2020 SB 1371
COMPLIANCE PLAN

SDGE A Sempra Energy utility®

SDGE

A Sempra Energy utility®

Rodger Schwecke
Senior Vice President
Gas Operations & Construction
555 W. 5th Street, M.L GT-21C3
Los Angeles, CA 90013
RSchwecke@semprautilities.com

March 16, 2020

Mr. Fred Hanes
Senior Utilities Engineer
Safety and Enforcement Division – RASA Section
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: Leak Abatement Compliance Plan

Dear Mr. Hanes:

San Diego Gas & Electric (SDG&E) submits its 2020 Leak Abatement Compliance Plan pursuant to California Public Utilities Commission (CPUC) Decision (D.) 17-06-015, Ordering Paragraph 6, implementing Senate Bill 1371. At the CPUC's direction, the operator must submit an overall program summary highlighting their major efforts to reduce methane emissions and estimated incremental costs where known. This Section summarizes the total anticipated emission reductions from the proposed practice projected for the two-year Compliance Period.

SDG&E's 2020 Leak Abatement Compliance Plan encompasses proposed activities to achieve methane emission reductions through the 26 Best Practices adopted in D.17-06-015. Proposed activities were evaluated for cost-effectiveness and emissions reduction opportunity, where data was available. Milestones were developed to achieve those emission reductions and develop a timeline for implementation, where possible. Activities include capture of blowdown gas, expansion of damage prevention programs, information technology projects, and development of tools to support monitoring, record-keeping, and reporting.

Table 1 below summarizes SDG&E's proposed major activities and estimated emissions reductions proposed in the 2020 SDG&E Leak Abatement Compliance Plan.

Table 1: Major Efforts to Reduce Emissions

Chapter	2021 Emissions Reduction, MCF	2025 Emissions Reduction, MCF	2030 Emissions Reduction, MCF	Simple Cost Effectiveness ($/MCF)
Chapter 1 - Leak Survey	1,978	2,241	2,241	$484.85
Chapter 2 - Blowdown Reduction Activities	1,700	1,700	1,700	$39.65
Summary	**3,678**	**3,941**	**3,941**	
Percentage Reduction	**1.304%**	**1.397%**	**1.397%**	

In addition to the major efforts summarized in Table 1, a variety of research, development, and demonstration (RD&D) projects are referenced where SDG&E is a direct funder or provides in-kind support. These projects were proposed and initiated by leading industry organizations, including SDG&E, in response to this proceeding and other environmental regulations targeting overall reduction of natural gas emissions. Additional RD&D projects and pilot studies are also proposed where tools and technologies require further development or where knowledge and information is needed to understand the potential for emissions reduction and to estimate the implementation cost for SDG&E.

San Diego Gas & Electric appreciates the opportunity to submit its 2020 Leak Abatement Compliance Plan and looks forward to continuing to work with the CPUC and its staff to further the goals of Senate Bill 1371 in a safe and cost-effective manner.

Sincerely,

Rodger Schwecke

Rodger Schwecke
Senior Vice President, Gas Operations & Construction

Introduction

SDG&E submits this Biennial Compliance Plan on March 16, 2020 (Compliance Plan). Implementation of the activities for each Best Practice will begin after cost recovery is approved, with an expectation of implementation for 2021 – 2022.

The Compliance Plan proposes to achieve methane emission reductions through the 26 Best Practices. Proposed activities are evaluated for cost-effectiveness and emission reduction opportunity, where data is available. All requests for cost recovery in this compliance plan are for activities that are incremental to safety and specific to the emission reduction goals of Decision (D) 19-08-020. SDG&E currently has policies and procedures in place to meet environmental regulations implemented by California Air Resources Board, Environmental Protection Agency, Local Air Pollution Control Districts, and the Department of Oil, Gas, and Geothermal Resources. Some of these environmental policies overlap with SB 1371 requirements, and that overlap is addressed in the relevant chapters herein.

Emissions Reductions

The current 2015 baseline for SDG&E's system is 282,047 MCF per year. Annual estimated emission reductions resulting from activities proposed in this Compliance Plan from 2021 – 2030 are estimated at 3,678 MCF. Expected annual emissions in 2030, based on modeling and assumptions as stated in this Compliance Plan, are 278,106 MCF, an estimated 1.4% reduction. It should be noted that the 2015 baseline is expected to change in Q2 2020 once proposals from the 2020 Winter Workshop are reviewed. As such, the estimated percentage reduction will likely change as a result of the new 2015 baseline.

The current estimate of a 1.3% reduction in emissions from the 2015 baseline by 2025 and 1.4% by 2030 is based on emissions models of the proposed 2020 Compliance Plan. However, there is insufficient data to model emission reductions for many of the proposed activities. In addition, the existing models may not be entirely accurate, and the projected reduction may be higher or lower in actual practice. For example, there are measures where emission reductions cannot be calculated but emissions may be reduced by the proposed activities, such as improved training, policy changes and project bundling, and better record keeping. As proposed research projects and pilots are completed, more accurate modeling may be available for activities such as the installation of methane sensors, transmission pipeline leaks, repairs of minor leaks, and above ground leak inspection and repair.

For SDG&E's 2018 Annual Emissions Report, 90% of emissions were based on population, facility, or component-based emission factors. Some of the reductions targeted in this plan are fugitive emissions, which are estimated using emission factor-based models. The emission factor estimates currently in use in these models cannot be changed without agreement from the relevant regulatory agencies. Since almost all fugitive emissions are based on emission factors, projecting and recording more than a 1.4% reduction will not be possible until these emission factors are addressed.

It should be noted that, in most cases, SDG&E is unable to evaluate historical cost-effectiveness due to implementation still being in progress. Revenue requirements can only be accurately calculated for historical measures when the measure is completed.

Table 1 below summarizes SDG&E's proposed major activities and estimated emissions reductions proposed in the 2020 SDG&E Leak Abatement Compliance Plan.

Table 1: Major Efforts to Reduce Emissions

Chapter	2021 Emissions Reduction, MCF	2025 Emissions Reduction, MCF	2030 Emissions Reduction, MCF	Simple Cost Effectiveness ($/MCF)
Chapter 1 - Leak Survey	1,978	2,241	2,241	$484.85
Chapter 2 - Blowdown Reduction Activities	1,700	1,700	1,700	$39.65
Summary	**3,678**	**3,941**	**3,941**	
Percentage Reduction	**1.304%**	**1.397%**	**1.397%**	

Calculating Cost Effectiveness

All cost effectiveness calculations used average annual revenue requirement, which was modeled by SDG&E based on data from December 2019. Annualized revenue requirement is calculated by dividing the cumulative revenue requirement for each measure by the useful life of the measure or asset.

Standard Cost Effectiveness:

$$\frac{Annualized\ Rev\ Req * 10\ years - Cost\ Benefits}{Emissions\ Reductions, 2021 - 2030}$$

Pursuant to D. 19-080929, SDG&E also calculates cost effectiveness with avoided Cap & Trade costs and social cost of methane as follows:

Cost Effectiveness with avoided Cap & Trade Costs:

$$\frac{Annualized\ Rev\ Req * 10\ years - Cost\ Benefits - Avoided\ Cap \,\&\, Trade\ Costs}{Emissions\ Reductions, 2021 - 2030}$$

Cost Effectiveness with avoided Social Cost of Methane and Cap & Trade Costs:

$$\frac{Annualized\ Rev\ Req * 10\ years - Cost\ Benefits - Avoided\ Cap \,\&\, Trade\ Costs - Social\ Cost\ of\ Methane}{Emissions\ Reductions, 2021 - 2030}$$

Common Assumptions for Cost Estimates

Below are the common assumptions SDG&E made when building cost estimates for the measures described in this Compliance Plan:

1. Full Time Equivalents (FTEs) are internal company employees and their costs are known as "Labor". The salary of these FTEs is assumed to be $100,000 in direct annual costs, unless noted otherwise. Contractors are included in "Non-Labor" Costs.
2. Vehicle costs for employees are included in the loaders for employees and, therefore, not are not specifically line itemed, unless noted otherwise.
3. Cost estimates were created in December 2019 dollars and loaded with December 2019 loading factors.
4. When measures benefit both SoCalGas and SDG&E and the cost split is unknown, the costs are assumed to be 91% SoCalGas and 9% SDG&E. This percentage split was calculated based on the 2016 Emissions Inventory (reported in 2017) to remain consistent with the 2018 Compliance Plan.
5. The social cost of methane used was $21/MCF, as noted on page 16 of D.19-08-020 for the year 2020 at a 3% discount rate.
6. The cost benefit of the reduced cost of gas was evaluated at the forecasted average annual Weighted Average Cost of Gas (WACOG) published in the 2018 California Gas Report, converted to cost per MCF using a BTU conversion factor of 1.0343 MCF/MMBtu, resulting in a cost benefit of $2.42/MCF.
7. Cap & Trade costs are $20.82/MTCO2e, assuming December 2022 vintage prices, based on a 5-day average of trading days January 6 – 10, 2020. This futures data was acquired from the International Exchange. Converting from MTCO2e to MCF results in a cost benefit of $13.61/MCF.
8. All loaded chapter costs include a 10% contingency, as noted in the Advice Letter and each chapter cost summary section.

SDG&E Table of Concordance

SDG&E Attachment Library

Attachment	Chapter	Attachment Name
A	1 - Leak Survey	Updated Gas Standard G8145
A1	1 - Leak Survey	Redline Edit Gas Standard G8146
B	1 - Leak Survey	Historic Project Schedule for Leak Survey
BB	2 - Blowdown Reduction Activities	Updated Gas Standards
C	4 - Recordkeeping IT Project	Historic Project Schedule for Data Lake
D	7 - Damage Prevention Public Awareness	Historic Work
E	9 - Repeat Offenders IT Systems	Historic Project Schedule for Repeat Offender System
F	10 - Gas Speciation	Gas Speciation Historic Work
G	12 - Methane GHG Policy	Updated SDG&E Environmental Excellence Policy
H	13 - Distribution Above Ground Leak Survey	Gas Standard T8172 Inspection Schedule
H1	13 - Distribution Above Ground Leak Survey	RMLD Technical Specifications
I	14 - Methane Emissions Training	Methane Emissions Training Historic Work
J	Research & Development	Research & Development Templates

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practices:

Best Practice 15: Gas Distribution Leak Surveys
Utilities should conduct leak surveys of the gas distribution system every 3 years, not to exceed 39 months, in areas where G.O. 112-F, or its successors, requires surveying every 5 years. In lieu of a system-wide three-year leak survey cycle, utilities may propose and justify in their Compliance Plan filings, subject to Commission approval, a risk-assessment based, more cost-effective methodology for conducting gas distribution pipeline leak surveys at a less frequent interval. However, utilities shall always meet the minimum requirements of G.O. 112-F, and its successors.
Best Practice 16: Special Leak Surveys
Utilities shall conduct special leak surveys, possibly at a more frequent interval than required by G.O. 112-F (or its successors) or BP 15, for specific areas of their transmission and distribution pipeline systems with known risks for natural gas leakage. Special leak surveys may focus on specific pipeline materials known to be susceptible to leaks or other known pipeline integrity risks, such as geological conditions. Special leak surveys shall be coordinated with transmission and distribution integrity management programs (TIMP/DIMP) and other utility safety programs. Utilities shall file in their Compliance Plan proposed special leak surveys for known risks and proposed methodologies for identifying additional special leak surveys based on risk assessments (including predictive and/or historical trends analysis). As surveys are conducted over time, utilities shall report as part of their Compliance Plans, details about leakage trends. Predictive analysis may be defined differently for differing companies based on company size and trends.

Leak surveys on distribution lines have historically been performed according to the requirements in 49 CFR 192.723 for safety reasons. SDG&E pipelines are typically leak surveyed at intervals of one, three, or five years. The frequency of this survey is determined by the pipe material involved (i.e. plastic or steel), the operating pressure, whether the pipe is under cathodic protection, and the proximity of the pipe to various population densities. In 2018, SDG&E increased the survey frequency for all Pre-1986 Aldyl-A pipe from five-year and three-year to annual. This activity was funded by the Distribution Integrity Management Program (DIMP).

In the 2018 Compliance Plan, SDG&E requested and was approved to move Vintage Steel pipe from three-year to annual leak survey cycles, Post-1986 Plastic pipe from five-year to three-year survey cycles, and protected steel (Post-1950) pipe from five-year to three-year leak survey cycles. To support these efforts, SDG&E staffed the following dedicated employees:

Three (3) Leak Patrollers;
One (1) Field Operations Supervisors; and
One (1) Office Employees.

SDG&E purchased vehicles and tools for the incremental employees and all the incremental staff have completed required training. Because increased survey will increase the number of leaks found, SDG&E also staffed incremental leakage personnel as outlined in Chapter 1 to support incremental leak repair.

In addition to surveying efforts above, a considerable amount of additional employee time is required for updating internal reporting and mapping systems (SAP & GIS) to update leak survey maps as a part of the increased survey cycle. Because of this, the leak survey department was split into two unique groups and the entire service territory was split into "North" and "South" regions.

Gas Standard G8145 was updated to reflect the annual survey cycles for Pre-86 Aldyl-A Vintage and Pre-1950 Vintage Steel pipe. An updated version of the Gas Standard is included as Attachment A1.

Emission Reductions Achieved

SDG&E has not had the opportunity to evaluate emission reductions for annual survey on Vintage Steel or three-year survey on protected steel and Post-86 plastic pipe due to full implementation beginning in 2020.

The portion of emissions associated with Pre-86 Aldyl A in the 2015 baseline Distribution Pipeline Leak Emissions was 1,062 MCF. The reduction achieved in 2018 after 1 year of annual survey performed on Pre-86 Aldyl A was 403 MCF, compared with the forecasted reduction of 16,749 MCF.

Cost Effectiveness Evaluation of Historic Work

Cost effectiveness cannot be calculated at this time for Vintage Steel annual survey or three-year survey cycles on protected steel and Post-86 plastic pipe because SDG&E has not had the opportunity to evaluate emission reductions due to full implementation beginning in 2020.

Regarding the annual survey of Pre-86 Aldyl-A, no costs were recorded to this program because this effort was funded through DIMP.

Part 2. Proposed New or Continuing Measure

SDG&E proposes to continue performing annual leak survey on Pre-1950 Vintage Steel Pipe and Pre-86 Aldyl-A pipe, as well as three-year leak survey cycles on Post-86 plastic pipe and protected steel pipe. SDG&E is not requesting additional funds for the Pre-86 Aldyl-A survey in this program.

The activities proposed in this measure can be achieved with the existing project management team, leak surveyors, field supervisors, leakage clerks, and planning associates that were hired to meet the requirements of the 2018 Compliance Plan. No operational changes are necessary beyond continuing implementation of the increased leak survey cycles.

Part 3. Abatement Estimates

SDG&E estimates that the emission reductions achieved by increasing leak survey cycles on Pre-1950 Vintage Steel Pipe and Pre-86 Aldyl-A to annual survey cycles and Post-86 plastic pipe and protected steel to three-year leak survey cycles will result in a total emission reduction of 1,302 MCF from the 2015 baseline by the end of this Compliance period. These emissions will be reduced from the Pipeline Leaks Emission Source Category within the Distribution Mains and Services System Category.

Scenario	Baselines Emissions (MCF)	Estimated Emission Reductions (MCF)					
Year	**2015**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-State of the Art Plastic (Pre-86 Aldyl-A) Pipe from 5 Yr to 1 Yr	1,062	403	636	740	845	845	845
Pre-1950 Steel Vintage Pipe survey	1,119	0	0	165	337	441	462
Post-86 Plastic Pipe from 5 Yr to 3 Yr	418	0	0	47	114	199	115
Protected Steel 5 Yr to 3 Yr	1,872	0	0	514	682	844	879

The calculation methodology used to calculate the estimated reduction in emissions is the same methodology used to calculate emissions from the distribution system in the Annual Emissions Report. The calculation methodology used to calculate the estimated reduction in emissions is found below:

1. Derive the annual system leak rates by materials and facilities
2. Estimate the number of leaks detected and their associated emissions when shifting the survey cycle from five-year and three-year to annually
3. Project emissions reduction in future years during and after implementation of this best practice

Part 4. Cost Estimates

Cost estimates below include only costs associated with annual survey cycles on Pre-1950 Vintage Steel and three-year survey cycles on protected steel and Post-86 plastic pipe. SDG&E is not requesting funding for Pre-86 Aldyl-A survey in this program.

O&M Cost Estimtes					
Activity	**2021**		**2022**		**Total Loaded O&M Cost with Contingency**
	Direct	**Loaded**	**Direct**	**Loaded**	
Incremental Leak Survey Field Employees	$251,515	$513, 979	$251,515	$513,979	$1,963,221
Incremental Leak Survey Office Employees	$83,838	$167,677	$101,200	$167,677	
Incremental Leak Survey Supervisors	$101,200	$207,067	$101,200	$207,067	

Total Revenue Requirement over expected life of investment: $2 million
Average Annual Revenue Requirement: $1,045,170

Cost Assumptions

- 6,114 feet surveyed per day
- Represented Employee Hourly Rate: $39.73
- 3 Incremental Leak Survey field FTE's
- 1 Incremental Survey Supervisor
- 1 Incremental Office Employee
- $100K annual salary for Supervisor
- 10% contingency is included in the total loaded O&M cost

Part 5. Cost Effectiveness/Benefits

Standard Cost Effectiveness Calculation
$484.85
Cost Effectiveness with Avoided Cap and Trade Cost
$482.13
Cost Effectiveness with avoided Social Cost of Methane
$477.93

Part 6. Supplemental Information/Documentation

Attachment A: Current Gas Standard G8145

Attachment A1: Red lined Gas Standard G8145

Attachment B: Historic Project Schedule for Leak Survey

Part 1. Evaluate the Current Practice Addressed in the Chapter

This Chapter addresses the following Best Practices:

Best Practice 23: Minimize Emissions from Operations, Maintenance and Other Activities
Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.
Best Practice 3: Pressure Reduction Policy
Written company policy stating that pressure reduction to the lowest operationally feasible level in order to minimize methane emissions is required before non-emergency venting of high-pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of Compliance Plan filing.
Best Practice 4: Project Scheduling Policy
Written company policy stating that any high-pressure distribution (above 60 psig), transmission or underground storage infrastructure project that requires evacuating methane will build time into the project schedule to minimize methane emissions to the atmosphere consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Projected schedules of high-pressure distribution (above 60 psig), transmission or underground storage infrastructure work, requiring methane evacuation, shall also be submitted to facilitate audits, with line venting schedule updates TBD. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.
Best Practice 5: Methane Evacuation Procedures
Written company procedures implementing the BPs approved for use to evacuate methane for non-emergency venting of high-pressure distribution (above 60 psig), transmission or underground storage infrastructure and how to use them consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.
Best Practice 6: Methane Evacuation Work Orders Policy
Written company policy that requires that for any high pressure distribution (above 60 psig), transmission or underground storage infrastructure projects requiring evacuating methane, Work Planners shall clearly delineate, in procedural documents, such as work orders used in the field, the steps required to safely and efficiently reduce the pressure in the lines, prior to lines being vented, considering alternative potential sources of supply to reliably serve customers. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

Best Practice 7: Bundling Work Policy
Written company policy requiring bundling of work, whenever practicable, to prevent multiple venting of the same piping consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Company policy shall define situations where work bundling is not practicable. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

SDG&E has documented use of cost-effective methods to reduce blowdown since 1993 during operations on high pressure construction projects, including pressure reduction using mobile compressors, transfer of gas to lower pressure systems, and isolation of sections using stopples. Operators of natural gas pipeline systems routinely reduce line pressure and discharge gas from pipeline sections to provide safe working conditions during maintenance and repair activities. Typically, operators block the smallest possible linear section of the pipeline and depressurize it by venting gas to the atmosphere. Using pump-down techniques to lower gas line pressure before performing maintenance and repair activities is an effective way to reduce emissions and yield significant economic savings. Pipeline pump-down techniques involve using in-line compressors either alone or in sequence with portable compressors. Using in-line compressors is generally justifiable because there are no capital costs, and payback is immediate. The cost-effectiveness of also using a portable compressor to increase gas recovery depends greatly on site-specific factors and operating costs. Regardless of the pump-down technique selected, emission reductions are directly proportional to how much pipeline pressure is reduced before venting occurs. Pipeline pump-down techniques are most economical for larger volume, higher pressure gas lines and work most effectively for planned maintenance activities and cases in which sufficient manifolding exists to connect a portable compressor.

In the 2018 Compliance Plan, SDG&E requested and was approved for funding to continue blowdown reduction efforts. SDG&E was also approved to increase the capabilities of blowdown gas capture. This includes but is not limited to purchasing compressors and ZEVAC units to reduce blowdown emissions, increasing field operations staffing to support the incremental time to reduce blowdown, and creating a record keeping and compliance process to document that the requirements of the Best Practices were being met.

No incremental staffing was required for this best practice. SDG&E will utilize SoCalGas' centralized organization dedicated to blowdown reduction.

Several Gas Standards were updated to increase blowdown reduction efforts as outlined in Best Practice's 3-7. Some of the standards listed below apply to both SoCalGas and SDG&E. The Gas Standards are included as attachments and are as follows:

GS 183.01 - Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities
GS 184.06 Gas-Handling and Pressure Control
GS 184.006 - General Construction Requirements for Distribution Service Lines
GS 182.0160 - Purging Pipelines and Components
GS 184.0015 - Construction Planning for Mains and Supply Lines
GS 223.0145 - Planning Shutdowns for Transmission and Storage
G7909 - Purging Pipelines and Components
Form 3466 - Reporting of Gas Blown to Atmosphere
Form 7011 - Blowdown Emission Reduction Plan Form
GS 182.0032 - Blowdown Time, Sizing, and Volume Calculations
GS 182.0155 - Gas Loss Estimation – Pipeline
G8148 - Gas Loss Estimation - Pipeline

Emission Reductions Achieved

Blowdown Emissions reported for Transmission Pipelines, M&R Stations, and Compressor Stations as the baseline in 2015 was 7,413 MCF. In the calendar year 2018, emissions from these categories totaled 1,642.9 MCF, an estimated reduction of 5,770 MCF. These reductions were achieved using GRC funds and was not charged to the Leak Abatement Balancing Account.

System Category	2015 Emissions (MCF)	2018 Emissions (MCF)	Emission Change 2015-2018 (MCF)
Transmission Pipelines	3,426	58.9	-3,367
Transmission M&R Stations	31	22	-9
Transmission Compressor Stations	3,956	1,562	-2,394
Total	7,413	1,642.9	-5,770

The reduction forecasted to be achieved from Transmission blowdown reduction by the end of 2019 in the 2018 Compliance Plan was 1,500 MCF. Final emissions reductions achieved by the end of 2019 will not be finalized until June 2020 when the 2020 Annual Emissions Report is due. Because the emissions from Blowdown Reduction are activity based, it is difficult to forecast emission reductions.

Cost Effectiveness Evaluation of Historic Work

The cost-effectiveness of this measure cannot be calculated at this time due to insufficient data.

Part 2. Proposed New or Continuing Measure

SDG&E requests funding to continue high pressure pipeline blowdown reduction efforts. SDG&E will continue to combine work on high pressure lines when it is practical to do so and will coordinate projects across departments. SDG&E also proposes the implementation of electronic blowdown reduction recordkeeping to better track and conduct blowdown reduction efforts.

Incremental work includes but is not limited to expanding the gas capture program to include capture on more projects, increasing the use of cross compression, additional funding for labor due to the increased time required for blowdown reduction, and capital work including installing fittings on valves to expand cross compression capabilities. In addition, there is an increased need to improve data collection and recordkeeping for blowdown reduction to improve capabilities for planning blowdown reduction and monitor progress and cost effectiveness. SDG&E proposes to develop an electronic form to plan blowdown reduction efforts and improve data aggregation and analysis.

Project Milestones

Complete Electronic Blowdown Reduction Recordkeeping: Estimated Q4 2021

Part 3. Abatement Estimates

SDG&E estimates that the emission reductions achieved by increasing blowdown reduction activities will result in a total emission reduction of 3,400 MCF from the 2015 baseline of 7,413 MCF. These emissions will be reduced from the Blowdown Emission Source Category within the Transmission Pipeline, Transmission M&R Stations, and Transmission Compressor Stations Category. The emission reductions are calculated using the emission factors from the Annual report and applying a shorter time to repair.

Part 4. Cost Estimates

Capital Cost Estimates					
Activity	**2021**		**2022**		**Total Loaded Capital Cost with Contingency**
	Direct	**Loaded**	**Direct**	**Loaded**	
Minimize Blowdowns in Transmission	$300,000	$301,770	$300,000	$301,770	$1,365,065

Total Revenue Requirement over expected life of investment: $2 million
Average Annual Revenue Requirement: $68,255

Cost Assumptions

- Assumed an increase of 20% per year of projects minimizing blowdowns in High Pressure Pipelines
- 10% Contingency is included in the total loaded O&M and Capital cost

Part 5. Cost Effectiveness/Benefits

Standard Cost Effectiveness
$39.65

Standard Cost Effectiveness including Cap and Trade Cost Benefits
$36.93

Standard Cost Effectiveness including Social Cost of Methane Benefits
$32.73

Part 6. Supplemental Information/Documentation

Attachment BB: Updated Gas Standards

GS 183.01 - Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities
GS 184.06 Gas-Handling and Pressure Control
GS 184.006 - General Construction Requirements for Distribution Service Lines
GS 182.0160 - Purging Pipelines and Components
GS 184.0015 - Construction Planning for Mains and Supply Lines
GS 223.0145 - Planning Shutdowns for Transmission and Storage
G7909 - Purging Pipelines and Components
Form 3466 - Reporting of Gas Blown to Atmosphere
Form 7011 - Blowdown Emission Reduction Plan Form
GS 182.0032 - Blowdown Time, Sizing, and Volume Calculations
GS 182.0155 - Gas Loss Estimation – Pipeline
G8148 - Gas Loss Estimation - Pipeline

2020 Compliance Plan
Chapter 3: Damage Prevention Algorithm and Proactive Intervention

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practices:

Best Practice 24: Dig-Ins and Public Education Program
Expand existing public education program to alert the public and third-party excavation contractors to the Call Before You Dig – 811program. In addition, utilities must provide procedures for excavation contractors to follow when excavating to prevent damaging or rupturing a gas line.
Best Practice 25: Dig-Ins and Company Standby Monitors
Utilities must provide company monitors to witness all excavations near gas transmission lines to ensure that contractors are following utility procedures to properly excavate and backfill around transmission lines.
Best Practice 26: Dig-Ins and Repeat Offenders
Utilities shall document procedures to address Repeat Offenders such as providing post-damage safe excavation training and on-site spot visits. Utilities shall keep track and report multiple incidents, within a 5-year period, of dig-ins from the same party in their Annual Emissions Inventory Reports. These incidents and leaks shall be recorded as required in the recordkeeping best practice. In addition, the utility should report egregious offenders to appropriate enforcement agencies including the California Contractor's State License Board. The Board has the authority to investigate and punish dishonest or negligent contractors. Punishment can include suspension of their contractor's license.

The State of California mandates a preconstruction meeting with excavators requesting Locate and Mark support and requires continuous monitoring of all excavations within ten feet of high-pressure pipelines per Cal. Gov't Code § 4216.2. Therefore, the requirements of Best Practice 25 are already met. SDG&E's public awareness program is driven by (1) the requirements of 49 C.F.R. § 192.61f, the technical document, (2) Public Awareness Programs for Pipeline Operators, API RP 1162 and (3) program expansion recommendations by regulators. SDG&E was approved to begin expanding the standby program to other areas where there could be challenges to controlling a damage, as proposed in the 2018 compliance period. This implementation was pending the completion of a risk algorithm analyzing the location of 811 tickets and prioritizing them to trigger expanded standby. In 2019 this algorithm was completed and piloted. However, field implementation has not yet begun. SDG&E has determined through the algorithm development that rather than expanding standby, it would be more efficient to perform more field interventions for these higher risk excavations. Rather than having an employee stand by and observe an excavation, which can often take multiple days, it would be more efficient to have that employee visit multiple excavators within the same timeframe to discuss damage prevention at their excavation sites.

Using the prioritized results from the risk analysis algorithm, company personnel can initiate communication with excavators to discuss the project and remind them of the importance of locating and protecting the natural gas pipe within their projects delineated area. The form of communication can be a phone call, text message, email, or job site visit, prior to the date of excavation. Through these proactive interventions, company personnel can effectively address a larger number of excavation projects than just performing standby. This proactive excavation intervention will enable SDG&E to minimize methane emissions from preventable damages.

In 2019, SDG&E utilized 4 Damage Prevention Analysts to engage, educate, and enforce 811 rules. Their work resulted in over 2,100 field contacts with excavators, over 200 educational safe excavation training sessions, and 300 damage investigations resulting in improved excavation safety.

Part 2. Proposed New or Continuing Measure

SDG&E proposes continuing to develop the damage prevention risk analysis algorithm; this information would be used to trigger a proactive intervention. Proactive interventions include activities that SDG&E can perform to address potential excavation sites that pose a high risk of damage, causing methane emissions. Using the prioritized results from the risk analysis algorithm, company personnel can initiate communication with the excavator to discuss the project and remind them of the importance of locating and protecting the natural gas pipe within their projects delineated area. The form of communication can be a phone call, text message, email, or job site visit, prior to the date of excavation. Through these proactive interventions, company personnel can effectively address a larger number of excavation projects. This proactive excavation intervention will enable SDG&E to minimize methane emissions from potentially preventable damages.

The existing risk algorithm that was completed in the 2018 Compliance period assigns a score for every new 811 ticket to provide SDG&E with prompt visibility into high-risk dig sites and mark out locations. SDG&E is proposing to make enhancements to the algorithm in the 2020 compliance period to further reduce potentially preventable damages. These planned enhancements to the algorithm include additional data layers that will provide increased benefits such as identifying:

- Excavator Error: Risk score derived from risk variables like work type, contractor name, topography, and weather conditions.
- No Call-Ins: Identification of possibly high-risk excavations without 811 ticket information, leveraging municipality permit data where data is publicly available.
- These risk scores will allow SDG&E to prioritize and conduct appropriate and timely interventions before damages occur. The No Call-Ins analysis will provide SDG&E visibility into repeat offenders who continue to conduct excavations without calling 811.

In order to implement these further enhancements, SDG&E will need to hire six (6) additional Damage Prevention Analysts to perform the increased volume of proactive intervention efforts with prioritized Dig Alert tickets.

<u>Project Milestones</u>

- Hire and train incremental Damage Prevention Analysts: Expected to be completed by Q1 2021.
- Collect data and perform proactive interventions: Continuous.

Part 3. Abatement Estimates

There is insufficient data to quantify emission reductions from these activities.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Risk Prevention Software Solution	$112,500	$113,164	$112,500	$113,164	$248,961

Total Revenue Requirement over expected life of investment: $265,301
Average Annual Revenue Requirement: $132,651

Cost Assumptions

- 9% of SoCalGas cost per year for damage prevention software

Part 5. Cost Effectiveness/Benefits

There is insufficient work to evaluate the cost effectiveness of these activities.

Part 6. Supplemental Information/Documentation

N/A

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 9: Recordkeeping
Written Company Policy directing the gas business unit to maintain records of all SB 1371 Annual Emissions Inventory Report methane emissions and leaks, including the calculations, data and assumptions used to derive the volume of methane released. Records are to be maintained in accordance with G.O. 112 F and succeeding revisions, and 49 CFR 192. Currently, the record retention time in G.O. 112 F is at least 75 years for the transmission system. 49 CFR 192.1011 requires a record retention time of at least 10 years for the distribution system. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

In the past, developing the Annual Emissions Report required by SB 1371 involved querying various records which were stored in varying formats, locations, databases, and with various record owners. Different record keeping practices have evolved over time and as new record-keeping requirements emerge, various new systems have been developed. These different record-keeping systems are not compatible, and data is not easily shared, integrated, or queried. This makes report generation a time-consuming manual process. An additional challenge is that these systems were not designed for generating reports for emissions, but rather for billing or operational record keeping. Because of this, the records may use varying types of nomenclature relevant to specific departments. Querying records from numerous departments in the company and combining them to generate a single report is quite challenging. To generate Annual Emissions Reports, data is pulled from thirty-six separate reports, which are generated from fourteen different systems. Generating an Annual Emissions Report requires four full time employees and engaging various departments to compile and analyze the data and properly format it for consistent report generation.

As proposed in the 2018 Compliance Plan, SDG&E is implementing a central data lake that obtains records from the various systems and stores them centrally, enabling automation of reporting as well as satisfying the retention and audit requirements. SDG&E is also developing an initial phase of the Engineering Data Analytics and Performance Optimization (EDAPO) system, to provide capabilities to support advanced analytics for Gas Operations & System Integrity, Distribution and Transmission.

SDG&E has also started enhancing existing systems to include additional data elements required for the methane emission calculations into all Maintenance and Inspection work management systems. The systems enhancement has been enabling the field personnel to record the required information into systems that previously have not been capable of recording specific information, such as detailed components. Such information enables SDG&E to report its operational activities accurately on required reports.

SDG&E has also conducted a field mobility project assessment. This project studied the status of the mobile capabilities of existing systems, digital forms, and paper forms in order to define the future mobility scope.

Finally, written company policies were developed and edited to maintain records for all SB 1371 relevant measured and estimated emissions, including calculations, data, and assumptions to derive the volume of methane released.

There is insufficient data to calculate emission reductions and cost effectiveness.

Part 2. Proposed New or Continuing Measure

This implementation is divided into 5 measures.

Measure 1: Data Lake

As stated in the 2018Compliance Plan, this project will be phased in over two Compliance periods. Therefore, SDG&E will be completing the initial data lake scope and continue to make enhancements to respond to evolving SB 1371 requirements throughout the 2021-2022 Compliance period.

As new requirements are identified, analysis, design, and development activities will include:

- Complete current data lake project scope
- Analyze and update existing data capture forms
- Design and modify existing enterprise systems to accommodate new data requirements
- Integrate system changes with the data lake
- Expand the scope of the data lake
- Back fill historical data for the entire reporting period to meet the new requirements
- Test the modified systems, integration, and reporting from the data lake
- Training and support
- Project and program manager time

Project Milestone

- Complete initial data lake scope: Estimated by Q2 2021
- Maintain and enhance the existing systems and data lake integration to capture new data for new requirements: Continuous

Measure 2: Engineering Data Analytics and Performance Optimization (EDAPO**)**

EDAPO’s advanced analytics will provide actionable insights on gas assets' current and future performance. EDAPO will be used to detect and help prioritize leak repairs and identify areas with high leak indicators. The analytics results will become SB 1371 records and be captured and stored in the data lake. EDAPO advanced analytics will implement the tools, infrastructure and resources to drive the improvement of business operations and enable the proactive management of gas assets. EDAPO will provide capabilities that will include:

Enable cost effective avoidance, reduction, and repair of leaks and leaking components
Evaluate the operations, maintenance, and repair practices to increase the effectiveness of practices to reduce methane leaks
Develop and use metrics to evaluate and track leaks geographically and over time

Project Milestones

- Identify sample data sets to be integrated: Estimated by Q1 2021
- Sample data integration for analytics: Estimated by Q4 2021
- Data Model validation/verification: Estimated by Q2 2022
- Implementation of EDAPO advanced analytics: Estimated by Q4 2022

Measure 3: Asset Field Verification

SDG&E will also continue enhancing existing systems efforts that started in the 2018 Compliance Plan. SDG&E will verify its assets data in the Maintenance and Inspection work management systems of various operational divisions such as Transmission. These verification efforts will enable SDG&E to query accurate methane emissions for its Annual Emissions Report.

The Field Verification Project will include:

- Data Governance – identify appropriate Gas Standards and apply to engineering tags capture, in addition to defining lookups for entry fields where possible.
- Review engineering drawings and identify assets that need to be in verified or added
- Field verification of assets, including photos, and collection of data points needed for maintenance and work management systems
- Organize photos and data

Project Milestones

- Field verification of Transmission assets: Estimated by Q4 2021
- Perform field verification and enhancement of Management systems assets and update engineering/mapping information to support improved data management and reporting accuracy expected to be completed by Q4 2022

Measure 4: Real-time data management for Methane Abatement/Monitoring Support for Other Gas Operational Units

Project will continue to:

- Modernize real-time data management software landscape and infrastructure to improve the existing methane emission systems
- Integrate existing infrastructure with enterprise compliance reporting software to support advanced and predictive analytics
- Integrate existing infrastructure into SB 1371 solutions to enhance company's compliance with methane emission requirements
- Enable additional analytics capabilities and provide ability to integrate with other enterprise initiatives.

Project Milestones:

- Design, develop, and implement real-time data management software: Continuous

Measure 5: Develop Mobile Field Forms

As part of the 2018 Compliance Plan, SDG&E completed an assessment to evaluate the mobile capabilities of the existing system, digital forms, and paper forms. SDG&E proposes to create digitized forms based on the assessment results. This strategy will digitize paper forms, update electronic forms, and establish a governance structure to support mobility. This measure is expected to create a simplified and consistent experience for the field employees, while increasing the accuracy of the captured data and providing near real-time integration with the associated IT systems e.g. data lake. This scope of work is expected to continue into the 2022 Compliance Plan.

Project Milestones:

- Validate scope of digitizing paper forms: Estimated by Q2 2021
- Digitizing paper forms and processes: Estimated by Q4 2024
- Modernizing and enhancing existing mobile solutions: Estimated by Q4 2024

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions from this activity.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	**2021**		**2022**		**Total Loaded O&M Cost with Contingency**
	Direct	**Loaded**	**Direct**	**Loaded**	
Measure 1	$93,600	$169,946	93,600	$169,946	$488,373
Measure 2	$0	$0	$0	$0	
Measure 3 (Transmission)	$50,560	$104,083	$0	$0	
Measure 4	$0	$0	$0	$0	
Measure 5	$0	$0	$0	$0	

Capital Cost Estimates					
Activity	**2021**		**2022**		**Total Loaded Capital Cost with Contingency**
	Direct	**Loaded**	**Direct**	**Loaded**	
Measure 1	$133,056	$133,841	$133,056	$133,841	$779,818
Measure 2	$24,000	$25,018	$24,000	$25,018	
Measure 3 (Transmission)	$0	$0	$0	$0	
Measure 4	$58,950	$59,807	$58,950	$59,807	
Measure 5	$135,000	$135,797	$135,000	$135,797	

Total Revenue Requirement over expected life of investment: $1.5 million
Average Annual Revenue Requirement: $447,786

Cost assumptions

- SDG&E will allocate an average of 9% of the following:

Measure 1:
- 2 years annual licensing
- Update IT systems to capture emissions data required by SB 1371
- 9 existing employees and 5 contractors needed to maintain and enhance IT systems

Measure 2:
- Development of advanced analytics
- 3 existing employees 2 contractors

Measure 3:
- Transmission:
- Inventory tasks across 34 gas producer sites
- 1 year of labor using 11 existing employees

Measure 4:
- 1 existing internal employee
- 2 contractors

Measure 5:
- 1 contracted project manager
- Labor for internal subject matter expert

Cost Benefits

There is insufficient data to estimate cost effectiveness for this activity.

Part 5. Cost Effectiveness/Benefits

Cost benefits for this activity include an anticipated reduction in labor needs to generate the Annual Emission Report. There is insufficient data to quantify those benefits at this time.

Part 6. Supplemental Information/Documentation

Attachment C: Historic Project Schedule for Data Lake

2020 Compliance Plan
Chapter 5: Geographic Tracking

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practices:

Best Practice 9: Recordkeeping
Written Company Policy directing the gas business unit to maintain records of all SB 1371 Annual Emissions Inventory Report methane emissions and leaks, including the calculations, data and assumptions used to derive the volume of methane released. Records are to be maintained in accordance with G.O. 112 F and succeeding revisions, and 49 CFR 192. Currently, the record retention time in G.O. 112 F is at least 75 years for the transmission system. 49 CFR 192.1011 requires a record retention time of at least 10 years for the distribution system. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.
Best Practice 20b: Geographic Tracking
Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emissions reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

To improve capabilities of leak surveys performed at storage facilities and compressor stations, SDG&E requested in the 2018 Compliance Plan to back model high pressure facilities in AVEVA and enable scanning technology on storage and compressor components. AVEVA is a system that enables engineering to create data centric 3D models of facilities. Having these 3D models will make it easier to estimate emission volumes, tie leaks with our supply management programs to order replacement parts when needed and identify lead times for replacement, and identify if leaks are on critical system which will influence plans for repair.

In the 2018 Compliance period, SDG&E will have completed the digitizing and mechanical walkdown of 1,200 Piping & Instrumentation Diagrams (P&IDs) for SDG&E Storage and Compressor stations. These intelligent P&IDs will allow engineering to locate tags for equipment or instrumentation that is currently found in these facilities. Furthermore, two storage facilities will have 3D models. These are digital twins to the facilities that will allow SDG&E to query data based on a tag, type of equipment, service, location, etc. The tags in the 3D model will link to the P&IDs, enabling proper engineering information to be provided. The 3D model will provide material information to help identify connection points and support queries for potential leak points in the existing facilities.

In the 2018 Compliance period, SDG&E hired and trained ten (10) employees to support this effort.

There is insufficient data to measure emission reductions or evaluate cost effectiveness of these activities.

Part 2. Proposed New or Continuing Measure

SDG&E proposes to continue completing updates of P&IDs and back modeling of complex high-pressure facilities. The goal of this project is to create the digital twin for the existing facilities to enable a quick query of its facilities. The intelligence found in the 3D model and the P&IDs will enable engineering and operations to identify, track and keep proper documentation linked within the two applications in AVEVA 3D Modeling and AVEVA P&ID. It will enable the future reporting from these databases that can include mileage of pipeline/service, the type of equipment and location, and the capability to connect the 3D model database systems to other SDG&E database systems. This will enable increased ability to calculate blowdown and bundle projects for blowdown, repair leaks more quickly, and identify materials with repeated leaks, indicating requirements for replacement.

SDG&E plans to complete approximately 800 P&IDs that were not part of the 2018 Compliance Plan. SDG&E also plans to model three small transmission sites and two compressor stations. In 2021-2022, SDG&E also plans to continue the Instrument & Controls (I&C) as-built for 2 storage facilities.

Part 3. Abatement Estimates

There is insufficient data to quantify emission reductions from these activities.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Gas Engineering Labor	$546,000	$1,123,996	$156,000	$321,142	$4,083,566
Scanning and 3D Modeling	$1,724,380	$1,734,554	$492,680	$495,587	$2,230,141
Labor for Field Verification	$9,000	$18,527	$9,000	$18,527	$37,054

Total Revenue Requirement over expected life of investment: $4.3 million
Average Annual Revenue Requirement: $2.1 million

Part 5. Cost Effectiveness/Benefits

There is insufficient work to evaluate the cost effectiveness of these activities.

Part 6. Supplemental Information/Documentation

N/A

2020 Compliance Plan

Chapter 6: Electronic Leak Survey

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 20B: Geographic Tracking
Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emissions reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

SDG&E is developing a mobile application for the Electronic Leak Survey process. Leak surveyors will carry iPads loaded with a mobile application to use GIS-generated leak survey routes instead of paper maps. Leak survey instrumentation will be used to track leaks, and leak data will be electronically uploaded into GIS. Bread crumb (GIS Location) data will be collected for the survey path walked.

Requirements gathering and vendor selection for mobile application were completed in 2018. System design activities were completed in 2019 and development of mobile application and supporting portal applications are expected to be completed in 2020. Required hardware (iPad mini, accessories, storage) and support software has been acquired. Team conducted system integration testing to validate integration paths and end to end functionality. Field demos of mobile application and portal applications were conducted in 2019 to review ease of use and gather feedback. User acceptance testing will be performed in Q1 2021. Application rollout to initial districts will start in Q2 2021 and deployment activities for all distribution districts will start in Q3 2021.

A change management team has started engaging stakeholders to provide information on the mobile application through Digi Boards, district locations, intranet articles and district visits.

<u>Emission Reductions Achieved and Cost Effectiveness Evaluation</u>

There is insufficient data to calculate emissions reductions and cost effectiveness for these activities.

Part 2. Proposed New or Continuing Measure

SDG&E proposes further developing the Electronic Leak Survey mobile application and implementing new and emerging technology. The scope of the current solution is defined based on requirements that were identified in initial requirement gathering sessions with stakeholders. There is an expectation that new enhancement requests will become apparent as the solution is deployed and employees begin utilizing it in the field. Software packages will go through upgrade cycle and the underlying product will be upgraded by a vendor to provide additional functionality and stability. After the deployment cycle is complete, SDG&E plans to consolidate all outstanding items that include issues that arose during deployment/training, additional requirements and enhancement requests.

SoCalGas requests funding for five Contractors to assist with the following areas:

- Assessment
- Development
- Deployment and Support
- Change management
- Training activities

The Gas Standards regarding leak survey procedures will need to be updated to reflect the new processes when they are in place.

Project Milestones

Q1-Q2 2021 – Assessment: Team will consolidate outstanding defects, issues, requirements and determine scope/technology potential solutions. Estimated 4-5 months.
Q2 2021- Q3 2022 – Design and Development: Estimated12-14 months.
Q3 2022 – Pilot/Test release of application to streamline for deployment: Estimated 2-3 months.
Q4 2022 – Training and Deployment in Q4 2022: Estimated 6 months.

Part 3. Abatement Estimates

There is insufficient data to calculate emission reductions for this activity.

Part 4. Cost Estimates

O&M Cost Estimates					
	2021		2022		Total Loaded O&M Costs with Contingency
Activity	Direct	Loaded	Direct	Loaded	
Further Develop Electronic Leak Survey Application	$20,700	$20,822	$0	$0	$22,904

Capital Cost Estimates					
	2021		2022		Total Loaded Capital Costs with Contingency
Activity	Direct	Loaded	Direct	Loaded	
Further Develop Electronic Leak Survey Application	$404,334	$406,720	$346,194	$348,237	$830,453

Total Revenue Requirement over expected life of investment: $1.1 million
Average Annual Revenue Requirement: $209,669

Cost Assumptions

- $180K Software purchases – Vendor software license and upgrades
- $108K Hardware upgrades
- $432K Labor (contractors + internal resources)
- $45K Training

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate the cost effectiveness for these activities.

