the effect of structured training takes time to fade, up to a decade, due to lack of refresher training and turn over. The fading effect is accounted for by dividing by 3.

For this category of projects, the residual risk multiplier is $(0.9 / 0.5) \times (100\%) \times (1) / (3) = 0.7$. Therefore, if the mitigation is not funded, the projected risk is 0.7 times the current residual risk.

- **Regulatory Compliance Systems (current control)**

The RSE modeling approach for these programs was the same as that used for distribution integrity programs with two exceptions. The first exception was that a different set of incident drivers is used to establish the worst state performance level. Potential drivers considered applicable to this category were: all causes. The second exception is that there was no secondary adjustment for the percentage of targeted assets and no effectiveness factor.

For this category of projects, the residual risk multiplier is $(3.8 / 0.5) \times (100\%) \times (1) = 8.2$. Therefore, if the mitigation is not funded, the projected risk is 8.2 times the current residual risk.

- **Expanded distribution integrity activities (incremental mitigation)**

The RSE modeling approach for these programs was the same as that used for distribution integrity programs with one exception. The exception was that a different set of incident drivers is used to establish the worst state performance level. Potential drivers considered applicable to this category were: corrosion and material failure of weld or pipe.

The average number of incidents per year from all potential drivers for the time period of interest is 0.5, the percentage of targeted miles being addressed is 12%, and the assumed replacement effectiveness is 5. Putting it all together, the residual risk multiplier is $(0.8 / 0.5) \times (12\%) \times (4) = 0.9$. Therefore, if the mitigation is not funded, the projected risk is 0.9 times the current residual risk.

8.3 Risk Spend Efficiency Results

Based on the foregoing analysis, SDG&E calculated the RSE ratio for each of the proposed mitigation groupings. Following is the ranking of the mitigation groupings from the highest to the lowest efficiency, as indicated by the RSE number:

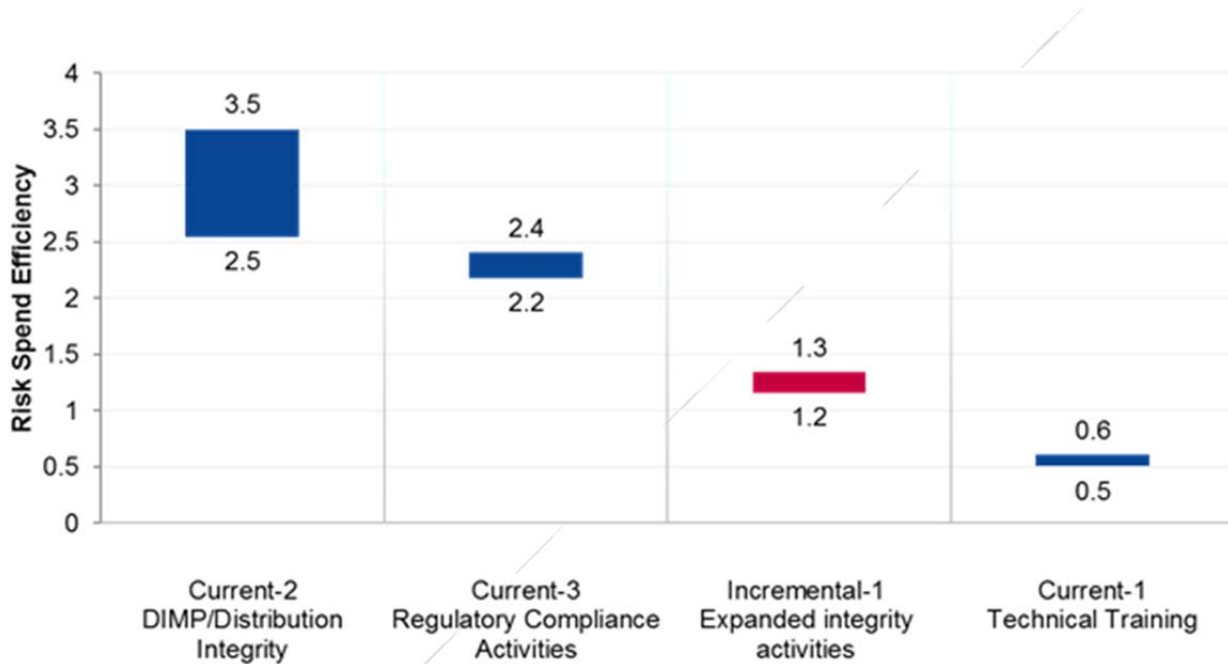
1. DIMP/Distribution integrity (current controls)
2. Regulatory compliance activities (current controls)
3. Expanded integrity activities (incremental mitigations)
4. Technical training (current controls)



Figure 3 displays the range²⁵ of RSEs for each of the SDG&E Medium Pressure Pipeline Failure risk mitigation groupings, arrayed in descending order.²⁶ That is, the more efficient mitigations, in terms of risk reduction per spend, are on the left side of the chart.

Figure 3: Risk Spend Efficiency

**Risk Spend Efficiency Ranges,
SDGE - MP**



9 Alternatives Analysis

SDG&E considered alternatives to the proposed mitigations for the Medium-Pressure Pipeline Failure risk. After consideration, these alternatives were dismissed in favor of the proposed plan, as described below.

²⁵ Based on the low and high cost ranges provided in Table 6 of this chapter.

²⁶ It is important to note that the risk mitigation prioritization shown in this Report, is not comparable across other risks in this Report.



9.1 Alternative 1 – Adjustments to Scope

For SDG&E, each individual proposed program was considered as an alternative risk mitigation plan (i.e. CP betterment, replacement of threaded main, Oil drip piping removal, etc.). SDG&E considered prioritizing the program that had the largest risk/benefit reduction, affordability, and reasonable completion time. However, this alternative was not considered because of the small impact relative to overall risk mitigation proposal and objective. The reason for this is that it is more effective to address all risks at the same time to ultimately have a larger risk/benefit impact in the overall scheme of mitigating the Medium-Pressure Pipeline Failure risk.

9.2 Alternative 2 – DIMP Status Quo

SDG&E considered maintaining the status quo for Aldyl-A medium pressure pipe replacement under the DIMP program. Each year the program would *require \$20 million per year* to operate and eventually eliminate all Aldyl-A pipe. Due to the fact that a small percentage of non-state-of-the-art pipes exist in the system, SDG&E determined there would be a higher benefit to eliminating the current risk associated with Aldyl-A pipe altogether in a timely manner rather than extending the time it will take to replace all of it.