Part 6. Supplemental Information/Documentation
N/A

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practices:

Best Practice 24: Dig-Ins and Public Education Program
Expand existing public education program to alert the public and third-party excavation contractors to the Call Before You Dig – 811program. In addition, utilities must provide procedures for excavation contractors to follow when excavating to prevent damaging or rupturing a gas line.
Best Practice 25: Dig-Ins and Company Standby Monitors
Utilities must provide company monitors to witness all excavations near gas transmission lines to ensure that contractors are following utility procedures to properly excavate and backfill around transmission lines.
Best Practice 26: Dig-Ins and Repeat Offenders
Utilities shall document procedures to address Repeat Offenders such as providing post-damage safe excavation training and on-site spot visits. Utilities shall keep track and report multiple incidents, within a 5-year period, of dig-ins from the same party in their Annual Emissions Inventory Reports. These incidents and leaks shall be recorded as required in the recordkeeping best practice. In addition, the utility should report egregious offenders to appropriate enforcement agencies including the California Contractor's State License Board. The Board has the authority to investigate and punish dishonest or negligent contractors. Punishment can include suspension of their contractor's license.

SDG&E has a federally mandated Public Awareness program, as prescribed in 49 CFR 192.616, which contributes to enhanced public safety. In addition, The State of California mandates a preconstruction meeting with excavators requesting Locate and Mark support and requires continuous monitoring of all excavations within ten feet of high-pressure pipelines per Cal. Gov't Code § 4216.2. The public awareness program is driven by (1) the requirements of 49 C.F.R. § 192.61f, the technical document, (2) Public Awareness Programs for Pipeline Operators, API RP 1162 and (3) program expansion recommendations by regulators.

2020 Compliance Plan
Chapter 7: Damage Prevention Public Awareness

In the 2018 Compliance Plan, SDG&E requested and was approved to expand the public awareness program and staff. SDG&E implemented the following activities to support these efforts:

- *Homeowner Focus groups* – residential focus groups were conducted to identify and explore current understanding of dig-in protocol, motivations and barriers for following dig-in procedures, and message improvements/opportunities. Two focus groups were completed.
- *Paradigm Excavator Outreach Meetings* – participation at contractor liaison meetings where pipeline operator can exchange pipeline safety information with local emergency/public officials and excavators. Participated at eight (8) liaison meetings.
- *National Excavator Initiative* - initiative support of a broad-based damage prevention effort that raises the awareness of underground infrastructure; increase the 811 system; and encourages stakeholders to take additional safety steps after the 811 call is made in order to protect themselves and the infrastructure.
- *Damage Prevention at K-5 Schools* – pilot program of natural gas pipeline public safety awareness outreach program targeting K-6 educators, students, and families in 25 high dig-in zip codes.
- *Next Door App* - 2-month campaign ran in top 60 dig-in zip codes with an estimated impression of 900,079.
- *National Safe Digging Month* - Los Angeles Angels partnership to get pipeline safety messages to the public during the month of April, National Safe Digging Month, which included radio spots on Angels Radio, in-stadium SDG&E dig-safe commercials and booth space.
- *Long Beach Grand Prix* - partnership to get pipeline safety messages to the general public during the Grand Prix, which is in April, National Safe Digging Month.
- *811 Day Campaign* – campaign consisted of bus ads (estimated impressions 107,819,504), digital freeway ads and in-cinema safety video run (estimated impressions of 1,393,119) for 2-4 weeks around the time of 811 Day.
- *Ventura County Fair* – booth space to get pipeline safety messages to the general public.
- *Pipeline Association for Public Awareness (PAPA) supplemental mailers* – provided additional pipeline safety mailers from PAPA's program to excavators, public officials, emergency responders in service territory.
- *Home Depot/Lowes Initiative* – pilot program to get safe digging messaging on tear-off sheets in the gardening, shovel, piping sections of Home Depot, Lowes and at plumbing/contractor supply stores. Approximately 175 stores participating with potential to add additional 150.
- *Continuous analysis of near-miss data, dig-ins, Claims repeat offenders* – monitoring of data to track and trend in order to determine changes needed to improve and increase public awareness communications and outreach tactics.

Emissions Reduction and Cost Effectiveness Evaluation on Historic Work

There is insufficient data to evaluate emission reductions or cost effectiveness for historical work at this time.

Part 2. Proposed New or Continuing Measure

SDG&E proposes to continue conducting incremental outreach and education to the general public, contractors, and excavators, mailing safe digging procedures to contractors, and maintaining the incremental FTE hired to support the public awareness program. Continued activities to support this measure include but are not limited to:

- Analyze excavation damage data and cause of incidents, utilize this information to develop and implement a target communication plan that will effectively address the damaging parties and reduce incidents
- Analyze the effectiveness of pipeline safety communications and engagement strategies; use data and analysis to develop strategies to increase effectiveness for continuous improvement plans.
- Conduct focus groups and refine messaging and strategies based on findings.
- Work with other departments to analyze repeat offender data and develop strategies to reduce damages.
- Be a point of contact for assisting with education services for pipeline and public awareness programs or concerns.

As shown in SDG&E' 2018 Compliance Plan, trending the relationship between investment in the Public Awareness Program and Third-Party Damages shows that investment in public awareness is negatively correlated with the number of third-party damages to company property. Therefore, an increase in public awareness campaigns should result in decreased damages, and therefore, lower emissions.

SDG&E proposes to increase funding in these areas to further contribute to lowering the numbers of third-party damages. To continue to maintain the expanded public awareness program, SDG&E will focus on outreach and education to the general public, outreach to contractors and excavators, and mailing safe digging procedures to contractors. The expanded public awareness program allows SDG&E to increase focus on minimizing emissions.

This measure will require the continued effort of two (2) employees. An Advisor will continue to analyze damage data and use the data to assist in the strategizing of effective communications. The Project Manager will continue to manage incremental projects and programs implemented for the measure.

Part 3. Abatement Estimates

Emissions reductions cannot be calculated for this measure, as the efforts overlap with Chapter 5. Please refer to Chapter 5 for the emissions reduction estimates forecasted for damage prevention activities.

Part 4. Cost Estimates

O&M Cost Estimates						
Activity	2021		2022		Total	Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	Direct	
Labor	$50,000	$102,930	$50,000	$102,930	$100,000	$1,332,936
Public Awareness Marketing Materials	$500,000	$502,950	$500,000	$502,950	$1,000,000	$1,005,900

Total Revenue Requirement over expected life of investment: $1.4 million
Average Annual Revenue Requirement: $710,110

Cost Assumption

- 1 part- time Contractor
- Marketing material includes production and distribution of mailers, pamphlets, brochures, key chains and additional materials for customers to bring awareness. Cost estimates based on historical implementations.

Part 5. Cost Effectiveness/Benefits

There is insufficient work to evaluate the cost effectiveness of these activities.

Part 6. Supplemental Information/Documentation

Attachment D: Historic Work

2020 Compliance Plan

Chapter 8: Pipe Fitting Specifications

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 22: Pipe Fitting Specifications
Companies shall review and revise pipe fitting specifications, as necessary, to ensure tighter tolerance/better quality pipe threads. Utilities are required to review any available data on its threaded fittings, and if necessary, propose a fitting replacement program for threaded connections with significant leaks or comprehensive procedures for leak repairs and meter set assembly installations and repairs as part of their Compliance Plans. A fitting replacement program should consider components such as pressure control fittings, service tees, and valves metrics, among other things

SDG&E has a supply management department that works with vendors to ensure purchased materials meet SDG&E material specifications (MSP) requirements for all components. When materials are received, samples are inspected at a warehouse facility to verify requirements are met. If there are any concerns regarding the quality of materials, including the threaded components and fittings, the Supply Management department is engaged to correct the issue and either engage the current vendor to increase quality assurance standards or to begin contract negotiations with alternative vendors to confirm all concerns are addressed.

In 2019, SDG&E hired a third-party consultant to review company MSPs and to identify consistent requirements across component categories. Results from the investigation will guide future improvement efforts.

Emission Reductions Achieved

There is insufficient data to estimate emission reductions for these activities.

Part 2. Proposed New or Continuing Measure

SDG&E will continue to improve MSP compliance of threaded fittings. SDG&E will continue to work with component manufacturers to align gauging practices and developing process controls to maintain high material thread quality standards. Upon conclusion of the third-party review of the company MSP and QC process, SDG&E will revise the MSPs, if necessary, to create consistent requirements across component categories. SDG&E will continue to evaluate additional feasible solutions based on results of material QC analysis.

Project Milestones

- Implement Quality Control inspection process: Estimate of 9 months.
- Update material specs, if necessary: Estimate of 18 months.

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions from the activities.

Part 4. Cost Estimates

O&M Costs Estimates					
Activity	**2021**		**2022**		**Total Loaded O&M Costs with Contingency**
	Direct	**Loaded**	**Direct**	**Loaded**	
Implementation of Recommendations	$200,000	$208,480	$200,000	$208,480	$458,656

Total Revenue Requirement over expected life of investment: $488,351
Average Annual Revenue Requirement: $244,176

Cost Assumptions

- Implement QC Process improvements at $200,000/year

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate cost effectiveness from the activities.

Part 6. Supplemental Information/Documentation

N/A

2020 Compliance Plan
Chapter 9: Repeat Offenders IT Systems

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 26: Dig-Ins and Repeat Offenders
Utilities shall document procedures to address Repeat Offenders such as providing post-damage safe excavation training and on-site spot visits. Utilities shall keep track and report multiple incidents, within a 5-year period, of dig-ins from the same party in their Annual Emissions Inventory Reports. These incidents and leaks shall be recorded as required in the recordkeeping best practice. In addition, the utility should report egregious offenders to appropriate enforcement agencies including the California Contractor's State License Board. The Board has the authority to investigate and punish dishonest or negligent contractors. Punishment can include suspension of their contractor's license.

SDG&E has a federally-mandated Public Awareness program, as prescribed in 49 CFR 192.616, and Damage Prevention Program 49 CFR192.614 which contribute to enhanced public safety by providing risk mitigation measures. When excavators generate a ticket through Underground Service Alert, locate and mark employees identify lines in the area and if a high-pressure line within ten feet is identified, an observer is assigned to monitor the excavation. Data shows that the more Underground Service Alert is used, the less damages occur.

Damage information is entered by hand into a form by the employee(s) dispatched to repair the damaged property. The information from this form is then manually transferred into the Company Property Damage Report System and that information is used by Claims to generate a bill for cost recovery if applicable. SDG&E operates three separate data systems that store line damage information. One system is the Incident Management System operated by the Dispatch department, one system is SAP which is for labor and asset management, and the other is the Company Property Damage Report System, which is operated by the Claims department. These systems currently do not have any synergy, which can generate challenges when reporting and requires employees to enter the same information three different times and three different ways.

In the past, SDG&E used a paper form of the Company Property Damage Report System to track repeat offenders, and any offender with more than two damages in the previous quarter will be added to a list that is provided on a quarterly basis to the CPUC. However, this process does not account for the fact that repeat offenders may have a multi-year history of damaging facilities, not only on SDG&E lines but on other utilities' lines.
As a result, SDG&E plans to complete the process of digitizing the Company Property Damage Report towards the end of 2020. Thereafter, transition to mobile platforms to capture damages to better perform analytics, to put in place preventative measures to mitigate damages. SDG&E plans to develop integration between enterprise systems to transmit and store new data to be captured via new mobile forms. This system will enable analyzing damage history holistically and identifying repeat offenders more readily and accurately to enhance reporting capabilities.

There is insufficient data to calculate emission reductions or cost effectiveness.

Part 2. Proposed New or Continuing Measure

SDG&E is proposing to complete, maintain, and enhance the digitized form and mobile platforms. SDG&E will also continue reviewing the business structure to facilitate the proper flow and functionality of the relevant digital forms.

Project Milestones

- Complete implementation of initial project scope: Estimated by Q1 2021
- Maintaining and enhancing the digitized form and mobile platforms: Continuous

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions from these activities.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	**2021**		**2022**		**Total Loaded O&M Cost with Contingency**
	Direct	**Loaded**	**Direct**	**Loaded**	
Complete, Maintain, and Enhance IT System	$33,393	$68,743	$33,393	$68,743	$151,235

Total Revenue Requirement over expected life of investment: $161,026
Average Annual Revenue Requirement: $80,513

Cost Assumptions

- SDG&E will allocate an average of 9% of the following:
- 2 Incremental FTEs for operations & maintenance
- 1.6 existing FTEs for operations & maintenance

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate emission reductions.

Part 6. Supplemental Information/Documentation

Attachment E: Historic Project Schedule for Repeat Offender System

2020 Compliance Plan
Chapter 10: Enhanced Methane Detection

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 17: Enhanced Methane Detection
Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.

SDG&E currently has a robust laboratory known as the Engineering Analysis Center (EAC). When a methane source is in question, the EAC will dispatch a mobile gas speciation van to identify the chemical content of the gas and identify its source.

SDG&E worked in 2019 to expand the capacity of the EAC to respond to requests from Operations for leak speciation where methane source is in question. The lower detection limits of new advanced leak detection instrumentation, in addition to the increased level of leak survey activities being driven by SB1371, require an expansion of these resources. SDG&E hired an additional employee and purchased additional gas speciation tools in 2019 to support the increase of gas speciation work.

Since the 2018 Compliance Plan was approved in October 2018, all milestones have been met. The van, tools, and equipment were purchased and will be delivered and installed in 2020. The van is expected to be operational in Q3 2020.

<u>Emissions Reduction and Cost Effectiveness Evaluation</u>

There is insufficient data to calculate emissions reductions and cost effectiveness for this activity.

Part 2. Proposed New or Continuing Measure

SDG&E proposes continuing to fund the incremental lab technician, hired as part of the 2018 Compliance Plan, to continue to maintain the expanded capacity of the EAC to respond to requests from Operations for leak speciation where methane source is in question. The lower detection limits of new advanced leak detection instrumentation plus increased level of leak survey activities being driven by SB1371 requires SDG&E to maintain the expansion of these resources.

No new milestones are proposed. This is an ongoing effort.

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions for this activity.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	**2021**		**2022**		**Total Loaded O&M Cost with Contingency**
	Direct	**Loaded**	**Direct**	**Loaded**	
Technician	$100,000	$205,860	$100,000	$205,860	$452,892

Total Revenue Requirement over expected life of investment: $482,214
Average Annual Revenue Requirement: $241,107

Cost Assumptions

- 1 employee at $100,000 a year

Part 5. Cost Effectiveness/Benefits

There is insufficient data to determine cost-effectiveness for this measure.

Part 6. Supplemental Information/Documentation

Attachment F: Gas Speciation Historic Work

2020 Compliance Plan
Chapter 11: Public Leak Maps

Part 1. Evaluate the Current Practices Addressed in this Chapter

Best Practice 20b: Geographic Tracking
Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emissions reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

In 2015, SDG&E developed and published publicly available geographic maps of nonhazardous leaks. SoCalGas updates these maps monthly with the locations where methane has been detected. The maps also provide details regarding repair scheduling and leak status. The website address for the maps is:

https://www.sdge.com/methane-gas/methane-emission-map

SDG&E did not propose any new activities related to leak mapping in the 2018 Compliance Plan.

Part 2. Proposed New or Continuing Measure

Per SED's request at the workshop that was held on October 21, 2019 in San Francisco, SDG&E will create emission maps that will be publicly available and will provide leak summaries by zip code, as required by Best Practice 20b.

Project Milestones

- Leak map creation: Expected to be completed Q2 2021
- Updating and maintaining the customer facing website and leak maps: Continuous

Part 3. Abatement Estimates

There is insufficient data to quantify emissions reductions from this activity.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	**2021**		**2022**		**Total Loaded O&M Cost with Contingency**
	Direct	**Loaded**	**Direct**	**Loaded**	
Update & Maintain Website & Leak Maps	$2,250	$4,632	$2,250	$4,632	$10,190

Total Revenue Requirement over expected life of investment: $10,850
Average Annual Revenue Requirement: $5,425

Cost Assumptions

- SDG&E will allocate an average of 9% of the following: 1 existing FTE for Operations & Maintenance

Part 5. Cost Effectiveness/Benefits

There is insufficient data to quantify emissions reductions from this activity. Therefore, cost effectiveness cannot be generated.

Part 6. Supplemental Information/Documentation

Not applicable.

2020 Compliance Plan
Chapter 12: Greenhouse Gas Policy Update

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 2: Methane GHG Policy
Written company policy stating that methane is a potent Green House Gas (GHG) that must be prevented from escaping to the atmosphere. Include reference to SB 1371 and SB 1383.

SDG&E updated their Environmental Excellence on January 16, 2019, in accordance with the requirements of Best Practice 2. The updated Environmental Excellent Policy is provided as Attachment G.

There were no costs associated with this measure.

Part 2. Proposed New or Continuing Measure

No further work is proposed.

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions for this activity.

Part 4. Cost Estimates

SDG&E is not proposing additional activities for this measure.

Part 5: Cost Effectiveness/Benefits

There is insufficient data to estimate cost effectiveness for this activity.

Part 6: Supplement Information/Documentation

Attachment G: Updated SDG&E Environmental Excellence Policy

2020 Compliance Plan
Chapter 13: Distribution Above Ground Leak Surveys

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 19: Aboveground Leak Surveys
Utilities shall conduct frequent leak surveys and data collection at above ground transmission and high-pressure distribution (above 60 psig) facilities including Compressor Stations, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). At a minimum, above ground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.

Above ground leak surveys have historically been completed to meet the requirements of 49 CFR 192 and GO 112F, which also satisfies the requirements defined in Best Practice 19. Historically, not all leakage survey inspections performed on Measurement and Regulation (M&R) stations have been performed using instrumentation, resulting in leak indications not being captured. Currently, many of the M&R Station leak inspections are performed using soap tests and by monitoring for indications using sight, sound, and smell.

In the 2018 Compliance Plan, SDG&E requested and was approved for funding to provide (M&R) Technicians with instrumentation to begin performing and recording instrumented leak surveys. SDG&E has purchased the required instruments to perform instrumented survey. SDG&E has also updated Gas Standard T8172, *Inspection Schedule – Regulator Station, Power Generating Plant Regulation Equipment Requirements*, to require M&R Technicians to soap test all connections during inspections and leave facilities free of leaks.

No incremental staffing was required to implement this measure. Training of existing M&R Technicians on the new instruments is planned to be conducted in 2020.

<u>Emissions Reduction and Cost Effectiveness Evaluation</u>

There is insufficient data to determine the emissions reductions and cost effectiveness achieved by this measure at this time.

Part 2. Proposed New or Continuing Measure

SDG&E will continue performing instrumented above ground leak surveys. The required instruments to perform above ground leak surveys have been purchased. SDG&E is not requesting additional funding in this Compliance period.

Part 3. Abatement Estimates

SDG&E cannot calculate or document emissions because the emissions related to this measure are based on a population-based emission factor.

Part 4. Cost Estimates

SDG&E is not requesting funding for this measure during this Compliance period.

Part 5. Cost Effectiveness/Benefits

Not applicable.

Part 6. Supplemental Information/Documentation

Attachment H: Gas Standard T8172 Inspection Schedule – Regulator Station, Power Generating Plant Regulation Equipment Requirements

Attachment H1: RMLD Technical Specifications

2020 Compliance Plan
Chapter 14: Methane Emissions Training

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 11: Methane Emissions Minimization Policies Training
A training program to educate workers as to why it is necessary to minimize methane emissions and abate natural gas leaks. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.
Best Practice 12: Knowledge Continuity Training Programs
Knowledge Continuity (transfer) Training Programs provide knowledge continuity for new methane emissions reductions best practices as workers, including contractors, leave and new workers are hired. Knowledge continuity training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

In 2018–2019, SDG&E worked with an instructional designer to develop a training module to educate company employees as to why it is necessary to minimize methane emissions and abate natural gas leaks. The training script received approval by SED, in consultation with CARB, in 2019. SDG&E will require training completion by all employees in 2020.

There is insufficient data to estimate emission reductions and cost effectiveness for these activities.

Part 2. Proposed New or Continuing Measure

SDG&E proposes to provide ongoing training to maintain knowledge continuity. Future training will be for all new company employees integrated in continuity modules.

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions from these activities.

Part 4. Cost Estimates

Costs will be incorporated into base business as they are expected to be minimal. Anticipated incremental time will be needed from employees for the following activities:

- 1 hour of training for an average of 300 new employees per year
- Administration of training completion tracking

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate cost effectiveness from the activities.

Part 6. Supplemental Information/Documentation

Attachment I: Methane Emissions Training Historic Work

PURPOSE **To describe the methods, required intervals, and record keeping requirements for leakage survey on Company facilities. The objective of a leakage survey is to conduct a thorough search for gas indications in an assigned area and report all detectable indications using an approved survey method.**

1. POLICY AND SCOPE

1.1. Leakage surveys are performed on Transmission and Distribution gas facilities at specified intervals by using approved methods specified in this Gas Standard. This document establishes the frequency of leakage surveys and specifies record keeping procedures to comply with Company and regulatory requirements.

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. **Field Organizations** (**Gas Transmission and Leakage Mitigation)** are responsible for conducting leak surveys per this procedure at the minimum intervals identified in **Section 4**. Surveys may be performed at more frequent intervals.

2.2. **Gas Operations Training -**Skills is responsible for ensuring the equipment and facilities used by an Operator for training and qualification of employees must be identical, or very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task per GO112-F 143.4.

2.3. **Field Organizations (Gas Transmission and Leakage Mitigation)** are responsible for selecting the appropriate leak survey method for each portion of their facilities per **Table 3** of this procedure.

2.4. **Leakage Mitigation, Distribution, and Transmission** qualified field employees are required to notify Supervision of all leak indications on a buried pipeline with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing). See **GS G8137**, *Leak Investigation - Distribution*.

2.5. **Leakage Mitigation, Distribution, and Transmission Supervisors** are required to notify the appropriate Gas Operations Area Manager and Transmission District Operations Manager of all leak indications on a buried pipeline with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing). See Section **GS G8137**, *Leak Investigation - Distribution*.

2.6. **Field Organizations (Gas Transmission and Leakage Mitigation)** are responsible for notifying the appropriate scheduler of maintenance inspections of any field conditions which may warrant a change in the leak survey schedule.

2.7. The employee conducting the leakage survey must be qualified per **GS G8113,** "*Operator Qualification Program.*"

2.8. If a watercraft is required for conducting a leakage survey, the watercraft used must comply with the governmental regulations and licensing requirements for its type.

2.8.1. The operator of any rented or owned Company watercraft must first complete and successfully pass a Boating Safety Course approved by the California Department of Boating and Waterways (CDBW).

2.8.2. The CDBW offers a boating course at no charge. See the website at http://www.dbw.ca.gov/BoaterInfo/BoatSafeCourse.aspx.

2.8.2.1. Personnel working in watercraft MUST wear a Coast Guard-approved life vest as a personal protective equipment (PPE)
Other recommended PPE:

- Mosquito repellant.
- Sunscreen.

3. **DEFINITIONS**

3.1. **HCA** – High Consequence Area. Refer to **GS G8170**, *Operations Technology for HCA Segment Identification*.

3.2. **Location Class** – See **GS G8121**, *Location Class – Determination and Changes*

3.3. **Department of Transportation Defined Transmission Line (DOT-T)** – Any pipeline operating over 20% SMYS. See **GAS GS G8116,** *Pipeline and Related Definitions*.

3.4. **Business District –** is an area identified on a leak survey map that depicts where distribution facilities are located within 100 feet of the property line of a land parcel that has been identified as being a potential commercial gathering place, a church, a school, a hospital or is location where people have limited mobility. The extent of the business district boundaries have been determined per the procedure outlined in **GS G8136**, *Maintenance of Leak Survey Maps*.

3.5. **Maximum Allowable Operating Pressure** (MAOP) – **See GS G8116,** *Pipeline and Related Definitions*.

3.6. **Barhole** – Probing or drilling holes in the surface to identify leakage using an approved leak detection instrument.

3.7. **Detecto Pak-Infrared® (DP-IR)** – is a portable optical-based methane gas detector to sample the atmosphere for gas near the ground surface using Infrared Controlled Interference Polarization Spectrometry. For additional instrumentation specifications, see **GS G8182,** *DP-IR Heath Detecto Pak-Infrared*.

3.8. **Remote Methane Leak Detector (RMLD)** – used as a portable "line of sight" laser-based methane gas detector to detect gas leaks from a remote distance (up to 100') by passing a laser through a gas plume. See GS **G8192**, *RMLD-Remote Methane Leak Detector*.

3.9. **Optical Methane Detector (OMD)** – method uses an optical-based methane detector mounted to the front of a vehicle to detect gas that passes between the light transmitter and receiver. The presence of methane is displayed in analog and digital form inside the vehicle. **GS G8138**, *Optical Methane Detector Operation and Maintenance*.

3.10. **GMI Gasurveyor SCG PPM Combustible Gas Indicator–** is a portable combustible gas indicator used to detect natural gas indications. See ***GS* G8220**, *GMI Gasurveyor SCG PPM Combustible Gas Indicator*

3.11. **Non-State-of-the-Art Pipe (NSOTA)** – Steel pipe, bare or coated, without cathodic protection (CP), and all DuPont Aldyl-A (PE) pipe installed before 1986. See **GS D8146**, *Replacement Criteria for Distribution Mains and Services*.

3.12. **State-of-the-Art Plastic Pipe (SOTA**) – Yellow or Orange TR418 resin, and 1986 and later Aldyl-A pipe. See GS D8146, *Replacement Criteria for Distribution Mains and Service*.

4. **PROCEDURE**

4.1. Table 1 is a summary of the minimum leak survey frequencies for pipe based upon location and operating status. See the referenced section of this procedure listed in Table 1 under 'Additional Requirements' for detailed requirements.

Table 1: Leak Survey Frequencies

Pressure	Operating Location or Operating Status	Frequency	Additional Requirements
Medium Pressure (	Located Within a Business District	At least once each calendar year	**see Sect. 4.2.1**
	All Non-State-of-the-Art PE main located outside a Business District and associated services		**See Sect 4.2.2**
	Located Outside of a Business Districts and Cathodically unprotected	At least once every 3 calendar years	**See Sect. 4.2.3**
	All other medium pressure pipe located outside a Business District	At least once every 5 calendar years	**see Sect. 4.2.4**
High Pressure (over 60 psig)	All high pressure ***not*** including DOT-Pipe	At least once each calendar year	**see Sect. 4.3**
DOT Defined Transmission Pipe (DOT-T)	Located in Non-HCA, Class 3	At least twice each calendar year	**see Sect. 4.4.1**
	Located in Non-HCA, Class 4	At least 4 times each calendar year	**see Sect. 4.4.2.1**
	Cathodically Unprotected Pipe, located in All Classes	At least 4 times each calendar year	**see Sect. 4.4.3**
	All other DOT-T Pipe	At least twice each calendar year	**see Sect. 4.4.1**

4.2. Medium Pressure Pipelines (Operating at 60 psig or Less)

4.2.1. Survey all pipe (including services) in business districts and adjacent schools, hospitals, and churches at intervals not exceeding 15 months, but at least once each calendar year.

4.2.2. Survey Non-State-of-the-Art PE main where the main is not located in a business district once every calendar year, at intervals not exceeding 15 months.

4.2.3. Survey all Cathodically unprotected pipe (including services), where electrical surveys for corrosion are impractical, at least once every 3 calendar years at intervals not exceeding 39 months.

4.2.4. Survey all State-of-the-Art PE and pipe and Cathodically protected main, where the main is not located in a business district (including services) least once every 5 calendar years at intervals not exceeding 63 months.

4.3. **High Pressure Pipelines (Operating over 60 PSIG) <u>not</u> including DOT-Transmission Pipelines**

4.3.1. Survey all pipelines and associated services every 15 months; but at least once every calendar year annually for all location classes.

4.4. **DOT-T Transmission Pipelines**

4.4.1. Non-HCA Transmission Pipeline Segments in Location Class 3* and all DOT-T pipe not covered in **Section 4.4.2.1 and 4.4.3.**

4.4.1.1. Survey every 7½ months; but at least twice each calendar year

4.4.2. Non-HCA Transmission Pipeline Segments in Location Class 4* and Transmission Pipelines in all Location Class without CP.

4.4.2.1. Survey Non-HCA Transmission Pipeline in Location Class 4 every 4½ months; but at least 4 times each calendar year.

4.4.3. If no CP is on a transmission pipeline (in any Location Class) or if electrical surveys are impractical, then survey every 4½ months; but at least 4 times each calendar year.

> *__Note:__ The implementation deadline to schedule future surveys for all non-HCA transmission pipelines according to the requirements in 49 CFR 192.935 is December 17, 2007. From this date forward surveys shall be performed in accordance with this survey-interval requirement.

4.5. **Special Survey**

4.5.1. Perform leak survey when:

4.5.1.1. Upon discovery that the MAOP of a pipeline is exceeded by 10% or more at any time during the life of the pipeline.

> **Note**: When the MAOP of a pipeline is exceeded by 10% or more, contact Engineering for guidance concerning any additional actions to be taken that could facilitate further analysis of the longer-term impact on the integrity of the pipe.

4.5.1.2. 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. See **GS G8202**, *Field Guidelines – Emergency Incident Distribution/Customer Service* or **GS G8205,** *Emergency Response Procedures for Gas Incidents- Transmission.*

4.5.1.2.1. For Earthquakes, see Operations Emergency Manuel (OEM) 01.040- SD Earthquake –Special Procedures.

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

4.5.1.4. In the case of blasting, an inspection, including leakage survey, may be required based upon recommendation from the Region Engineer.

4.5.1.5. When increasing the MAOP of a pipeline, per **GS G8115,** *Changing Maximum Allowable Operating Pressure and Maximum Operating Pressure*.

4.5.1.6. When minimum survey requirements are not considered adequate because of pipe condition, limited opportunity for gas to vent safely, or other reasons.

4.5.1.7. There is a need to monitor pipe condition for special situations, such as:

4.5.1.7.1. Material evaluations.

4.5.1.7.2. Proposed street improvement projects.

4.5.1.7.3. As a mitigative measure for the Integrity Management Program.

4.5.1.8. Survey at the frequency listed in Table 2 based upon the location of the known shorted casing, confirmed to be shorted through inspection and testing and have not been repaired/cleared according to **GS G8027**, *Cathodic Protection – Electrical Isolation*.

Table 2: Known Shorted Crossing Survey Frequency

Location Class	Frequency
Highway and Railroad Crossings	7½ months; but at least twice each calendar year
All Other Locations	15 months; but at least once every calendar year

4.5.2. A *special leak survey* may require special accounting; contact Field Operations Supervisor for proper account numbers.

4.5.3. Survey may also be considered in conjunction with major underground construction projects, see **GS G8122**, *Prevention of Damage to Company Facilities.*

4.5.4. After the occurrence of lightning strikes, transformer arcs, stray current or other electrical discharge events involving company facilities.

4.5.4.1. Electrical current induced onto facilities will take all paths to ground.

4.5.4.1.1. Lightning strikes and high voltage electrical discharge events can result in multiple damages and leaks.

4.5.4.1.2. Induced voltage on foreign facilities or substructures due to lightning strikes or electrical discharge events can also arc onto company facilities.

4.5.4.1.3. Locating wire used for identifying PE pipe installations is electrically conductive and can damage pipe if induced.

4.5.4.2. Survey all company facilities in the immediate vicinity of the area where the lightning strike or electrical discharge event occurred.

4.5.4.3. Contact System Protection/Region Engineering to identify the segment of pipe and determine the area to be surveyed.

4.6. **Application of Leak Survey Methods**

4.6.1. Field Organizations must follow Table 3 when selecting an approved method for conducting leakage surveys of Transmission and Distribution Facilities.

Table 3: Approved Leak Survey Method by Facility

Facility	*DP-IR*	*OMD*	*RMLD*	*Barhole GMI Gasurveyor*
Med Press. Pipe (Annual, 3yr ,5yr)	X	*X	*X	X
High Press. Pipe Over 60 psig (Annual)	X	*X	*X	X
DOT-T Transmission (Class 1,2)	X	X	X	X
DOT-T Transmission (Class 3, 4)	X	X	X	X
Shorted Casing	X		X	X
Pipe over Waterways	X		X	

*see sub-section for limitations

4.7. Instrumented Survey Routine Survey Method

4.7.1. The method consists of using an approved leak survey instrument listed in Table 3 to sample the atmosphere near the surface of the ground in the vicinity of buried company facilities, and in street openings and other accessible crevices and locations where gas is likely to vent.

4.7.2. Survey shall include visual examinations of all above ground Company facilities. Search along the route of the pipe at all locations where gas is most likely to vent. Determine pipe location as accurately as possible using map, existing paint marks, old patches, etc.

4.7.3. Choose locations such as loose earth, paving cracks, old bar holes, repair patches and around the base of poles, trees, fence posts, etc., if they are near the pipe.

4.7.4. Watch for, and check areas where vegetation appears to be affected by gas leakage.

Note:	Grass and vegetation areas can be affected in several ways: There may be patches of brown, dry, even dead grass. In some instances, affected vegetation and grass may appear very green compared to surrounding areas.

4.7.5. Search along the route of all services at locations where gas is most likely to vent.

4.7.5.1. Determine the service location as accurately as possible using the map, curb markings, meter location, etc. If any doubt exists as to route of the service such as at corner lots, check both possible routes.

4.7.5.2. Search as close to the service location as practical, over earth, at building foundations or at cracks and/or paving edge if service is under paving.

4.7.5.3. Search along all services from the curb or pavement edge to the riser. Check at service-to-main connections if traffic permits.

4.7.5.4. Check all manholes and other street openings such as valve casings, curb meter vaults, drains, water valves, meter boxes, street lighting, power, telephone, etc.

4.7.5.5. For long-side services it is necessary to visibly look for indications of possible leakage under the street such as: evidence of recent construction, foreign trench marks, pavement cuts, bar holes, etc. along the service route. Where visible indications are present, use approved ground leak detection equipment such as DP-IR or RMLD.

Note:	When casing vents are presents they must be inspected to ensure they are in satisfactory condition and designed to prevent entry of water, insects, and other foreign matter. Vents should extend at least four feet above finished grade and at least four feet below overhead electric wires. Vents shall be located in an area away from traffic and other hazardous locations.

4.7.5.6. Survey all risers and other above ground Company Infrastructure including meters set assemblies. If a riser and connected facility is not readily accessible by customer contact or other means during the regular survey, and the survey cannot be completed using the RMLD (**see 5.2.5.7** below), the "cannot get in" (CGI) must be documented for a follow-up to complete the survey. Check the riser and any portion of the service that was not surveyed. The follow-up shall be completed within the established compliance window for the inspection.

4.7.5.7. Districts have the option of utilizing a Remote Methane Leak Detector (RMLD) to check services up to the riser when access is restricted. See **GS G8192,** *RMLD-Remote Methane Leak Detector*.

Note: Districts are responsible for tracking and completing services that are not accessible at the time of survey (commonly referred to as 'Can't Get Ins" (CGI's). Records should be kept per the retention scheduled identified **Section 7**.

4.7.5.8. Check the casing end inside the building when a service enters a building. Reseal the casing end.

4.8. **OMD Mobile Survey Method**

4.8.1. This method consists of driving a vehicle along the route of the underground gas piping and sampling the atmosphere near the earth or paving over the pipe or paving edge with sensitive continuous sampling leak detection equipment especially designed and engineered for mounting on a vehicle. See **GS G8138,** *Optical Methane Detector Operation and Maintenance*.

4.8.2. The OMD is to be used to perform leakage survey on high pressure and medium pressure pipelines.

4.8.2.1. In paved locations survey is performed by driving along or as near as possible, the curb to the side of the street where the pipeline is located. In the instance of dual pipelines, particularly wide streets, pipelines in traffic islands or divided traffic lanes, a particular street may be traversed in both directions.

4.8.2.2. In unpaved locations survey is performed by driving directly over or within 5 feet of the pipeline.

Note: The Gas Patroller must know the location of the pipeline and other subsurface substructures that are part of the survey work order. Pipeline location is determined using the map, curb markings, pipeline markers, etc.

4.8.3. Associated services, crossovers and other buried infrastructure that cannot be driven over shall be surveyed using appropriate instrumentation (See section 4.7). Any services, taps, or other pressure carrying facilities that are part of the survey work order and are not suitable for survey by OMD must be surveyed with an appropriate device (see **Section 4.7**).

Note:	Check all manholes and other street openings such as valve casings, curb meter vaults, drains, water valves, meter boxes, street lighting, power, telephone, etc.

4.9. **Barhole**

4.9.1. Prior to drilling bar holes, notify Underground Service Alert (USA). See **GS G8123**, *Underground Service Alert and Temporary Marking.*

4.9.2. Drill a hole over the suspected leak area and surrounding facilities for the specific purpose of testing for subsurface gas indications per **GS G8194,** *Optical Methane Detector Operation and Maintenance*.

4.9.3. Use an instrument probe, such as the combustible gas indicator, e. g., GMI Gasurveyor SCG PPM Combustible Gas Indicator or DP-IR. Read gas indications.

4.10. **Water Crossing**

4.10.1. SAFETY

4.10.1.1. Serious bodily injury could occur when entering waterways without proper training and personal protective equipment (PPE). See sections 2.5 for required and recommended PPE.

4.10.1.2. The following are examples of hazards impacting this work:

4.10.1.2.1. Weather and waterway conditions.

4.10.1.2.2. Fast currents.

4.10.1.2.3. Tripping and slipping hazards.

4.10.1.2.4. Sunburn from water reflection.

4.10.1.2.5. Drowning.

4.10.1.2.6. Hypothermia.

4.10.1.2.7. Other watercraft.

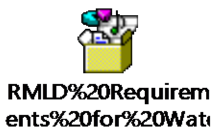
4.10.1.2.8. Wildlife.

4.10.1.2.9. Environmental surroundings.

4.10.2. SPECIAL REQUIREMENTS

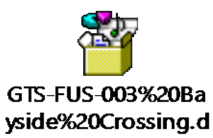
4.10.2.1. Use only approved leak survey instruments listed in Table 3.

4.10.2.2. If using RMLD, see the additional requirements listed in the attached document.



4.10.3. For Distribution Piping Crossing the Bay

4.10.3.1. Use the following:



4.11. BUSINESS DISTRICT

4.11.1. A business district is an area that is 100 feet from the property line of a parcel of property that has been identified as significant commercial gathering point, a school, a hospital, a church or is a place where inhabitants have limited mobility.

4.11.2. Leak survey any distribution mains and associated services that have been identified as being within a business districts at the frequency established per Table 1.

4.11.3. The procedure for determining the business district is detailed in GS G8136, *Maintenance of Leak Survey Maps.*

4.11.4. If during the survey, the leak surveyor identifies land uses that could potentially trigger a business district determination that is not currently depicted upon the leak survey map; they should identify this location for additional evaluation. The surveyor should document as follows:

4.11.4.1. The surveyor should circle the land parcel that potentially has triggered the business district and denote the following on the map cover sheet.

4.11.4.2. Select the checkbox identifying a potential business district was found on the leak survey map and the appropriate box in the Click Mobile Form.

4.11.4.3. In the Comment Section of the Map Coversheet, describe the land use of the parcel that should be evaluated for meeting the business district designation (i.e. business, hospital, school, church, a significant commercial gathering point).

4.11.4.4. Return the completed survey map and comments to **Leakage Mitigation** for processing.

4.12. **Abnormal Operating Conditions (AOC)**

4.12.1. Issue Follow up orders to investigate and correct any AOC's encountered, These AOC's include: but are not limited to the following:

4.12.1.1. Meters in prohibited or hazardous meter locations, damaged, or corroded meter sets and meters buried in earth or paving.

4.12.1.2. Regulators in confined areas not vented to a safe location.

4.12.1.3. Broken or missing curb meter vault or curb valve lids.

4.12.1.4. Service valves not readily accessible or otherwise inoperable.

4.12.1.5. Pipelines (including services) having buildings constructed over them.

4.12.1.6. Pipelines (including services) that are endangered by foreign construction.

4.12.1.7. Curb valves not readily accessible on services to schools, hospitals or churches.

4.12.1.8. Exposed piping showing evidence of atmospheric corrosion, chemical corrosion and other conditions that warrant concern.

4.12.1.9. Stress on exposed piping facilities as a result of earth movement or other causes.

4.12.1.10. When MSA protection (barricades or barriers) are required per **GS D7115**, *Barricades for Gas Meter Sets.*

4.12.1.11. Missing, broken and damaged casing vents.

4.13. **Evaluation of Leakage**

4.13.1. The **Gas Patroller** evaluates all gas indications found and assigns an appropriate leakage priority classification based on potential hazard. See **G8135**, *Leakage Classification and Mitigation Schedules*.

4.13.1.1. Employees shall notify Supervision of all Leak indications detected over buried pipelines with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing), See **GS G8137**, *Leak Investigation* **- -** *Distribution*.

4.13.1.2. When a Code 1 Leak is identified by a Patroller (Gas) the Patroller will maintain surveillance (remain on-site) until one of the following occurs:

4.13.1.2.1. A Gas Repair Crew arrives on scene and releases the Patroller.

4.13.1.2.2. The originating Patroller is relieved by a relief Patroller.

4.13.1.2.3. The Patroller is released by either the M&R/System Protection Manager or the Leakage Mitigation Supervisor once they have responded to the location and determined a release is appropriate.

4.13.1.3. When an AG Hazardous Leak is identified by a Patroller (Gas) the Patroller will remain on-site until one of the following occurs:

4.13.1.3.1. If the Hazardous Leak is on the RISER, until a Gas Repair Crew arrives on scene and releases the Patroller.

4.13.1.3.2. If the Hazardous Leak is on a Customer Service Field (CSF) MSA, until a CSF representative arrives and releases the Patroller.

4.13.1.3.3. If the Hazardous Leak is on an M&R (Pipeline Operations) MSA, until a Pipeline Ops repair crew arrives.

4.13.1.3.4. The originating Patroller is relieved by a relief Patroller.

4.13.1.3.5. The Patroller is released by either the M&R/System Protection Manager or the Leakage Mitigation Supervisor once they have responded to the location and determined a release is appropriate.

4.13.2. Any gas indication that is investigated and presumed to be an outside company or agency should be promptly reported to the company or agency.

4.13.3. When a **Gas Transmission District** detects gas indications on a **Distribution Region** facility, promptly contact **Gas Technical Services**.

4.13.4. When a **Distribution Region** detects leakage on a **Transmission Operated** facility, promptly contact the **Transmission District.**

4.13.5. The survey person will confirm any gas indication with a combustible gas indicator; **see GS G8220,** GMI Gasurveyor SCG PPM *Combustible Gas Indicator.*

4.13.6. If the gas indication is located under street or paving, a hole must be drilled to take the read.

4.13.7. When gas indications are suspected to be from field or swamp gas:

4.13.7.1.1. The gas indication will be evaluated with an electronic ethane detector first. If ethane is not detected the **crew** contacts **Environmental Analysis Services (EAS)** and arranges for the testing of a gas sample to determine if the indications are the Company's responsibility.

4.13.7.1.2. When a suspected safety-related condition is found, report it to the **immediate supervisor** the same day the condition is discovered. See **GS G8229,** *Region Reports of Safety-Related Pipeline Conditions*.

4.14. Reporting

4.14.1. When a suspected safety-related condition is found, report it to the immediate supervisor the same day the condition is discovered.

4.14.2. Report all leaks and corrosion on **DOT-T** T**ransmission lines** as outlined in **GS G8229,** *Region Reports of Safety-Related Pipeline Conditions*.*"*

4.14.3. To ensure a safe response, communicate emergency incident as outlined in **GS G8202,** *Field Guidelines – Emergency Incident Distribution/Customer Service* or **GS G8205,** *Emergency Response Procedures for Gas Incidents-Transmission.*

4.15. Documentation on the Leak Survey Map

4.15.1. The Gas Patroller performing the leak survey is provided with maps of the areas to be surveyed. The maps used for survey will depict pipeline location to be surveyed and the surrounding streets.

4.15.1.1. The Gas Patroller is required to balloon around, initial, and date all completed areas and/or segments they surveyed for that day on the Leakage Survey map using colored pens.

4.15.1.2. All below ground leak indications are noted in red, marked with an "X", and tallied on the Leak Survey Map Cover Sheet.

- New below ground leaks are identified using the location (sequence) number.
- Above ground leaks are identified using the location (sequence) number.

4.15.1.2.1. If leakage spread is twenty (20) feet or more use dotted red line to indicate spread on map.

4.15.2. Document potential business district changes per Section 6.4 (Distribution Only).

5. EXCEPTION PROCEDURE

(See **GS** G7007, *Exception Procedure for Company Operations Standards*.

5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

5.2. An exception from a standard shall not be allowed unless **GS G7007,** *Exception Procedure for Company Operations Standards* is followed, and approval is given by those as required by G7007.

6. OPERATOR QUALIFICATION COVERED TASKS

(See **GS G8113,** *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 09.01.** – 49 CFR 192.706 – Performing leakage surveys: transmission lines

- **Task 09.02** – 49 CFR 192.723 – Performing leakage surveys: distribution systems

7. RECORDS

7.1. Electronic Data Collection

7.1.1. Gas Transmission

7.1.1.1. Schedule, track, and document all routine leakage surveys on an approved computerized maintenance management system (i.e., MAXIMO).

7.1.1.2. Document all leak indications and leak repairs on **Form 677-1SD,** Pipeline Condition and Maintenance Report (Transmission).

7.1.2. Distribution

7.1.3. Click Mobile forms should be used to:

- Document *Leak Investigation* on form 4030 in click Mobile
- Document *Leak Indication* on form 4040 in click mobile
- Document *Distribution leak repair* on form 4050 in click mobile
- Use Excavation form in click mobile to document pipe conditions

7.1.4. If Click Mobile forms are unavailable, record leak repairs on medium pressure SDG&E Distribution lines on Form **108-00200,** *Gas Leak Repair/Pipe Inspection Report.* For leak repairs on high pressure SDG&E Distribution pipelines, prepare both Form **677-1SD** and Form **108-00200** and forward to **Gas Engineering - Pipeline Integrity**. Also forward a copy of the completed Form **108-00200** to **GTS Miramar – Leakage Mitigation Clerk.**

7.2. **Records Retention**

7.2.1. Records covering leakage surveys, leaks discovered, and repairs made are filed by the appropriate **Transmission District** or by **Gas Technical Services** (**Distribution**) and maintained for the life of the pipeline plus six years.

7.2.2. Records covering leakage surveys, leaks discovered, and repairs made on transmission pipelines are documented using an approved computerized maintenance management system (e. g., MAXIMO or SAP) and filed by the appropriate **Gas Transmission District**, **Storage Field**, or **Distribution**

Region, and must be retained per Records Management Retention Schedule. See Records Retention Standards on Sempra Net, http://home.sempranet.com/rm/.

7.3. In addition to the other recordkeeping requirements of these rules, each Operator shall maintain the following records for transmission lines for the periods specified:

A. The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipeline remains in service or there is no longer pipe within the system of the same manufacturer, size and / or vintage as the pipeline on which repairs are made, whichever, is longer.

B. The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 75 years. Repairs or findings of easement encroachments, generated by patrols, surveys, inspections, or tests required by subparts L and M of 49 CFR Part 192 must be retained in accordance with paragraph (c) of this section.

C. A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 75 years.

8. APPENDICES

8.1. Not Applicable.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Conducted a functional review to re-establish 5-year review cycle. Reformatted to comply with document outline requirements. Updated Hyperlinks. Minor word changes throughout document for additional clarity. Policy was revised to better explain the requirements when leak indications are detected on a buried pipeline with an MAOP of 20% SMYS or more. Revisions made to provide guidance for performing leakage surveys due to lightning strikes. Information Bulletin 1719 and 1721 information was added to policy. Added section 4.15 to provided clarity on the documentation process for completed leak survey maps. Removed Operator Qualification Task 02.13 – 49 CFR 192.481 – Monitoring for atmospheric corrosion from GS. Added a new section 5 Exception Procedures, a new section 6, Operator Qualification Task and a new section 8, Appendices.

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	01/01/2019
Last Full Review Completed On:	10/31/2018
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
Category (Prior FCD system only):	
If Merged, Merged To Document Number:	
Utility:	SDG&E
Department:	Gas System Integrity Staff & Programs
Number of Common Document:	223.0100
Confidential Sections:	
Part of SoCalGas O&M Plan:	No
Part of SDG&E O&M Plan:	Yes
Contains OPQUAL Covered Task:	Yes
OpQual Tasks	09.01 09.02
Last O&M Review date:	10/9/2019
O&M 49 CFR Codes & Impacted Sections of Document:	192.481(a): Entire Doc 192.613(a): Entire Doc 192.706: Entire Doc 192.709(a): Entire Doc 192.709(b): Entire Doc 192.709(c): Entire Doc 192.721(a): Entire Doc 192.723: Entire Doc
Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	Yes
Part of Transmission IMP (TIMP)	Yes
Part of Storage IMP (SIMP)	No
Impacts GO112F	Yes
GO112F Codes & Impacted Sections of Document	145.1: (a)10, 11, (b)10, 11, (c)8, 9, 10, 11 143.1: Entire Doc
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	DIMP2, GSSD, TIMP2

NOP Learning Module (LM) Training Code:	NOP01158

PURPOSE **To describe the methods, required intervals, and record keeping requirements for leakage survey on Company facilities. The objective of a leakage survey is to conduct a thorough search for gas indications in an assigned area and report all detectable indications using an approved survey method.**

1. POLICY AND SCOPE

1.1. Leakage surveys are performed on Transmission and Distribution gas facilities at specified intervals by using approved methods specified in this Gas Standard. This document establishes the frequency of leakage surveys and specifies record keeping procedures to comply with Company and regulatory requirements.

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. **Field Organizations** (**Gas Transmission and Leakage Mitigation)** are responsible for conducting leak surveys per this procedure at the minimum intervals identified in **Section 4**. Surveys may be performed at more frequent intervals.

2.2. **Gas Operations Training -**Skills is responsible for ensuring the equipment and facilities used by an Operator for training and qualification of employees must be identical, or very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task per GO112-F 143.4.

2.3. **Field Organizations (Gas Transmission and Leakage Mitigation)** are responsible for selecting the appropriate leak survey method for each portion of their facilities per **Table 3** of this procedure.

2.4. **Leakage Mitigation, Distribution, and Transmission** qualified field employees are required to notify Supervision of all leak indications on a buried pipeline with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing). See **GS G8137**, *Leak Investigation - Distribution*.

2.5. **Leakage Mitigation, Distribution, and Transmission Supervisors** are required to notify the appropriate Gas Operations Area Manager and Transmission District Operations Manager of all leak indications on a buried pipeline with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing). See Section **GS G8137**, *Leak Investigation - Distribution*.

2.6. **Field Organizations (Gas Transmission and Leakage Mitigation)** are responsible for notifying the appropriate scheduler of maintenance inspections of any field conditions which may warrant a change in the leak survey schedule.

2.7. The employee conducting the leakage survey must be qualified per **GS G8113,** "*Operator Qualification Program.*"

2.8. If a watercraft is required for conducting a leakage survey, the watercraft used must comply with the governmental regulations and licensing requirements for its type.

2.8.1. The operator of any rented or owned Company watercraft must first complete and successfully pass a Boating Safety Course approved by the California Department of Boating and Waterways (CDBW).

2.8.2. The CDBW offers a boating course at no charge. See the website at http://www.dbw.ca.gov/BoaterInfo/BoatSafeCourse.aspx.

2.8.2.1. Personnel working in watercraft MUST wear a Coast Guard-approved life vest as a personal protective equipment (PPE)
Other recommended PPE:

- Mosquito repellant.
- Sunscreen.

3. DEFINITIONS

3.1. **HCA** – High Consequence Area. Refer to **GS G8170**, *Operations Technology for HCA Segment Identification*.

3.2. **Location Class** – See **GS G8121**, *Location Class – Determination and Changes*

3.3. **Department of Transportation Defined Transmission Line (DOT-T)** – Any pipeline operating over 20% SMYS. See **GAS GS G8116,** *Pipeline and Related Definitions*.

3.4. **Business District –** is an area identified on a leak survey map that depicts where distribution facilities are located within 100 feet of the property line of a land parcel that has been identified as being a potential commercial gathering place, a church, a school, a hospital or is location where people have limited mobility. The extent of the business district boundaries have been determined per the procedure outlined in **GS G8136**, *Maintenance of Leak Survey Maps*.

3.5. **Maximum Allowable Operating Pressure** (MAOP) – **See GS G8116,** *Pipeline and Related Definitions*.

3.6. **Barhole** – Probing or drilling holes in the surface to identify leakage using an approved leak detection instrument.

3.7. **Detecto Pak-Infrared® (DP-IR)** – is a portable optical-based methane gas detector to sample the atmosphere for gas near the ground surface using Infrared Controlled Interference Polarization Spectrometry. For additional instrumentation specifications, see **GS G8182,** *DP-IR Heath Detecto Pak-Infrared*.

3.8. **Remote Methane Leak Detector (RMLD)** – used as a portable "line of sight" laser-based methane gas detector to detect gas leaks from a remote distance (up to 100') by passing a laser through a gas plume. See GS **G8192**, *RMLD-Remote Methane Leak Detector*.

3.9. **Optical Methane Detector (OMD)** – method uses an optical-based methane detector mounted to the front of a vehicle to detect gas that passes between the light transmitter and receiver. The presence of methane is displayed in analog and digital form inside the vehicle. **GS G8138**, *Optical Methane Detector Operation and Maintenance*.

3.10. **GMI Gasurveyor SCG PPM Combustible Gas Indicator–** is a portable combustible gas indicator used to detect natural gas indications. See ***GS* G8220**, *GMI Gasurveyor SCG PPM Combustible Gas Indicator*

3.11. **Non-State-of-the-Art Pipe (NSOTA)** – Steel pipe, bare or coated, without cathodic protection (CP), and all DuPont Aldyl-A (PE) pipe installed before 1986. See **GS D8146**, *Replacement Criteria for Distribution Mains and Services*.

3.12. **State-of-the-Art Plastic Pipe (SOTA**) – Yellow or Orange TR418 resin, and 1986 and later Aldyl-A pipe. See GS D8146, *Replacement Criteria for Distribution Mains and Service*.

4. **PROCEDURE**

4.1. Table 1 is a summary of the minimum leak survey frequencies for pipe based upon location and operating status. See the referenced section of this procedure listed in Table 1 under 'Additional Requirements' for detailed requirements.

Table 1: Leak Survey Frequencies

Pressure	Operating Location or Operating Status	Frequency	Additional Requirements
Medium Pressure (	Located Within a Business District	At least once each calendar year	**see Sect. 4.2.1**
	All Non-State-of-the-Art PE main located outside a Business District and associated services		**See Sect 4.2.2**
	Located Outside of a Business Districts and Cathodically unprotected	At least once every 3 calendar years	**See Sect. 4.2.3**
	All other medium pressure pipe located outside a Business District	At least once every 5 calendar years	**see Sect. 4.2.4**
High Pressure (over 60 psig)	All high pressure **not** including DOT-Pipe	At least once each calendar year	**see Sect. 4.3**
DOT Defined Transmission Pipe (DOT-T)	Located in Non-HCA, Class 3	At least twice each calendar year	**see Sect. 4.4.1**
	Located in Non-HCA, Class 4	At least 4 times each calendar year	**see Sect. 4.4.2.1**
	Cathodically Unprotected Pipe, located in All Classes	At least 4 times each calendar year	**see Sect. 4.4.3**
	All other DOT-T Pipe	At least twice each calendar year	**see Sect. 4.4.1**

4.2. Medium Pressure Pipelines (Operating at 60 psig or Less)

4.2.1. Survey all pipe (including services) in business districts and adjacent schools, hospitals, and churches at intervals not exceeding 15 months, but at least once each calendar year.

4.2.2. Survey Non-State-of-the-Art PE main where the main is not located in a business district once every calendar year, at intervals not exceeding 15 months.

4.2.3. Survey all Cathodically unprotected pipe (including services), where electrical surveys for corrosion are impractical, at least once every 3 calendar years at intervals not exceeding 39 months.

4.2.4. Survey all State-of-the-Art PE and pipe and Cathodically protected main, where the main is not located in a business district (including services) least once every 5 calendar years at intervals not exceeding 63 months.

4.3. High Pressure Pipelines (Operating over 60 PSIG) not including DOT-Transmission Pipelines

4.3.1. Survey all pipelines and associated services every 15 months; but at least once every calendar year annually for all location classes.

4.4. DOT-T Transmission Pipelines

4.4.1. Non-HCA Transmission Pipeline Segments in Location Class 3* and all DOT-T pipe not covered in **Section 4.4.2.1 and 4.4.3.**

4.4.1.1. Survey every 7½ months; but at least twice each calendar year

4.4.2. Non-HCA Transmission Pipeline Segments in Location Class 4* and Transmission Pipelines in all Location Class without CP.

4.4.2.1. Survey Non-HCA Transmission Pipeline in Location Class 4 every 4½ months; but at least 4 times each calendar year.

4.4.3. If no CP is on a transmission pipeline (in any Location Class) or if electrical surveys are impractical, then survey every 4½ months; but at least 4 times each calendar year.

> *__Note:__ The implementation deadline to schedule future surveys for all non-HCA transmission pipelines according to the requirements in 49 CFR 192.935 is December 17, 2007. From this date forward surveys shall be performed in accordance with this survey-interval requirement.

4.5. Special Survey

4.5.1. Perform leak survey when:

4.5.1.1. Upon discovery that the MAOP of a pipeline is exceeded by 10% or more at any time during the life of the pipeline.

> **Note**: When the MAOP of a pipeline is exceeded by 10% or more, contact Engineering for guidance concerning any additional actions to be taken that could facilitate further analysis of the longer-term impact on the integrity of the pipe.

4.5.1.2. 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. See **GS G8202**, *Field Guidelines – Emergency Incident Distribution/Customer Service* or **GS G8205,** *Emergency Response Procedures for Gas Incidents- Transmission.*

4.5.1.2.1. For Earthquakes, see Operations Emergency Manuel (OEM) 01.040- SD Earthquake –Special Procedures.

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

4.5.1.4. In the case of blasting, an inspection, including leakage survey, may be required based upon recommendation from the Region Engineer.

4.5.1.5. When increasing the MAOP of a pipeline, per **GS G8115,** *Changing Maximum Allowable Operating Pressure and Maximum Operating Pressure*.

4.5.1.6. When minimum survey requirements are not considered adequate because of pipe condition, limited opportunity for gas to vent safely, or other reasons.

4.5.1.7. There is a need to monitor pipe condition for special situations, such as:

4.5.1.7.1. Material evaluations.

4.5.1.7.2. Proposed street improvement projects.

4.5.1.7.3. As a mitigative measure for the Integrity Management Program.

4.5.1.8. Survey at the frequency listed in Table 2 based upon the location of the known shorted casing, confirmed to be shorted through inspection and testing and have not been repaired/cleared according to **GS G8027,** *Cathodic Protection – Electrical Isolation.*

Table 2: Known Shorted Crossing Survey Frequency

Location Class	Frequency
Highway and Railroad Crossings	7½ months; but at least twice each calendar year
All Other Locations	15 months; but at least once every calendar year

4.5.2. A *special leak survey* may require special accounting; contact Field Operations Supervisor for proper account numbers.

4.5.3. Survey may also be considered in conjunction with major underground construction projects, see **GS G8122**, *Prevention of Damage to Company Facilities.*

4.5.4. After the occurrence of lightning strikes, transformer arcs, stray current or other electrical discharge events involving company facilities.

4.5.4.1. Electrical current induced onto facilities will take all paths to ground.

4.5.4.1.1. Lightning strikes and high voltage electrical discharge events can result in multiple damages and leaks.

4.5.4.1.2. Induced voltage on foreign facilities or substructures due to lightning strikes or electrical discharge events can also arc onto company facilities.

4.5.4.1.3. Locating wire used for identifying PE pipe installations is electrically conductive and can damage pipe if induced.

4.5.4.2. Survey all company facilities in the immediate vicinity of the area where the lightning strike or electrical discharge event occurred.

4.5.4.3. Contact System Protection/Region Engineering to identify the segment of pipe and determine the area to be surveyed.

4.6. **Application of Leak Survey Methods**

4.6.1. Field Organizations must follow Table 3 when selecting an approved method for conducting leakage surveys of Transmission and Distribution Facilities.

Table 3: Approved Leak Survey Method by Facility

Facility	*DP-IR*	*OMD*	*RMLD*	*Barhole GMI Gasurveyor*
Med Press. Pipe (Annual, 3yr ,5yr)	X	*X	*X	X
High Press. Pipe Over 60 psig (Annual)	X	*X	*X	X
DOT-T Transmission (Class 1,2)	X	X	X	X
DOT-T Transmission (Class 3, 4)	X	X	X	X
Shorted Casing	X		X	X
Pipe over Waterways	X		X	

*see sub-section for limitations

4.7. Instrumented Survey Routine Survey Method

4.7.1. The method consists of using an approved leak survey instrument listed in Table 3 to sample the atmosphere near the surface of the ground in the vicinity of buried company facilities, and in street openings and other accessible crevices and locations where gas is likely to vent.

4.7.2. Survey shall include visual examinations of all above ground Company facilities. Search along the route of the pipe at all locations where gas is most likely to vent. Determine pipe location as accurately as possible using map, existing paint marks, old patches, etc.

4.7.3. Choose locations such as loose earth, paving cracks, old bar holes, repair patches and around the base of poles, trees, fence posts, etc., if they are near the pipe.

4.7.4. Watch for, and check areas where vegetation appears to be affected by gas leakage.

Note: Grass and vegetation areas can be affected in several ways: There may be patches of brown, dry, even dead grass. In some instances, affected vegetation and grass may appear very green compared to surrounding areas.

4.7.5. Search along the route of all services at locations where gas is most likely to vent.

4.7.5.1. Determine the service location as accurately as possible using the map, curb markings, meter location, etc. If any doubt exists as to route of the service such as at corner lots, check both possible routes.

4.7.5.2. Search as close to the service location as practical, over earth, at building foundations or at cracks and/or paving edge if service is under paving.

4.7.5.3. Search along all services from the curb or pavement edge to the riser. Check at service-to-main connections if traffic permits.

4.7.5.4. Check all manholes and other street openings such as valve casings, curb meter vaults, drains, water valves, meter boxes, street lighting, power, telephone, etc.

4.7.5.5. For long-side services it is necessary to visibly look for indications of possible leakage under the street such as: evidence of recent construction, foreign trench marks, pavement cuts, bar holes, etc. along the service route. Where visible indications are present, use approved ground leak detection equipment such as DP-IR or RMLD.

Note: When casing vents are presents they must be inspected to ensure they are in satisfactory condition and designed to prevent entry of water, insects, and other foreign matter. Vents should extend at least four feet above finished grade and at least four feet below overhead electric wires. Vents shall be located in an area away from traffic and other hazardous locations.

4.7.5.6. Survey all risers and other above ground Company Infrastructure including meters set assemblies. If a riser and connected facility is not readily accessible by customer contact or other means during the regular survey, and the survey cannot be completed using the RMLD (**see 5.2.5.7** below), the “cannot get in” (CGI) must be documented for a follow-up to complete the survey. Check the riser and any portion of the service that was not surveyed. The follow-up shall be completed within the established compliance window for the inspection.

4.7.5.7. Districts have the option of utilizing a Remote Methane Leak Detector (RMLD) to check services up to the riser when access is restricted. See **GS G8192,** *RMLD-Remote Methane Leak Detector*.

Note:	Districts are responsible for tracking and completing services that are not accessible at the time of survey (commonly referred to as 'Can't Get Ins" (CGI's). Records should be kept per the retention scheduled identified **Section 7**.

4.7.5.8. Check the casing end inside the building when a service enters a building. Reseal the casing end.

4.8. **OMD Mobile Survey Method**

4.8.1. This method consists of driving a vehicle along the route of the underground gas piping and sampling the atmosphere near the earth or paving over the pipe or paving edge with sensitive continuous sampling leak detection equipment especially designed and engineered for mounting on a vehicle. See **GS G8138,** *Optical Methane Detector Operation and Maintenance*.

4.8.2. The OMD is to be used to perform leakage survey on high pressure and medium pressure pipelines.

4.8.2.1. In paved locations survey is performed by driving along or as near as possible, the curb to the side of the street where the pipeline is located. In the instance of dual pipelines, particularly wide streets, pipelines in traffic islands or divided traffic lanes, a particular street may be traversed in both directions.

4.8.2.2. In unpaved locations survey is performed by driving directly over or within 5 feet of the pipeline.

Note:	The Gas Patroller must know the location of the pipeline and other subsurface substructures that are part of the survey work order. Pipeline location is determined using the map, curb markings, pipeline markers, etc.

4.8.3. Associated services, crossovers and other buried infrastructure that cannot be driven over shall be surveyed using appropriate instrumentation (See section 4.7). Any services, taps, or other pressure carrying facilities that are part of the survey work order and are not suitable for survey by OMD must be surveyed with an appropriate device (see **Section 4.7**).

Note:	Check all manholes and other street openings such as valve casings, curb meter vaults, drains, water valves, meter boxes, street lighting, power, telephone, etc.

4.9. **Barhole**

4.9.1. Prior to drilling bar holes, notify Underground Service Alert (USA). See **GS G8123**, *Underground Service Alert and Temporary Marking.*

4.9.2. Drill a hole over the suspected leak area and surrounding facilities for the specific purpose of testing for subsurface gas indications per **GS G8194,** *Optical Methane Detector Operation and Maintenance*.

4.9.3. Use an instrument probe, such as the combustible gas indicator, e. g., GMI Gasurveyor SCG PPM Combustible Gas Indicator or DP-IR. Read gas indications.

4.10. **Water Crossing**

4.10.1. SAFETY

4.10.1.1. Serious bodily injury could occur when entering waterways without proper training and personal protective equipment (PPE). See sections 2.5 for required and recommended PPE.

4.10.1.2. The following are examples of hazards impacting this work:

4.10.1.2.1. Weather and waterway conditions.

4.10.1.2.2. Fast currents.

4.10.1.2.3. Tripping and slipping hazards.

4.10.1.2.4. Sunburn from water reflection.

4.10.1.2.5. Drowning.

4.10.1.2.6. Hypothermia.

4.10.1.2.7. Other watercraft.

4.10.1.2.8. Wildlife.

4.10.1.2.9. Environmental surroundings.

4.10.2. SPECIAL REQUIREMENTS

4.10.2.1. Use only approved leak survey instruments listed in Table 3.

4.10.2.2. If using RMLD, see the additional requirements listed in the attached document.

RMLD%20Requirements%20for%20Wat

4.10.3. For Distribution Piping Crossing the Bay

4.10.3.1. Use the following:

GTS-FUS-003%20Bayside%20Crossing.d

4.11. BUSINESS DISTRICT

4.11.1. A business district is an area that is 100 feet from the property line of a parcel of property that has been identified as significant commercial gathering point, a school, a hospital, a church or is a place where inhabitants have limited mobility.

4.11.2. Leak survey any distribution mains and associated services that have been identified as being within a business districts at the frequency established per Table 1.

4.11.3. The procedure for determining the business district is detailed in GS G8136, *Maintenance of Leak Survey Maps.*

4.11.4. If during the survey, the leak surveyor identifies land uses that could potentially trigger a business district determination that is not currently depicted upon the leak survey map; they should identify this location for additional evaluation. The surveyor should document as follows:

4.11.4.1. The surveyor should circle the land parcel that potentially has triggered the business district and denote the following on the map cover sheet.

4.11.4.2. Select the checkbox identifying a potential business district was found on the leak survey map and the appropriate box in the Click Mobile Form.

4.11.4.3. In the Comment Section of the Map Coversheet, describe the land use of the parcel that should be evaluated for meeting the business district designation (i.e. business, hospital, school, church, a significant commercial gathering point).

4.11.4.4. Return the completed survey map and comments to **Leakage Mitigation** for processing.

4.12. **Abnormal Operating Conditions (AOC)**

4.12.1. Issue Follow up orders to investigate and correct any AOC's encountered, These AOC's include: but are not limited to the following:

4.12.1.1. Meters in prohibited or hazardous meter locations, damaged, or corroded meter sets and meters buried in earth or paving.

4.12.1.2. Regulators in confined areas not vented to a safe location.

4.12.1.3. Broken or missing curb meter vault or curb valve lids.

4.12.1.4. Service valves not readily accessible or otherwise inoperable.

4.12.1.5. Pipelines (including services) having buildings constructed over them.

4.12.1.6. Pipelines (including services) that are endangered by foreign construction.

4.12.1.7. Curb valves not readily accessible on services to schools, hospitals or churches.

4.12.1.8. Exposed piping showing evidence of atmospheric corrosion, chemical corrosion and other conditions that warrant concern.

4.12.1.9. Stress on exposed piping facilities as a result of earth movement or other causes.

4.12.1.10. When MSA protection (barricades or barriers) are required per **GS D7115**, *Barricades for Gas Meter Sets.*

4.12.1.11. Missing, broken and damaged casing vents.

4.13. **Evaluation of Leakage**

4.13.1. The **Gas Patroller** evaluates all gas indications found and assigns an appropriate leakage priority classification based on potential hazard. See **G8135**, *Leakage Classification and Mitigation Schedules*.

4.13.1.1. Employees shall notify Supervision of all Leak indications detected over buried pipelines with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing), See **GS G8137**, *Leak Investigation* - - *Distribution*.

4.13.1.2. When a Code 1 Leak is identified by a Patroller (Gas) the Patroller will maintain surveillance (remain on-site) until one of the following occurs:

4.13.1.2.1. A Gas Repair Crew arrives on scene and releases the Patroller.

4.13.1.2.2. The originating Patroller is relieved by a relief Patroller.

4.13.1.2.3. The Patroller is released by either the M&R/System Protection Manager or the Leakage Mitigation Supervisor once they have responded to the location and determined a release is appropriate.

4.13.1.3. When an AG Hazardous Leak is identified by a Patroller (Gas) the Patroller will remain on-site until one of the following occurs:

4.13.1.3.1. If the Hazardous Leak is on the RISER, until a Gas Repair Crew arrives on scene and releases the Patroller.

4.13.1.3.2. If the Hazardous Leak is on a Customer Service Field (CSF) MSA, until a CSF representative arrives and releases the Patroller.

4.13.1.3.3. If the Hazardous Leak is on an M&R (Pipeline Operations) MSA, until a Pipeline Ops repair crew arrives.

4.13.1.3.4. The originating Patroller is relieved by a relief Patroller.

4.13.1.3.5. The Patroller is released by either the M&R/System Protection Manager or the Leakage Mitigation Supervisor once they have responded to the location and determined a release is appropriate.

4.13.2. Any gas indication that is investigated and presumed to be an outside company or agency should be promptly reported to the company or agency.

4.13.3. When a **Gas Transmission District** detects gas indications on a **Distribution Region** facility, promptly contact **Gas Technical Services**.

4.13.4. When a **Distribution Region** detects leakage on a **Transmission Operated** facility, promptly contact the **Transmission District.**

4.13.5. The survey person will confirm any gas indication with a combustible gas indicator; **see GS G8220,** GMI Gasurveyor SCG PPM *Combustible Gas Indicator.*

4.13.6. If the gas indication is located under street or paving, a hole must be drilled to take the read.

4.13.7. When gas indications are suspected to be from field or swamp gas:

4.13.7.1.1. The gas indication will be evaluated with an electronic ethane detector first. If ethane is not detected the **crew** contacts **Environmental Analysis Services (EAS)** and arranges for the testing of a gas sample to determine if the indications are the Company's responsibility.

4.13.7.1.2. When a suspected safety-related condition is found, report it to the **immediate supervisor** the same day the condition is discovered. See **GS G8229,** *Region Reports of Safety-Related Pipeline Conditions*.

4.14. **Reporting**

4.14.1. When a suspected safety-related condition is found, report it to the immediate supervisor the same day the condition is discovered.

4.14.2. Report all leaks and corrosion on **DOT-T** T**ransmission lines** as outlined in **GS G8229,** *Region Reports of Safety-Related Pipeline Conditions*."

4.14.3. To ensure a safe response, communicate emergency incident as outlined in **GS G8202**, *Field Guidelines – Emergency Incident Distribution/Customer Service* or **GS G8205**, *Emergency Response Procedures for Gas Incidents-Transmission.*

4.15. Documentation on the Leak Survey Map

4.15.1. The Gas Patroller performing the leak survey is provided with maps of the areas to be surveyed. The maps used for survey will depict pipeline location to be surveyed and the surrounding streets.

4.15.1.1. The Gas Patroller is required to balloon around, initial, and date all completed areas and/or segments they surveyed for that day on the Leakage Survey map using colored pens.

4.15.1.2. All below ground leak indications are noted in red, marked with an "X", and tallied on the Leak Survey Map Cover Sheet.

- New below ground leaks are identified using the location (sequence) number.
- Above ground leaks are identified using the location (sequence) number.

4.15.1.2.1. If leakage spread is twenty (20) feet or more use dotted red line to indicate spread on map.

4.15.2. Document potential business district changes per Section 6.4 (Distribution Only).

5. EXCEPTION PROCEDURE

(See **GS** G7007, *Exception Procedure for Company Operations Standards*.

5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

5.2. An exception from a standard shall not be allowed unless **GS G7007**, *Exception Procedure for Company Operations Standards* is followed, and approval is given by those as required by G7007.

6. OPERATOR QUALIFICATION COVERED TASKS

(See **GS G8113**, *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 09.01.** – 49 CFR 192.706 – Performing leakage surveys: transmission lines

- **Task 09.02** – 49 CFR 192.723 – Performing leakage surveys: distribution systems

7. RECORDS

7.1. Electronic Data Collection

7.1.1. Gas Transmission

7.1.1.1. Schedule, track, and document all routine leakage surveys on an approved computerized maintenance management system (i.e., MAXIMO).

7.1.1.2. Document all leak indications and leak repairs on **Form 677-1SD,** Pipeline Condition and Maintenance Report (Transmission).

7.1.2. Distribution

7.1.3. Click Mobile forms should be used to:

- Document *Leak Investigation* on form 4030 in click Mobile
- Document *Leak Indication* on form 4040 in click mobile
- Document *Distribution leak repair* on form 4050 in click mobile
- Use Excavation form in click mobile to document pipe conditions

7.1.4. If Click Mobile forms are unavailable, record leak repairs on medium pressure SDG&E Distribution lines on Form **108-00200,** *Gas Leak Repair/Pipe Inspection Report.* For leak repairs on high pressure SDG&E Distribution pipelines, prepare both Form **677-1SD** and Form **108-00200** and forward to **Gas Engineering - Pipeline Integrity**. Also forward a copy of the completed Form **108-00200** to **GTS Miramar – Leakage Mitigation Clerk.**

7.2. **Records Retention**

7.2.1. Records covering leakage surveys, leaks discovered, and repairs made are filed by the appropriate **Transmission District** or by **Gas Technical Services** (**Distribution**) and maintained for the life of the pipeline plus six years.

7.2.2. Records covering leakage surveys, leaks discovered, and repairs made on transmission pipelines are documented using an approved computerized maintenance management system (e. g., MAXIMO or SAP) and filed by the appropriate **Gas Transmission District**, **Storage Field**, or **Distribution**

Region, and must be retained per Records Management Retention Schedule. See Records Retention Standards on Sempra Net, [redacted]

7.3. In addition to the other recordkeeping requirements of these rules, each Operator shall maintain the following records for transmission lines for the periods specified:

A. The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipeline remains in service or there is no longer pipe within the system of the same manufacturer, size and / or vintage as the pipeline on which repairs are made, whichever, is longer.

B. The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 75 years. Repairs or findings of easement encroachments, generated by patrols, surveys, inspections, or tests required by subparts L and M of 49 CFR Part 192 must be retained in accordance with paragraph (c) of this section.

C. A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 75 years.

8. APPENDICES

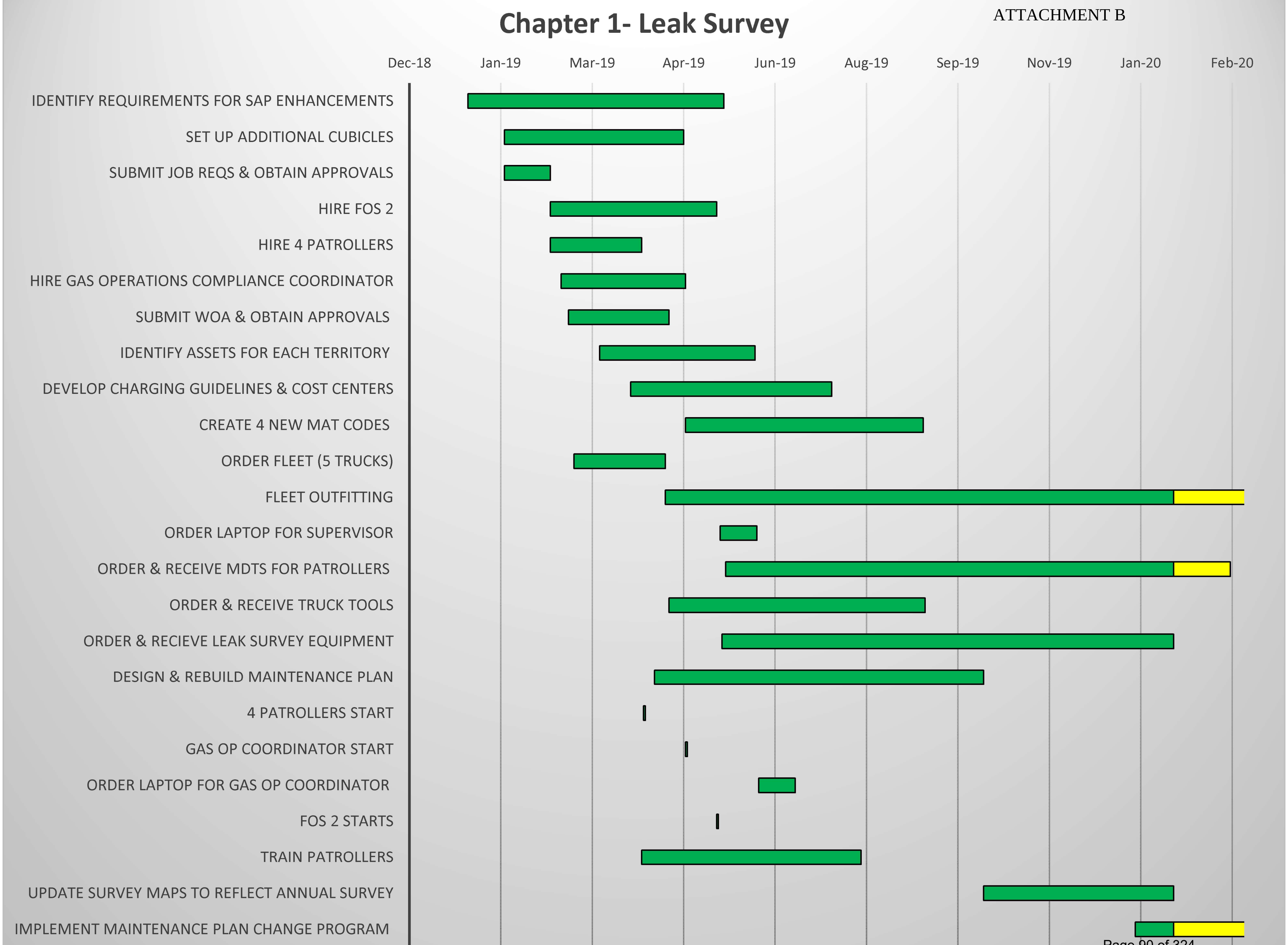
8.1. Not Applicable.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Conducted a functional review to re-establish 5-year review cycle. Reformatted to comply with document outline requirements. Updated Hyperlinks. Minor word changes throughout document for additional clarity. Policy was revised to better explain the requirements when leak indications are detected on a buried pipeline with an MAOP of 20% SMYS or more. Revisions made to provide guidance for performing leakage surveys due to lightning strikes. Information Bulletin 1719 and 1721 information was added to policy. Added section 4.15 to provided clarity on the documentation process for completed leak survey maps. Removed Operator Qualification Task 02.13 – 49 CFR 192.481 – Monitoring for atmospheric corrosion from GS. Added a new section 5 Exception Procedures, a new section 6, Operator Qualification Task and a new section 8, Appendices.

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	01/01/2019
Last Full Review Completed On:	10/31/2018
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
Category (Prior FCD system only):	
If Merged, Merged To Document Number:	
Utility:	SDG&E
Department:	Gas System Integrity Staff & Programs
Number of Common Document:	223.0100
Confidential Sections:	
Part of SoCalGas O&M Plan:	No
Part of SDG&E O&M Plan:	Yes
Contains OPQUAL Covered Task:	Yes
OpQual Tasks	09.01 09.02
Last O&M Review date:	10/9/2019
O&M 49 CFR Codes & Impacted Sections of Document:	192.481(a): Entire Doc 192.613(a): Entire Doc 192.706: Entire Doc 192.709(a): Entire Doc 192.709(b): Entire Doc 192.709(c): Entire Doc 192.721(a): Entire Doc 192.723: Entire Doc
Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	Yes
Part of Transmission IMP (TIMP)	Yes
Part of Storage IMP (SIMP)	No
Impacts GO112F	Yes
GO112F Codes & Impacted Sections of Document	145.1: (a)10, 11, (b)10, 11, (c)8, 9, 10, 11 143.1: Entire Doc
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	DIMP2, GSSD, TIMP2

NOP Learning Module (LM) Training Code:	NOP01158

ATTACHMENT B



Attachment BB: Updated Gas Standards

GS 183.01 - Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities
- Section 1.5 updated to provide guidelines for Project Managers and Planners to reduce methane emissions while planning projects

GS 184.06 Gas-Handling and Pressure Control
- Section 4.1.4.2 added to provide guidelines for Project Managers and Planners to reduce methane emissions while creating gas-handling or pressure control procedures

GS 184.006 - General Construction Requirements for Distribution Service Lines
- Section 1.6 modified to ensure reference to 184.06

GS 182.0160 - Purging Pipelines and Components
- Section 5.3.6 added to provide guidelines for Project Managers and Planners to reduce methane emissions while creating purge procedures

GS 184.0015 - Construction Planning for Mains and Supply Lines
- Section 4.4.9 modified to ensure reference to 184.06

GS 223.0145 - Planning Shutdowns for Transmission and Storage
- Section 4.1.4 added to provide guidelines for Operations to reduce methane emissions while planning shutdowns

G7909 - Purging Pipelines and Components
- Section 5.3.6 added to provide guidelines for Project Managers and Planners to reduce methane emissions while creating purge procedures

Form 3466 - Reporting of Gas Blown to Atmosphere
- Form updated to mirror Form 7011 and track emissions reductions from blowdown events
- Although form is already in use it has not officially been published as of 2/14/2020, the form attached is a draft

Form 7011 - Blowdown Emission Reduction Plan Form
- Form created to track emissions reductions for planned blowdown events
- Although form is already in use it has not officially been published as of 2/14/2020, the form attached is a draft

Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities	SCG:	183.01

PURPOSE **To describe the planning, coordination, and notifications necessary for planned and emergency shutdowns of Distribution pipelines and to establish isolation area requirements.**

1. POLICY AND SCOPE

1.1. **Distribution Regions** follow these guidelines in preparation for planned or emergency shutdown of segments of medium pressure districts.

1.2. A written shut down plan is prepared when:

1.2.1. Work on medium pressure Distribution lines involves the re-routing of gas that may impact more than 25,000 customer's meters.

1.2.2. Work on supply lines and/or regulator stations would significantly alter (displacement of one million cubic feet or more per hour) the flow of gas required from the **Transmission** system, affect flow of gas to a Utility Electrical Generation (UEG) customer, or affect receipt of gas from a producer.

1.3. **Distribution Regions** select an emergency shutdown plan that meets the needs of each situation and targets safe and practical facility restoration to minimize hazards to life or property.

1.4. **Distribution Regions** design, establish and maintain isolation areas so that each area contains no more than 25,000 customer meters.

1.5. **Project Managers, Project Engineers, and Planners** will build time into the project schedule to reduce methane emissions when planned shutdowns require gas blown to atmosphere.

1.5.1. Consider alternative sources of supply to maintain service to customers and maintain project feasibility.

1.5.2. Operating pressure should be reduced to the lowest operationally feasible level to minimize methane emissions before non-emergency venting of high-pressure distribution, transmission and underground storage infrastructure consistent with safe operations.

1.5.3. Work should be bundled to prevent multiple venting of the same piping, when practicable.

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. Ahead of any proposed shutdown period, **Distribution Planning & Engineering**:

2.1.1. Coordinates planned and probable emergency shutdowns with **Gas Control**.

2.1.2. **C**oordinates with **Transmission Technical Services** on planned shutdowns and probable emergency shutdowns of pipelines that affect **Transmission**.

2.1.3. Coordinates planned shutdowns and probable emergency shutdowns described in the scope that affect **Distribution Field Operations** with both the **Measurement & Regulation Operations Manager** and the **Area Resource Manager**.

2.2. **Project Managers**, **Operating Supervisors**, and other **Company personnel** responsible for projects that necessitate shutdowns shall notify **Energy Markets** and/or **Commercial/Industrial Services** when a shutdown affects the flow of gas to UEG/wholesale customers or affects Producers.

2.3. **Gas Control** reviews planned shutdowns and related plans; coordinates changes in planning schedules; coordinates with suppliers, producers, and UEG/wholesale customers; and advises **Distribution Planning & Engineering** regarding gas handling arrangements (valve operations, etc.).

2.4. **Distribution Field Operations, Measurement & Regulation Operations Manager,** and **Area Resource Manager** review planned shutdowns and advise **Distribution Planning & Engineering** regarding gas handling arrangements (e.g., providing input on valve operating procedures for the Measurement & Regulation technicians).

2.5. **Distribution Planning & Engineering** designs and establishes isolation area boundaries; confirms that pipeline system changes preserve boundary integrity; and periodically reviews the customer count in each isolation area.

2.6. **Asset Maintenance & Inspection department** maintains the attributes such as the valve location, type, size and status of isolation area valves in SAP.

3. DEFINITIONS

3.1. EOC – Emergency Operations Center

3.2. Isolation Area – a pre-established medium pressure operating area that can be physically shutdown by the closing of isolation valves in the event of an emergency as defined in Section 5.1

3.3. Isolated Section – any section of pipeline facility that is physically shutdown in an emergency or planned shutdown

3.4. Medium Pressure – MAOP of 60 psig or less

3.5. High Pressure – MAOP of greater than 60 psig

3.6. Pressure District – Network of pipes operating at a common pressure with an MAOP less than or equal to 60 psig

3.7. Pressure Zone – Network of pipes operating at a common pressure with an MAOP greater than 60 psig

4. PLANNED SHUTDOWN PROCEDURE

4.1. Coordination With Gas Control

4.1.1. For planned shutdowns described in section 1.2, **Distribution Planning & Engineering** shall notify **Gas Control** of any possible timing flexibility to enhance coordination with other planned shutdowns.

4.1.2. When shutdown **operations** are deemed significant by **Gas Control**, **Distribution Planning & Engineering** report the details of which valves will be shut, when, and for how long, seven days in advance of the shutdown.

4.1.3. **Gas Control** may request additional information as needed.

4.1.4. **Distribution Planning & Engineering** and **Measurement & Regulation groups** work with **Gas Control** to minimize gas blown to atmosphere through the use of other **Distribution** facilities to reduce gas line pack prior to blow down.

4.2. **Distribution Planning & Engineering** notifies the following parties (if affected):

- **Transmission Field Operations and/or Transmission Technical Services Manager**
- **Storage Technical Services Manager** and affected **Storage Operations Manager**
- **Distribution Field Operations, Measurement & Regulation Manager** and/or **Area Resource Managers.**

4.3. **Written Shutdown Plans**

4.3.1. **Distribution Planning & Engineering** develops written plans for handling planned shutdowns described in Section 1.2. Plans are specific and definitive in order to maintain well established operations.

4.3.1.1. Plans must include procedures for starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits, plus the build-up allowed for operation of pressure-limiting and control devices.

4.3.2. **Distribution Field Operations** provide their field operations personnel with a written plan for gas facility shutdowns delineating all critical activities associated with the shutdown.

4.3.3. The shutdown plan and subsequent job discussion includes, but is not limited to, the following information. The level of detail should be appropriate to the safe and efficient completion of the project:

- List of work to be accomplished prior to the shutdown.
- List of crucial equipment needed at the job site including hazardous materials cleanup equipment.
- List of all concerned governmental agencies, affected **Transmission** and **Storage personnel**, other Company personnel, local businesses, and residents to be notified.
- Sequence of operations, including numbers and locations of valves to be operated and the estimated time when these operations will occur.
- Schematic of the section to be shut down with all pertinent valves and valve positions clearly labeled.
- List of all active customers or customer taps.

NOTE: All taps feeding a customer(s) must have a plan for an alternate feed that identifies who is responsible for the alternate feed.

- Schematics of the installation and removal sections.
- Detailed step-by-step procedure for all fire-control activities. See **STANDARD 223.0165**, *Controlled Fire Operations*. Detailed, step-by-

step procedure for any purge performed. See **STANDARD 182.0160,** *Purging Pipelines and Components*.

- Plan for personnel protection using Lockout/Tag-out when required.

- List of impacts to telemetry and pressure monitoring devices (e.g., out of service data signals, availability of pressure monitoring).

4.3.4. With no less than seven (7) working days' notice, prepare and distribute **FORM 3506,** *Notice of Shutdown / Operational Deviation*, which notifies **Gas Control**, affected **Transmission** and **Storage Technical Services**, **Distribution Operations**, and/or **Major Markets** and confirms the arrangements and schedule of all shutdowns. If the date of the shutdown is likely to change, make a note to that effect on **FORM 3506.** Reach an agreement between **Transmission** and **Storage Operations** organization, **Distribution Regions**, other affected parties, and **Gas Control** as to the minimum amount of time prior to the shutdown that a firm date must be set.

5. EMERGENCY SHUTDOWN PROCEDURE

5.1. In the event of a major or wide-spread emergency (e.g., earthquake, terrorist attack, flooding, firestorm, natural gas shortage, etc.) and the **EOC** is activated and operational to respond to the event, the **EOC Director** should discuss the following three (3) factors with the **Executive-in-Charge** and **Gas Control** before implementing a shutdown in large isolated sections in the gas system unless Section 5.2.2.3.2 applies:

1. Size of Isolated Section

   - The isolated section is large enough to encompass an isolation area
   - The isolated section is a whole pressure district with more than one District Regulator Station
   - The isolated section will impact 25,000 or more customer meters (restores)
   - The isolated section could result in displacement of one million cubic feet or more per hour on the flow of gas required from the Transmission system

2. Impacts to Sensitive/Critical Customers

   - Health/Safety

- Hospitals
- Schools
- Stadiums/Large Public Gathering Sites/Arenas/Sports Centers that can be used for evacuation shelters
- Municipal Gas Systems (e.g., Long Beach Gas)
- City/County/State Emergency Operation Centers that are open and running (See ER-1 Ch 12 for more information)

o Economic

- Non-core firm UEG customers
- Refineries
- Co-Generation Facilities (> 20 megawatts)

o Major Airports (e.g., Los Angeles International Airport (LAX), San Diego International Airport (SAN), John Wayne Airport (SNA), LA/Ontario International Airport (ONT), Bob Hope Airport (BUR))

3. Need for Inter-Region Coordination or Mutual Assistance

o Response across multiple operating organizations or with assistance from outside the Company is required to implement the isolated section

5.2. When implementing a shutdown of a large-scale isolated section of the gas system, the responsible **Distribution management person** or **EOC Director** shall:

5.2.1. **Initiate a Message Center Report**. See **STANDARD 183.05**, *Reports to the Message Center*

5.2.2. **Evaluate Response Criteria** to determine the appropriate mitigation method.

5.2.2.1. **Table 1** lists the criteria that should be used when determining the appropriate mitigation method to respond to an incident. A more complete guideline may be found in **STANDARD 183.03**, *Field Guidelines — Emergency Incident*.

5.2.2.2. Squeezing operations shall be performed according to the standards listed in **Table 2**.

5.2.2.3. When Affecting Supply Lines:

5.2.2.3.1. Consult with the **Gas Control Supervisor** to arrange the re-routing of gas, operation of valves, and/or obtaining permission to close off connections prior to shutting down supply lines that affect the flow of gas to UEG/wholesale customers or that would significantly alter normal source gas (pressure/volume) from the Transmission system or that would affect producers.

5.2.2.3.2. Consultation or permission from **Gas Control Supervisor** *is not* needed when the responsible **Distribution management person** at the site determines any of the following:

- Injury or death have occurred or is imminent
- Communications are not possible from the site and leaving the site would risk additional damage or injury. In such cases the Gas Control Supervisor is notified at the first opportunity directly or by the EOC (if activated).

TABLE 1: RESPONSE CRITERIA

CONTROL METHOD	CRITERIA
Squeezing	• May be utilized when there is a localized incident with no practical access to valves or PC fittings • Can be performed on both polyethylene and steel pipe (see Table 2) • Should only be used on steel piping installed after 1932
Closing of Valves and/or Pressure Control Fittings	• May be used to shutdown small sections of the system • May be utilized when squeezing is inappropriate or when there is difficulty in accessing an incident site • Shutdown of a supply line should be performed with sectionalizing valves installed on the supply line
Shutdown of an Isolation Area	• May be performed in the event of multiple line breaks • May be implemented when the number of incidents exceeds the Company's ability to mitigate an incident locally

CONTROL METHOD	CRITERIA
	• May be implemented when the affected area is approaching the size of the isolation area
Shutdown of a Pressure District	• Can be used to shutdown a small pressure district with less than 25,000 customers and limited feeds • Is used to shutdown a large pressure district (more than 25,000 customers) only when maintaining safety warrants the wide-scale disruption of service to customers

TABLE 2: SQUEEZING REQUIREMENTS

TYPE	REQUIREMENT
Polyethylene Pipe	• Shall be performed according to GS **184.0340** for all plastic pipe
Hot and Cold Squeezing of Steel Pipe	• Shall be performed according to GS **184.0310** for 1-¼” and smaller steel pipe • Shall be performed according to GS **184.0315** for 1-½” and smaller steel pipe • Shall be performed according to GS **184.0320** for 2” steel pipe • Shall be performed according to GS **184.0330** for 3” and 4” steel pipe • Shall be performed according to GS **184.0335** for 6” through 12” steel pipe

5.2.3. **Select Type of Mitigation Method to Response**

5.2.3.1. Squeezing near an emergency incident site.

5.2.3.2. Closing of the nearest main-line or regulator station valve

5.2.3.3. Utilization of the nearest pressure control fitting

IMPORTANT NOTE #1:	Squeezing, closing of nearest valves, and the utilization of pressure control fittings are responses designed to minimize the number of affected customers and to expedite restores. These responses should only be used when an incident can be safely managed by isolating one or more localized sections of the Distribution system.

5.2.3.4. Isolation and/or shutdown of an affected isolation area

5.2.3.5. Shutdown of a pressure district or pressure zone

IMPORTANT NOTE #2:	Isolation area, pressure district, or pressure zone shutdowns are responses to minimize hazard of life and property in an event of a major or wide-spread emergency.

5.3. Isolation Area Establishment and Requirements

5.3.1. Each isolation area will have pre-defined valves that may be used to isolate an area.

5.3.2. Each isolation area valve is a critical valve and shall be inspected as per **STANDARD 184.16**, *Valve Inspection and Maintenance – Distribution*.

5.3.3. As part of the regular planning process, new pipe installation or configuration changes shall be evaluated to confirm that the integrity of the associated isolation area is preserved. If an isolation area is compromised, **Distribution Planning & Engineering** re-establishes the boundaries of the affected isolation area in accordance with this Gas Standard.

5.3.4. **Distribution Planning & Engineering** evaluates isolation area boundaries for accuracy on a five-year cycle. Each isolation area shall also be checked for potential impact to adjacent areas in the event of an emergency shutdown.

5.3.5. Plans must include procedures for starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits, plus the build-up allowed for operation of pressure-limiting and control devices.

5.4. Isolation Area Design

5.4.1. Each isolation area shall not exceed 25,000 customer meters

5.4.2. It is recommended to consider establishing an isolation area for pipeline segments susceptible to natural disasters (e.g. landslides, flooding) as long as the 25,000 customer meter limit is not exceeded.

5.4.3. The customer meter count in each isolation area should be reviewed and noted on an 18-month cycle by Distribution **Region Engineering**. If the customer meter count exceeds the 25,000 customer meter limit, **Region Engineering** shall evaluate the isolation area to re-establish new isolation boundaries to meet the appropriate size requirements before the next review process.

5.4.4. **Distribution Planning & Engineering** shall design, construct, and maintain each isolation area such that:

5.4.4.1. The isolation area boundaries are established with valves.

5.4.4.2. Supply lines are not used as part of an isolation area system.

5.4.4.3. The outlet valves at regulator stations in combination with open valves within the pressure district are designated as the control points to isolate each isolation area.

5.4.4.4. If a pressure district has less than 25,000 customer meters, then the pressure district boundaries may be used to define the isolation area. If this option is used, all valves, if any, used to define the pressure district must be tracked in SAP.

5.4.5. The locations of all schools and hospitals should be tracked and be identifiable in the event of an emergency.

6. EXCEPTION PROCEDURE
(See GS 182.0004, *Exception Procedure for Company Operations Standards*)

6.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

6.2. An exception from a standard shall not be allowed unless GS 182.0004, *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

7. RECORDS

Isolation Area Documentation

7.1. Each **Region** shall maintain its isolation areas and the locations of its isolation valves on the **Company's Geographical Information System (GIS)**. When an isolation area extends into an adjacent Distribution Region, the affected **Planning & Engineering Managers** for each Region shall agree on who will have primary responsibility for maintenance of the isolation area.

7.2. Each isolation valve shall be identified as a critical valve and have maintenance history. Attributes such as the valve location, type, size and status should be included in SAP and be maintained by the **Asset Maintenance & Inspection Department**.

7.3. If an isolation valve is replaced or relocated, a new valve number will be assigned in SAP. The old valve number shall be deactivated in SAP.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Fully reviewed. The Emission Strategy Program (also known as Leak Abatement) is working to ensure that we comply with SB1371, which aims to reduce methane emissions from our operations. One of the requirements for SB 1371 is to implement blowdown reduction activities whenever possible. GS 183.01 has a new section 1.5 under Policy and Scope that outlines what is expected when a planned shutdown requires gas blown to atmosphere.

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	11/01/2019
Last Full Review Completed On:	09/19/2019
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
Category (Prior FCD system only):	
If Merged, Merged To Document Number:	
Utility:	SoCalGas
Department:	Gas Engineering
Number of Common Document:	
Confidential Sections:	
Part of SoCalGas O&M Plan:	Yes
Part of SDG&E O&M Plan:	No
Contains OPQUAL Covered Task:	No
OpQual Tasks	
Last O&M Review date:	9/9/2019
O&M 49 CFR Codes & Impacted Sections of Document:	192.605(b)(3): 6 192.605(b)(5): 4, 5 192.615(a)(6): 5
Part of Non-O&M Parts 191-193 Plan	Yes
Non-O&M 49 CFR Codes & Impacted Sections of Document	192.181(a): 5.3, 5.4
Part of Distribution IMP (DIMP)	No
Part of Transmission IMP (TIMP)	No
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
GO112F Codes & Impacted Sections of Document	
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	DISTM, EMGM, TRNG
NOP Learning Module (LM) Training Code:	NOP00271

PURPOSE: **To provide guidelines and requirements for gas handling/shutdown and pressure control operations that involve introducing or interrupting gas flow. This includes the operation of valves, pressure control fittings, and squeeze closures to prevent overpressure of pipelines beyond Maximum Allowable Operating Pressure (MAOP).**

1. POLICY AND SCOPE

1.1. This Standard establishes guidelines and requirements for written gas handling plans, alternative gas handling plans and various considerations when performing gas handling/pressure control on the gas piping system. Employees are to adhere to these guidelines when performing these duties.

1.2. **Precautions**

1.2.1. Prior to a shut-down, **take precautions** to prevent outage, over and under pressurization caused by unknown obstructions, a rapid increase in load, and/or errors in mapping or planning.

1.2.2. Adhere to all safety concerns and policies.

1.2.3. Utilize approved gauges and/or temporary EPM (electronic pressure monitor) devices to mitigate over-pressure or under-pressure events as part of the Distribution gas handling procedures.

1.2.3.1. When the project creates a dead-end that is not rated for the available source pressure, a temporary EPM installation is *required* to be part of the gas handling to remotely monitor a terminal point within that dead-end portion *when* personnel are not available on site to monitor. The temporary EPM shall remain in service until the potential for over-pressurization or under pressurization of the dead-end is eliminated. **See Section 4.1.5.**

1.3. When multiple departments (Distribution, M&R, Transmission, and/or Storage) are working the same project, the completion of **Form 2865,** *Gas Handling/Shutdown Coordination Form***,** is required. This form is used to coordinate critical handoffs between departments during the Gas Handling/Shutdown instructions created specifically for that project. See **Company Form Instruction 2865**.

1.4. All "**planned blowdowns"** that have the potential to create external activity (media attention, customer odor calls, etc.), will require Supervisors performing the planned blowdown to send an email to **Blowdown@semprautilities.com** at least 5 days prior to planned blowdown. This email address contains all "internal" contacts that may need to be informed to prepare for potential responses or communications (**See Section 2.1**).

2. RESPONSIBILITIES AND QUALIFICATIONS

2.1. **Supervision performing** a "planned blowdown" **(See Section 1.4)** are responsible to send an email to [redacted] at least 5 days prior to the planned blowdown. The email will contain the following information:

- **Title the subject line** of the email "Planned Blowdown: Insert name of city/county or cities/counties impacted".
- The **location information** should include as much as the following as possible: Section Segment Number, GPS, address, street intersection, project name (title, work order number).
- A **brief description** of the project (i.e., pipeline number, pressure, blowdown duration, equipment used, etc.).
- A **general description of the area surrounding the project area** (i.e., within 1 mile). Urban or Rural, critical facilities (hospitals, schools, etc.), major landmarks, freeways, major streets, intersections, residential, business, or otherwise. The description should give the recipient an understanding of the surrounding environment in relationship to the project.
- If possible, a screen-print or attachment of a **map** that provides a general understanding of the surroundings: freeways, major streets, critical facilities (hospitals, schools, etc.), residents, businesses, etc. The map should be viewable from any handheld device.
- Please notate **if assistance will be needed** from other departments: Public Affairs, Office of Media and Public Information, etc.

Note:	In the event there are revisions to the planned blow-down, Field Supervision shall send a follow up email to blowdown@semprautilities.com detailing the changes.

2.2. For a single project that includes multiple departments, it is the responsibility of the **department initiating the project** to assign an **Operations Coordinator**. See **Form 2865**.

2.2.1. The **Operations Coordinator** will be responsible for communications between the departments and initiating/maintaining any changes during the Gas Handling/Shutdown process.

2.3. **Each organization** is responsible to designate specific supervisors to be responsible for gas handling/shutdown operations. The following guidelines are intended to indicate the extent this responsibility may be delegated on various types of work:

2.3.1. Written Gas Handling/Shutdown plans are required for work involving transmission lines, supply lines, medium pressure mains, high pressure services, power-generating plants and any job that is extensive enough for safe handling of gas as determined by the Planner and/or Supervisor. The plans shall be reviewed by the Region Field Operations Manager *and* Gas Control (where applicable) except in an emergency.

2.3.2. Written Gas Handling/Shutdown plans shall be prepared for other pre-planned projects that require pressure control operations. This includes medium pressure services being tied to the main or tied to another service (as a branch) using any fitting *larger than* a 2-inch steel service tee and/or 2-inch PE SMC fitting.

NOTE: Steel and PE tees installed 'inline' on main to obtain full opening will require a Gas Handling plan regardless of size.

2.3.2.1. The Distribution Gas Handling Instructions are provided separately in Word format and are used in conjunction with the gas handling locations depicted on the construction sketch. See **GS 192.0010**, *Preparation of Construction Sketches*, and **Appendix A** of this document.

2.3.2.2. As a part of the project package pre-construction routing for reviews, the Planner creates and finalizes a Planner's Sketch and preliminary Gas Handling plan. These items along with any pertinent project contents are routed for review, signatures, corrections and/or recommendations. See **GS 184.0016**, *Main Construction Project Routing.*

2.3.2.3. At post-construction, the responsible supervisor will sign and date the Distribution Gas Handling Instructions to verify the operations were performed as planned.

2.3.2.3.1. If the performance of the actual gas handling operations varies significantly from the Distribution Gas Handling Instructions, the responsible supervisor will amend the document in Word and print, sign, and attach the revised Gas Handling Instructions to the original copy and return them in the project package.

2.3.3. If possible, an alternative gas handling plan shall be included with a package (12 inch or larger pipe, or 60 psig and greater) in case of the inability to achieve a "no gas flow" shut-in (potential bypassing valves or line stoppers).

2.3.3.1. The sequence of activities in the gas handling plan shall be prioritized. Equipment to monitor and control the pressure shall be installed and operational prior to the system being pressurized and remain in place as long as the system is pressurized.

2.3.3.2. The gas handling plan shall require that the work site be left in a safe condition, and any out of service pipe or equipment be closed to gas flow and protected from accidental overpressure due to valve leak-by or other unexpected condition.

2.3.3.3. When any work is performed on, or which results in, an isolated pipeline section of 1000 feet or less being served by an active regulator station(s), valve and squeezing operations (both closure and opening) should be executed slowly (over a period of no less than one minute) in order to allow for transient conditions to be dampened, to avoid over-pressuring a short section of pipeline. This is particularly important where the upstream regulator station is served by pilot-operated gas regulators. Pipeline pressure should be noted and recorded after each of these operations.

Note: Although work plans and gas handling plans may support information conducive to a successful shutdown, it is the responsibility of the field supervisor to verify information is accurate before/after making a shutdown.

2.3.4. Supervision ensures that safety and gas system integrity are maintained during the Gas Handling Operation. Supervision reviews the Gas Handling Procedure with the crew before the start of the job. In addition, all Main/Line stop operations are performed under the direction of the responsible supervisor.

2.3.5. Review gas-handling procedures with the crew(s) performing the job operations mentioning key elements such as, but not limited to:

- Timeline of events
- Maximum and minimum pressures
- Operation sequence
- Each member’s responsibilities
- Items of safety concerns

2.3.6. When work is performed by a contractor, the supervisor responsible for the gas handling operations confirms that the contractor understands the requirements concerning the installation of pressure gauges and/or EPM’s, bypass connections, etc., as well as the purging and gas handling plans.

Designated Company representative observes, directs or assists the contractor in conducting the gas handling and purging operations as needed.

2.3.7. Bypass district regulator stations shall be performed only under the direction of a qualified employee **(**such as a Meter and Regulation Technician #1). Gauges showing the district pressure are observed continuously while bypassing stations.

3. DEFINITIONS

3.1. **Blow-down** – Reduce line pressure by venting.

3.2. **Blow-down stack** – A vertical metallic pipe through which air or gas is vented.

3.3. **Dead-End** – An isolated pipeline segment that is downstream of a regulator station, valve or pressure control fitting and serves no customer gas demand.

3.4. **EPM (**Electronic Pressure Monitor) - a microprocessor-based, stand-alone, self-powered data recorder that measures gas pressure, gas temperature, case temperature, and internal battery voltages.

3.5. **Pressure gauge** – Instrument used to measure pressure.

3.6. **SMC** – Service to Main Connection.

Note:	Install pressure gauges upstream and downstream of the portion of main to be shut-down. Pressure gauge stack is not used as a blow-down stack.

4. PROCEDURE

4.1. **Shut-Down of Supply, Feeder, Transmission, and Distribution-Operated Lines**

4.1.1. Follow this procedure when supply lines, feeder lines, Transmission lines, and Distribution lines are shut down.

4.1.2. A detailed written procedure shall be prepared for each shutdown that involves gas handling or fire control work. Exception: emergency situations.

4.1.2.1. The sequence of activities in the gas handling plan shall be prioritized. Equipment to monitor and control the pressure shall be installed and operational prior to the system being pressurized and remain in place as long as the system is pressurized.

4.1.2.2. The gas handling plan shall require that the work site be left in a safe condition, and any out of service pipe or equipment be closed to gas flow and protected from accidental overpressure due to valve leak-by or other unexpected condition.

4.1.3. Review plans with Gas Control, where applicable and pursuant to **GS CRMP6**, *Gas Control Management of Change*, and **GS 223.0145**, *Planning Shutdowns for Transmission and Storage*, when conducting transmission system shutdowns.

4.1.4. Efforts to limit inconvenience to the general public and governmental agencies shall be made as practical, without jeopardizing any items pertaining to safety. Such agencies may include:

- Air Pollution Control Districts
- Police Departments
- Fire Departments
- Civil Aeronautics Board
- Airfields
- Highway or Street Departments

4.1.4.1. Notify the appropriate agencies of any planned blow-down or release of gas to the atmosphere and coordinate the work with their activities as necessary. See **GS 180.0085**, *Valve Usage and Selection Guide* for location of blow-down valves.

4.1.4.2. High pressure projects that require gas blown to atmosphere will build time into the project to reduce methane consistent with safe operations and consider alternative potential sources of supply to reliably serve customers and maintain feasibility. Operating pressure should be reduced to the lowest operationally feasible level in order to minimize methane emissions before non-emergency venting of high-pressure distribution (above 60 psig), transmission, and underground storage infrastructure consistent with safe operations and whenever practicable, work should be bundled to prevent multiple venting of the same piping.

4.1.4.3. If possible, notify the public immediately adjacent to a blow-down site at least one day in advance of blow-down to avoid public concern about noise or odor.

4.1.4.4. Notify the Customer Services Department serving the affected area and arrange for customer notification in shutdowns that will curtail service. Commercial and Industrial meter accounts are notified of impact and or curtailment by means of the RER (Request for Engineering Review) and the various personnel working in the C/I Services group.

4.1.4.5. Notify Customer Call Center, informing them of the areas that may be impacted.

> **Note:** A minimum of 3 days notification to hospitals and schools (within 500') is required before starting non-emergency construction. See **GS 184.011**, *Notification of Excavation and Construction Activities - Assembly Bill Number 1937/ PUC Code 955.5*

4.1.5. Action Required:

4.1.5.1. When closing any valve or conducting operations that produces a 'Dead-End' pipeline exiting a regulator station and the isolated pipe is not rated for the full-inlet pressure of the regulator station, an EPM is required on the dead-end portion when personnel are not available on site to monitor:

> **IMPORTANT**: The monitoring of gauges needs to continuously be performed during squeezing operations, the application of pressure control fittings (line stoppers), closing of valves, the application of artificial load, and before the cutting of any pipe.

4.1.5.1.1. Install pressure monitoring equipment and monitor the pressure both upstream and downstream of any valve or regulator subject to manual operation or for any bypass operation.

4.1.5.1.1.1. If this requires the installation of gauges, make every effort to find a suitable location to install such in the area in which you are working. If this is not practical, employ personnel and/or gauges at locations in the nearest vicinity of your work location where pressures indicative of the pressure on each side of your valve can be monitored.

4.1.5.1.1.2. For work which holds the potential to affect a Distribution pressure district or supply line operation, use of EPM devices (either permanent or temporary) **will be** employed in coordination with Distribution Region Engineering.

4.1.5.1.1.3. Continually monitor pressures for no less than 15 minutes on each side of a valve after conducting such work, to ensure no system upset or destabilization has occurred.

4.1.5.1.1.4. Similar pressure monitoring and work coordination should be made with Gas Control pursuant to **GS CRMP6**, *Gas Control Management of Change*, and **GS 223.0145**, *Planning Shutdowns for Transmission and Storage* when conducting transmission system shutdowns.

4.1.5.1.2. Close the inlet valves to the regulator run(s) in the station prior to downstream valve closure or pinching operation. The handling of regulator station facilities shall be performed only under the direction of a qualified employee (such as a Meter and Regulation Technician #1).

4.1.5.1.3. Monitor isolation section pressure for no less than 15 minutes after all valves are closed to ensure a secure shut-in.

4.1.5.2. Plan for Equipment Malfunctions.

4.1.5.2.1. Be aware that while our system is designed with the highest quality components and redundant safety systems, sometimes equipment operates imperfectly or is otherwise compromised. This potential should be considered in your work plans and execution.

4.1.5.2.1.1. Have a backup plan if a valve or regulator does not seal completely or other piece of equipment fails, and be aware of anything that looks out of the ordinary.

4.1.5.3. If unsure about a specific operation, plan or Gas Standard, seek guidance from your immediate supervisor or management team.

4.1.5.4. Know and understand the piping system you are working on, and the implications of valve operation on upstream and downstream pressures on each relevant pipeline section before beginning work.

4.2. **Transmission Line Shut-Downs**

4.2.1. Determine the effect of the Transmission Line shut-down on the distribution system and make plans for necessary distribution operations:

4.2.1.1. Make test shut-downs of distribution facilities when necessary to determine the effect of the transmission shut-down on distribution pressures.

4.2.1.2. Assist the responsible supervisor, if required, in conducting shutdowns of transmission facilities for the same purpose.

4.2.1.3. Evaluate remedial measures (providing temporary facilities, more favorable shut-down schedule, etc.) when adverse effects are found.

4.2.1.4. Review the proposed transmission shutdown plan. When conflicts are encountered, work out a mutually satisfactory alternate schedule or arrangement with the responsible supervisor.

4.2.1.5. Make every effort to assist the responsible supervisor in reducing line pack prior to blow-down in order to minimize the amount of gas blown to atmosphere.

4.2.1.6. Plan and arrange for other distribution work that can be performed in conjunction with the shut-down provided the shut-down time is not unduly extended.

4.2.1.7. Plan for alternate supply and/or notification to customers affected by the shutdown.

4.2.1.8. Isolate distribution facilities from the transmission facilities being shut down. Perform other distribution work as planned only after confirmation of the shutdown is obtained from the responsible supervisor.

4.2.1.9. Observe progress of the transmission job, as necessary, to maintain operating control of the distribution system.

4.2.1.10. Return the distribution system to normal operation after notification from responsible supervisor.

4.3. **Valve Verification**

4.3.1. Prior to beginning a gas handling procedure, a physical inspection of all affected valves shall be conducted to verify the valve type and position match written gas handling plans, in addition to confirmation of the valves being operable. See **GS 184.16**, *Valve Inspection and Maintenance – Distribution*. If the physical inspection reveals the valve type or position does not match the written gas handling plans, do not move forward with work until consulting with Engineering to determine the impact and to correct the written gas handling plans.

4.4. **Pressure Gauge and Bypass Installations**

4.4.1. Pressure gauges are to be of a range that will allow the observer to detect minor changes in pressure. For example, use a 0-15 psi gauge when the operating pressure is 10 PSIG rather than using a 0-60 psi gauge. Prior to use, validate that gauges are accurate and in satisfactory working condition.

4.4.2. Where two or more pressurized pipelines are being connected, the pressure in each pipeline being connected must be determined prior to allowing gas to flow between the pipelines. Utilize pressure gauges and bypasses in distribution facilities shut down as follows.

4.4.3. Two-Way Feed:

4.4.3.1. Where a two-way feed is indicated, verification is required. Install pressure gauges on each side of the portion of the main to be shut-down whether or not a bypass is used.

4.4.3.2. The squeeze method of closing off a steel main does not allow it to be reopened immediately or throttled. Install an adequate bypass and gauges around the first squeeze, or the section to be squeezed, to prevent an accidental outage where a two-way feed is indicated but which may not exist.

4.4.3.3. The designated supervisor specifies the type and size of the bypass based on pressure and load conditions. When requested, Planning will size the bypass. When working with Distribution facilities, Region Engineering will confirm Planning's bypass recommendation.

4.4.3.4. The bypass requirement does not apply when a squeeze is used in combination with a valve or pressure control fitting when the valve or pressure control fitting is used first to stop the flow of gas through the main and the two-way feed is verified.

4.4.3.5. On plastic pipe the squeeze method permits immediate reopening; therefore, a bypass may not be necessary.

4.4.4. One-Way Feed:

4.4.4.1. Where a one-way feed is indicated, and a bypass is used, install pressure gauges upstream and downstream of the portion of main to be shut-down.

4.4.4.2. Where a one-way feed is indicated, and service is not to be maintained downstream of the shut-down, install a pressure gauge on the upstream and downstream side of the closure to verify one-way feed is accurate.

4.4.4.3. Pressure Gauge Locations:

4.4.4.3.1. Install pressure gauges on existing service connections or pressure taps where they can be properly manned for pressure observation and immediate communication with the responsible supervisor in charge of the shut-down.

4.4.4.3.2. If there are no convenient service connections or pressure taps on the main, make mainline taps adjacent to the closure device for installing pressure gauges. Do not install pressure gauges on blow-down stacks, bypass, or bypass fittings.

4.5. **Pressure Observations**

4.5.1. Artificial Load

4.5.1.1. Install a blow-down stack or use an adjacent service and create an artificial load, to make certain that facilities to remain in service are adequately supplied. Reduce the main pressure two or more times by means of the stack. Determine that the main pressure returns to district pressure each time the stack is closed after blowing.

4.5.2. Blow-down Stack

4.5.2.1. The blow-down stack and related fittings must be of sufficient size to create a flow in the system which is large enough to verify that an adequate supply exists to serve the area being isolated.

4.5.3. Observe gauges to check the effects of operating valves, fittings, or squeeze closures.

4.5.3.1. When a valve or pressure control fitting is used, or a squeeze is made in plastic pipe, close it slowly so that any change in pressure may be observed before the main is completely shut-down.

4.5.3.2. After closure, observe the pressure for no less than 15 minutes to verify pressure has stabilized before proceeding with any piping changes.

4.5.3.3. If the pressure does not hold as planned, reposition the valve or stopper immediately to restore supply unless the pressure has dropped too low to maintain adequate pressure on customers' facilities.

4.5.3.3.1. If the pressure has dropped too low, leave closed and handle as an outage. Do not re-pressure until all affected customers have been shut-off at the meter.

4.6. **Temporary Gas Supply**

4.6.1. If you have a need for portable Gas Pods and/or for portable manifolds (Christmas tree) please contact.

4.6.1.1. **During regular working hours 6:00 AM – 2:30 PM, Monday – Friday**.

- For Gas Pods: Call the Shipping Dispatcher at (562) 806-4222.
- For manifolds (Christmas tree): Call the Natural Gas Vehicles Group at (562) 806-4309.

4.6.1.2. **During off hours**

- The Logistics On-Call Supervisor through the Message Center at (213)-244-8900 during off-hours.

5. EXCEPTION PROCEDURE
(See **GS 182.0004**, *Exception Procedure for Company Operations Standards*)

5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

5.2. An exception from a standard shall not be allowed unless **GS 182.0004**, *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

6. RECORDS

Not Applicable

7. APPENDICES

Appendix A

Distribution Gas Handling Template *(see next page)*

SoCalGas
A Sempra Energy utility

Gas Handling Instructions
Standard 184.06 Gas Handling and Pressure Control
Standard 184.0350 Pressure Control - General

Click here to enter text.

Notification No. Click here to enter text. **Work Order No.** Click here to enter text.

Pre- Construction Review/Approval		
	SIGN (PRINT NAME BELOW LINE)	DATE
LPA		
	SIGN (PRINT NAME BELOW LINE)	DATE
TSS		
	SIGN (PRINT NAME BELOW LINE)	DATE
FTL OR FOSII		

Construction Approval/ Verification		
	SIGN (PRINT NAME BELOW LINE)	DATE
FTL OR FOSII		

NOTE: If Gas Handling changed from the Pre-Construction plan, modify the document to suit in Word, print – sign – date the revised document and attach it to the original Instructions and return it with the project package. Check the box below if Instructions are revised.

☐ **Revised Gas Handling Instructions**

NOTE: Install a test fitting or utilize a suitable existing fitting to verify system pressure is 35 PSIG.

1.

Double click the icon below to save a copy of the Distribution Gas Handling template.

Gas%20Handling%
20Template%20Distr

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Added SB1371 language in Section 4.1.4.2.

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	07/01/2019
Last Full Review Completed On:	02/27/2017
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
Category (Prior FCD system only):	
If Merged, Merged To Document Number:	
Utility:	SoCalGas
Department:	Gas System Integrity Staff & Programs
Number of Common Document:	N/A - To be created in future
Confidential Sections:	
Part of SoCalGas O&M Plan:	Yes
Part of SDG&E O&M Plan:	No
Contains OPQUAL Covered Task:	No
OpQual Tasks	
Last O&M Review date:	8/30/2019
O&M 49 CFR Codes & Impacted Sections of Document:	192.605(b)(5): Entire Document
Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	No
Part of Transmission IMP (TIMP)	No
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
GO112F Codes & Impacted Sections of Document	
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	CF, CM, DISTM, MR, MS, PC, PCF, PSEP, STOR, TRAN, TRNG
NOP Learning Module (LM) Training Code:	NOP00410

PURPOSE: **To provide guidelines and requirements for distribution service installations, alterations and replacements for services operating at less than 20% Specified Minimum Yield Strength (SMYS).**

1. POLICY AND SCOPE

1.1. Excavation shall comply with:

- **GS 191.0045,** *Excavation Permits/Paving Repairs*
- **GS 184.0175,** *Prevention of Damage to Subsurface Installations*
  - Notify Transmission a minimum of 48 hours prior to any construction when transmission lines are within 10' of the construction area
- **GS 184.0200,** *Underground Service Alert and Temporary Marking*
- **GS 184.011,** *Notification of Excavation and Construction Activities - Assembly Bill Number 1937/ PUC Code 955.5*
- **GS 184.0171,** *Prevention of Sewer Lateral Intrusions and Damage*

1.2. Join polyethylene (PE) pipe and fittings using approved methods, fittings, tools, procedures. See **GS 182.0140,** *Polyethylene Plastic Pipe - General Application Requirements.*

1.3. Join steel pipelines and fittings using approved welding procedures and appropriately rated fittings. See **GS 187.0055,** *General Welding Requirements*.

1.4. For installation, alteration or replacement of any gas service, see **GS 187.0146,** *Excess Flow Valve (EFV) - Installation and Operation*. For sizing requirements when installing EFVs, see **GS 182.005,** *Service Pipe and Excess Flow Valve Sizing.*

1.4.1. If a curb valve was installed in lieu of an excess flow valve and the curb valve is replaced for any reason, first preference shall be the installation of an EFV that qualifies to serve the total load. See **GS 187.0146,** *Excess Flow Valve (EFV) - Installation and Operation.* For installation requirements and location, see **GS 182.005,** *Service Pipe and Excess Flow Valve Sizing.*

Note:	For customer requested Excess Flow Valves on existing services, see **GS 187.0146,** *Excess Flow Valve (EFV) - Installation and Operation*, and **GS 182.005,** *Service Pipe and Excess Flow Valve Sizing.*

1.5. Send all defective or leaking materials that can be cut out to the Engineering Analysis Center (EAC), Pico Rivera, (SC723B). Leaking materials require a completed **Form 4050,** *Leak Repair Order* attached. See **GS 223.0030,** *Investigation of Failures on Distribution and Transmission Pipeline Facilities*, for the chain of custody.

1.5.1. When replacing an EFV because of a suspected problem and/or failure:

- Document the incident on **FORM 5336,** *EFV Incident Report.*
- Route a copy of the completed **FORM 5336,** *EFV Incident Report* to Gas Engineering at ML SC722S.
- Route copies of the completed **FORM 5336,** *EFV Incident Report* and the removed EFV to the M&E Group, Engineering Analysis Center, Pico Rivera, ML SC723.

1.6. To determine if gas handling is necessary, see GS 184.06, *Gas Handling and Pressure Control.*

1.7. Construction tasks identified in **GS 191.0025,** *Inspection and Scoring of Construction Work*, shall be **Independently Inspected** and captured by the "**Company Authorized Representative**" using the FACT form for Company crews and ISN form for Contractor crews. Personnel who performed the construction task (installing pipe, fusing, welding, etc.) requiring inspection shall not perform the **Independent Inspection**.

2. RESPONSIBILITIES AND QUALIFICATIONS

2.1. Only personnel qualified through **Gas Operations Training** or **Welding Training** may perform these operations See **GS 187.0180,** *Qualification and Re-Qualification of Welders*, **GS 187.0181,** *Qualification of Personnel - Polyethylene Pipe Joiners and* **GS 167.0100,** *Operator Qualification Program.*

2.2. **Gas Operations Training** is responsible for ensuring the equipment and facilities used by an Operator for training and qualification of employees must be identical, or very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task.

2.2.1. The Applicant Installation Program does not qualify contractors for any phase of pressure control. Therefore, **applicant installers** are prohibited and shall not squeeze any PE pipe.

2.3. Only qualified personnel (**Company and Contractor**) shall perform pressure control operations on the gas system. See **GS 184.0590,** *Pressure Control Qualification Requirements*, and **GS 167.0100,** *Operator Qualification Program.*

2.3.1. All sources of ignition shall be eliminated in the immediate vicinity while pressure control or gas handling operations are in progress. No open flame, electrical spark or welding is permitted. See **GS 166.0025,** *Prevention of Accidental Ignition of Natural Gas.*

2.4. **Qualified Personnel** are responsible to visually inspect all pressure control equipment including squeezers prior to performing any pressure control operation. Do not use any damaged or defective equipment. Notify supervision if any defects are found.

2.5. When contractor personnel are working on pressurized gas lines, it is the responsibility of **Field Operations Supervisor** to ensure that contractor personnel are qualified to perform these operations.

2.6. **Contractors** shall be responsible for completing the "Small Pressure Control/Train the Trainer" course, administrating the training to their employees and ensuring their employees follow the procedures in the standards covered.

2.7. **Company Field Employees** shall be responsible for adhering to company procedures and shall wear appropriate personal protective equipment during all duties performed. See Injury and Illness Prevention Program, **MANUAL IIPP.4**, *Employee Responsibilities.*

2.8. **Contractors** shall adhere to their Company Safety Procedures/Practices and are expected to comply with all applicable Federal, State and Local laws, ordinances and regulations to ensure the safety of their employees. See **GS 167.04**, *Contractor Safety Program* and *SCG Contractors Safety Manual – Class 1 Contractors*.

2.9. **When applicable, Regions** shall be responsible to designate specific (trained and knowledgeable) supervisors to be responsible for gas handling operations within their respected areas.

2.10. **Districts** shall be responsible for compliance and administering the implementation of this and all other Gas Standards related to or concerning distribution service line.

2.11. **Gas Material - Gas Engineering** shall be responsible for administrating the development and coordinating the approval of material specifications that are used for distribution service lines (PE and steel pipe and fittings).

3. DEFINITIONS

3.1. **PE** – Polyethylene.

3.2. **Substructures -** (Subsurface Installations) any belowground pipeline, conduit, duct, casing, wire or any other structure.

3.3. **Tools-Type Order -** Indicates any instance where an employee is required to use tools (i.e. pneumatic and/or hand operated tools such as an Impacto Bar) to install, replace, or adjust fittings on the MSA (e.g., regulator change, leak orders, or anytime the service valve is turned on).

4. PROCEDURE

4.1. **Customer Communication**

4.1.1. When performing a construction activity on the customer's premises (e.g., an area that a customer may be the caretaker of, such as the parkway), communicate or attempt to communicate the following to a customer:

- All appropriate actions to be taken by the Company
- The type of work to be performed
- Any future follow-up actions
- Any and all other pertinent information

Note:	Attempts to communicate with a customer are intended for orders that have an actual or physical address (indicating dwelling or habitation) associated with the worked being performed.

4.1.2. If the customer is not present or not available when leaving the job site:

- Leave **FORM 2001**, *Customer Communications Tag – Distribution.*
  - Mark the appropriate box and/or write a brief explanation on **FORM #2001** describing the type of work performed and indicate whether a return visit is required.
- Contact Dispatch and request that a memo be added to the Customer's Account and make sure to describe the type of work performed. The memo shall include any and all future follow-up actions and any other pertinent information communicated to the customer.

4.1.3. Request **Supervision** assistance when a customer expresses concern(s) regarding the work to be performed or is not satisfied with the explanation provided, on the same day of the request (or immediately, if the situation warrants it).

Note:	Employee shall disclose all pertinent and relevant communications made between customer and employee to their **Supervisor**.

4.1.4. Provide no less than three (3) working days' notice to the administration of a School, Hospital and/or Registered Licensed Day Care Facility prior to undertaking non-emergency excavation or construction of a gas pipeline if the work is located within 500 feet of the School, Hospital and/or Registered Licensed Day Care Facility. See **GS 184.011,** *Notification of Excavation and Construction Activities - Assembly Bill Number 1937/ PUC Code 955.5*, Include all of the following in the notification:

- The name, address, telephone number, and emergency contact information for the company.
- The specific location of the gas pipeline where the excavation or construction will be performed.
- The specific location of the gas pipeline where the excavation or construction will be performed.
- An invitation and a telephone number to call for further information on what the School, Hospital and/or Registered Licensed Day Care Facility should do in the event of a leak.

4.1.5. Planner Communication To Customer

- For applications where the service will terminate within a building/substructure, the Planner is to specify to the developer/customer during the initial field visit the specifications that will be required to install an AL Riser to avoid Prefabricated Risers, which are required to be cathodically protected. For all other meter room requirements, see **GS 182.0206**, *Gas Meter room Requirements.*

4.2. **Source of Supply**

4.2.1. Use the closest gas main, when two or more are available, unless field conditions (e.g., traffic hazard, depth of main, medium pressure vs. high pressure, etc.) or economics (e.g., paving repair, etc.) dictate otherwise.

4.2.2. Use "Branch Service" installation procedure when a standard or branch service is the source of supply. See **GS 184.005,** *Planning for Distribution Services.*

4.2.3. During the initial planning stage, contact and obtain permission from Transmission when a transmission line is the only source of supply. See **GS 182.0165,** *Tap Requirements*.

4.3. **Route of Service**

4.3.1. Install the service along the most practical route to avoid conflict with future construction. Install services in public property at right angles to the centerline of the street, whenever feasible.

4.3.2. Do not cross lot lines with a standard service or branch service without written right-of-way authorization. See **GS 106.0021**, *Land and Right of Way Amendments*, and **GS 184.005,** *Planning for Distribution Services.*

4.4. **Substructure Clearances**

4.4.1. Independently installed gas pipelines (gas only), when independently installed, shall be separated, where practical from electrical supply systems, communication, or other pipe systems or other foreign substructures, by a clearance of at least 12 inches when paralleling and by at least 6 inches when crossing.

Note: New gas pipelines inserted within, and utilizing as conduit, pipeline facilities installed prior to the effective date of this rule (01/01/2017) are exempt from the paralleling requirements of this paragraph but not the requirements related to crossings.

4.4.2. Concurrently installed (joint trench) gas pipelines, when concurrently installed with electrical supply systems, communication, other pipe systems, or other foreign substructures, shall be installed with the separation of 12 inches when paralleling and by at least 6 inches when crossing.

Note: The Gas Company will only participate in "**Dry Utility**" joint trench.

4.4.3. **Establish and maintain greater separation or an increased distance from the heat source for special conditions, such as hot oil, steam, and water lines**. Polyethylene pipelines must be installed with sufficient clearances, or must be installed, from any source of heat so as to prevent the heat from impairing the serviceability or the pipe. Contact **Gas Engineering** for possibility of installing insulating barriers between steam lines and steel and/or polyethylene pipelines in both paralleling and crossing installations. See **GS 182.0010**, *Request for Pipeline Engineering Assistance*.

4.4.4. In all instances where the required separations cannot be maintained, it is the responsibility of the party last installing facilities to confer with the utility and ensure that the reduced separations do not adversely impact the integrity of the gas pipeline facilities, which includes any cathodic protection that may be applied to the gas pipeline facilities. See **Section 5** for Exception Procedures and requirements.

4.4.5. All gas pipelines are to be installed with enough clearance from other substructures to allow for future maintenance and to protect against damage that might result from proximity to other structures. For additional trench specifications, see **Table 1. F**or jobs with applicant provided trench, see **GS 184.010**, *Planning Applicant Provided Trench Project* for additional information.

4.5. Excavations

4.5.1. Ensure and maintain that excavations, pavement cuts, and bore slots are no larger than necessary for safe and proper pipe installation(s).

4.5.2. Undercutting of pavement shall be permitted only when authorized or requested by the City, County, or State Inspector, and it is determined that it can be performed safely.

4.5.3. Shore or slope excavations as required. See **GS 223.0140**, *Excavating, Shoring and Sloping*.

4.5.4. For direct burial excavations, excavate or attempt to excavate only when necessary, so that the pipe is installed on undisturbed and/or well-compacted soil and the backfill is free of materials that may damage the pipe and/or its coating.

4.5.5. Exercise caution and care when installing pipe using open trench or trenchless construction (e.g., boring or jetting into place) to prevent damage to the pipe, tracer wire, or pipe coating. See **GS 184.0170**, *Trenchless Construction Methods*, **GS 184.0171**, *Prevention of Sewer Lateral Intrusions and Damage*, **GS 184.0125**, *Tracer Wire Installation for Polyethylene (PE) Pipe Installations*, **GS 186.0110**, *Field Tape Wrapping Requirements* and **GS 184.0235**, *Polyethylene (PE) Pipe Repair*, for maximum allowable damage to polyethylene pipe.

4.5.6. Bores

4.5.6.1. See **GS 184.0170**, *Trenchless Construction Methods* and **GS 184.0171**, *Prevention of Sewer Lateral Intrusions and Damage* for Trenchless Construction guidelines and requirements.

4.5.7. Casings

4.5.7.1. See **GS 182.0148**, *Casing Assemblies - Plastic Carrier Pipe*, **GS 184.0100**, *Inserting PE Pipe - Service Replacement*, **GS 182.0140**, *Polyethylene Plastic Pipe - General Application Requirements*, and **GS 182.0080**, *Casing Assemblies - Steel Carrier Pipe* for service casing requirements.

4.6. Depth/Cover Requirements

4.6.1. Install all services to cover requirements of the permit issuing agency or the following, whichever is deeper. See **Table 1**.

TABLE 1

Normal Installation (Minimum Cover)	Public Property	Private Property
Steel Service (Operating above 60 PSIG)	24" *	20" *
Steel Service (Operating at 60 PSIG and below)	24" *	12" *
PE Service: • Below gutter flow line • Below the lowest point of the roadway where no curbs or gutters exist. • Between curb and property line unless subsurface installations necessitate less	24" *	20" *
Service (Cross lot branch services. 30" min @) lot line)	N/A	30"
PE Service (In Steel Casing)	24"	12"
PE Service (In Plastic Casing)	24"	20"
Railroad Crossing	60" (below ground, plus ballast height)	60"
State Highway	42"	N/A
Navigable River, Stream, or Harbor	**Contact Pipeline Engineering	**Contact Pipeline Engineering

*30" cover is recommended for machine-excavated services.

All gas pipe installed in a **Navigable River, Stream, or Harbor must be installed with a minimum cover of 48" in soil or 24" in consolidated rock from the underwater natural bottom. **Contact Pipeline Engineering** for approval. See **GS 182.0010**, *Request for Pipeline Engineering Assistance*.

4.6.2. Measure service depth/cover from proposed finished grade, rather than the existing, when street widening, or other improvement is proposed, and the new grade can be determined.

4.6.3. Notify supervision when depth/cover or other pertinent factors concerning knowledge of existing pipe may be compromised.

Note:	Deviations are made and recorded only when sub-structures prevent minimum depth/cover from being attained. **See Section 5,** ***Exception Procedures*.**

4.6.4. Shallow Service Installation

4.6.4.1. When subsurface installations make it necessary to install a service at less than the required depth/cover in public property, write on the service order in the Excavation Section, "**Request permit for shallow service**". Attach a sketch to the order illustrating size the and depth/cover of substructure; depth/cover and length of gas service; and depth/cover of the gas main.

4.6.4.2. Encase or reinforce shallow services to protect services from any anticipated external load and/or strain or potential damage.

4.7. **Bedding / Shading**

4.7.1. Properly support each service line on undisturbed and/or well compacted soil.

4.7.1.1. When native soil conditions (i.e., rock, hardpan, etc.,) create a trench bottom that is unsatisfactory, add a minimum of 4" of approved bedding material free of rocks and debris, before installing pipe.

4.7.2. Shade all service pipe with a minimum of 12" of well compacted approved shade material.

4.7.2.1. A thorough inspection of the pipe is required before shading when non-pressurized pipe is exposed for a significant duration of time.

4.7.3. Shade all gas pressurized pipe or fittings before leaving job site.

4.8. **Backfilling and Compaction**

4.8.1. Use backfill around the pipe and ensure and verify that the area is free of materials (e.g. rocks, building material, debris, etc.) that may cause damage to the pipe and/or its coating. Comply with the requirements of the permit issuing agency and/or the responsible inspector regarding the use of backfill material. See **GS 184.0055,** *Hand Backfill, Compaction Method*, **GS 184.0002,** *Site Restoration Specification* and **GS 107.0400,** *Dynamic Cone Penetrometer (DCP)*.

4.8.2. Compact the soil in compliance with the requirements of the permit issuing agency and/or the responsible inspector, see **GS 184.0055,** *Hand Backfill and Compaction Method*.

4.8.3. When equipment is used in the backfilling process, the pipe must be backfilled in a manner that prevents damage to the pipe and coating from the equipment.

4.8.4. Install and backfill each service line with the intent to minimize anticipated piping strain and/or external loading.

Note: **Do not** pneumatically compact directly over PE pipe or fittings with less than 12" of cover and **Do not** hydra-hammer over PE installations with less than 24" of cover. **Do not** hydra hammer over tie-ins.

4.9. **Material**

4.9.1. **PE Pipe/Material**

4.9.1.1. To properly store, transport, and handle all PE pipe and PE material, see **GS 184.0447**, *Handling and Storage of Polyethylene (PE) Materials*.

4.9.1.2. For a temporary bypass or temporary situation, all PE pipe and PE material installed above ground shall meet the above ground exposure requirements in **GS 182.0140**, *Polyethylene Plastic Pipe – General Application Requirements*.

4.9.1.3. Cap, plug, or otherwise seal all PE pipes prior to and until the installation is complete.

4.9.2. **Steel Material**

4.9.2.1. Protect pipe and protective coating from damage using reasonable care when loading, transporting, unloading and installing pipe.

4.9.2.2. Install only Company approved steel pipe and fittings of adequate design pressure. See **GS 182.0125**, *Steel Service Design – 60 PSIG or Less.*

4.9.3. **All Material**

4.9.3.1. Only Install company approved pipe and fittings of adequate design and pressure rating. See **GS 180.0001**, *Material Usage and Selection.*

4.9.3.2. For the chain of custody, see **GS 223.0030**, *Investigation of Failures on Distribution and Transmission Pipeline Facilities*.

4.9.3.3. For casing used as conduit to facilitate the installation of gas services in residential and commercial subdivisions, see **Section 4.5.7** above.

4.10. **Inspection**

4.10.1. **PE Pipe/Material**

4.10.1.1. Inspect all PE pipe, pre-tested PE pipe, PE fittings, AL risers, transition fittings, and PE excess flow valves prior to installation. Do not use any pipe that has kinks, dents, gouges, cuts or other imperfections, which could impact its serviceability. See **GS 184.0235,** *Polyethylene (PE) Pipe Repair.*

4.10.1.1.1. Verify the manufacture dates of PE pipe, pre-tested PE pipe, PE fittings, AL risers, transition fittings, and PE excess flow valves are NOT out of compliance prior to installation. See **GS 184.0447**, *Handling and Storage of Polyethylene (PE) Materials*.

4.10.1.2. The Fuser shall visually inspect all PE pipe and fitting joints.

4.10.1.2.1. The Fuser (i.e. the authorized individual exercising dominion and control of the fuse) is responsible for cutting out any and all defective fusions and repeating the fusion process, as necessary.

4.10.1.2.2. All visual inspections of completed fusions must meet the Visual Inspection Characteristics and Criteria for completed fusions identified in **GS 187.0115,** *Fusion Requirements for Polyethylene Pipe.*

4.10.2. **Steel Pipe**

4.10.2.1. Inspect all welds in compliance with Company procedures. See **GS 187.0175,** *Inspection and Testing of Welds on Company Steel Piping.*

4.10.2.2. Inspect steel pipe for protective coating damage and repair as necessary. See **GS 186.0100**, *Approved Protective Coatings for Below Ground Corrosion Control.*

4.10.3. **All Pipe(s) Inspection**

4.10.3.1. Inspect all pipes for visible defects before and during installation to ensure and verify that the pipe(s) have not sustained any damage that could impact its serviceability.

4.10.3.2. Ensure and verify all pipe ends are clean and free from any and all defects before initiating any joining procedure.

4.10.3.3. Ensure and verify that the inside of the pipe(s) are clean and free of debris and foreign material before joining it to another length of pipe.

4.10.3.4. Align pipe and fittings to avoid lateral strain and/or tension.

4.10.3.5. Send all PE failures that can be cut out to the Engineering Analysis Center (EAC), Pico Rivera, (SC723B), with a copy of the completed **Form 4050,** *Leak Repair Order*. For the chain of custody, see **GS 223.0030**, *Investigation of Failures on Distribution and Transmission Pipeline Facilities.*

4.11. **Pipe Aligning and Assembly**

4.11.1. Weld all steel pipes in accordance with **GS 187.0056**, *Welding Field Guide*, and **GS 187.0055**, *General Welding Requirements*.

4.11.2. Heat fuse or join all PE pipe connections in accordance with **GS 187.0115**, *Fusion Requirements for Polyethylene Pipe*.

4.11.3. Verify size, type and location of gas main prior to installing service to main connections to prevent accidental tapping of casings or foreign substructure installations. See **GS 187.0210**, *Service-Connections to Steel Pipelines.*

4.11.4. Install PE pipe so its natural curve lies on a smooth trench bottom free of rock and debris.

4.11.5. Provide appropriate end closures when stubbing services, see **GS 182.0085**, *Pipe End Closures.*

4.11.6. For PE pipe minimum bending radius, see **GS 182.0140**, *Polyethylene Plastic Pipe – General Application Requirements*.

4.11.7. **PE Pipe End Joining - Selection Guidelines**

4.11.7.1. **Table 2** is intended to assist the joiner and/or planner in selecting the optimum PE pipe end joining technique based on pipe size, joint requirements and joining circumstances.

Table 2

Pipe Size	Joining Circumstances			
	Socket	**Butt**	**Electro**	
½”	**1**	**N**	**N**	**Above ground**, one or both pipe ends have lateral in-line freedom of movement
1”	**1**	**N**	**2**	
2”	**2**	**1**	**3**	
3” & Over	**N**	**1**	**2**	
½”	**1**	**N**	**N**	**Within excavation**, one or both pipe ends have lateral in-line freedom of movement
1”	**1**	**N**	**2**	
2”	**2**	**1**	**3**	
3” & Over	**N**	**2**	**1**	
½”	**1**	**N**	**N**	**Within excavation**, both pipe ends lack lateral in-line freedom of movement
1”	**2**	**N**	**1**	
2” & Over	**N**	**N**	**1**	

Fusion Selection Codes:
1 = First Preference
2 = Second Preference
3 = Third Preference
N = Not Used
N/A = Not Applicable

4.12. **Testing**

4.12.1. Test all newly installed, repaired, or reinstated piping in compliance with **GS 184.0150,** *Leak Testing of Distribution Piping with MAOP <= 60 PSIG* and/or **GS 182.0170,** *Strength Testing - High Pressure Pipelines and Facilities*.

4.13. **Squeezing**

4.13.1. **PE Pipe**

4.13.1.1. For squeezing PE pipe, see **GS 184.0340**, *Squeezing Polyethylene PE Pipe - 1/2" Through 8"*.

4.13.2. **Steel pipe**

4.13.2.1. For squeezing steel services, see **GS 184.0315,** *Squeezing Steel Pipe 1-1/2" and Smaller Powell® S-4H and S-3A Pipe Squeezer* or **GS 184.0320,** *Squeeze Steel Pipe 2 inch with Regent® Pipe Squeezer*.

4.14. **Purging**

4.14.1. After tapping service to main connection, purge service with gas to remove air and possible debris from piping. See **GS 182.0160,** *Purging Pipelines and Components,* **GS 182.0162,** *Purging and Locking Service Risers, and* **GS 166.0025,** *Prevention of Accidental Ignition of Natural G*as.

4.15. **Heaters**

4.15.1. Heaters used for PE fusions are calibrated as per **GS 184.0130,** *Polyethylene Heater - Temperature Measurement and Adjustment.*

4.16. **Prohibited Locations for PE Pipe**

4.16.1. All PE pipe(s) are **prohibited** from any and all activity:

- Above ground, except on bridges through a casing or temporary situation.
- No wet (water/sewer) utilities in joint trench.
- In vaults
- Near steam lines, hot water lines or any other source of heat.
- Under any structures such as buildings, patios, carports or breezeways; except for isolated cases that are designed and approved by **Engineering.**
- Under electric facilities, such as but not limited to, splice boxes, transformer pads, etc.
- Where pipeline(s) can reasonably be subject to natural hazards, exposure to heat or excessive stresses, or significant buoyant force. See **Section 4.17** below.

Note:	**Region Planning and Engineering** shall approve all PE pipe installations in and/or on bridges. See **GS 182.0090,** *Designs for Pipelines in Bridges.*

4.17. **Protection from Hazards**

4.17.1. Ensure all necessary and practical steps are taken to protect the pipeline from future natural hazards such as, washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads when installing services. In addition, ensure all necessary and practical steps are taken to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations etc.

4.17.2. Contact **Region Engineering** if any of the following conditions are found in the pipeline system, such as, but not limited to:

- Where pipelines are exposed due to erosion.
- Where pipelines may be crossing a seismic fault.
- Where pipelines cross areas which are normally under water or subject to flooding (such as lakes, bays, swamps and river crossings) and may require anchorage to prevent flotation.
- Where pipelines are in unstable banks and bed locations.

4.17.3. Protect all aboveground services from any and all potential damage by vehicular traffic or other causes by placing the service at a safe distance from traffic or by installing barricades.

4.17.4. Protect all PE services temporarily installed aboveground from deterioration and external damage. PE services temporarily installed aboveground shall not be used to support external loads.

4.17.4.1. Contact **Pipeline Engineering** to initiate corrective actions if any of the above conditions are found in the existing pipeline system and/or the pipeline system being constructed.

4.17.5. Install pipe with sufficient clearances and/or insulation from any and all sources of heat to prevent impairing the serviceability of the pipe.

4.17.6. Areas that may be subjected to excessive external stresses and external loading, i.e., vehicular traffic, or construction activity, shall be reinforced to protect installed pipe from potential damage.

4.18. **Installation of Belowground Services Under Buildings**

Note:	Install belowground medium pressure services under buildings only when there is NO other alternative.

4.18.1. Install services using the following provisions:

- The belowground service pipe installed under a building must be encased and extend beyond the building dimensions by 2' at the open end of the casing.
  - The casing must meet the standup test requirements, so the casing is gas tight. See **GS 184.0150**, *Leak Testing of Distribution Piping with MAOP <= 60 PSIG.*
- The space between the casing and service pipe is sealed with Duxseal and plastic tape to prevent potential gas migration into the building if leakage occurred.
- The riser end of the casing is normally sealed; leaving the opposite end open.
  - If the casing is sealed at both ends, install a vent line, extending from the casing to a point above ground where gas would not be a hazard. See **GS 182.0080**, *Casing Assemblies - Steel Carrier Pipe,* and **GS 182.0148**, *Casing Assemblies - Plastic Carrier Pipe.*

CAUTION:	**Do not install belowground high-pressure services under buildings**.

4.19. **Installation of Services into Buildings**

Note:	Install medium-pressure services into buildings only when there is NO other alternative. If unavoidable, contact **Engineering** to handle the situation.

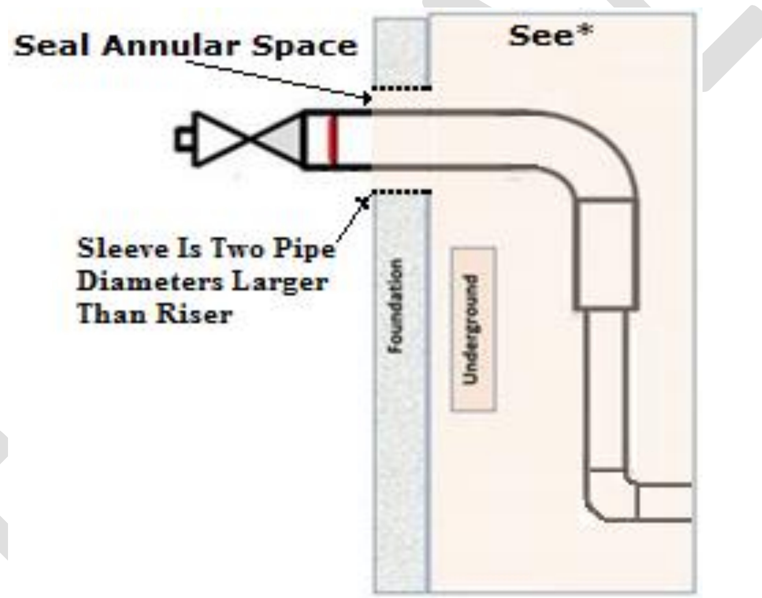
4.19.1. If there is no other alternative, then install services using the following provisions:

- The piping design and associated supports shall be reviewed and approved by Pipeline Engineering to ensure design specifications are acceptable. See **GS 182.0010**, *Request for Pipeline Engineering Assistance* and **GS 182.0206**, *Gas Meter room Requirements.*
- When PE pipe is used for service piping that terminates within a building:
  - The preferred installation method for services into a building is a PE service utilizing an AL Riser to penetrate the structure. If installation utilizing an AL Riser in not feasible, steel pipe must be used for the portion that enters the structure and must be cased and sealed (see **GS 186.0005**, *Cathodic Protection - Mixed Piping System)* also described in **Section 4.18 above**.
    - To protect the PE pipe from damage, a steel offset between the transition fitting and the building is recommended or:

- That portion of steel service located within an underground garage or basement must be rigidly secured but does not require encasement.

o When using an AL riser for the portion that enters the structure

- The orientation of the riser going through the wall is very important as to determining support.
- The AL riser bend is below ground, thus supporting any torsional movement. The steel casing will support against shearing. See **Figure 1 or Figure 2:**

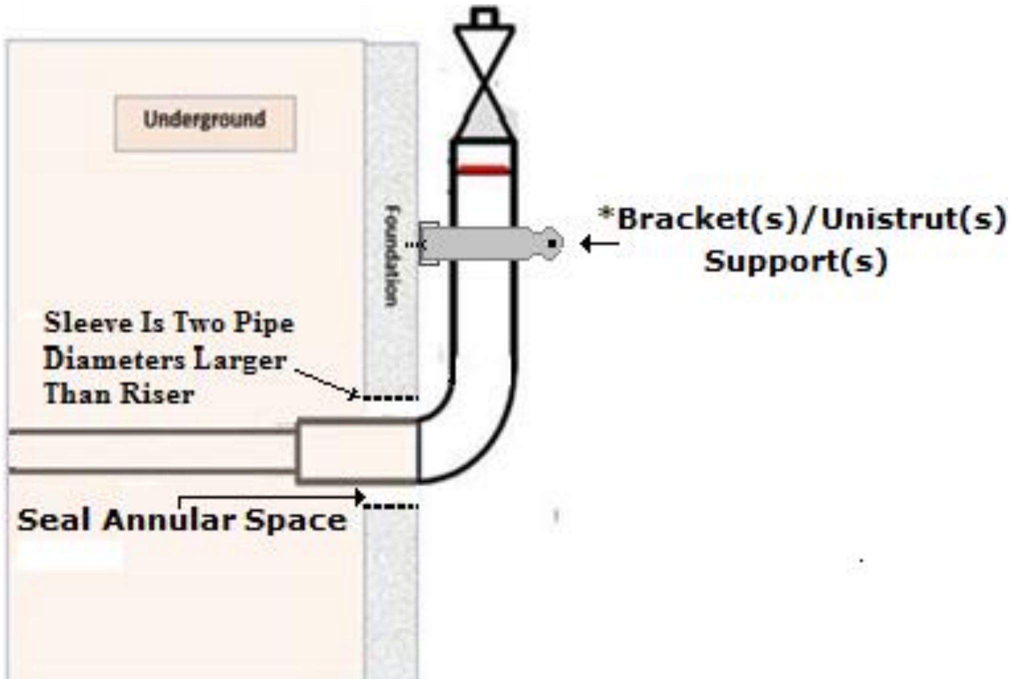


*Vertical Unistrut support(s) are required in conjunction with Horizontal Unistrut supports when using an AL riser to ensure the load in equally distributed and no stress or weight is carried by the AL riser. Vertical supports should be placed as close as practicable to the elbow transitioning the riser from the vertical position to the horizontal position.

FIGURE 1

Note:	In **Figure 1 and Figure 2** it is important to have the red line exposed and not in the wall. The riser casing must also extend outside of the wall below ground. This also is an important step. Make sure to seal the inside wall and if sealing the outside, run a vent line out.

- The AL riser bend is in the building. Riser needs to be Bracketed/ supported inside the bldg. against the foundation wall (*). The steel casing will support against shearing. See **Figure 2**.



*Vertical Unistrut support(s) are required in conjunction with Horizontal Unistrut supports when using an AL riser to ensure the load in equally distributed and no stress or weight is carried by the AL riser. Vertical supports should be placed as close as practicable to the elbow transitioning the riser from the vertical position to the horizontal position.

FIGURE 2

- That portion of steel service located within an underground garage or basement must be rigidly secured but does not require encasement.
- When steel pipe is used for service piping that is to terminate within a building, a casing must be installed through the foundation wall and extend into the building to a normally usable and accessible part of the building.
- Seal the riser end of the casing with Duxseal and plastic tape and leave the opposite end of casing open to prevent leakage into the building. See **GS 182.0080,** *Casing Assemblies - Steel Carrier Pipe.*
- Steel used as casing (excluding AL Risers) must be Cathodically Protected in accordance with **GS 186.09,** *Cathodic Protection - Casings*. All segments of submerged Steel Carrier pipe must be Cathodically Protected in accordance with **GS 186.0005,** *Cathodic Protection – Mixed Piping System*. A Cathodic protection Test Station (ETS) as shown in **GS 186.09,** *Cathodic Protection – Casings* must be installed external to the building for both the steel casing and carrier pipe and accessible for

routine monitoring.

- The service line must be protected against external damage.
- Above ground piping must terminate at an approved meter location and meet requirements for service valve installation. See **GS 185.0001**, *Meter Locations*, and **GS 184.0090**, *Valve Selection and Installation – Services.*

Note: Do not install high-pressure services (greater than 60 PSIG) within buildings.

4.20. **Existing Services Under Buildings**

4.20.1. When work is to be performed on a service and any portion of the uncased service is found belowground and under a building, that portion of the service must be altered or encased.

4.21. **Drilling Foundations**

4.21.1. Drill holes at a minimum of 12” from any opening and no less than 4” from the top of the foundation to prevent cracking of the foundation walls.

4.22. **Extending Beyond the Main**

4.22.1. Do not extend service beyond the end of the main ("leading the main"), unless one of these situations exists:

- Future main extension is improbable or unnecessary because of physical barriers.
- Present facilities are adequate to serve any future customers.
- Installing a service diagonal to the main can eliminate a main extension of 50’ or less. **Distribution Technical Services** must authorize these service routes after considering future growth potential.

4.23. **Mobile Home Services**

4.23.1. Use the following guidelines when planning new business services for mobile homes:

- Delay installation until the liquid waste disposal system, concrete patio, and/or the carport slabs are installed. When practical, do not install service piping under concrete slabs or paved driveways that may be directly under the designated area for a mobile home.
- Obtain from the owner a plot plan of the property including location, dimensions of the coach in relation to the property line and the gas stub-

out location and whether the mobile home is to be placed on a "foundation system" or not.

- Inform the owner that the stub-out locations shown on the plot plan are final and any desire to relocate the service after the service has been installed would be at the owner's expense.

4.24. **Service Discrepancies**

4.24.1. Installation crews are expected to meet deadline dates to avoid customer inconvenience. Contact supervision whenever the following service discrepancies occur:

- Customer deems meter location as unsatisfactory. See **GS 185.0001**, *Meter Locations.*
- Negotiate a change order to be signed by the customer if the method of installation or pipe footage is different from what was planned and would result in higher cost to the Company.

4.25. **Marking Service Locations on Curb**

4.25.1. Chisel a "G" on the top of curb or sidewalk where service crosses the curb or sidewalk.

Note:	**Not all entities allow this practice**. Before chiseling a "G" on the top of curb or sidewalk, check with your local inspector.

4.26. **Service Converted to Main-Identification**

4.26.1. Install two harness rings on the service shut off when a portion of the service is converted to main. (Example: main extension installed in parkway from an existing service to avoid cutting pavement.) See **GS 223.0415**, *Pipeline and Related Definitions*.

4.27. **Cathodic Protection**

4.27.1. For steel pipe installation and cathodic protection (CP), see **GS 186.0002**, *Design and Application of Cathodic Protection*.

4.27.2. For existing steel services that will be tied over to a PE main as the result of a main replacement, see **GS 186.0005**, *Cathodic Protection - Mixed Piping System*.

4.28. **Tracer Wire Installation**

4.28.1. Follow the installation guidelines for locating wire when installing, replacing, and/or repairing PE piping, see **GS 184.0125,** *Tracer Wire Installation for Polyethylene (PE) Pipe Installations*.

4.29. **Curb Meter Vaults**

> **Note:** Discourage the installation of new business curb meter vaults and only install them if there is no other alternative and all other possible meter locations have been explored. The Project Manager shall approve all meter and service regulator installations in curb meter vaults or other subsurface installations.

4.29.1. Install or extend all existing services in curb meter vaults to an acceptable aboveground location agreed to by the property owner and the Company subject to one or more of the following conditions:

- Routine service replacements initiated by leakage.
- Service replacement and/or tie-overs involved in main replacements due to maintenance, franchise or street improvement projects.
- Repair of broken curb meter vaults or MSA parts.
- Pedestrian hazard, MSA leakage, regulator malfunction, pressure problems, chronic flooding problems, and/or repeat call-backs for service.
- Service alterations due to customer request or houseline leakage.

> **Note**: All work performed due to customer's request-is negotiated as per **GS 191.0090,** *D-Ticket - Collectible Work Agreements*.

4.30. **Warning Mesh Installation**

4.30.1. For pipelines operating at greater than 60 PSIG, see **GS 184.0050,** *General Construction Requirements for Distribution Mains for warning mesh requirements.*

4.31. **Material Traceability**

4.31.1. **For pipelines operating at greater than 60 PSIG,** see **GS 182.0056,** *Material Traceability for High-Pressure Systems.*

- To ensure compliance with "Quality Practices" and "Rejection of Defective" Materials.
- For traceability when materials are altered or segmented in the field.
- To ensure material batch information traceability is captured during installation.

5. EXCEPTION PROCEDURE
(See **GS 182.0004**, *Exception Procedure for Company Operations Standards*)

5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

5.2. An exception from a standard shall not be allowed unless **GS 182.0004**, *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

6. OPERATOR QUALIFICATION COVERED TASKS
(See **GS 167.0100**, *Operator Qualification Program*, Appendix A, *Covered Task List).*

- **Task 01.01. -** 49 CFR 192.319 **-** Installing Transmission Pipelines and Distribution Pipelines in a Ditch.
- **Task 01.02. -** 49 CFR 192.327 **-** Maintaining minimum cover over pipelines.

7. RECORDS

7.1. All records will be noted and retained on appropriate work orders and As-Built drawing.

7.2. Retain original documents in file in compliance with the Corporate Records Retention Schedule.

7.3. Material Traceability

7.3.1. **For pipelines operating at greater than 60 PSIG,** see **GS 192.0026,** Records Management for High Pressure Project Closeout**.**

- To ensure compliance with High Pressure Project Reconciliation Closeout and Turnover.
- For documentation and traceability.

8. APPENDICES

Not Applicable.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: The policy was revised to add clarity for cover below Railroad crossings in Table 1. Removed policy in policy verbiage in section 4.9.1. Added additional reference to section 4.12 for testing pipelines. Update Hyperlinks.

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	01/24/2020
Last Full Review Completed On:	11/14/2017
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
If Merged, Merged To Document Number:	
Utility:	SoCalGas
Department:	Gas System Integrity Staff & Programs
Number of Common Document:	G7460
Confidential Sections:	
Part of SoCalGas O&M Plan:	No
Part of SDG&E O&M Plan:	No
Contains OPQUAL Covered Task:	Yes
OpQual Tasks	01.02 01.01
Last O&M Review date:	
O&M 49 CFR Codes & Impacted Sections of Document:	
Part of Non-O&M Parts 191-193 Plan	Yes
Non-O&M 49 CFR Codes & Impacted Sections of Document	192.503(a): 4.12 192.375(b): 4.19 192.361(f): 4.18 192.361(e): 4.19 192.361(d): 4.6, 4.8, 4.17 192.361(b): 4.5, 4.7, 4.8 192.361(a): 4.6 192.307: 4.8
Part of Distribution IMP (DIMP)	Yes
Part of Transmission IMP (TIMP)	No
Part of Storage IMP (SIMP)	No
Impacts GO112F	Yes
GO112F Codes & Impacted Sections of Document	142.1: 4.9
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	CF, CM, DIMP2, DISTM, MKTG, MS, TRNG
NOP Learning Module (LM) Training Code:	NOP00304

PURPOSE **This gas standard provides the policy and procedures for safely purging natural gas pipelines. All company and contract employees shall follow these guidelines when purging pipeline systems.**

1. POLICY AND SCOPE

1.1. Pipelines are purged to prevent the presence of a combustible mixture of gas and air. Failure to abide by the requirements of this Gas Standard may result in serious or catastrophic consequences.

1.2. This procedure **does not include** purging operations that utilize air movers. For these purges, see GS **187.0103**, *Purging Pipelines Using Air Movers For Cold Tie Operations*.

1.3. The Purging Operation Supervisor shall conduct a meeting, prior to a purging activity, to ensure all personnel engaged in purging operations understand the procedures involved. The Purging Operation Supervisor shall ensure that all employees and contractors involved in purging understand the potential hazards of improper operation. If changes in operations occur, all personnel will be informed of the changes before proceeding.

1.4. Limit access to the work area of the purging operation to only those persons who are necessary to perform the activity, keeping all-non-essential personnel and the public clear of harm's way.

1.5. All personnel directly involved in purging shall be outfitted with personal protective equipment including ear and eye protection, gas monitors, gloves, head protection, etc.

1.6. Gas shall be vented into the atmosphere without hazard to workers, public and property.

1.7. Considerations must be given to the public with regard to objectionable noise and odor as well as any noise or pollution abatement requirements. Such considerations may include the use of noise suppression equipment, notification of law enforcement, Fire Department and Air Pollution Control District.

1.8. All parts and equipment involved in the purging operation shall be in proper working condition and are visually inspected before use.

1.9. Adequate visual and/or radio communications shall be established between all work locations including the injection and venting points.

1.10. Fire extinguishers are manned and readily available at injection, vent, and upwind of the vent location.

1.11. When purging out-of-service follow procedures stated in GS **182.0032**, *Blowdown Time, Sizing, and Volume Calculations* and **Form 3466,** *Reporting of Gas Blown to Atmosphere* to account for the gas lost to atmosphere.

1.12. Any deviation from this Gas Standard shall be reviewed and approved by **Gas Engineering - Pipeline Engineering**.

2. RESPONSIBILITIES AND QUALIFICATIONS

2.1. Only Company personnel qualified through Gas Operations Training may perform these operations. See GS **167.0100,** *Operator Qualification Program*.

2.2. **Distribution Region, Transmission District or Storage Facility Planning Office** Purging Planner, or the District Operations Manager, shall be responsible for preparing the written purging procedures. See **Section 5.4** for further requirements.

2.3. **Region, District, or Storage representatives, as applicable,** are responsible to designate **trained and knowledgeable** supervisors to be responsible for gas handling operations, including purging, within their respected areas.

2.4. **Gas Operations Training** and **Contractors** are responsible for ensuring the equipment and facilities used for training and qualification of employees must be identical, or very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task.

2.5. **Company field employees** are responsible for adhering to Company procedures and shall wear appropriate personal safety equipment during all duties performed. See Injury and Illness Prevention Program **Manual IIPP.4**, *Employee Responsibilities.*

2.6. **Contractors** are responsible for adhering to their Company Safety Procedures / Practices, and are expected to comply with all applicable Federal, State and Local laws, ordinances and regulations to ensure the safety of their employees. See **GS 167.04**, *Contractor Safety Program* and *SCG Contractors Safety Manual – Class 1 Contractors*.

SoCalGas_Contract
orSafetyManual_Cla

2.7. The Purging Operation Supervisor shall verify that all sources of ignition have been identified and eliminated prior to purging gas, performing pressure control operations or bypassing meters. See **GS 166.0025**, *Prevention of Accidental Ignition of Natural Gas*.

2.7.1. **Field Employees** are responsible for ensuring that an approved fire extinguisher (minimum 40 BC) is readily accessible and its location is known at the work site.

2.7.2. **Qualified Operators** are responsible to visually inspect all pressure control equipment prior to performing any pressure control operation. Do not use any damaged or defective equipment. Notify supervision if any defects are found.

3. DEFINITIONS

3.1. **Blow-down -** To reduce pipeline pressure to atmospheric pressure by venting gas to atmosphere.

3.2. **Cursory Odor Sniff Test -** A quick release of natural gas into the atmosphere that is sniffed to determine if odorant is detectible by smell.

3.3. **Direct Purge** – The act of either directly purging gas with air or air with gas at high velocities **without** a nitrogen slug.

3.4. **Indirect Purge** – The act of either purging from gas to air or from air to gas with a nitrogen slug between the air and gas to prevent the formation of a combustible mixture.

3.5. **Purge -** The act of removing all the air from a pipeline and replacing it with natural gas or removing all the natural gas from a pipeline and replacing it with air.

3.6. **Purging out of service** – *(Gas to Air/Nitrogen)* The process of replacing natural gas content in a pipeline with air/nitrogen by injecting air or nitrogen at sufficiently high flow rates.

3.7. **Purging into Service** – *(Air/Nitrogen to Gas)* The process of replacing air or nitrogen content in a pipeline with natural gas by injecting natural gas at sufficiently high flow rates.

3.8. **Purging Operation Supervisor** – The designated trained and knowledgeable supervisor responsible for gas handling operations, including purging.

3.9. **Slug** – As it relates to this standard, is a quantity of nitrogen gas injected between the gas and air during an indirect purge. The slug moves through the pipe as a distinct mass to prevent mixing of the gas and air.

3.10. **Total Displacement Purge** – The act of purging from gas to air or air to gas by injecting an amount of nitrogen slightly greater than the entire internal volume of the pipeline segment or facility to be purged.

3.11. **CGI** – Combustible Gas Indicator

3.12. **BC** – Fire extinguisher rating effective for flammable liquid fires and "live" electrical equipment.

4. REQUIREMENTS PRIOR TO PURGING

4.1. **ISOLATION -** Completely isolate the piping segment to be purged from the system.

4.1.1. Isolation may be accomplished by one or more methods including the use of blind flanges, closing valves, placing blanking discs between flanges, pressure control fittings or physically disconnecting laterals or other sources of gas.

4.1.2. Squeezing of PE pipe may be an acceptable means of isolation for purging. Only Company approved squeeze tools shall be used. *See* **GS 184.0340,** *Squeezing Polyethylene (PE) Pipe – ½" Through 8".*

4.1.3. If valves are used to isolate the section to be purged from the pressurized system, they should be verified to stroke properly and not to leak.

4.1.4. A thorough physical check shall be made to ensure that isolation is prepared as planned and free of leakage prior to the start of the purging operation.

4.2. **NITROGEN -** When using nitrogen as a separating medium (slug) or for Total Displacement Method, practicality, availability and economics determine whether to use cylinders (bottles) or a tank truck. A tank truck is normally the less costly option when a large volume of nitrogen is required.

4.2.1. Standard cylinders typically have 250 standard cubic feet (scf) of nitrogen at 2265 psig.

4.2.2. If an Indirect Purge is required, use **Table A3** in Appendix A to determine the minimum number of cylinders required. If the use of a nitrogen truck is desired, such as when large volumes are required, see **Table A5** in Appendix A to obtain required nitrogen volumes.

4.2.3. If a Total Displacement Purge is required or desired, use **Table A4** in Appendix A to determine the minimum number of cylinders required for a Total Displacement Purge.

5. PROCEDURE

5.1. Selection of Purging Method

5.1.1. **Purging Operation Supervisor** must understand and approve the written procedures to provide a safe and successful completion of the purging operation. See **Section 5.5** for further details about the written plan. **Using Table 1 below, select the proper purging method based on the combination of pipe diameter and length of the segment to be purged.**

Diameter (in)	Length (ft)	Purging Method
$D \leq 4$	Any	Direct (Section 5)
$D \geq 6$	$L < 500$	Direct (Section 5)
$D \geq 6$	$L \geq 500$	Indirect (Section 7)

Table 1

The Total Displacement Method (**Section 3.10**) shall be used when:

- A potential hazard exists due to the presence of liquids or solids
- A potential hazard exists due to a complex piping situation, such as with stubs, or in compressor and regulator stations
- Permanently abandoning a transmission line or main that is not free of liquids or solids, or if required by the permitting agency. See **GS 184.0085,** *Abandonment or Inactivation of Gas Distribution Pipelines*, or **GS 223.0130,** *Abandonment, Conversion and Reinstatement of Transmission Pipelines.*

5.2. Sources of Ignition

5.2.1. All possible sources of ignition shall be eliminated in accordance with **GS 166.0025,** *Prevention of Accidental Ignition of Natural Gas.*

5.2.2. When purging, especially with old piping, it shall be kept in mind that purging removes only gaseous or volatile materials. Undetected liquid or solid combustibles can be ignited by sparks carried back into a purged pipeline when it is cut. Take necessary precautions to ensure removal of difficult to detect combustibles.

5.2.3. Consider purging with the Total Displacement Method with nitrogen if the presence of liquids or solids exists. See **Section 3.10** for definition of Total Displacement Purge.

5.2.4. Care shall be taken to avoid static electrical discharge before, during and after purge by grounding all machinery and equipment where static electricity might accumulate. Pipelines are bonded or grounded before purging, cutting, or disconnecting in accordance with **GS 184.0230**, *Bonding Steel Mains and Services*. Before severing or disconnecting a steel pipe, a bond wire must be attached to the metallic pipe at two points to provide a connection across the proposed severance or disconnection which connects both sides of the remaining pipe. For purging Polyethylene (PE) pipe, see **GS 166.0025**, *Prevention of Accidental Ignition of Natural Gas.*

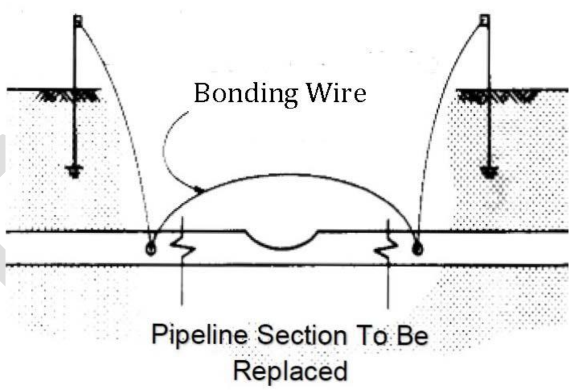


Figure 0. – Bonding wire placed across proposed severance or disconnection

5.2.5. Cathodic protection rectifiers shall be turned off.

5.3. **Venting**

5.3.1. See **Table A1** for vent stack sizing.

5.3.2. The steel vent stack should consist of a full opening tap in the pipeline to be purged.

5.3.3. When a vent valve is used, it shall be full opening.

5.3.4. When selecting venting locations, care is taken to prevent accidental ignition during purging operations. Avoid venting under or in close proximity to overhead power lines, per **GS 182.0161** – *Purging Operations – Minimum Distance Between Purging Stack and Ignition Sources*.

5.3.5. Never discharge purging medium through a plastic vent pipe.

5.3.6. Any project that requires gas blown to atmosphere will build time into the project schedule to reduce methane consistent with safe operations and consider alternative potential sources of supply to reliably serve customers and maintain feasibility. Operating pressure should be reduced to the lowest operationally feasible level in order to minimize methane emissions before non-emergency venting of high-pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations. and whenever practicable, work should be bundled to prevent multiple venting of the same piping.

5.3.7. If a new Transmission pipeline assembly is enclosed with wet canvases, the assembly may be directly purged into service using one canvas end as a vent provided that:

- When purging through a wet canvas, the canvas opening should be approximately ⅓ of the cross-section of the pipe. The opening is at the bottom when purging into service. See GS 223.016, *Temporary End Closures.*

5.4. Planning a Purge

5.4.1. Use **Table A1** in **Appendix A** to obtain the standard purging parameters for specific pipe diameters:

- These parameters include the standard injection fittings, injection pressures, vent sizes and flow rates.
- If orifices are to be utilized, use the required minimum flow rates from **Table A1**. Select the appropriate orifice size and inlet pressure based on required flow rates.
- Place the orifice immediately upstream of the injection fitting to eliminate any unplanned pressure drop.
- Orifices are normally placed in screwed orifice unions, but a tapped abandonment fitting can also be used. Injection and bypass fittings selected shall not have an internal diameter smaller than the hose or orifice to be used. See **Figure 6** for typical orifice set-up.

5.4.2. When using an orifice, the pressure gauge to measure minimum pressure should be installed just upstream of the orifice. The tapped diameter when using an abandonment fitting needs to be equal to or greater than the orifice size.

5.4.3. Use **Table A2** in **Appendix A** to obtain an approximate arrival time at specific lengths when using a standard set up. When indirectly purging, this time indicates the arrival of the slug.

5.4.4. When purging out of service using an air compressor, make certain that the selected compressor is rated with at least 15% more flow rate capacity than the minimum flow rate listed in **Table A1**.

5.4.5. When possible, purge from air/nitrogen to gas downhill, and purge from gas to air/nitrogen uphill.

5.4.6. A piping system containing loops or branches requires a detailed evaluation to ensure each pipe section is properly isolated and purged which typically requires isolating and purging in stages.

5.5. **Written Plan**

5.5.1. An approved written plan shall be available for all purging procedures.

5.5.2. Service lines and small diameter pipelines can be purged using the general procedures of this gas standard as the written plan. More complex purging operations require a specific detailed written plan.

5.5.3. The written plan shall include, but is not limited to, the required purging method, location of isolation points, injection set up, injection pressures and flow rates, venting location and stack size, operational sequences, an equipment list (model of gas scope, air compressor, etc.) and provisions for a communication system.

5.6. **Non-Typical Purging Operations**

5.6.1. When purging a service that has an Excess Flow Valve installed; see **GS 187.0146**, *Excess Flow Valve (EFV) - Installation and Operation.*

5.6.2. Certain small diameter and lengths of mains and services do not require purging prior to abandonment, see **GS 184.0080**, *Abandonment of Gas Services and Gas Light Tap Assemblies*, and **GS 184.0085**, *Abandonment or Inactivation of Gas Distribution Pipelines.*

5.6.3. Air Movers may be used for purging large diameter (≥ 8”) pipelines out of service; see GS **187.0103**, *Purging Pipelines Using Air Movers For Cold Tie-In Operations.*

5.6.4. If a standard indirect purge is not practical or possible, in cases such as long pipeline lengths yielding unreasonable purging times or if the use of larger injection fittings and/or vents is desired, contact **Gas Engineering - Pipeline Engineering** for analysis.

5.6.5. All non-standard purges require a written plan approved by **Gas Engineering - Pipeline Engineering**.

6. PURGING OUT OF SERVICE USING THE DIRECT PURGE METHOD (GAS TO AIR)

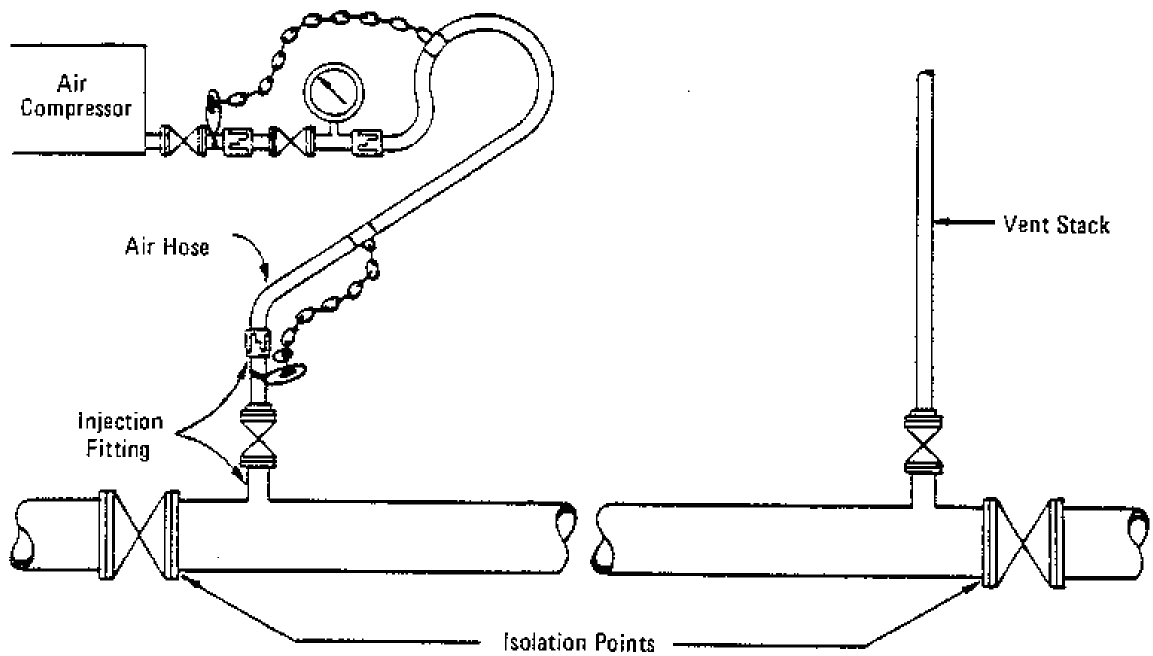


Figure 1. - Arrangement for Directly Purging Gas from Pipelines.

6.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all Company policies are adhered to. See **Section 5.5**.

6.2. Remove all ignition sources in accordance with **Section 5.2**.

6.3. Isolate section of line to be purged. See **Section 4.1**.

6.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level. See **Figure 1**.

6.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. Connect air hose and valve to pressure gauge. See **Figure 1**.

6.6. Connect gauge and valve end of air hose to air compressor and attach other end of hose to injection fitting. See **Figure 1**.

6.7. Open valve on vent stack and blow down line.

6.8. With the air compressor valve open, gradually open the valve on injection fitting and inject air. Inject at or above the minimum injection pressure. Injection of air shall be continued without interruption until the pipeline is purged of all gas. Control pressure with valve attached to compressor end of air hose. See **Figure 1**.

6.9. Stop injection of air when pipeline is purged of all gas. Use an approved combustible gas indicator to verify pipeline is 100% air. See **GS 107.0287**, *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or **GS 223.0160**, *Use of Portable Ranarex Gravitometers/Check Purges*.

7. PURGING INTO SERVICE USING THE DIRECT PURGE METHOD (AIR/NITROGEN TO GAS)

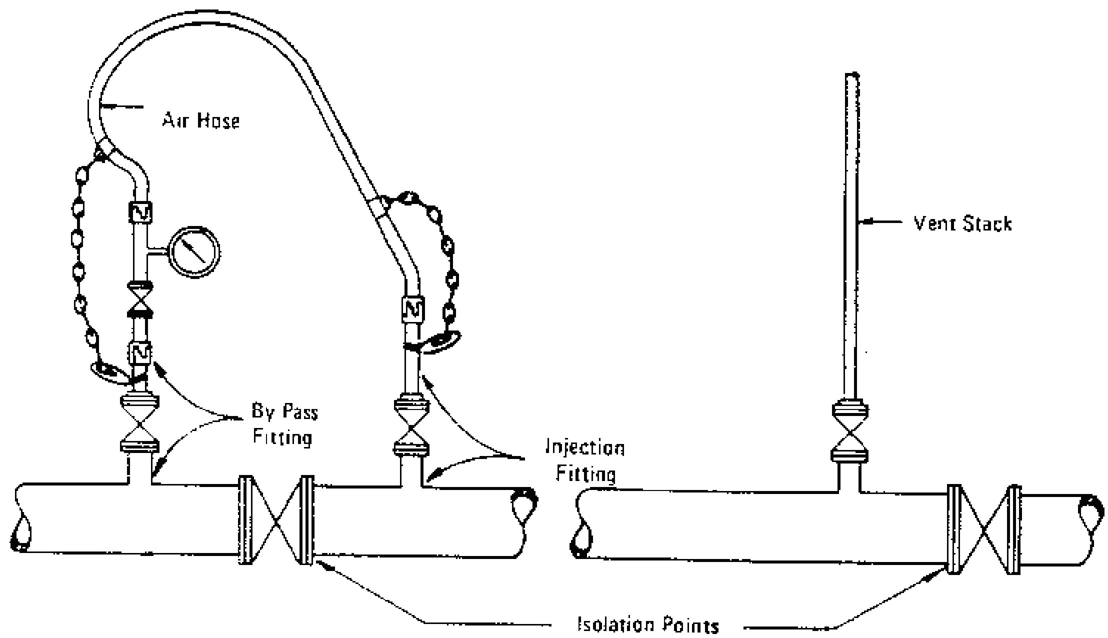


Figure 2 - Arrangement for Directly Purging Pipelines into Service.

7.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.

7.2. Remove all ignition sources in accordance with **Section 5.2**.

7.3. Isolate section of line to be purged. See **Section 4.1**.

7.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level. See **Figure 2**.

7.5. Install injection fitting as close as practical to, but not more than 5 feet away from the injection end of pipeline. See **Figure 2**. If available, gas may be injected by opening a line valve instead of using a bypass, however, contact **Gas Engineering - Pipeline Engineering** to obtain the downstream pressure needed to control the purge.

7.6. If needed, install bypass fitting on live pipeline for gas source. See **Figure 2**.

7.7. Connect gauge and valve to bypass fitting. Connect an air hose or pressure hose from pressure gauge end to injection fitting. See **Figure 2**.

7.8. Open valve on vent stack.

7.9. Gradually open valve on injection fitting and inject gas. Inject at or above the minimum injection pressure. Injection of gas shall be continued without interruption until the pipeline is purged of all air. Control pressure with valve attached to bypass fitting. See **Figure 2**.

7.10. Stop injection of gas when pipeline is purged of air. Use an approved combustible gas indicator to verify pipeline is 100% gas. See **GS 107.0287**, *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or **GS 223.0160**, *Use of Portable Ranarex Gravitometers/Check Purges*.

A ***cursory odor sniff test*** shall be performed immediately after the purging process and verifying 100% gas is obtained.

7.11. For purging directly into service with high volume tapping tee and gas services less than 2” see **Section 12**.

8. PURGING OUT OF SERVICE USING THE INDRECT PURGE METHOD (GAS TO AIR)

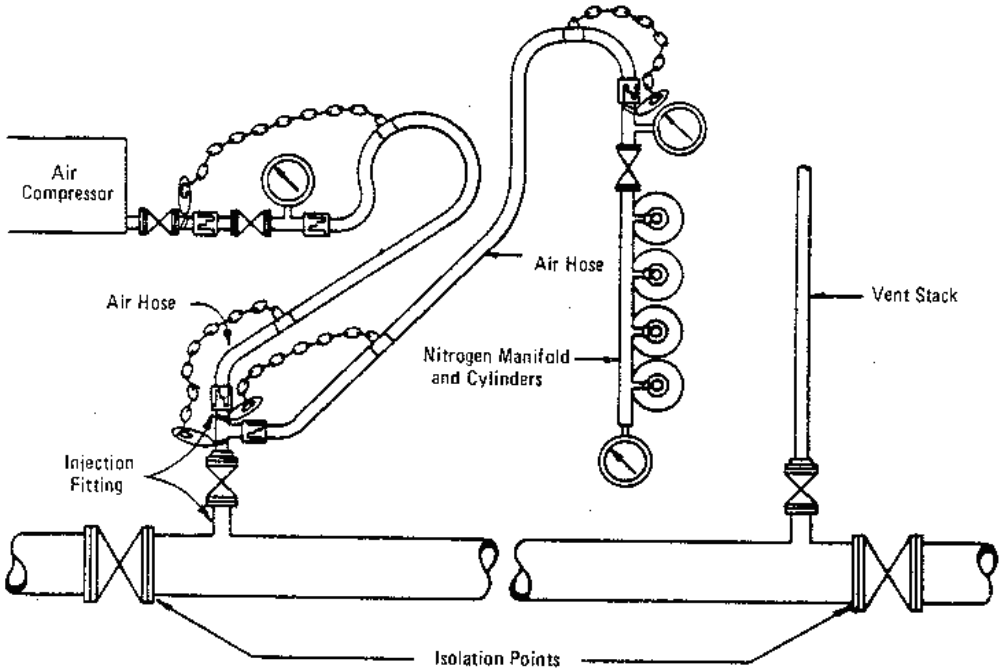


Figure 3. Arrangement for Purging Out of Service using Indirect Method

8.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.

8.2. Remove all ignition sources in accordance with **Section 5.2**.

8.3. Isolate section of line to be purged. See **Section 4.1**.

8.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level. See **Figure 3**.

8.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. See **Figure 3**.

8.6. Connect gauge and valve to air compressor and attach hose from the other end of the injection fitting. See **Figure 3**.

8.7. If nitrogen cylinders are to be used, connect the nitrogen cylinders to the manifold. Close valve on manifold and open valves on nitrogen cylinders. See **Figure 3**.

8.8. Connect manifold hose or high-pressure hose to injection fitting. See **Figure 3**.

8.9. Open valve on vent stack and allow pipeline to blow-down.

8.10. Once the pipe segment has been blown down, gradually open valve on injection fitting.

Note: Verify this valve is open to prevent damage to the gauge on the manifold.

8.11. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure controlling pressure with the manifold valve. See **Figure 3**.

8.12. Begin injecting air as soon as the minimum gauge pressure of nitrogen, cannot be maintained. Close valve on nitrogen manifold immediately after air injection has started. Air must be injected at or above the minimum gauge pressure. Control pressure with valve attached to compressor end of air hose. See **Figure 3**.

8.13. Stop injection of air when pipeline is purged of gas. Use an approved combustible gas indicator to verify pipeline is 100% air. See **GS 107.0287**, *GMI Gasurveyor – Combustible Gas Indicator (CGI)* and or **GS 223.0160**, *Use of Portable Ranarex Gravitometers/Check Purges*.

9. PURGING INTO SERVICE USING THE INDIRECT PURGE METHOD (AIR TO GAS)

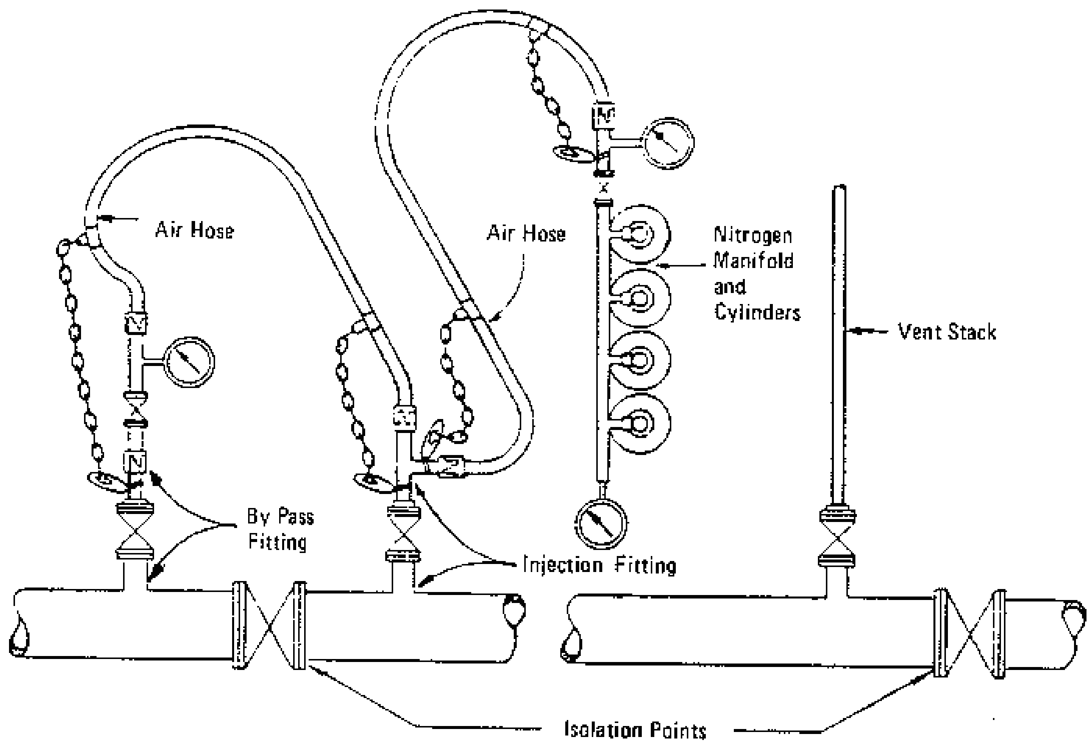


Figure 4. Arrangement for Purges into Service using Indirect Method

9.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.

9.2. Remove all ignition sources in accordance with **Section 5.2**.

9.3. Isolate section of line to be purged. See **Section 4.1**.

9.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level. See **Figure 4**.

9.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. See **Figure 4**. If available, gas may be injected by opening a line valve instead of using a bypass, however, contact **Gas Engineering - Pipeline Engineering** to obtain the downstream pressure needed to control the purge.

9.6. If needed, install bypass fitting on pipeline as a gas source. See **Figure 4**.

9.7. Connect gauge and valve to bypass fitting. Connect an air hose from pressure gauge end to injection fitting. See **Figure 4**.

9.8. Connect nitrogen cylinders to the manifold. Close valve on manifold and open valves on nitrogen cylinders.

9.9. Connect manifold hose or high-pressure hose to injection fitting. See **Figure 4**.

9.10. Open valve on vent stack.

9.11. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure controlling pressure with the manifold valve. See **Figure 4**.

9.12. Begin injecting gas as soon as the minimum gauge pressure of nitrogen, cannot be maintained. Close valve on nitrogen manifold immediately after gas injection has started. Gas must be injected at or above the minimum gauge pressure. Control pressure with valve attached to bypass fitting. See **Figure 4**.

9.13. Stop injection of gas when pipeline is purged of air. Use an approved combustible gas indicator to verify pipeline is 100% gas. See **GS 107.0287**, *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or **GS 223.0160**, *Use of Portable Ranarex Gravitometers/Check Purges*.

A ***cursory odor sniff test*** shall be performed immediately after the purging process and verifying 100% gas is obtained.

.

10. PURGING OUT OF SERVICE USING THE TOTAL DISPLACEMENT METHOD (GAS TO NITROGEN)

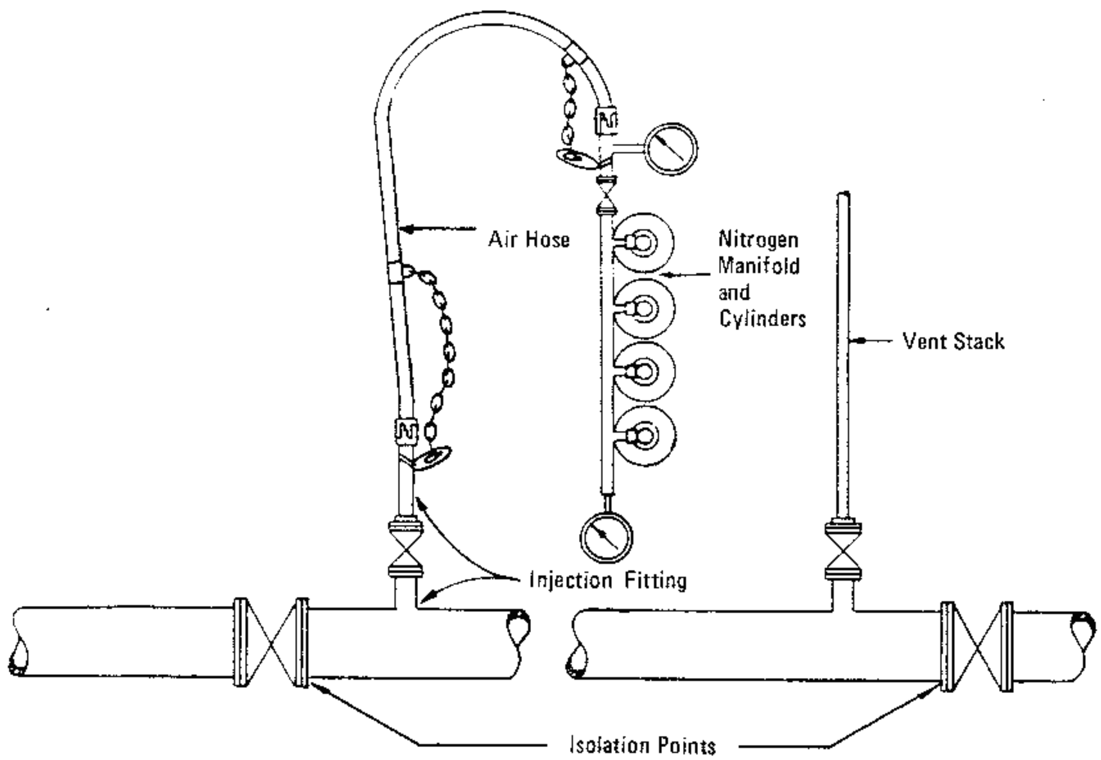


Figure 5. Arrangement for Purging Out of Service using Total Displacement Method

10.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.

10.2. Remove all ignition sources in accordance with **Section 5.2.**

10.3. Isolate section of line to be purged. See **Section 4.1**.

10.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level.

10.5. Install injection fitting as close as practical from the injection end of pipeline.

10.6. If nitrogen cylinders are to be used, connect the nitrogen cylinders to the manifold. Close valve on manifold and open valves on nitrogen cylinders. See **Figure 5**.

10.7. Connect manifold hose to injection fitting. See **Figure 5**.

10.8. Open valve on vent stack and blow-down the pipeline.

10.9. Once the pipe segment is blown-down, open valve on injection fitting. Be sure this valve is open to prevent damage to the gauge on the manifold. See **Figure 5**.

10.10. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure controlling pressure with the manifold valve. See **Figure 5**.

10.11. Stop injection of nitrogen when pipeline is purged of gas. Use an approved combustible gas indicator to verify pipeline is purged of all gas. See **GS 107.0287**, *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or **GS 223.0160**, *Use of Portable Ranarex Gravitometers/Check Purges*.

10.12. Sections with pipe left with 100% nitrogen must be stenciled "Nitrogen". Also adjourning valves must be stenciled "Nitrogen".

11. TYPICAL ORIFICE SET UP (DIRECT PURGE)

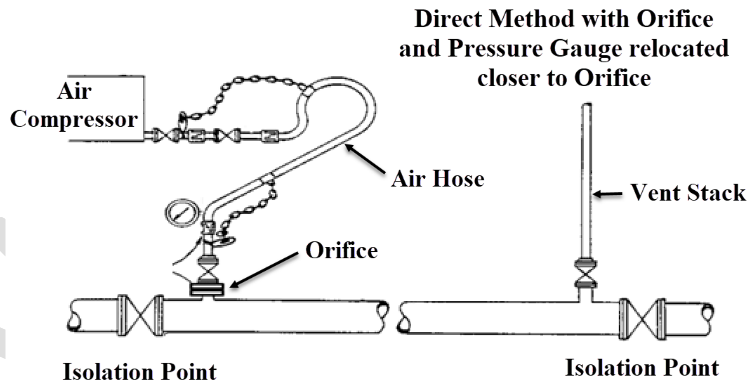


FIGURE 6

12. ADDITIONAL REQUIREMENTS FOR PURGING POLYETHYLENE (PE) PIPE

CAUTION:	**Squeezers are never used as a control valve during purging operations.**

12.1. Use one of the following methods when purging PE pipelines:

- A service riser without an EFV shall be used to purge a PE main. Install a temporary service-to-main connection (SMC) within 1 ft of the end of the main. A minimum 18" long steel nipple shall be installed in the service valve to help protect employees in the event of ignition.
- An anodeless riser shall be grounded with metallic grounding cable such as, but not limited to, a bond wire or jumper cable. Care shall be taken to avoid static electrical discharge before, during and after the purge by grounding all machinery and equipment where static electricity might accumulate.
- Purge through a purge assembly. Purge assemblies may be fabricated in the field, see **Figure 7** below.
- A purge assembly shall end with steel pipe, which is grounded, and the unit shall contain some method of positive control such as a service valve or ball valve.
  - A minimum 18" long vertical steel nipple should be installed in the service valve to help protect employee in the event of ignition
  - Fuse purge assembly to main
  - Ground purge stack and secure purge assembly from movement
  - Select the applicable purge operation, (e.g., direct purge from air to gas)

12.2. Use an approved combustible gas indicator to determine if pipeline is completely purged. See **GS 107.0287**, *GMI Gasurveyor – Combustible Gas Indicator (CGI)* and or **GS 223.0160**, *Use of Portable Ranarex Gravitometers/Check Purges*.

Abandon purge assembly if required. If a service-saddle or tapping tee was used, install appropriate protective sleeve over stub.

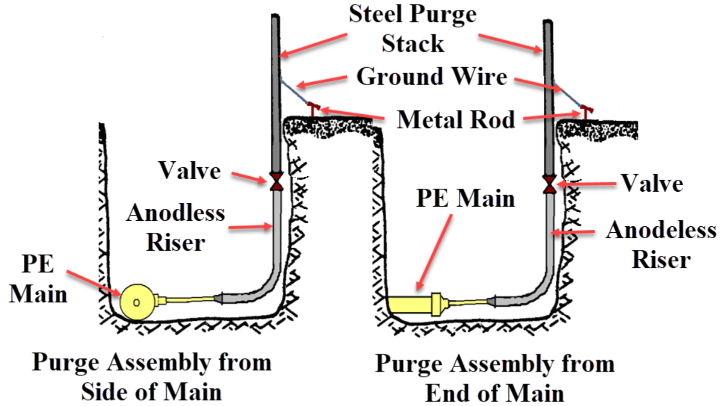


FIGURE 7

13. SPECIAL INSTRUCTION FOR PURGING DIRECTLY INTO SERVICE USING A HIGH-VOLUME TAPPING TEE AND FOR GAS SERVICES LESS THAN 2” DIAMETER

13.1. **Direct purging into service a new 2-inch diameter medium pressure PE Main using a high-volume tapping tee as a pressure control fitting connected from 6” or 8” header main**

13.1.1. Use the high-volume tapping tee as a pressure control fitting. It is not necessary to use a 50 ft. bypass hose to directly purge the new main into service. The high-volume tapping tee will become the purge source.

13.1.2. Install the high-volume tapping tee in accordance with GS **184.0115**, *Tapping/ Stopping PE Fittings*.

13.1.3. Tie new main onto the high volume tapping tee and leak test per GS **184.0150**, *Leak Testing of Distribution Piping with MAOP <= 60 PSIG*.

13.1.4. Blow down the medium used for leak testing.

13.1.5. Ensure vent-stack is in place, grounded and control valve is open. See **GS 166.0025**, *Prevention of Accidental Ignition of Natural Gas* for proper grounding and to verify all potential sources of ignition are eliminated.

NOTE: Using a properly sized 50 ft. bypass hose is also allowed, but squeezing the 2" PE pipe next to the outlet of the high-volume tapping tee will be needed. Squeezing needs to be performed before directly purging the new main into service in order isolate "back fed" gas from the bypass connection. The squeezer can be released after the high-volume tapping tee has been installed, tapped, capped, and sealed.

13.1.6. Ensure the ratchet wrench is grounded then place tapping tool and start tapping per GS **184.0115** *Tapping/Stopping PE Fittings*. Thread the cutter down until it seats in the main to effectively shut off the gas flow.

13.1.6.1. The high-volume tapping tee will now act as a pressure control fitting to directly purge the new main into service.

13.1.7. The crew member located at the vent stack is to maintain the control valve fully open and ready for the purge to commence.

13.1.8. Begin the purge discharge (at the riser outlet) by backing off the high-volume tapping tee and introducing natural gas to the new 2" main.

13.1.9. Confirm the purge is complete by verifying 100% gas at the vent location using a Company approved combustible gas indicator at the vent location. See **GS 107.0287**, *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or **GS 223.0160**, *Use of Portable Ranarex Gravitometers/Check Purges*.

13.1.10. After a complete purge has been confirmed, close the control valve. The new main is now pressurized and purged into service.

13.2. **Direct purging of steel gas services less than 2" diameter can be accomplished using a service tee or pin-off tee as the purge source.**

14. PURGING SERVICES LINES THROUGH RISERS

CAUTION: **The greatest potential hazard of static electricity is when gas is being vented to the atmosphere at high velocity. Care shall be taken to avoid static electrical discharge before, during and after purge by grounding all machinery and equipment where static electricity might accumulate. See GS 166.0025, *Prevention of Accidental Ignition of Natural Gas* to address this hazard**.

14.1. See **Section 12** for additional requirements when purging a Polyethylene (PE) pipeline.

14.2. Keep public clear of the area. If pedestrian encroachment is anticipated, post warning signs, barricades, etc., to deter persons from entering area.

14.3. Verify service valves are in the closed position.

14.4. Remove the threaded plug from the closed service valve of the service riser and install a purge stack or purge bag.

14.5. Insert grounding rod into earth. Whenever possible, moisten the soil around the grounding rod to increase the grounding effect.

14.6. Connect one end of a ground wire to the purge stack and the other end to a grounding rod.

14.7. Direct the blowing of air, gas and possible debris into the open atmosphere, away from workers, the public and private property. Exhaust gas away from buildings, equipment, enclosures and any possible sources of ignition, including overhead power lines.

14.8. If it is anticipated that an extensive amount of purging is to take place, dispatch should be notified of possible area odor complaints.

14.9. When an Excess Flow Valve (EFV) has been installed, open the service valve slowly and sufficiently to near the maximum flowrate that can be achieved without tripping the EFV. If the EFV trips during purging, wait for the EFV to re-set, and repeat the purge process again at a slightly slower flowrate. Refer to **GS 187.0146**, *Excess Flow Valve (EFV) - Installation and Operation*, for reset time based on pressure, size and length of service.

14.10. For Service Lines without an EFV, open the service valve quickly to purge.

14.11. Use an approved combustible gas indicator to determine if pipeline is completely purged. See **GS 107.0287**, *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or **GS 223.0160**, *Use of Portable Ranarex Gravitometers/Check Purges*.

A ***cursory odor sniff test*** shall be performed immediately after the purging process and verifying 100% gas is obtained.

> **Note:** If gas odor is not detectable by smell, notify supervision. If situation cannot be resolved, supervision is to contact the Region Engineer.

14.12. Close the service valve and remove the purge stack and grounding wire.

14.13 Replace the threaded plug in the closed service valve and soap test for leaks, per GS **184.0150**, *Leak Testing of Distribution Piping with MAOP <= 60 PSIG*.

15. OPERATOR QUALIFICATION COVERED TASKS
(See GS **167.0100**, *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 07.01 -** 49 CFR 192.629 – Purging pipelines
- **Task 16.02 -** 49 CFR 192.745 – Inspecting, operating, and maintaining transmission pipeline valves
- **Task 16.03 -** 49 CFR 192.747 – Inspecting, operating, and maintaining distribution system valves

16. EXCEPTION PROCEDURE
See **STANDARD 182.0004**, *Exception Procedure for Company Operations Standards*)

16.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

16.2. An exception from a standard shall not be allowed unless **GS 182.0004**, *Exception Procedure for Company Operations Standards,* is followed and approval is given by those as required by 182.0004.

17. RECORDS

Not Applicable.

18. APPENDICES

18.1. Appendix A

APPENDIX A

Table A1
Minimum Equipment Requirements for Purging Pipeline

Nominal Pipe Size (inches)	Hose Diameter** (inches)	Minimum Nominal Stack Stack Size*** (inches)	Minimum Gauge Pressure * Gas (psig)	Nitrogen/Air (psig)	Minimum Injection Flow Rate (SCFM)
4 and less	¾	3/4	3	3	11
6	¾	1 -1/2	6	8	29
8	¾	1 -1/2	15	18	56
10	¾	2	28	35	96
12	¾	3	47	59	149
16	1 1/4	3	19	26	273
18	1 1/4	4	28	40	367
20	1 1/4	4	41	55	489
22	1 1/4	4	55	75	615
26	2	6	21	30	930
30	2	6	32	45	1331
34	2	6	45	65	1821
36	2	6	54	77	2117

* Pressures listed are based upon placing a pressure gauge 50 feet upstream of the injection point. Shorter distances yield greater injection rates and shorten purge durations. Contact **Gas Engineering - Pipeline Engineering** if hose distances are greater than 50 feet.

** If it's necessary to use a Hose Diameter larger than specified, contact **Gas Engineering** - **Pipeline Engineering** for the lower required minimum gauge pressure.

*** For vents in excess of 10 ft long, go to next larger pipe size. Multiple vent stacks are allowed if a single vent stack does not meet the minimum requirements. The total internal flow area of the multiple vents needs to be greater to the internal flow area of the required vent size. Contact **Gas Engineering - Pipeline Engineering** for guidance on correct combinations of vent stacks.

Note: The diameter of manifolds should at least be equal to the hose diameter required for purging.

Table A1*

Measuring Rates Through Orifices
Use these figures for measuring the injection rates while purging.
(Note: All Hose and Orifice Sizes are Internal Diameters)

Inject Rate (cfm)	Pressure Upstream of Orifice (psig) (Note: All Hose and Orifice Sizes are Internal Diameters)									
	Orifice Size (inches)									
	3/8		1/2		5/8		3/4		7/8	
	Gas	N_2 Air	Gas	N_2 Air	Gas	N_2 Air	Gas	N_2 Air	Gas	N_2 Air
10										
20										
40	7	12								
60	19	26	5	8						
80	30	39	11	16	2	5				
100	41	53	18	24	6	10				
120	52	67	25	31	10	14				
140	63	80	31	39	14	19				
160	75	94	38	47	19	24				
180	86	107	44	54	23	29				
200	97	121	51	62	27	34				
220	106	136	53	70	29	39	17	22	9	13
240	117	150	59	78	33	44	20	26	11	15
260	128	163	66	85	37	49	22	29	13	18
280	139	177	72	93	41	54	25	33	15	20
300	150	191	78	101	45	59	28	36	17	23
320	161	205	84	109	49	64	31	39	19	25
340	172	218	90	116	53	69	34	43	21	28
360	183	232	97	124	57	74	37	46	24	30
380	194	246	103	132	61	78	40	50	26	33
400	205	259	109	139	65	83	43	53	28	35
420	216	273	115	147	69	88	45	56	30	38
440	227	287	121	155	73	93	48	60	32	40
460	238	301	128	163	77	98	51	63	34	43
480	249	314	134	170	81	103	54	67	36	45
500	260	328	140	178	85	108	57	70	39	48
550	286	362	156	197	95	120	61	79	41	53
600	314	397	171	217	105	133	68	87	46	59
650	341	431	187	236	115	145	75	96	51	65
700	369	465	202	255	125	157	82	104	56	71
750	396	500	218	275	135	170	89	113	62	77
800	423	534	233	294	145	182	95	121	67	83
850	451	568	249	313	155	194	102	130	72	90
900	478		264	332	165	206	109	138	77	96
950	506		280	352	175	219	116	147	82	102
1000	533		295	371	185	231	123	155	87	108
1050	560		311	390	195	243	130	164	92	114
1100	588		326	410	205	256	137	172	97	120
1150			342	429	215	268	144	181	102	126
1200			357	448	225	280	151	189	107	133
1250			373	468	235	293	158	198	113	139
1300			388	487	245	305	164	206	118	145
1350			404	506	255	317	171	215	123	151
1400			419	525	265	329	178	223	128	157
1450			435	545	275	349	185	232	133	163
1500			450	564	285	354	192	240	138	170
1550			466	583	295	366	199	249	143	176
1600			481		305	379	206	257	148	182
1650			497		315	391	213	266	153	188
1700			512		325	403	220	274	158	194
1750			528		335	416	227	283	164	200
1800			543		345	428	233	291	169	206
1850			559		355	440	240	300	174	213
1900			574		365	452	247	308	179	219
1950			590		375	465	254	317	184	225
2000					385	477	261	325	189	231
2050					395	489	268	334	194	237
2100					405	502	275	342	199	243

Table A1 (continued)*

Measuring Rates Through Orifices

Use these figures for measuring the injection rates while purging.

(Note: All Hose and Orifice Sizes are Internal Diameters)

Pressure Upstream of Orifice (psig) (Note: All Hose and Orifice Sizes are Internal Diameters)								
	Orifice Size (inches)							
Inject Rate (cfm)	1-1/8		1-3/8		1-1/2		1-3/4	
	Gas	N_2 Air	Gas	N_2 Air	Gas	N_2 Air	Gas	N_2 Air
10								
20								
40								
60								
80								
100								
120								
140								
160								
180								
200								
220		2						
240		3						
260	2	5						
280	3	6						
300	4	8						
320	5	9						
340	7	11						
360	8	12						
380	9	14						
400	11	15						
420	12	17						
440	13	18						
460	14	20						
480	16	21						
500	17	23						
550	20	26	9	13				
600	23	30	11	15				
650	26	34	13	18				
700	29	38	15	20				
750	32	41	17	23				
800	35	45	19	25				
850	39	49	22	28				
900	42	53	24	30				
950	45	56	26	33				
1000	48	60	28	35	18	26	9	15
1050	51	64	30	38	20	28	10	17
1100	54	68	32	40	21	30	11	18
1150	57	71	34	43	23	32	13	20
1200	61	75	37	45	25	34	14	21
1250	64	79	39	48	26	36	15	23
1300	67	83	41	50	28	38	16	24
1350	70	86	43	53	30	40	17	26
1400	73	90	45	55	31	42	19	27
1450	76	94	47	58	33	44	20	29
1500	80	98	50	60	35	47	21	30
1550	83	101	52	63	36	49	22	32
1600	86	105	54	65	38	51	23	33
1650	89	109	56	68	39	53	25	35
1700	92	113	58	70	41	55	26	36
1750	95	116	60	73	43	57	27	38
1800	98	120	62	75	44	59	28	39
1850	102	124	65	78	46	61	29	41
1900	105	128	67	80	48	63	31	42
1950	108	131	69	83	49	65	32	44
2000	111	135	71	85	51	67	33	45
2050	114	139	73	88	53	69	34	47
2100	117	143	75	90	54	71	35	48

Table A2**

Pipe Size	Estimated Duration of Purge (min) Length of Pipe (feet)									
(in.)	1000	2000	3000	4000	5000	6000	8000	10000	20000	50000
4 and less	8	16	24	32	40	48	64	80	160	400
6	8	16	23	31	39	46	62	77	154	385
8	7	14	20	27	34	40	54	67	134	334
10	6	12	18	25	31	37	49	61	122	303
12	6	11	17	22	28	34	45	56	111	278
16	5	10	15	19	24	29	38	48	96	238
18	5	9	14	18	23	28	37	46	91	228
20	5	9	13	17	22	26	34	43	85	213
22	4	8	13	16	21	25	33	41	82	205
26	4	8	12	15	19	23	30	38	76	189
30	4	7	11	14	18	21	28	35	70	176
34	4	7	10	13	17	20	27	33	66	164
36	3	7	10	13	16	19	26	32	64	159

Values of time for length not shown may be interpolated. For assistance with interpolation, contact **Gas Engineering - Pipeline Engineering.

Table A3
Number of Nitrogen Cylinders (250 Cubic Feet Each) Required To Form Slug in Pipeline
Indirect Method

Pipe Size (inches)	Pipe Length (ft)									
	500**	1000	2000	3000	4000	5000	7500	10,000	20,000	50,000
4	1	1	1	1	1	1	1	1	1	1
6	1	1	1	1	1	1	1	1	1	2
8	1	1	1	1	1	1	1	1	2	2
10	1	1	1	1	1	2	2	2	2	3
12	1	1	2	2	2	2	2	2	3	4
16	2	2	2	2	3	3	3	4	5	7
18	2	2	3	3	3	4	4	5	6	9
20	2	3	3	4	4	4	5	6	7	11
22	3	3	4	4	5	5	6	7	9	13
26	4	4	5	6	6	7	8	9	12	18
30	5	5	7	8	8	9	11	12	16	24
34	6	7	9	11	12	13	15	17	23	35
36	7	8	10	12	13	15	17	19	26	39

** Pipelines less than 500 ft may be displaced directly with air or gas. Please refer to **Table 1** "Purging Method" in this Gas Standard for additional guidance.

Table A4
Number of Nitrogen Cylinders (250 Cubic Feet Each) Required To Fill Pipeline
Total Displacement Method

Pipe Size (inches)	Pipe Length (ft) 500	1000	2000	3000	4000	5000	6000	8000	10,000	20,000	50,000
2	1	1	1	1	1	1	1	1	2	3	5
3	1	1	1	1	1	2	2	2	3	5	11
4	1	1	1	2	2	3	3	4	5	9	19
6	1	1	2	3	4	5	6	8	10	19	*42
8	1	2	4	5	7	9	10	13	17	*33	*74
10	2	3	6	8	11	13	16	21	26	*52	*116
12	2	4	8	11	15	19	22	29	*37	*73	*164
16	3	6	12	17	23	28	*34	*45	*56	*112	*254
18	4	8	15	22	29	*36	*43	*58	*72	*143	*325
20	5	9	18	27	*36	*45	*54	*72	*89	*178	*405
22	6	11	22	*33	*44	*55	*66	*87	*109	*217	*494
26	8	16	31	*46	*62	*77	*92	*123	*154	*307	*696
30	11	21	*42	*62	*83	*103	*124	*165	*206	*411	*934
34	14	27	*54	*80	*107	*133	*160	*213	*266	*531	*1206
36	15	30	*60	*90	*120	*150	*179	*239	*299	*597	*1356

* Consider using a nitrogen truck for purges. See Table A5 for volume in SCF.

■

Table A5
Volume (SCF) of Nitrogen Required To Form Slug in Pipeline
Indirect Method

Pipe Size (inches)	*Pipe Length in Feet 2000	3500	5000	7500	10,000	20,000	50,000
12	263	321	368	433	486	653	985
16	430	527	605	712	802	1080	1632
18	553	677	777	915	1030	1387	2097
20	689	844	968	1139	1283	1728	2611
22	831	1017	1168	1375	1548	2085	3151
26	1162	1424	1633	1923	2165	2916	4406
30	1546	1895	2173	2561	2880	3880	5863
34	2204	2722	3137	3711	4189	5677	8630
36	2480	3067	3531	4179	4716	6391	9714

*Consider using bottles for smaller diameters and shorter lengths.

Table A6
Volume (SCF) of Nitrogen Required To Fill Pipeline
Total Displacement Method

Pipe Size (inches)	Pipe Length in Feet 500	1000	2000	3000	4000	5000	6000	8000	10,000	20,000	50,000
6	*116	*231	*461	*691	*921	*1,151	*1,381	*1,840	*2,300	4,600	11,498
8	*202	*403	*805	*1,206	*1,608	*2,010	*2,412	*3,215	4,019	8,037	20,091
10	*320	*639	*1,277	*1,915	*2,552	*3,190	*3,828	5,104	6,379	12,758	31,893
12	*451	*902	*1,802	*2,703	*3,604	4,504	5,405	7,206	9,007	18,014	45,032
16	*699	*1,397	*2,792	4,188	5,584	6,979	8,375	11,166	13,957	27,914	69,782
18	*894	*1,786	*3,571	5,357	7,142	8,927	10,712	14,283	17,853	35,705	89,261
20	*1,112	*2,224	4,447	6,670	8,893	11,116	13,339	17,784	22,230	44,459	111,147
22	*1,357	*2,713	5,425	8,136	10,848	13,560	16,272	21,695	27,119	54,237	135,591
26	*1,915	*3,828	7,655	11,482	15,309	19,136	22,964	30,618	38,272	76,543	191,355
30	*2,568	5,134	10,268	15,401	20,534	25,668	30,801	41,068	51,334	102,668	256,668
34	*3,316	6,632	13,262	19,893	26,523	33,154	39,784	53,045	66,307	132,612	331,529
36	*3,729	7,457	14,912	22,368	29,823	37,279	44,734	59,645	74,557	149,112	372,779

* Consider using bottles for purges.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Fully reviewed. Re-structured and re-formatted the standard for clarity, added/revised Sections 12, 13, and 14. Provided additional clarity on CGI requirements for purging operations, and various editorial changes.

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	09/01/2019
Last Full Review Completed On:	07/30/2019
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
If Merged, Merged To Document Number:	
Utility:	SoCalGas
Department:	Gas Engineering
Number of Common Document:	G7909
Confidential Sections:	
Part of SoCalGas O&M Plan:	Yes
Part of SDG&E O&M Plan:	No
Contains OPQUAL Covered Task:	Yes
OpQual Tasks	07.01 16.02 16.03
Last O&M Review date:	2019-09-24
O&M 49 CFR Codes & Impacted Sections of Document:	192.727(e): Entire Doc 192.727(c): Entire Doc 192.727(b): Entire Doc 192.629(b): Entire Doc 192.629(a): Entire Doc 192.605(b)(6): Entire Doc 192.605(b)(5): Entire Doc
Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	No
Part of Transmission IMP (TIMP)	No
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
GO112F Codes & Impacted Sections of Document	
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	CF, CM, DISTM, MR, MS, PC, PCF, STOR, TRAN, TRNG
NOP Learning Module (LM) Training Code:	NOP00250

PURPOSE **To provide guidelines and requirements for construction planning of Distribution mains, supply lines, and related service installations.**

1. POLICY AND SCOPE

   1.1. The Company provides guidance and instruction to properly plan the installation of Distribution natural gas facilities.

2. RESPONSIBILITIES AND QUALIFICATIONS

   2.1. Gas Operations is responsible for the content and administration of this Gas Standard.

   2.2. The Regions are responsible for implementation of, and adherence to, this Standard.

   2.3. Only personnel qualified through Field Operations Training or Welding Training may perform these operations. See STANDARD 167.0100, *Operator Qualification Program* and STANDARD 184.0590 *Pressure Control Qualification Requirements*.

   2.4. Field employees are responsible for adhering to Company procedures and shall wear appropriate personal safety equipment during any and all duties performed. See *Injury and Illness Prevention Program Binder* under MANUAL IIPP.4, *Employee's Responsibilities*.

3. DEFINITIONS

   3.1. Not applicable.

4. PROCEDURE

   4.1. Items typically provided by the Planning and Engineering office include;

      4.1.1. Job "package" envelope, tract map, plot plan, grading plan, etc.

      4.1.2. Print of proposed work order sketch / base sketch or other map of the job location suitable for field preparation of the "planner's sketch." See Standard 192.0005 *Preparation of Work Order / Base Sketch*. Figure 1 below demonstrates a sample base sketch drawing using GIS data.

Figure 1

4.1.3. Strip map (reproduction of a Company atlas), denoting the limits of the proposed installation or replacement.

4.1.4. All substructure data available including proposed utilities if known

4.1.5. For replacement work, include archive copies of the original completion sketches (As-Built) for all existing facilities involved if available.

4.1.6. Public and private improvement plans (if applicable).

4.1.7. Special permit requirements or depth requirements.

4.1.8. Proposed pipe size, kind and design level. Specify branch connections to be installed in header mains to provide for known future laterals.

4.1.9. Service list or plan and service history information.

4.1.10. Valve requirements. See STANDARD 180.0085, *Valve Usage and Selection Guide*.

4.1.11. Main ties that affect an isolation area and the isolation area number.

4.1.12. Ties and dead ends for pipe to be installed and abandoned.

NOTE: The gas supply to the entire affected piping system must be reviewed to correctly identify the source(s) of gas related to the construction area. Ensure piping and gas supply is properly identified to assure a constant supply of gas to the area during and after construction.

4.2. Corrosion control requirements and the locations of Company and foreign impressed current anode systems and the facilities they protect.

4.2.1. As much information as possible about paving and soil conditions.

4.3. Downstream filtration requirements see STANDARD 184.0281, *Filtration Requirements for Regulator Stations*.

4.4. Field planning requirements include (site investigation and consideration):

4.4.1. On site working conditions such as residential or industrial area, type and thickness of paving, if known, shoring requirements, traffic control needs, etc.

4.4.2. Determine if excavating operations will take place within 500 feet of a school (K-12) or hospital requiring pre-construction notification to the facility(s) per Assembly Bill (AB) 1937.

4.4.3. Locations of property lines and curbs.

4.4.4. Foreign substructures.

4.4.5. Locations of specified job terminals.

4.4.6. Locations and depth requirements for main and related facilities

4.4.7. Methods of installation.

4.4.8. Special permit requirements.

4.4.9. Pressure control and gas handling requirements. See Standard 184.06, *Gas-Handling and Pressure Control.*

4.4.10. For steel pipe installation, determine the need for odorant “seasoning” of the line; see Standard 189.002 *Odor Conditioning of New Steel Lines*.

4.4.11. Cathodic protection requirements.

4.4.12. Related service work.

4.4.13. Material requirements.

4.4.14. Installation and abandonment footage.

4.4.15. Planning for subdivisions.

4.4.16. Construction marking requirements.

4.4.17. Written gas handling procedures. See Standard 184.06, *Gas-Handling and Pressure Control.*

4.5. Environmental

4.5.1. Consider proximity to environmental resources when planning the facility locations.

4.5.2. If the site is known to be in proximity to a sensitive resource, an environmental review must be conducted by a Field Environmental Representative (FER) or Environmental Services (EPro).

4.5.2.1. Document compliance with environmental pre-screening in the current construction management system and on the main package cover sheet.

4.6. Preparation of sketches by the project planner:

4.6.1. Prepare a rough sketch, also called a "Planner's Sketch", of the proposed field layout after field planning. Draw the sketch on a print of the work order / base sketch.

4.6.1.1. A rough sketch may be drawn on a strip map, tract map, atlas sheet, or other suitable map of the job site and transferred to the work order sketch / base sketch prior to routing to the Planning and Engineering office.

4.6.1.2. The Planner's Sketch will be used to create the Construction Sketch and it must contain all required information for that process. See STANDARD 192.0010 *Preparation of Construction Sketches*.

4.6.2. Prepare the substructure sketch using information obtained from local municipalities and other utilities. (Utility member contact information can be obtained from underground service alert). Add any additional substructures found within the job limits during the on-site visit. See STANDARD 192.0015 *Preparation of Substructure Sketch*.

4.6.2.1. Especially note surface structures when planning the route of the new pipeline, i.e. sewer manholes, telephone vaults, etc. The actual underground structure may be substantially larger than what is observed on the surface.

NOTE: A copy of Agency composite substructure map or improvement plans showing substructures are not an acceptable alternate to the substructure sketch.

4.6.3. Route Planners Sketch for approvals per STANDARD 184.0014 *New Business Project Package Routing* and/or STANDARD 184.0016 *Main Construction Project Package Routing*.

4.7. Planning and Engineering tasks include:

4.7.1. Distribution pipelines considered transmission lines as defined by STANDARD 223.0415 *Pipeline and Related Definitions (Interpretation of 49 CFR 192.3)*, are evaluated to determine if the pipeline will be constructed in a High Consequence Area (HCA) per STANDARD 192.02, *Operations Technology Procedure*.

4.7.1.1. FORM 4262, *Request for Pipeline Assistance*, shall be used to document that a review has been performed to determine any impacts to transmission pipelines within HCA's. See Standard 182.0010, *Request For Pipeline Design Assistance*.

4.7.2. Submit approved Planners Sketch for preparation of Construction Sketch. See STANDARD 192.0010, *Preparation of Construction Sketches*.

4.7.3. Prepare a Request for Proposal (RFP) for those jobs that are considered for bid. See STANDARD 103.0010, *Special Specifications – Request for Proposal (RFP) Process*.

4.7.4. For high pressure jobs enter all pipe, fittings and design information into the Design Data Sheet (DDS) Manager program to verify that all materials qualify for the design level and to determine strength testing requirements. See STANDARD 182.0170 *Strength Testing Pipelines and Facilities*, and FORM 3222, *Design Data Sheet (DDS).*

4.7.5. When required, process a *New Steel Pipeline Information Form* to the EAC Project Manager to procure an odorization plan for the pipeline. See 189.002, *Odor Conditioning of New Steel Lines*.

4.7.6. Obtain Right of Way and Railroad Crossing Agreements, when applicable. See STANDARD 106.0021, *Land and Right of Way Amendments*.

NOTE: The need for Right of Way or easements should be identified and the process started as soon as possible to prevent delays in the project.

4.7.7. Review permit requirements prior to releasing job package for special requirements that can be added to construction sketch.

5. OPERATOR QUALIFICATION COVERED TASKS

Not applicable.

6. RECORDS

6.1. The main job packages are to be retained per Company Records Retention Policy OPS-20-02, life of the asset plus five years (LOA+5).

7. APPENDICES

Not applicable.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Replaced Figure 1 with GWD based sample, changed references to suit new systems and programs (ex: CMS vs. CPD), various grammar and narrative changes not eefecting the intent of the document.

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	08/26/2015
Last Full Review Completed On:	08/26/2015
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
Category (Prior FCD system only):	
If Merged, Merged To Document Number:	
Utility:	SoCalGas
Department:	Distribution Operations
Number of Common Document:	G7450 & G7460
Confidential Sections:	
Part of SoCalGas O&M Plan:	No
Part of SDG&E O&M Plan:	No
Contains OPQUAL Covered Task:	No
OpQual Tasks	
Last O&M Review date:	
O&M 49 CFR Codes & Impacted Sections of Document:	
Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	Yes
Part of Transmission IMP (TIMP)	Yes
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
GO112F Codes & Impacted Sections of Document	
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	DIMP2, DISTM, TIMP2, TRNG
NOP Learning Module (LM) Training Code:	NOP00291

PURPOSE **The purpose of this Gas Standard is to describe the planning, coordination, and notifications necessary for planned and emergency shutdowns of Transmission and Storage Operations pipelines, compressor stations, and storage fields.**

1. POLICY AND SCOPE

1.1. Gas facility shutdowns which require a written shutdown plan:

- **Transmission Pipelines** — all work on transmission pipelines except work of very short duration (e.g., stroking valves as part of preventative maintenance inspection).
- **Compressor Stations** — all work that reduces the throughput capacity of station, except work on individual units which results in reduction of throughput for less than two hours
- **Underground Storage Fields** — all work affecting injection or withdrawal capability, except routine well testing (e.g. sand test, individual engine use for unloading wells).

> NOTE: All **Transmission** and **Storage** shutdowns, even those not requiring written plan, must be coordinated through **Gas Control** and must receive **Gas Control** approval prior to commencement. (Certain emergency situations are excepted — see Section 4.4, below.)

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. **Transmission** and **Storage Operations** develop written plans for coordination and execution of gas facility (pipeline, compressor station, storage field) shutdowns to ensure operational effectiveness, as well as public, employee, and facility safety.

2.2. **Transmission** and **Storage Operations** will coordinate all planned and probable shutdowns with **Gas Control** ahead of the proposed shutdown period.

2.3. **Project Managers**, **operating supervisors**, and other **Company personnel** responsible for projects that necessitate shutdowns shall notify **Energy Markets** and/or **Commercial/Industrial** when shutdowns affect the flow of gas to Utility Electrical Generation (UEG)/wholesale customers or that would affect producers.

2.4. **Gas Control** reviews forecasted shutdowns and related plans; coordinates changes in planning schedules; coordinates with suppliers, producers, and UEG/wholesale customers and advises **operating supervisors** regarding gas handling arrangements (valve operations, etc.).

3. DEFINITIONS

3.1. EOC – Emergency Operations Center for Company

3.2. GEC – Gas Emergency Center for Region

3.3. Isolated Section – any section of pipeline facility that is physically shutdown in an emergency or planned shutdown

3.4. Shutdown – Any work that restricts the use or availability of transmission pipelines, compressor stations, or storage fields, including instrumentation repair and calibration at affected facilities and pipelines

4. PROCEDURE

4.1. Planned Shutdown

4.1.1. **Transmission** and **Storage Operations** shall notify **Gas Control** of any possible timing flexibility to enhance coordination with other planned shutdowns.

4.1.2. Notify the following affected parties (if affected):

- **Transmission Technical Services Manager**
- **Storage Technical Services Manager** and affected **Storage Operations Manager**
- The affected **Distribution Region Technical Services Manager**

4.1.3. Plan work so that the duration of the shutdown is held to a minimum.

4.1.4. Working with **Gas Control** and **Distribution Region Technical Services**, plan to minimize gas blown to atmosphere through the use of **Distribution** facilities to reduce gas pipeline inventory. Any project that requires gas blown to atmosphere will build time into the project schedule to reduce methane consistent with safe operations and consider alternative potential sources of supply to reliably serve customers and maintain feasibility. Operating pressure should be reduced to the lowest operationally feasible level in order to minimize methane emissions before non-emergency venting of high-pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations. and whenever practicable, work should be bundled to prevent multiple venting of the same piping.

4.1.5. Consult with **Gas Control** and **Distribution Region Technical Services** as necessary to plan and coordinate activities with other **Transmission** and

Storage Operations organizations, affected **Distribution Regions**, suppliers, producers, and customers.

4.1.6. Plan and execute shutdowns to assure that pressures in adjoining sections of the pipeline will not drop below minimum operating requirements. As necessary during the planning and execution phases, consult with affected **Distribution Region Technical Services** and **Gas Control**.

4.1.7. When tentative arrangements can be reasonably determined, contact:

- **Gas Control**
- The affected **Distribution Region Technical Services** to plan remedial action on the distribution system and for notifications, such as transportation customers, etc.
- Producers, where affected.

4.1.8. The following notifications will be made in advance of scheduled shutdowns:

- **Gas Control**; prior to the shutdown gas control shall be notified in advance of the shutdown schedule.
- The affected **Distribution Regions Technical Services** to schedule remedial action on the distribution system and for notification of customers, such as transportation customers, etc.
- UEG/wholesale customers and producers, when affected

4.1.9. To confirm arrangements and schedule of all shutdowns, prepare and distribute Form **3506**, *Notice of Shutdown / Operational Deviation* prior to the date of shutdown. If the date of the shutdown is likely to change, make a note to that effect on Form **3506**. Reach an agreement between the **Transmission** and **Storage Operations** organization, **Distribution Regions**, other affected parties, and **Gas Control** as to the minimum amount of time prior to the shutdown that a firm date must be set.

4.1.10. Each written plan (see Section 4.2) is reviewed by the appropriate responsible **Transmission** or **Storage Operations management personnel**.

4.1.11. Prior to the shutdown, give a copy of the written plan to and review with each person assigned to work on the project. When a contractor is providing work forces for a tie-in, give a copy of the plan to the **contractor's supervisors**. A pre-shutdown briefing is conducted by the **Transmission or Storage Operations management person** responsible for directing the operation.

4.1.12. Confirm shutdown arrangements by calling **Gas Control** and the affected **Distribution Region Technical Services** prior to the beginning of the shutdown.

NOTE: **Gas Control** has the authority to approve and to disapprove shutdowns if conditions warrant.

4.1.13. If gas is to be blown to atmosphere, notify public authorities (police, fire, Civil Aeronautics Administration [CAA] when appropriate, Air Quality Management District [AQMD], airport authorities, highway or street departments, etc.), and nearby businesses and residents, including local home-owner groups and associations. Also, notify interested Company departments.

4.1.14. Make regular phone or radio reports to the **Gas Control Supervisor** and affected **Distribution Regions** concerning job progress, such as status, estimated time of completion, valve operations, when delayed, when completed, etc.

4.1.15. Return the facility to normal service and coordinate with **Gas Control** to insure proper line pack and gas routing.

4.1.16. Document pressure prior to blowdown and complete Form **3466**, *Reporting of Gas Blown to Atmosphere.*

4.2. Written Plans

4.2.1. **Transmission** and **Storage Operations** develop written plans for handling planned shutdowns. Plans are specific and definitive in order to maintain well established operations.

4.2.2. The written plan for handling shutdowns under emergency conditions is of necessity general in nature because operations and conditions vary from one shutdown to another.

Written Plans — Field Operations

4.2.3. **Transmission** and **Storage Operations** provide their field operations personnel with a written plan for gas facility shutdowns delineating all critical activities associated with the shutdown.

4.2.4. The plan and subsequent job discussion includes, but is not limited to, the following information. The level of detail should be appropriate to the safe and efficient completion of the project:

- List of work to be accomplished prior to the shutdown.
- List of crucial equipment needed at the job site including hazardous materials cleanup equipment.

- List of all concerned governmental agencies, affected **Distribution personnel**, other Company personnel, local businesses, and residents to be notified.

- Sequence of operations, including numbers and locations of valves to be operated and the estimated time when these operations will occur.

- Schematic of the section to be shut down with all pertinent valves and valve positions clearly labeled.

- List of all active customer and **Distribution** taps.

NOTE: All taps feeding a customer(s) or **Distribution Operations** systems must have a plan for an alternate feed that identifies who is responsible for the alternate feed.

- Schematics of the installation and removal sections.

- Detailed step-by-step procedure for all fire-control activities. See Gas Standard **223.0165**, *Controlled Fire Operations*.

- Detailed, step-by-step procedure for any purge performed. See Gas Standard **182.0160**, *Purging Pipelines and Components*.

- Plan for personnel protection using Lockout/Tag-out when required.

- Indicate any changes to telemetry (i.e., if data signals will be out of service or unavailable).

Written Plans — Gas Control

4.2.5. **Transmission** and **Storage Operations** provide **Gas Control** with a written plan for gas facility shutdowns which includes, but is not limited to, the following information:

- Sequence of operations, including numbers and locations of valves to be operated and the estimated time when these operations will occur

- Schematic drawing of the section to be shut down with all pertinent valves and valve positions clearly labeled.

- List of all active customer and **Distribution** taps.

- Schematic drawings of the installation and removal sections.

4.3. **Gas Control** Shutdown Activities

4.3.1. Review list of forecasted shutdowns.

4.3.2. Identify schedule conflicts.

4.3.3. Coordinate changes in planning schedules.

4.3.4. Advise **operating management** regarding gas handling arrangements.

4.3.5. Notify **Distribution Region Technical Services** as to whether their planned operations are deemed significant or not.

4.3.6. When a shutdown impacts the systems capability to accept full out-of-state supplies, a System Status Information report with shutdown details will be posted on the Company's on-line electronic communications system (**EEB**) as soon as the information is known as required by Remedial Measure 23.

4.3.7. As soon as it becomes evident that deliveries to a UEG customer are (or may be) affected, notify the appropriate **Energy Markets personnel**. Confirm shutdown prior to onset of actual work. For other major customers, notify **Commercial/Industrial**.

4.3.8. Before the shutdown, the **Gas Control Supervisor** works with **Transmission** to plan for alternate operations while arranging the transition to normal gas operations at the completion of a shutdown. During the shutdown, **Gas Control** operates the system.

> NOTE: The **Gas Control Supervisor** has the authority to stop or change a shutdown during its progress.

4.4. Emergency Shutdown Plans

4.4.1. **Transmission** and **Storage Operations** Responsibilities

4.4.1.1. Each **Transmission** and **Storage Operations** organization's emergency shutdown plan is modified to meet the needs of each situation and to assure the facility is back in service as soon as possible.

4.4.1.2. In the event of a major, wide-spread emergency (i.e. earthquake, terrorist attack, flooding, firestorm, etc.) and a **GEC** and the **EOC** are both open and operational to respond to the event, the **GEC** should consider the following three (3) factors for alerting and involving the **Executive-in-Charge** at the **EOC** and **Gas Control** before implementing a large isolated section in the gas system unless Section 4.4.1.4 applies:

1. Size of Isolated Section
    - The isolated section will impact 25,000 or more customers (restores)
    - The isolated section could result in displacement of one million cubic feet or more per hour on the flow of gas required from the transmission system
2. Impacts to Sensitive/Critical Customers
    - Health/Safety
        - Hospitals
        - Schools
        - Stadiums/Large Public Gathering Sites/Arenas/Sports Centers that can be used for evacuation shelters
        - Municipal Gas Systems (e.g., Long Beach Gas)
        - City/County/State Emergency Operation Centers that are open and running
    - Economic
        - Non-core firm UEG customers
        - Refineries
        - Co-Generation Facilities (> 20 MW)
    - Major Airports (e.g., Los Angeles International Airport (LAX), San Diego International Airport (SAN), John Wayne Airport (SNA), LA/Ontario International Airport (ONT), Bob Hope Airport (BUR))

3. Requiring Inter-Region Coordination or Mutual Assistance

    - Response across multiple operating organizations or with assistance from outside the Company required to implement the isolated section

4.4.1.3. The responsible **Transmission** or **Storage Operations management person** shall:

- Initiate a Message Center Report. See **183.0110**, *Field Procedure – Emergency Incidents – Transmission*.

- Consults with the **Gas Control Supervisor** to arrange the re-routing of gas flow and/or obtain permission to close off connections prior to shutting down.

4.4.1.4. **Transmission** or **Storage Operations** personnel may operate valves that affect gas flow without first clearing with the **Gas Control Supervisor** only when the responsible **Transmission** or **Storage Operations** management person at the site determines either of the following:

- Injury or death have occurred or is imminent

- Communications are not possible from the site and leaving the site would risk additional damage or injury. In such the **Gas Control Supervisor** is notified at the first opportunity directly or by **GEC** (if operational).

4.4.2. **Gas Control** Responsibilities

4.4.2.1. Re-routes supplies, as required.

4.4.2.2. Post outages impacting capacity in Envoy.

4.4.2.3. Notifies **Energy Markets**, when UEG and/or wholesale customers are affected.

5. EXCEPTION PROCEDURE
(See GS 182.0004, *Exception Procedure for Company Operations Standards*)

5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

5.2. An exception from a standard shall not be allowed unless GS 182.0004, *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

6. OPERATOR QUALIFICATION COVERED TASKS
(See GS **167.0100**, *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 16.2 -** 49 CFR 192.745 – Inspecting, operating, and maintaining transmission pipeline valves

7. RECORDS

7.1. Completed Form **3506** and the completed procedure or work instructions package for the project that necessitated the shutdown must be retained for life of the pipeline asset.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Fully reviewed. 4.1.4; Added procedure for minimizing methane emissions before blowdown

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	08/01/2019
Last Full Review Completed On:	06/26/2019
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
Category (Prior FCD system only):	
If Merged, Merged To Document Number:	
Utility:	SoCalGas
Department:	Gas Control
Number of Common Document:	G8147
Confidential Sections:	
Part of SoCalGas O&M Plan:	Yes
Part of SDG&E O&M Plan:	No
Contains OPQUAL Covered Task:	No
OpQual Tasks	
Last O&M Review date:	8/13/2019
O&M 49 CFR Codes & Impacted Sections of Document:	192.605(b)(5): 4 192.615(a)(6): 4.4
Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	No
Part of Transmission IMP (TIMP)	Yes
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
GO112F Codes & Impacted Sections of Document	
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	DISTM, OEMSTOR, PSEP, STOR, TIMP2, TRAN, TRNG
NOP Learning Module (LM) Training Code:	NOP00610

PURPOSE **This gas standard provides the policy and procedures for safely purging natural gas pipelines above 60 psig. All company and contract employees shall follow these guidelines when purging pipeline systems.**

1. POLICY AND SCOPE

1.1. Pipelines are purged to prevent the presence of a combustible mixture of gas and air. Failure to abide by the guidelines and procedures of this Gas Standard may result in serious or catastrophic consequences.

1.2. This procedure **does not include** purging operations that utilize air movers. For these purges, see **STANDARD G7910**, *Purging Pipelines Using Air Movers For Cold Tie Operations*. For more specific purging information regarding purging into service medium pressure pipelines, see **STANDARD D7911**, *Purging of Distribution Gas Lines of 60 PSIG.*

1.3. Written procedures shall be understood and approved by the Purging Operation Lead so as to assure the safe and successful completion of the job. See **Section 5.5** for further details about the written plan.

1.4. The Purging Operation Lead shall conduct a meeting, prior to a purging activity, to ensure all personnel engaged in purging operations understand the procedures involved. The Purging Operation Lead shall ensure that all employees and contractors involved in purging understand the potential hazards of improper operation. If changes in operations occur, all personnel will be informed of the changes before proceeding.

1.5. The Purging Operation Lead shall make the final determination on the adequacy of the purge before proceeding with any hot-work.

1.6. Limit access to the work area of the purging operation to only those persons who are necessary to perform the activity, keeping all-non-essential personnel and the public clear of harm's way.

1.7. Employees are responsible for adhering to company procedures and shall wear appropriate personal safety equipment during any and all duties performed as outlined in Rule 4100 of **Manual ESHSD-4100**, *Gas Distribution and Transmission*.

1.8. Gas shall be vented to atmosphere without hazard to workers, public, and property. See **Section 5.3**.

1.9. Considerations must be given to the public with regard to objectionable noise and odor as well as any noise or pollution abatement requirements. Such considerations may include the use of noise suppression equipment, notification of law enforcement, Fire Department and Air Pollution Control District.

1.10. All parts and equipment involved in the purging operation shall be in proper working condition and are visually inspected before use.

1.11. Adequate visual and/or radio communications shall be established between all work locations including the injection and venting points.

1.12. When purging out-of-service follow procedures stated in **STANDARD G8146,** *Blowdown Time, Sizing, and Volume Calculations*, and **FORM 3466SD,** *Reporting of Gas Blown to Atmosphere*, to account for the gas lost to atmosphere.

1.13. When purging into service a new steel pipeline, the pipeline must be odor conditioned (also known as seasoned or pickled) to minimize a reduction in the odor content of natural gas due to interaction of gas odorant with new steel. See **STANDARD G8132,** *Odor Conditioning of New Steel Lines*.

1.14. Any deviation from this gas standard shall be reviewed and approved by **Gas Engineering - Pipeline Engineering**.

2. RESPONSIBILITIES AND QUALIFICATIONS

2.1. Only Company personnel qualified through Gas Operations Training may perform these operations. See **STANDARD G8113,** *Operator Qualification Program*.

2.2. **Region Engineering Miramar** or **Transmission Operations Manager** shall prepare the written purging procedures. See **Section 5.5** for further requirements.

2.3. **Purging Operation Lead** shall be responsible for supervising purging operations. This lead shall have thorough technical knowledge and previous purging experience. This lead is also responsible for ensuring that all aspects of this standard are being followed.

2.4. **Distribution Region, Transmission District, and GTS Miramar** personnel performing purging activities shall be Operator Qualified. See **STANDARD G8113,** *Operator Qualification Program* for requirements.

2.5. **Gas Operations Training - Skills** is responsible for training, qualification and all related certification and documentation for company and contract personnel.

2.6. **Field Employees** are responsible for ensuring that an approved fire extinguisher (minimum 40 BC) is readily accessible and its location known to all employees at the work site.

2.7. **Qualified Operators** are responsible to visually inspect all pressure control equipment prior to performing any pressure control operation. Do not use any damaged or defective equipment. Notify supervision if any defects are found.

3. DEFINITIONS

3.1. **Blow-down -** To reduce pipeline pressure to atmospheric pressure by venting gas to atmosphere.

3.2. **CGI** – Combustible Gas Indicator

3.3. **Cursory Odor Sniff Test -** A quick release of natural gas into the atmosphere that is sniffed to determine if odorant is detectible by smell.

3.4. **Direct Purge** – The act of either directly purging gas with air or air with gas at high velocities without a nitrogen slug.

3.5. **Indirect Purge** – The act of either purging from gas to air or from air to gas with a nitrogen slug between the air and gas to prevent the formation of a combustible mixture.

3.6. **Orifice** – A reduced opening which reduces flow rate.

3.7. **Purge -** The act of removing all the air from a pipeline and replacing it with natural gas or removing all the natural gas from a pipeline and replacing it with air.

3.8. **Purging out of service** – *(Gas to Air/Nitrogen)* The process of replacing natural gas content in a pipeline with air/nitrogen by injecting air or nitrogen at sufficiently high flow rates.

3.9. **Purging into Service** – *(Air/Nitrogen to Gas)* The process of replacing air or nitrogen content in a pipeline with natural gas by injecting natural gas at sufficiently high flow rates.

3.10. **Purging Operation Supervisor** – The designated trained and knowledgeable supervisor responsible for gas handling operations, including purging.

3.11. **Slug** – As it relates to this standard, is a quantity of nitrogen gas injected between the gas and air during an indirect purge. The slug moves through the pipe as a distinct mass to prevent mixing of the gas and air.

3.12. **Total Displacement Purge** – The act of purging from gas to air or air to gas by injecting an amount of nitrogen slightly greater than the entire internal volume of the pipeline segment or facility to be purged.

3.13. **BC** – Fire extinguisher rating effective for flammable liquid fires and "live" electrical equipment.

4. REQUIREMENTS PRIOR TO PURGING

4.1. **ISOLATION -** Completely isolate the piping segment to be purged from the system.

4.1.1. Isolation may be accomplished by one or more methods including the use of blind flanges, closing valves, placing blanking discs between flanges, pressure control fittings or physically disconnecting laterals or other sources of gas.

4.1.2. Squeezing of PE pipe may be an acceptable means of isolation for purging. Only Company approved squeeze tools shall be used. *See* **STANDARD D7279,** *Squeezing Polyethylene (PE) Pipe – ½" Through 8".*

4.1.3. If valves are used to isolate the section to be purged from the pressurized system, they should be verified to stroke properly and not to leak.

4.1.4. A thorough physical check shall be made to ensure that isolation is prepared as planned and free of leakage prior to the start of the purging operation.

4.2. **NITROGEN** - When using nitrogen as a separating medium (slug) or for Total Displacement Method, practicality, availability and economics determine whether to use cylinders (bottles) or a tank truck. A tank truck is normally the less costly option when a large volume of nitrogen is required.

4.2.1. Standard cylinders typically have 250 standard cubic feet (scf) of nitrogen at 2265 psig.

4.2.2. If an Indirect Purge is required, use **Table A3** in Appendix A to determine the minimum number of cylinders required. If the use of a nitrogen truck is desired, such as when large volumes are required, see **Table A5** in **Appendix A** to obtain required nitrogen volumes.

4.2.3. If a Total Displacement Purge is required or desired, use **Table A4** in **Appendix A** to determine the minimum number of cylinders required for a Total Displacement Purge.

4.2.4. Nitrogen Gas Safety - Be aware that the accumulation of large quantities of nitrogen gas can present an asphyxiation hazard to personnel. In trenches or confined spaces where nitrogen is being purged and can accumulate, keep ventilated and check for oxygen level before personnel enters the space.

5. PROCEDURE

5.1. **Selection of Purging Method**

5.1.1. **Purging Operation Supervisor** must understand and approve the written procedures to provide a safe and successful completion of the purging operation. See **Section 5.5** for further details about the written plan. **Using Table 1 below, select the proper purging method based on the combination of pipe diameter and length of the segment to be purged.**

5.1.2. The indirect method can be substituted for the direct method.

Diameter (in)	Length (ft)	Purging Method
$D \leq 4$	Any	Direct (Section 5)
$D \geq 6$	$L < 500$	Direct (Section 5)
$D \geq 6$	$L \geq 500$	Indirect (Section 7)

Table 1

The Total Displacement Method (**Section 3.12**) shall be used when:

- A potential hazard exists due to the presence of liquids or solids
- A potential hazard exists due to a complex piping situation, such as with stubs, or in compressor and regulator stations
- Permanently abandoning a pipeline or main that is not free of liquids or solids, or if required by the permitting agency. (See **STANDARD D7381,** *Abandonment or Inactivation of Gas Distribution Pipelines*, or **STANDARD T7381,** *Abandonment, Conversion and Reinstatement of Transmission Pipelines*).

5.2. **Sources of Ignition**

5.2.1. Eliminate all sources of ignition. Extinguish any open flames (smoking is prohibited). Do not carry any items designed to produce sparks such as but not limited to: matches, cigarette lighters, welding torch igniters, cell phones or any other electrical devices in the immediate vicinity any time while working in a gaseous atmosphere. See **Manual ESHSD-4100,** *Gas Distribution and Transmission,* and **STANDARD G8169**, *Prevention of Accidental Ignition of Natural Gas.*

5.2.2. When purging, especially with old piping, it shall be kept in mind that purging removes only gaseous or volatile materials. Undetected liquid or solid combustibles can be ignited by sparks carried back into a purged pipeline when it is cut. Take necessary precautions to ensure removal of difficult to detect combustibles. Consider purging using the Total Displacement Method with nitrogen if the presence of liquids or solids exists. See **Section 3.12** for definition of Total Displacement Purge.

5.2.3. Consider purging with the Total Displacement Method with nitrogen if the presence of liquids or solids exists. See **Section 3.12** for definition of Total Displacement Purge.

5.2.4. Care shall be taken to avoid static electrical discharge before, during and after purge by grounding all machinery and equipment where static electricity might accumulate. Pipelines are bonded or grounded before purging, cutting, or disconnecting in accordance with **STANDARD G8169,** *Prevention of Accidental Ignition of Natural Gas.* Before severing or disconnecting a steel pipe, a bond wire must be attached to the metallic pipe at two points to provide a connection across the proposed severance or disconnection which connects both sides of the remaining pipe. For purging Polyethylene (PE) pipe, see **STANDARD G8169,** *Prevention of Accidental Ignition of Natural Gas.*

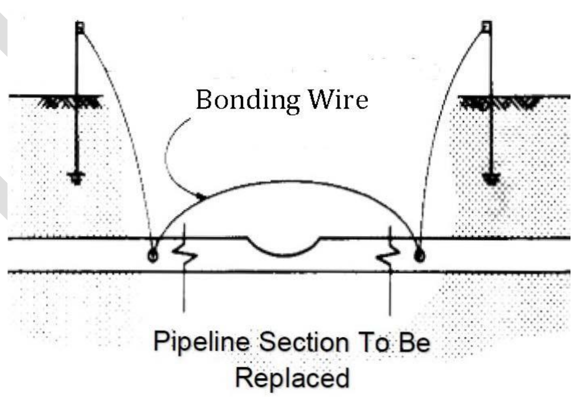


Figure 0. – Bonding wire placed across proposed severance or disconnection

5.2.5. Cathodic protection rectifiers shall be turned off.

5.3. Venting

5.3.1. See **Table A1** for vent stack sizing.

5.3.2. The steel vent stack should consist of a full opening tap in the pipeline to be purged.

5.3.3. When a vent valve is used, it shall be full opening.

5.3.4. When selecting venting locations, care is taken to prevent accidental ignition during purging operations. Avoid venting under or in close proximity to overhead power lines, per **STANDARD G8183** – *Purging Operations – Minimum Distance Between Purging Stack and Ignition Sources*.

5.3.5. Never discharge purging medium through a plastic vent pipe.

5.3.6. Any project that requires gas blown to atmosphere will build time into the project schedule to reduce methane consistent with safe operations and consider alternative potential sources of supply to reliably serve customers and maintain feasibility. Operating pressure should be reduced to the lowest operationally feasible level in order to minimize methane emissions before non-emergency venting of high-pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations. and whenever practicable, work should be bundled to prevent multiple venting of the same piping.

5.3.7. If a new Transmission pipeline assembly is enclosed with wet canvases, the assembly may be directly purged into service using one canvas end as a vent provided that:

- When purging through a wet canvas, the canvas opening should be approximately ⅓ of the cross-section of the pipe. The opening is at the bottom when purging into service. See **STANDARD D7114**, *Pipe End Closures*.

5.3.8. If a steel vent stack is to be assembled on an existing blow-off that does not meet size and full opening description, **Gas Engineering - Pipeline Engineering**, will determine the adequacy of the blow-off.

5.4. Planning a Purge

5.4.1. Use **Table A1** in **Appendix A** to obtain the standard purging parameters for specific pipe diameters:

- These parameters include the standard injection fittings, injection pressures, vent sizes and flow rates.
- If orifices are to be utilized, use the required minimum flow rates from **Table A1**. Select the appropriate orifice size and inlet pressure based on required flow rates.
- Place the orifice immediately upstream of the injection fitting to eliminate any unplanned pressure drop.
- Orifices are normally placed in screwed orifice unions, but a tapped abandonment fitting can also be used. Injection and bypass fittings selected shall not have an internal diameter smaller than the hose or orifice to be used. See **Figure 6** for typical orifice set-up.

5.4.2. When using an orifice, the pressure gauge to measure the minimum required pressure should be installed just upstream of the orifice. The tapped diameter when using an abandonment fitting needs to be equal to or greater than the orifice size.

5.4.3. When using a 50 foot hose to measure and maintain minimum flow rates as required in **Table A1**, the pressure gauge must be installed at the upstream end of the 50 foot hose connected to the injection point.

5.4.4. Use **Table A2** in **Appendix A** to obtain an approximate arrival time at particular lengths of pipe when using a standard set up. When purging by the indirect method, this approximate time indicates the arrival of the nitrogen slug.

5.4.5. When using an Indirect Purge (with a slug of nitrogen) it is important to maintain the minimum slug speed (minimum injection flow rate) as indicated by the use of **Table A1** to minimize the mixing of the gas interface to maintain the slug.

5.4.6. When purging out of service using an air compressor, make certain that the selected compressor is rated with at least 15% more flow rate capacity than the minimum flow rate listed in **Table A1**.

5.4.7. When possible, purge from air/nitrogen to gas downhill, and purge from gas to air/nitrogen uphill.

5.4.8. A piping system containing loops or branches requires a detailed evaluation to ensure each pipe section is properly isolated and purged which typically requires isolating and purging in stages.

5.5. **Written Plan**

5.5.1. An approved written plan should be available for all purging procedures.

5.5.2. Service lines and small diameter pipelines can be purged using the general procedures of this gas standard as the written plan. More complex purging operations require a specific detailed written plan.

5.5.3. The written plan should include, but is not limited to, the required purging method, location of isolation points, injection set up, injection pressures and flow rates, venting location and stack size, operational sequences, an equipment list (Combustible gas indicator, air compressor, etc.) and provisions for a communication system.

5.6. **Non-Typical Purging Operations**

5.6.1. When purging a service that has an Excess Flow Valve installed; see **STANDARD G7643** *Excess Flow Valve (EFV) - Installation and Operation.*

5.6.2. For Abandonment of Distribution Mains and Services see **STANDARD D7110**, *Abandonment of Gas Services and Gas Light Tap Assemblies* and **STANDARD D7381**, *Abandonment or Inactivation of Gas Distribution* Pipelines for diameters and lengths of piping that do not require purging prior to abandonment.

5.6.3. Air Movers may be used for purging large diameter (≥ 8") pipelines out of service; see **STANDARD G7910**, *Purging Pipelines Using Air Movers For Cold Tie Operations.*

5.6.4. If a standard indirect purge is not practical or possible, in cases such as long pipeline lengths yielding unreasonable operation times or if the use of larger injection fittings and/or vents is desired, contact **Gas Engineering - Pipeline Engineering** for analysis.

5.6.5. All non-standard purges require a written plan approved by **Gas Engineering - Pipeline Engineering**.

6. PURGING OUT OF SERVICE USING THE DIRECT PURGE METHOD (GAS TO AIR)

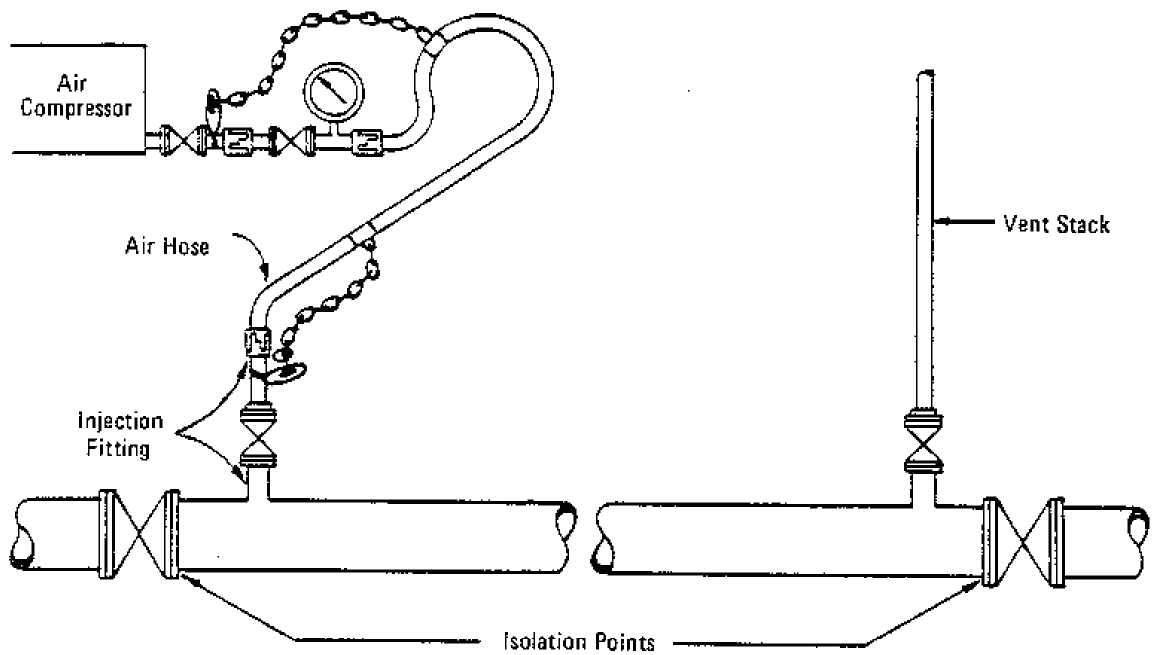


Figure 1. - Arrangement for Directly Purging Gas from Pipelines.

6.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.

6.2. Remove all ignition sources in accordance with **Section 5.2**.

6.3. Isolate section of line to be purged. See **Section 4.1**.

6.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft. See **Figure 1**.

6.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. Connect air hose and valve to pressure gauge. See **Figure 1**.

6.6. Connect gauge and valve end of air hose to air compressor and attach other end of hose to injection fitting. See **Figure 1.**

6.7. Open valve on vent stack and blow down line.

6.8. With the air compressor valve open, gradually open the valve on injection fitting and inject air. Inject at or above the minimum injection pressure, see **Table A1**. Injection of air shall be continued without interruption until the pipeline is purged of all gas. Control pressure with valve attached to compressor end of air hose. See **Figure 1**.

6.9. Stop injection of air when pipeline is purged of all gas. Use approved CGI device to determine if pipeline is 100% purged of all gas. See **STANDARD G8220**, *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures*.

7. PURGING INTO SERVICE USING THE DIRECT PURGE METHOD (AIR/NITROGEN TO GAS)

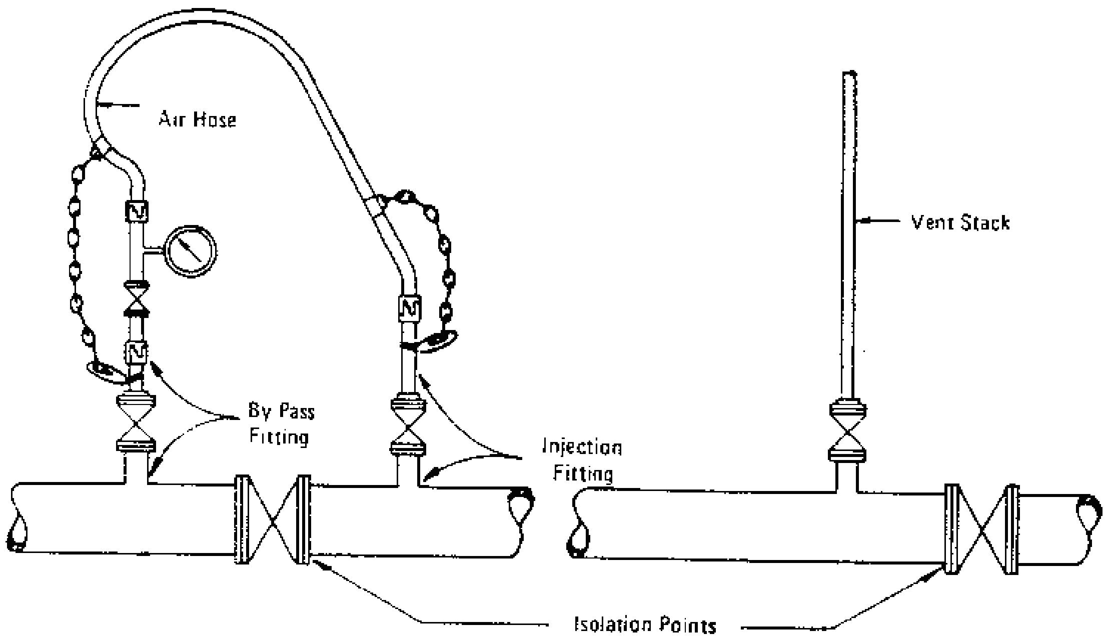


Figure 2 - Arrangement for Directly Purging Pipelines into Service.

7.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5.**

7.2. Remove all ignition sources in accordance with **Section 5.2**.

7.3. Isolate section of line to be purged. See **Section 4.1**.

7.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft. See **Figure 2**.

7.5. Install injection fitting as close as practical to, but not more than 5 feet away from the injection end of pipeline. See **Figure 2**. If available, gas may be injected by opening a line valve instead of using a bypass, however, contact **Gas Engineering - Pipeline Engineering** to obtain the downstream pressure needed to control the purge.

7.6. If needed, install bypass fitting on live pipeline for gas source. See **Figure 2**.

7.7. Connect gauge and valve to bypass fitting. Connect an air hose or pressure hose from pressure gauge end to injection fitting. See **Figure 2**.

7.8. Open valve on vent stack.

7.9. Gradually open valve on injection fitting and inject gas. Inject at or above the minimum injection pressure. Injection of gas shall be continued without interruption until the pipeline is purged of all air. Control pressure with valve attached to bypass fitting. See **Figure 2**.

7.10. Stop injection of gas when pipeline is purged of air. Use approved CGI device to determine if pipeline is 100% gas. Use approved CGI device to determine if pipeline is 100% purged of all gas. See **STANDARD G8220**, *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures*.

7.11. A ***cursory odor sniff test*** (a quick release of natural gas into the atmosphere that is sniffed to determine if odorant is detectible by smell) shall be performed immediately after the purging process and verifying 100% gas is obtained.

7.12. Direct purging of gas services less than 2’’ steel can be accomplished using a service tee or pin-off tee as the purge source.

8. PURGING OUT OF SERVICE USING THE INDIRECT PURGE METHOD (GAS TO AIR)

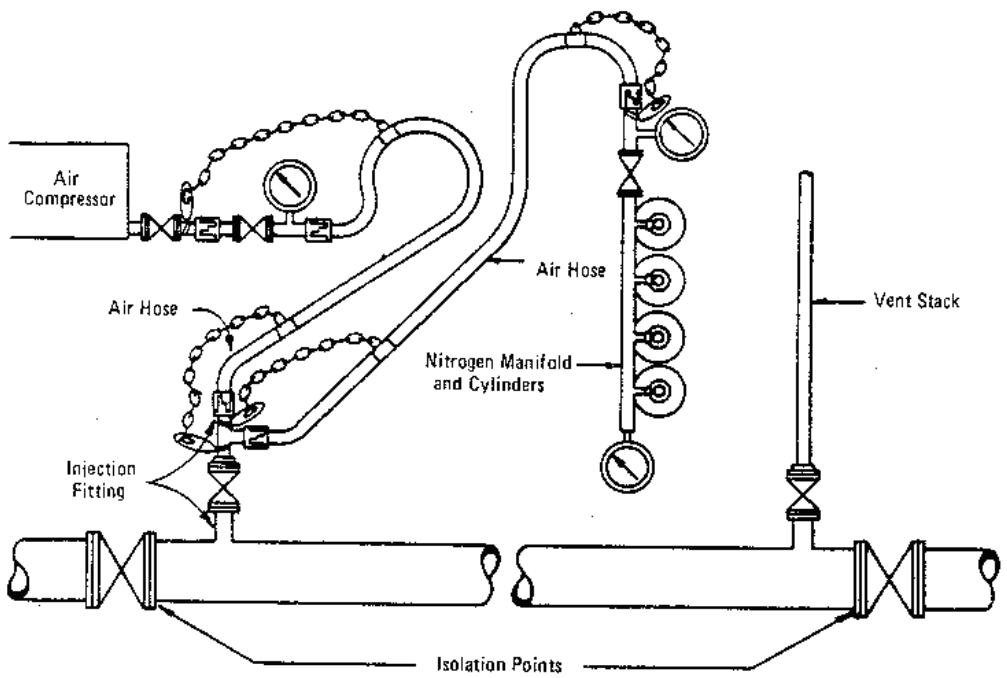


Figure 3. Arrangement for Purging Out of Service using Indirect Method

8.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.

8.2. Remove all ignition sources in accordance with **Section 5.2**.

8.3. Isolate section of line to be purged. See **Section 4.1**.

8.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft. See **Figure 3**.

8.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. See **Figure 3**.

8.6. Connect gauge and valve to air compressor and attach hose from the other end of the injection fitting. See **Figure 3**.

8.7. If nitrogen cylinders are to be used, connect the nitrogen cylinders indicated in **Table A3** to the manifold. Close valve on manifold and open valves on nitrogen cylinders. See **Figure 3**.

8.8. Connect manifold hose or pressure hose to injection fitting. See **Figure 3**.

8.9. Open valve on vent stack and blow-down the pipeline.

8.10. Once the pipe segment has been blown down, gradually open valve on injection fitting.

Note: Verify this valve is open to prevent damage to the gauge on the manifold.

8.11. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure as indicated in **Table A1** to maintain minimum flow rate controlling pressure with the manifold valve. See **Figure 3**.

8.12. Begin injecting air as soon as the minimum gauge pressure of nitrogen, cannot be maintained. Close valve on nitrogen manifold immediately after air injection has started. Air must be injected at or above the minimum gauge pressure as indicated in **Table A1** to maintain minimum flow rate. Control pressure with valve attached to compressor end of air hose. See **Figure 3**.

8.13. Stop injection of air when pipeline is 100% purged of all gas. Use approved CGI device to determine if pipeline is 100% purged of all gas. See **STANDARD G8220**, *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures*.

9. PURGING INTO SERVICE USING THE INDIRECT PURGE METHOD (AIR TO GAS)

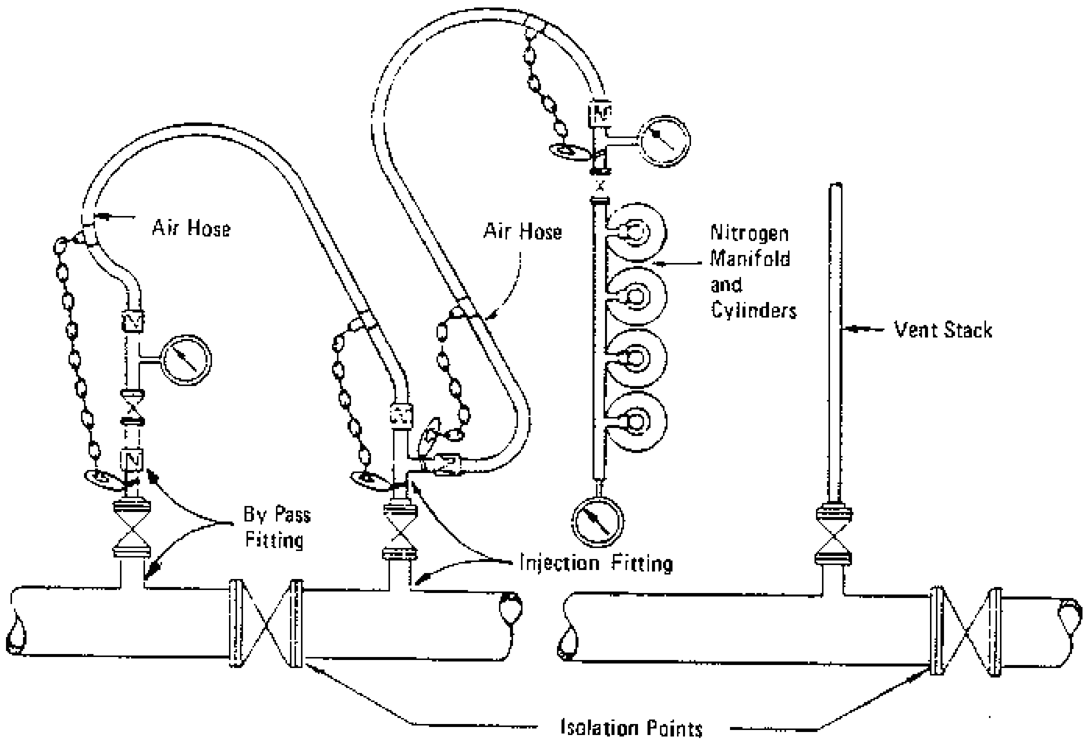


Figure 4. Arrangement for Purges into Service using Indirect Method

9.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.

9.2. Remove all ignition sources in accordance with **Section 5.2**.

9.3. Isolate section of line to be purged. See **Section 4.1**.

9.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft. See **Figure 4.**

9.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. See **Figure 4**. If available, gas may be injected by opening a line valve instead of using a bypass, however, contact **Gas Engineering - Pipeline Engineering** to obtain the downstream pressure needed to control the purge.

9.6. If needed, install bypass fitting on pipeline as a gas source. See **Figure 4**.

9.7. Connect gauge and valve to bypass fitting. Connect an air hose or pressure hose from pressure gauge end to injection fitting. See **Figure 4.**

9.8. Connect nitrogen cylinders as indicated in **Table A3** to the manifold. Close valve on manifold and open valves on nitrogen cylinders.

9.9. Connect manifold hose or high pressure hose to injection fitting. See **Figure 4**.

9.10. Open valve on vent stack.

9.11. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure as indicated in **Table A1** to maintain minimum flow rate controlling pressure with the manifold valve. See **Figure 4**.

9.12. Begin injecting gas as soon as the minimum gauge pressure of nitrogen, cannot be maintained. Close valve on nitrogen manifold immediately after gas injection has started. Gas must be injected at or above the minimum gauge pressure as indicated in **Table A1** to maintain the minimum flow rate. Control pressure with valve attached to bypass fitting. See **Figure 4**.

9.13. Stop injection of gas when pipeline is purged of air. Use approved CGI device to determine if pipeline is 100% purged of all gas. See **STANDARD G8220**, *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures*.

9.14. A ***cursory odor sniff test*** (a quick release of natural gas into the atmosphere that is sniffed to determine if odorant is detectible by smell) shall be performed immediately after the purging process and verifying 100% gas is obtained.

10. PURGING OUT OF SERVICE USING THE TOTAL DISPLACEMENT PURGE METHOD (GAS TO NITROGEN)

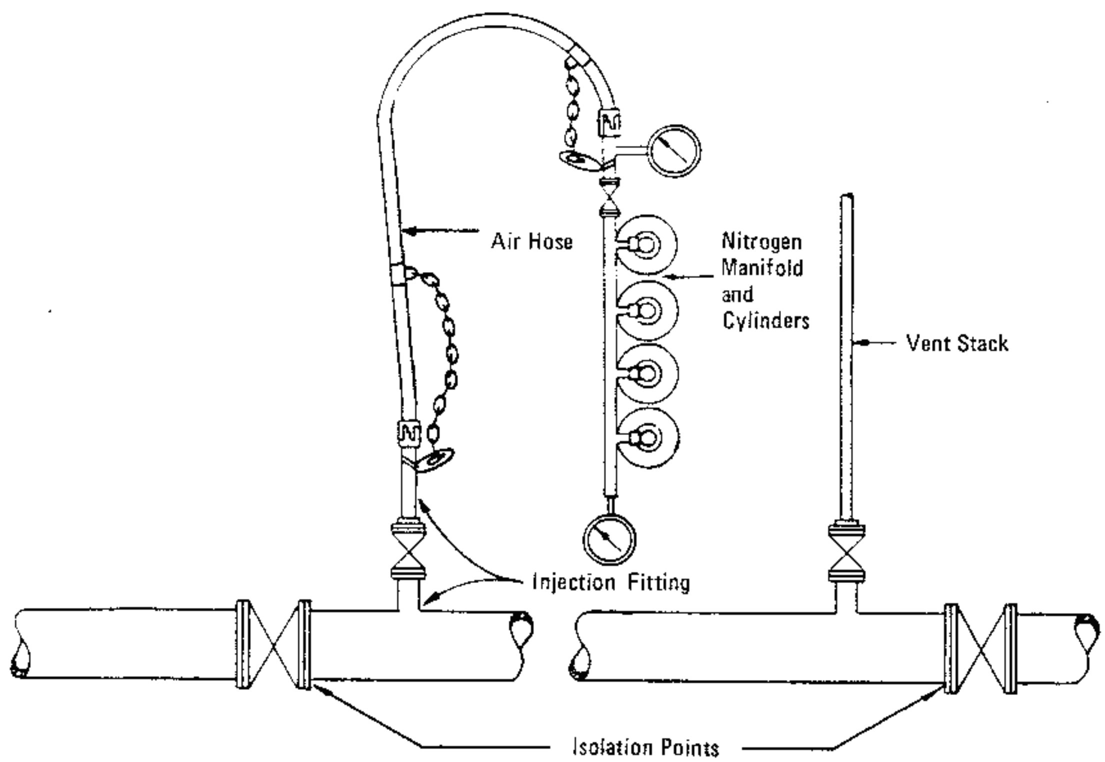


Figure 5. Arrangement for Purging Out of Service using Total Displacement Method

10.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.

10.2. Remove all ignition sources in accordance with **Section 5.2**.

10.3. Isolate section of line to be purged. See **Section 4.1**.

10.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft.

10.5. Install injection fitting as close as practical from the injection end of pipeline, but not more than 5 feet from the injection end of pipeline. See **Figure 5.**

10.6. If nitrogen cylinders are to be used, connect the nitrogen cylinders to the manifold. Close valve on manifold and open valves on nitrogen cylinders. See **Figure 5**.

10.7. Connect manifold hose or pressure hose to injection fitting. See **Figure 5**.

10.8. Open valve on vent stack and blow-down the pipeline.

10.9. Open valve on injection fitting. Be sure this valve is open to prevent damage to the gauge on the manifold. See **Figure 5**.

10.10. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure as indicated in **Table A1** to maintain minimum flow rate controlling pressure with the manifold valve. See **Figure 5**.

NOTE: When abandoning a pipeline using the Total Displacement Method stop injection once pipeline is completely purged of gas then proceed in capping the pipe.

10.11. Stop injection of nitrogen when pipeline is 100% purged of all gas. Use approved CGI device to determine if pipeline is 100% purged of all gas. See **STANDARD G8220**, *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures.*

10.12. Sections with pipe left with 100% nitrogen must be stenciled “Nitrogen”. Also adjourning valves must be stenciled “Nitrogen”.

11. TYPICAL ORIFICE SET UP (DIRECT PURGE)

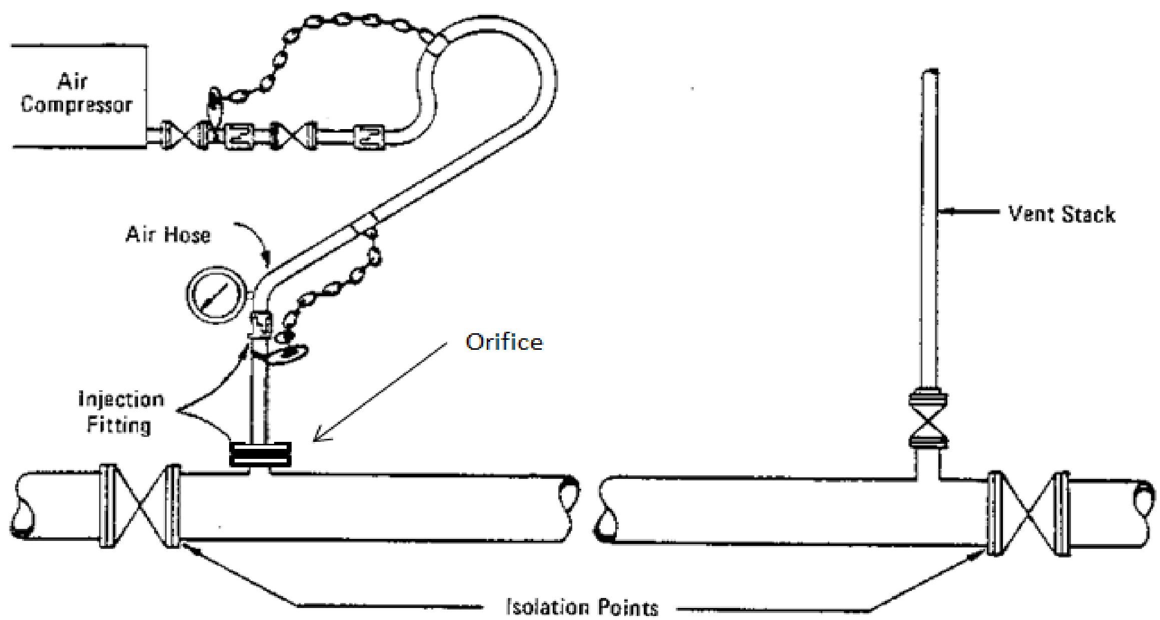


Figure 6. Direct Method with Orifice and pressure gauge relocated closer to orifice. (Direct Purging)

12. OPERATOR QUALIFICATION COVERED TASKS
(See **STANDARD G8113**, *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 07.01-1651 -** Purge Direct: Flammable or Inert Gas
- **Task 07.02-1651 -** Purge Indirect: Flammable or Inert Gas

13. EXCEPTION PROCEDURE

(See **STANDARD G7007**, *Exception Procedure for Company Operations Standards*)

13.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

13.2 An exception from a standard shall not be allowed unless **GS G7007**, *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by G7007.

14. RECORDS

Not Applicable.

15. APPENDICES

15.1. Appendix A

APPENDIX A

Table A1
Minimum Equipment Requirements for Purging Pipeline

Nominal Pipe Diameter (inches)	Hose Diameter ID** (inches)	Minimum Nominal Vent Stack Size*** (inches)	Minimum Gauge Pressure * Gas (psig)	Nitrogen/Air (psig)	Minimum Injection Flow Rate (SCFM)
4 and less	¾	3/4	3	3	11
6	¾	1 -1/2	6	8	29
8	¾	1 -1/2	15	18	56
10	¾	2	28	35	96
12	¾	3	47	59	149
16	1 1/4	3	19	26	273
18	1 1/4	4	28	40	367
20	1 1/4	4	41	55	489
22	1 1/4	4	55	75	615
26	2	6	21	30	930
30	2	6	32	45	1331
34	2	6	45	65	1821
36	2	6	54	77	2117

* Pressures listed are based on placing a pressure gauge on 50 feet of hose at the upstream end of the injection point. Shorter distances yield greater injection rates and shorten purge durations. Contact **Gas Engineering – Pipeline Engineering** if hose distances are greater than 50 feet.

** If it's necessary to use a larger diameter hose larger specified, contact **Gas Engineering** - **Pipeline Engineering** for the lower required minimum gauge pressure.

*** For vents in excess of 10 ft. long, go to next larger pipe size. Multiple vents stacks are allowed if a single vent stack does not meet the minimum diameter requirements. The total internal flow area of the multiple vents needs to be greater than the internal flow area of the required vent size. Contact **Gas Engineering** - **Pipeline Engineering** for guidance on correct combinations of vent stacks.

Note: The diameter of manifolds should be at least equal to the size of the hose diameter required for purging.

Table A1*

Measuring Rates through Orifices
Use these figures for measuring the injection rates while purging.
(Note: All Hose and Orifice Sizes are Internal Diameters)

Inject Rate (cfm)	Pressure Upstream of Orifice (psig) (Note: All Hose and Orifice Sizes are Internal Diameters)									
	Orifice Size (inches)									
	3/8		1/2		5/8		3/4		7/8	
	Gas	N_2 Air	Gas	N_2 Air	Gas	N_2 Air	Gas	N_2 Air	Gas	N_2 Air
10										
20										
40	7	12								
60	19	26	5	8						
80	30	39	11	16	2	5				
100	41	53	18	24	6	10				
120	52	67	25	31	10	14				
140	63	80	31	39	14	19				
160	75	94	38	47	19	24				
180	86	107	44	54	23	29				
200	97	121	51	62	27	34				
220	106	136	53	70	29	39	17	22	9	13
240	117	150	59	78	33	44	20	26	11	15
260	128	163	66	85	37	49	22	29	13	18
280	139	177	72	93	41	54	25	33	15	20
300	150	191	78	101	45	59	28	36	17	23
320	161	205	84	109	49	64	31	39	19	25
340	172	218	90	116	53	69	34	43	21	28
360	183	232	97	124	57	74	37	46	24	30
380	194	246	103	132	61	78	40	50	26	33
400	205	259	109	139	65	83	43	53	28	35
420	216	273	115	147	69	88	45	56	30	38
440	227	287	121	155	73	93	48	60	32	40
460	238	301	128	163	77	98	51	63	34	43
480	249	314	134	170	81	103	54	67	36	45
500	260	328	140	178	85	108	57	70	39	48
550	286	362	156	197	95	120	61	79	41	53
600	314	397	171	217	105	133	68	87	46	59
650	341	431	187	236	115	145	75	96	51	65
700	369	465	202	255	125	157	82	104	56	71
750	396	500	218	275	135	170	89	113	62	77
800	423	534	233	294	145	182	95	121	67	83
850	451	568	249	313	155	194	102	130	72	90
900	478		264	332	165	206	109	138	77	96
950	506		280	352	175	219	116	147	82	102
1000	533		295	371	185	231	123	155	87	108
1050	560		311	390	195	243	130	164	92	114
1100	588		326	410	205	256	137	172	97	120
1150			342	429	215	268	144	181	102	126
1200			357	448	225	280	151	189	107	133
1250			373	468	235	293	158	198	113	139
1300			388	487	245	305	164	206	118	145
1350			404	506	255	317	171	215	123	151
1400			419	525	265	329	178	223	128	157
1450			435	545	275	349	185	232	133	163
1500			450	564	285	354	192	240	138	170
1550			466	583	295	366	199	249	143	176
1600			481		305	379	206	257	148	182
1650			497		315	391	213	266	153	188
1700			512		325	403	220	274	158	194
1750			528		335	416	227	283	164	200
1800			543		345	428	233	291	169	206
1850			559		355	440	240	300	174	213
1900			574		365	452	247	308	179	219
1950			590		375	465	254	317	184	225
2000					385	477	261	325	189	231
2050					395	489	268	334	194	237
2100					405	502	275	342	199	243

Table A1 (continued)*

Measuring Rates through Orifices

Use these figures for measuring the injection rates while purging.

(Note: All Hose and Orifice Sizes are Internal Diameters)

Inject Rate (cfm)	Pressure Upstream of Orifice (psig) (Note: All Hose and Orifice Sizes are Internal Diameters) — Orifice Size (inches): 1-1/8 Gas	1-1/8 N_2 Air	1-3/8 Gas	1-3/8 N_2 Air	1-1/2 Gas	1-1/2 N_2 Air	1-3/4 Gas	1-3/4 N_2 Air
10								
20								
40								
60								
80								
100								
120								
140								
160								
180								
200								
220		2						
240		3						
260	2	5						
280	3	6						
300	4	8						
320	5	9						
340	7	11						
360	8	12						
380	9	14						
400	11	15						
420	12	17						
440	13	18						
460	14	20						
480	16	21						
500	17	23						
550	20	26	9	13				
600	23	30	11	15				
650	26	34	13	18				
700	29	38	15	20				
750	32	41	17	23				
800	35	45	19	25				
850	39	49	22	28				
900	42	53	24	30				
950	45	56	26	33				
1000	48	60	28	35	18	26	9	15
1050	51	64	30	38	20	28	10	17
1100	54	68	32	40	21	30	11	18
1150	57	71	34	43	23	32	13	20
1200	61	75	37	45	25	34	14	21
1250	64	79	39	48	26	36	15	23
1300	67	83	41	50	28	38	16	24
1350	70	86	43	53	30	40	17	26
1400	73	90	45	55	31	42	19	27
1450	76	94	47	58	33	44	20	29
1500	80	98	50	60	35	47	21	30
1550	83	101	52	63	36	49	22	32
1600	86	105	54	65	38	51	23	33
1650	89	109	56	68	39	53	25	35
1700	92	113	58	70	41	55	26	36
1750	95	116	60	73	43	57	27	38
1800	98	120	62	75	44	59	28	39
1850	102	124	65	78	46	61	29	41
1900	105	128	67	80	48	63	31	42
1950	108	131	69	83	49	65	32	44
2000	111	135	71	85	51	67	33	45
2050	114	139	73	88	53	69	34	47
2100	117	143	75	90	54	71	35	48

Table A2**

Pipe Size (in.)	Estimated Duration of Purge (min) (at the minimum injection rates shown in Table A1) Length of Pipe (feet) **1000**	**2000**	**3000**	**4000**	**5000**	**6000**	**8000**	**10000**	**20000**	**50000**
4 and less	8	16	24	32	40	48	64	80	160	400
6	8	16	23	31	39	46	62	77	154	385
8	7	14	20	27	34	40	54	67	134	334
10	6	12	18	25	31	37	49	61	122	303
12	6	11	17	22	28	34	45	56	111	278
16	5	10	15	19	24	29	38	48	96	238
18	5	9	14	18	23	28	37	46	91	228
20	5	9	13	17	22	26	34	43	85	213
22	4	8	13	16	21	25	33	41	82	205
26	4	8	12	15	19	23	30	38	76	189
30	4	7	11	14	18	21	28	35	70	176
34	4	7	10	13	17	20	27	33	66	164
36	3	7	10	13	16	19	26	32	64	159

The time for lengths not shown may be interpolated. For assistance with interpolation, contact **Gas Engineering - Pipeline Engineering.

Table A3

Number of Nitrogen Cylinders (250 Cubic Feet Each)
Required To Form the Minimum Slug Size in a Pipeline
Indirect Method

Pipe Size (inches)	Pipe Length (ft)									
	500**	**1000**	**2000**	**3000**	**4000**	**5000**	**7500**	**10,000**	**20,000**	**50,000**
4	1	1	1	1	1	1	1	1	1	1
6	1	1	1	1	1	1	1	1	1	2
8	1	1	1	1	1	1	1	1	2	2
10	1	1	1	1	1	2	2	2	2	3
12	1	1	2	2	2	2	2	2	3	4
16	2	2	2	2	3	3	3	4	5	7
18	2	2	3	3	3	4	4	5	6	9
20	2	3	3	4	4	4	5	6	7	11
22	3	3	4	4	5	5	6	7	9	13
26	4	4	5	6	6	7	8	9	12	18
30	5	5	7	8	8	9	11	12	16	24
34	6	7	9	11	12	13	15	17	23	35
36	7	8	10	12	13	15	17	19	26	39

Pipelines less than 500 ft. may be displaced directly with air or gas. Refer to **Table 1 "Purging Method" for additional guidance or when indirect purge is to be used.

Table A4
Number of Nitrogen Cylinders (250 Cubic Feet Each) Required To Fill Pipeline
Total Displacement Method

Pipe Size (inches)	Pipe Length (ft) 500	1000	2000	3000	4000	5000	6000	8000	10,000	20,000	50,000
2	1	1	1	1	1	1	1	1	2	3	5
3	1	1	1	1	1	2	2	2	3	5	11
4	1	1	1	2	2	3	3	4	5	9	19
6	1	1	2	3	4	5	6	8	10	19	*42
8	1	2	4	5	7	9	10	13	17	*33	*74
10	2	3	6	8	11	13	16	21	26	*52	*116
12	2	4	8	11	15	19	22	29	*37	*73	*164
16	3	6	12	17	23	28	*34	*45	*56	*112	*254
18	4	8	15	22	29	*36	*43	*58	*72	*143	*325
20	5	9	18	27	*36	*45	*54	*72	*89	*178	*405
22	6	11	22	*33	*44	*55	*66	*87	*109	*217	*494
26	8	16	31	*46	*62	*77	*92	*123	*154	*307	*696
30	11	21	*42	*62	*83	*103	*124	*165	*206	*411	*934
34	14	27	*54	*80	*107	*133	*160	*213	*266	*531	*1206
36	15	30	*60	*90	*120	*150	*179	*239	*299	*597	*1356

* Consider using a nitrogen truck for purges. See Table A6 for volume in SCF.

Table A5
Volume (SCF) of Nitrogen Required To Form the Minimum Required Slug Size in Pipeline
Indirect Method

Pipe Size (inches)	*Pipe Length in Feet 2000	3500	5000	7500	10,000	20,000	50,000
12	263	321	368	433	486	653	985
16	430	527	605	712	802	1080	1632
18	553	677	777	915	1030	1387	2097
20	689	844	968	1139	1283	1728	2611
22	831	1017	1168	1375	1548	2085	3151
26	1162	1424	1633	1923	2165	2916	4406
30	1546	1895	2173	2561	2880	3880	5863
34	2204	2722	3137	3711	4189	5677	8630
36	2480	3067	3531	4179	4716	6391	9714

*Consider using bottles for smaller diameters and shorter lengths.

Table A6
Volume (SCF) of Nitrogen Required to Fill Pipeline
Total Displacement Method

Pipe Size (inches)	Pipe Length in Feet										
	500	1000	2000	3000	4000	5000	6000	8000	10,000	20,000	50,000
6	*116	*231	*461	*691	*921	*1,151	*1,381	*1,840	*2,300	4,600	11,498
8	*202	*403	*805	*1,206	*1,608	*2,010	*2,412	*3,215	4,019	8,037	20,091
10	*320	*639	*1,277	*1,915	*2,552	*3,190	*3,828	5,104	6,379	12,758	31,893
12	*451	*902	*1,802	*2,703	*3,604	4,504	5,405	7,206	9,007	18,014	45,032
16	*699	*1,397	*2,792	4,188	5,584	6,979	8,375	11,166	13,957	27,914	69,782
18	*894	*1,786	*3,571	5,357	7,142	8,927	10,712	14,283	17,853	35,705	89,261
20	*1,112	*2,224	4,447	6,670	8,893	11,116	13,339	17,784	22,230	44,459	111,147
22	*1,357	*2,713	5,425	8,136	10,848	13,560	16,272	21,695	27,119	54,237	135,591
26	*1,915	*3,828	7,655	11,482	15,309	19,136	22,964	30,618	38,272	76,543	191,355
30	*2,568	5,134	10,268	15,401	20,534	25,668	30,801	41,068	51,334	102,668	256,668
34	*3,316	6,632	13,262	19,893	26,523	33,154	39,784	53,045	66,307	132,612	331,529
36	*3,729	7,457	14,912	22,368	29,823	37,279	44,734	59,645	74,557	149,112	372,779

* Consider using bottles for purges.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Fully reviewed. Re-structured and re-formatted the standard for clarity, added/revised Sections 12, 13, and 14. Provided additional clarity on CGI requirements for purging operations, added/removed updated Operator Qualification covered tasks, and various editorial changes.

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	09/01/2019
Last Full Review Completed On:	07/30/2019
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
If Merged, Merged To Document Number:	
Utility:	SDG&E
Department:	Gas Engineering
Number of Common Document:	182.0160
Confidential Sections:	
Part of SoCalGas O&M Plan:	No
Part of SDG&E O&M Plan:	Yes
Contains OPQUAL Covered Task:	Yes
OpQual Tasks	07.01 07.02
Last O&M Review date:	2019-09-24
O&M 49 CFR Codes & Impacted Sections of Document:	192.727(e): Entire Doc 192.727(c): Entire Doc 192.727(b): Entire Doc 192.629(b): Entire Doc 192.629(a): Entire Doc 192.605(b)(6): Entire Doc 192.605(b)(5): Entire Doc
Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	No
Part of Transmission IMP (TIMP)	No
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
GO112F Codes & Impacted Sections of Document	
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	CFSD, CSFSD, GSSD, MSSD
NOP Learning Module (LM) Training Code:	NOP01101

SoCalGas
A Sempra Energy utility

ROUTING (COLLECTIBLE)
[redacted]
(FORM 3466 & CO. PROPERTY DAMAGE REPORT)

ROUTING (NON-COLLECTIBLE)
[redacted]

If gas loss is on a transmission asset, please also route to [redacted]

REPORTING OF GAS BLOWN TO ATMOSPHERE

Date Gas Blown	Location (Lay down yard, end points, or GPS coordinates)	City	District	Department

Reason For Gas Blown:

Account #	I/O#	USA Ticket #	SAP Plant Maintenance #	Cost Center	Collectible?
					No

Line Number	Outside Diameter (in)	Wall Thickness (in)	Pipeline Isolation Points (Stationing)		Total Miles Isolated
			From:	To:	

Company Damages

Is this project a result of company damage? No

Blowdown Reduction Methods and Approach

Is this project bundled with other projects that resulted in a net blowdown reduction?
- (●) Yes
- ( ) No

Project #1 IO	
Project #1 Percentage	
Project #2 IO	
Project #2 Percentage	

Project Bundling Details

How was the pipeline pressure reduced prior to blowdown?
- ☐ Cross Compression
- ☐ CNG Capture (tanking)
- ☐ Draw Down Pressure
- ☐ Diverting to Other Local Lines
- ☐ Volume Reduction Via Stopple Fittings
- ☐ Thermal Oxidizers
- ☐ Other

If other, provide details:

Is the total volume released >500 MCF? Does exceed 500 MCF

Provide explanation why:
e.g. Safety or Reliability of service

Blowdown Estimation per Gas Std. 182.0032

Select automatic calculations or manual data entry for the following: Automatic Calculations

Operating pressure before pressure reduction (MOP if unknown):	0	PSIG
Gas consumed by equipment for blowdown reduction (will be provided by CNG team, otherwise 0):	0	MSCF
Pipeline pressure at the start of blowdown, after pressure reductions:	0	PSIG
Pipeline pressure at the end of blowdown (default is zero):	0	PSIG
Volume of Gas Saved Due to Pressure Reduction:	0.000	MSCF
Volume Emitted Due to Blowdowns or Purges:	0.000	MSCF

Prepared By:	Date:	Approved By:	Date:

SoCalGas
A Sempra Energy utility

Please route to [redacted]

BLOWDOWN EMISSION REDUCTION PLAN

Planned Blowdown Date	Location (Lay down yard, end points, or GPS coordinates)	City	District	Department

Line Number	Outside Diameter (in)	Wall Thickness	Pipeline Isolation Points (Stationing)		Total Miles Isolated
			From:	To:	

How will the pipeline pressure be reduced prior to blowdown?

- ☐ Cross Compression
- ☐ CNG Capture (tanking)
- ☐ Draw Down Pressure
- ☐ Diverting to Other Local Lines
- ☐ Volume Reduction Via Stopple Fittings
- ☐ Thermal Oxidizers
- ☐ Other

If other, provide details:

Provide verification:
Check all Supporting Documentation

- ☐ Reserve or ZEVAC Quotes for Cross Compression
- ☐ Communication Records of Gas Control Confirming availability of time for extended outage
- ☐ RER Identifying Taps for Drawdown
- ☐ Requests for CNG capture service
- ☐ Other

Note: for ILI projects, please determine the cumulative volume for the entire project based upon the number of blowdowns at each launcher/receiver location.

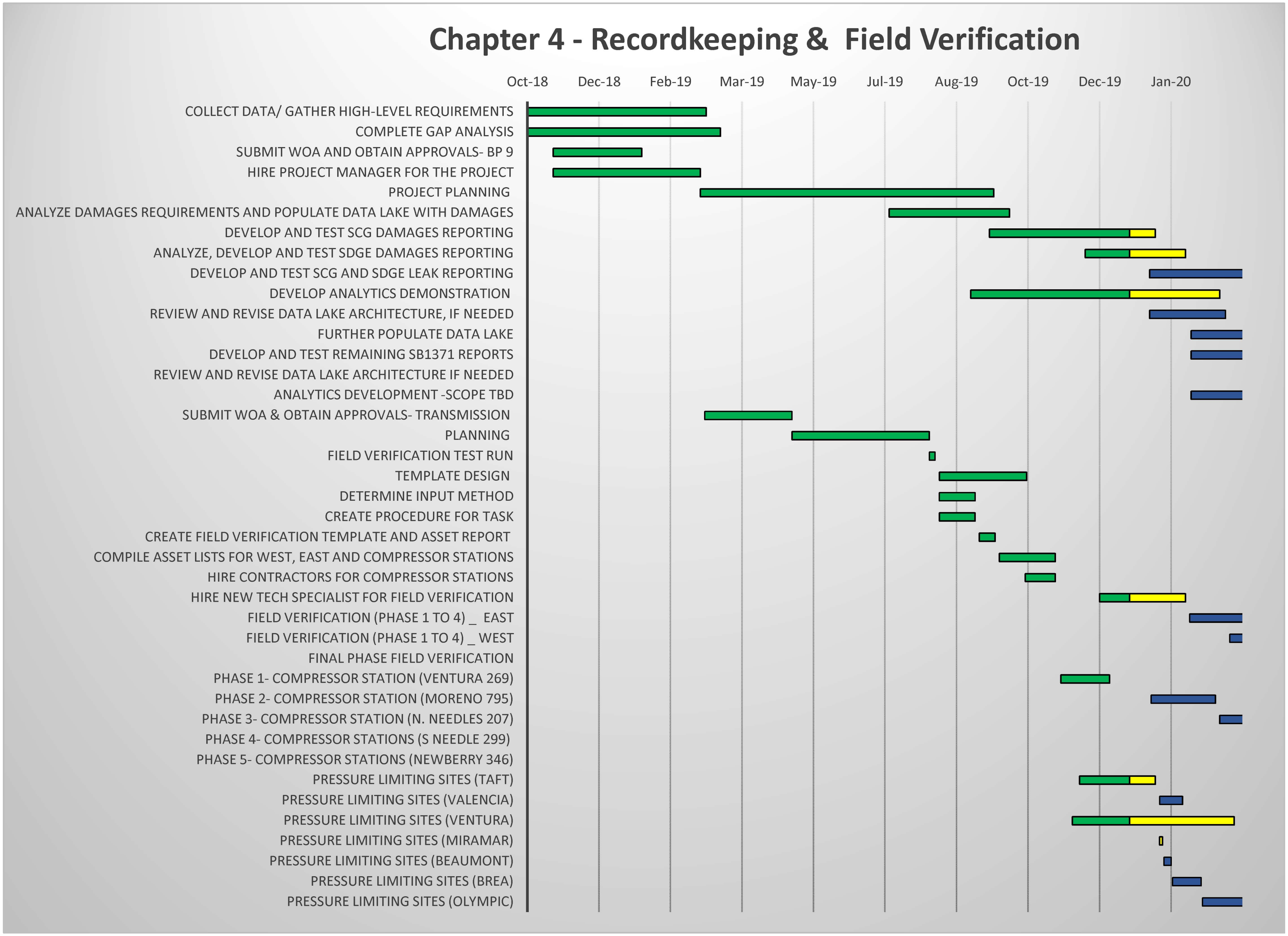
If other, provide details:

Blowdown Estimation per Gas Std. 182.0032

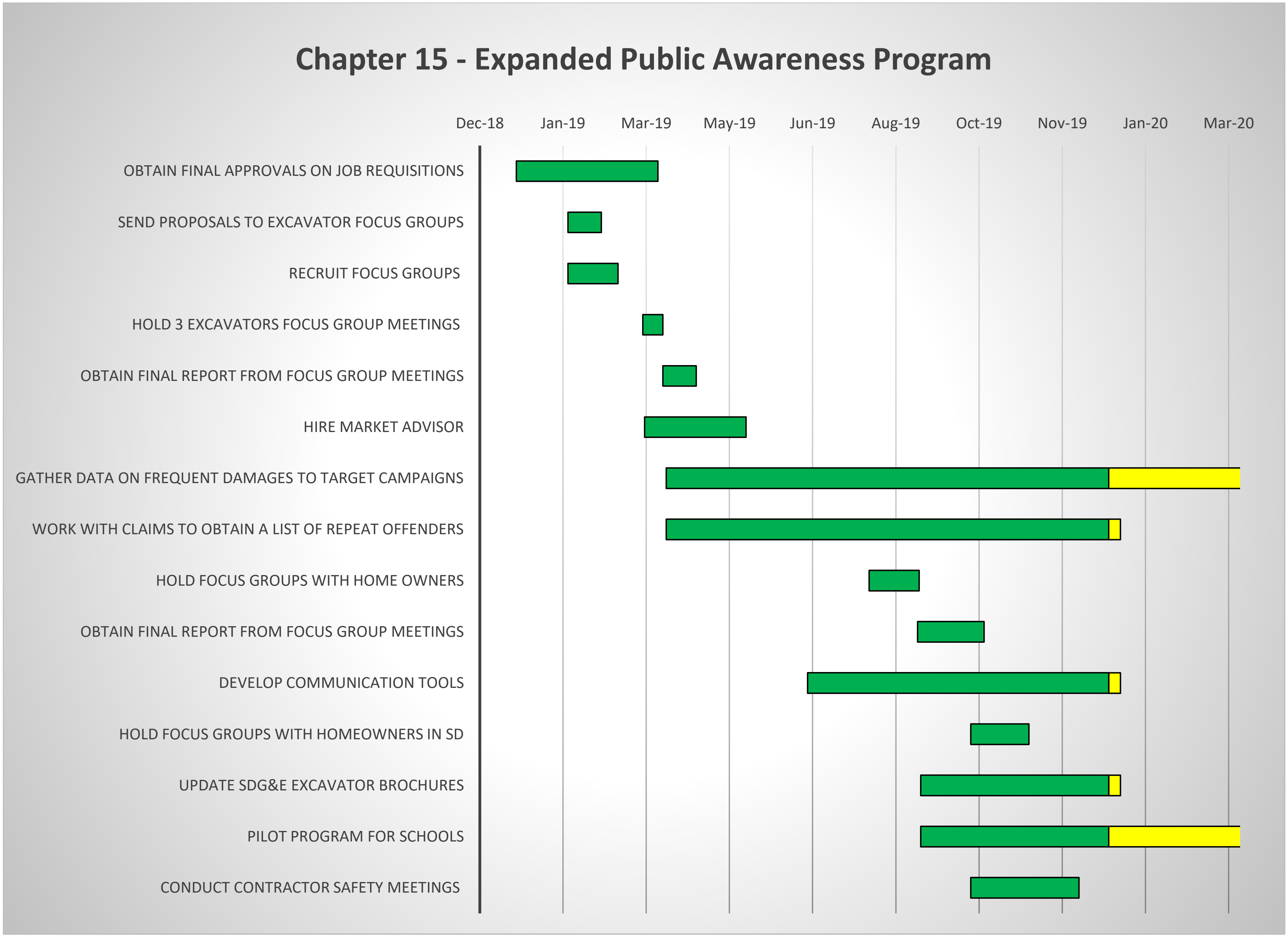
Select automatic calculations or manual data entry for the following: Automatic Calculations

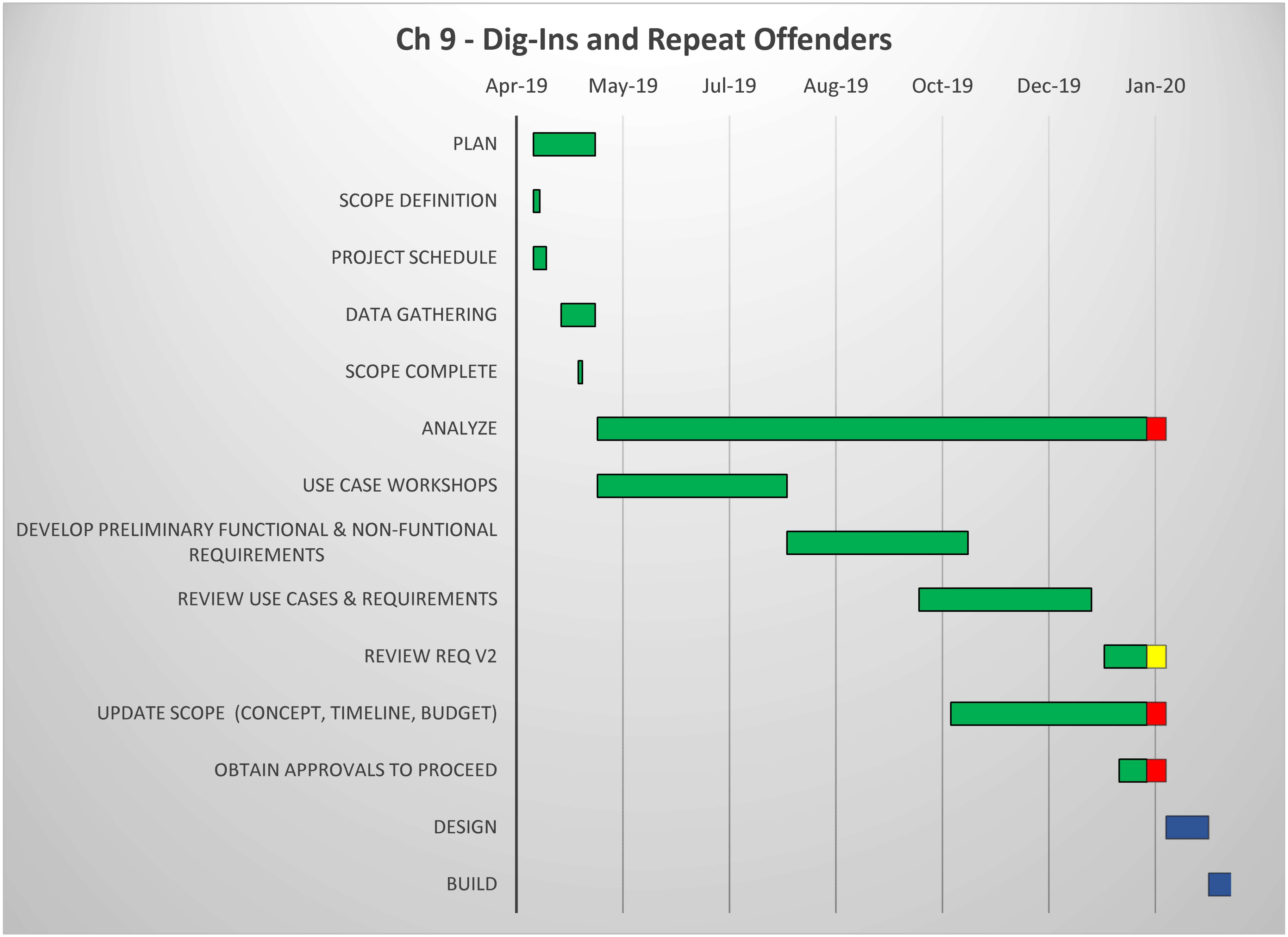
Estimated Operating pressure before pressure reduction (Enter MOP if unknown):		PSIG
Estimated Gas consumed by equipment for blowdown reduction (will be provided by CNG team, otherwise 0):	0	MCF
Estimated Pipeline pressure at the start of blowdown, after pressure reductions:		PSIG
Estimated Pipeline pressure at the end of blowdown (default is zero):	0	PSIG
Projected Volume of Gas Saved Due to Pressure Reduction:		MCF
Volume Planned to be Emitted Due to Blowdowns/Purges:	0.0	MCF

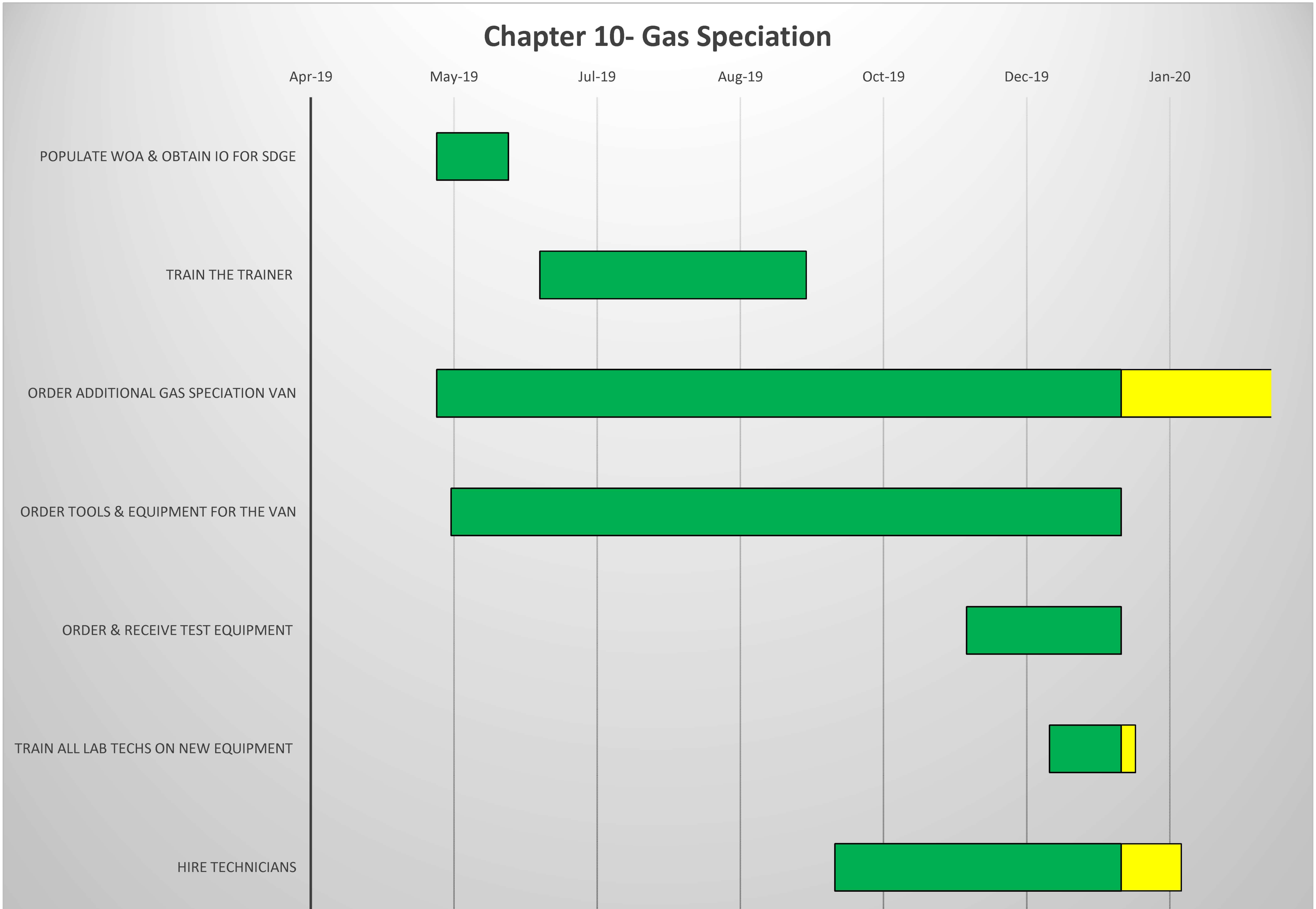
Prepared By: **Date:**



Chapter 4 - Recordkeeping & Field Verification
Oct-18
Dec-18
Feb-19
Mar-19
May-19
Jul-19
Aug-19
Oct-19
Dec-19
Jan-20
COLLECT DATA/ GATHER HIGH-LEVEL REQUIREMENTS
COMPLETE GAP ANALYSIS
SUBMIT WOA AND OBTAIN APPROVALS- BP 9
HIRE PROJECT MANAGER FOR THE PROJECT
PROJECT PLANNING
ANALYZE DAMAGES REQUIREMENTS AND POPULATE DATA LAKE WITH DAMAGES
DEVELOP AND TEST SCG DAMAGES REPORTING
ANALYZE, DEVELOP AND TEST SDGE DAMAGES REPORTING
DEVELOP AND TEST SCG AND SDGE LEAK REPORTING
DEVELOP ANALYTICS DEMONSTRATION
REVIEW AND REVISE DATA LAKE ARCHITECTURE, IF NEEDED
FURTHER POPULATE DATA LAKE
DEVELOP AND TEST REMAINING SB1371 REPORTS
REVIEW AND REVISE DATA LAKE ARCHITECTURE IF NEEDED
ANALYTICS DEVELOPMENT -SCOPE TBD
SUBMIT WOA & OBTAIN APPROVALS- TRANSMISSION
PLANNING
FIELD VERIFICATION TEST RUN
TEMPLATE DESIGN
DETERMINE INPUT METHOD
CREATE PROCEDURE FOR TASK
CREATE FIELD VERIFICATION TEMPLATE AND ASSET REPORT
COMPILE ASSET LISTS FOR WEST, EAST AND COMPRESSOR STATIONS
HIRE CONTRACTORS FOR COMPRESSOR STATIONS
HIRE NEW TECH SPECIALIST FOR FIELD VERIFICATION
FIELD VERIFICATION (PHASE 1 TO 4) _ EAST
FIELD VERIFICATION (PHASE 1 TO 4) _ WEST
FINAL PHASE FIELD VERIFICATION
PHASE 1- COMPRESSOR STATION (VENTURA 269)
PHASE 2- COMPRESSOR STATION (MORENO 795)
PHASE 3- COMPRESSOR STATION (N. NEEDLES 207)
PHASE 4- COMPRESSOR STATIONS (S NEEDLE 299)
PHASE 5- COMPRESSOR STATIONS (NEWBERRY 346)
PRESSURE LIMITING SITES (TAFT)
PRESSURE LIMITING SITES (VALENCIA)
PRESSURE LIMITING SITES (VENTURA)
PRESSURE LIMITING SITES (MIRAMAR)
PRESSURE LIMITING SITES (BEAUMONT)
PRESSURE LIMITING SITES (BREA)
PRESSURE LIMITING SITES (OLYMPIC)


Chapter 15 - Expanded Public Awareness Program
Dec-18
Jan-19
Mar-19
May-19
Jun-19
Aug-19
Oct-19
Nov-19
Jan-20
Mar-20
OBTAIN FINAL APPROVALS ON JOB REQUISITIONS
SEND PROPOSALS TO EXCAVATOR FOCUS GROUPS
RECRUIT FOCUS GROUPS
HOLD 3 EXCAVATORS FOCUS GROUP MEETINGS
OBTAIN FINAL REPORT FROM FOCUS GROUP MEETINGS
HIRE MARKET ADVISOR
GATHER DATA ON FREQUENT DAMAGES TO TARGET CAMPAIGNS
WORK WITH CLAIMS TO OBTAIN A LIST OF REPEAT OFFENDERS
HOLD FOCUS GROUPS WITH HOME OWNERS
OBTAIN FINAL REPORT FROM FOCUS GROUP MEETINGS
DEVELOP COMMUNICATION TOOLS
HOLD FOCUS GROUPS WITH HOMEOWNERS IN SD
UPDATE SDG&E EXCAVATOR BROCHURES
PILOT PROGRAM FOR SCHOOLS
CONDUCT CONTRACTOR SAFETY MEETINGS


Ch 9 - Dig-Ins and Repeat Offenders
Apr-19
May-19
Jul-19
Aug-19
Oct-19
Dec-19
Jan-20
PLAN
SCOPE DEFINITION
PROJECT SCHEDULE
DATA GATHERING
SCOPE COMPLETE
ANALYZE
USE CASE WORKSHOPS
DEVELOP PRELIMINARY FUNCTIONAL & NON-FUNTIONAL REQUIREMENTS
REVIEW USE CASES & REQUIREMENTS
REVIEW REQ V2
UPDATE SCOPE (CONCEPT, TIMELINE, BUDGET)
OBTAIN APPROVALS TO PROCEED
DESIGN
BUILD


Chapter 10- Gas Speciation
Apr-19
May-19
Jul-19
Aug-19
Oct-19
Dec-19
Jan-20
POPULATE WOA & OBTAIN IO FOR SDGE
TRAIN THE TRAINER
ORDER ADDITIONAL GAS SPECIATION VAN
ORDER TOOLS & EQUIPMENT FOR THE VAN
ORDER & RECEIVE TEST EQUIPMENT
TRAIN ALL LAB TECHS ON NEW EQUIPMENT
HIRE TECHNICIANS

A Sempra Energy utility®

Environmental Excellence Policy

Responsible Dept.: Environmental Services
Responsible Officer: VP of Operations Support and Chief Environmental Officer
Applicability: **All Employees of SDG&E**

EFFECTIVE DATE: 05/14/2012
REVISION DATE: 12/18/2018
REVIEW DATE: 12/18/2018
INFORMATION TYPE: **Public**
Questions?
Contact: Environmental Services

1. POLICY:

Environmental excellence means being a responsible steward of the earth's cultural and natural resources and conserving plant and animal species along with their habitats San Diego Gas and Electric (SDG&E) is a responsible steward and conducts its activities in a way that protects the current and long-term wellbeing of our employees, the public, and the environment to meet the needs of the present without impacting the ability of future generations to meet their needs. SDG&E is committed to the following program activities to support Environmental Excellence.

1.1. Energy Efficiency & Air Quality /Climate Change

- Energy efficiency is a fundamental element in the progress toward a sustainable energy future. SDG&E is determined to assist our customers in consuming less energy.
- SDG&E recognizes that meeting customer energy needs requires diversification of energy sources along with efficiency both in production and use of all energy resources. SDG&E is determined to produce cleaner energy and will continue to focus on delivering a reliable energy supply and services that are competitively priced and support a low-carbon model that includes natural gas, energy efficiency, renewable power, clean transportation, distributed generation, and innovative technologies while reducing the emission of criteria pollutants greenhouse gases that contribute to climate change.
- SDG&E recognizes that methane is a potent Green House Gas that must be prevented from escaping to the atmosphere and supports the activities prescribed in Senate Bills 1371 and 1383 to reduce methane emissions.

1.2. Natural and Cultural Diversity

- San Diego County is rich in natural and cultural resources. It also has more biodiversity than any other county in North America, and along with the rest of California is among the top ten biodiversity regions on earth.
- SDG&E recognizes the overall challenge of environmental sustainability is the protection of biodiversity and natural and cultural resources.
- SDG&E is committed to conducting its operations in a way that promotes the maintenance of our regional biodiversity and the habitat upon which it depends through a coordinated and comprehensive program of avoidance, minimization and /or mitigation of impacts
- SDG&E is further committed to reducing freshwater consumption and preserving water quality through the design and operation of our facilities.

1.3. Lifecycle of Operations and Other Business Activities

- SDG&E is committed to preventing pollution throughout the life cycle of our operations and business activities by improving our environmental management systems. This includes minimizing energy and fuel usage, "greening" procurement practices, maintaining control over the chemical substances and materials used, reducing, substituting, and eliminating substances that have potentially significant impacts, and maximizing the recycling of wastes and byproducts.

2. BACKGROUND.

California is among the top ten biodiversity regions in the United States and as a result is rich in natural and cultural resources. **Biodiversity** is defined as the existence of a wide variety of plant and animal species in their natural environments. We are committed to protecting, preserving and enhancement of biodiversity in areas where we operate.

SDG&E uses water in a responsible and sustainable manner, and abides by applicable water related laws, regulations and permit requirements.

Environmental procedures are developed to manage environmental impacts including water reuse, recycling and waste minimization, greenhouse gas and other air emissions reduction programs and air quality improvements.

3. RELATED DOCUMENTS

Environmental Standards and Fact Sheets related to this policy can be found on the Sempra Utilities Operations Document System.

4. INFORMATION RETENTION GUIDANCE

For guidance as to the appropriate retention period for information related to this policy, please refer to the Information Management Policy.

Company Operations Standard
Gas Standard
Gas Engineering

Inspection Schedule - Regulator Station, Power Generating Plant Regulation Equipment Requirements	SDG&E:	T8172

PURPOSE **Measurement, Regulation & Control (MRC) with Region consultation determines the frequency of inspections of measurement and regulation equipment based on regulatory requirements, equipment performance and problems reported. Published inspections are minimum requirements. Regions have the option of performing more frequent inspections where conditions indicate the need.**

1. POLICY AND SCOPE

1.1. To maintain the integrity of all measurement, regulation equipment, records and schedules for associated equipment with regulator stations and power generating plants.

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. **Regulator Technicians** perform inspections and tests on regulator station and power generating plant equipment to ensure that the station/plant is in good mechanical condition, set to function at the correct pressure, and is properly installed and protected from dirt, liquids, erosion, or other adverse conditions affecting operation.

2.2. **Instrument Technicians** perform inspections on flow computers, transmitters, correctors, electronic pressure recorders, SCADA and various types of communication equipment to ensure equipment is in good working condition and accurate when compared to reference standards.

2.3. **Regions** are responsible for conducting on-the-job training and self-audit programs to ensure compliance with this Standard.

3. DEFINITIONS

3.1. SAP – System, Applications & Products in data processing

3.2. SAP-PM – Plant Maintenance (SAP-PM is the Plant Maintenance module for SAP application)

3.3. Click Schedule – application used by the Area Resource & Scheduling Organization to plan, schedule and assign work to field crews.

3.4. Click Mobile – (Field mobile application software) – this is the approved Company software that is loaded onto each M&R field technician's Mobile Data Terminal

3.5. MAXIMO – The computerized maintenance management system used by SoCalGas and SDG&E to assist with planning, scheduling, and documentation of maintenance work on transmission and underground storage piping and equipment.

4. PROCEDURE

4.1. **Regulator Technicians** report dirt, liquids, erosion and other adverse conditions to supervision within one workday. Supervision to initiate installation of a screen or filter**.**

4.2. Records documenting new facility installation, field inspections and maintenance for each regulator and power generating plant facility, are maintained by the responsible **Distribution/Transmission Regions**.

4.3. **Regions** schedule more frequent inspections as conditions warrant.

4.3.1. **Regulator Technicians** complete inspection steps for the following:

4.3.2. Regulator station requirements listed in new **Appendix A** of this Standard.

4.3.3. Piston operated valve regulator requirements listed in new **Appendix B** of this Standard.

4.3.4. Power generating plant requirements listed in new **Appendix C** of this Standard.

4.4. Each pressure limiting station, relief device (except rupture discs), signaling device 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:

4.4.1. In good mechanical condition;

4.4.2. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

4.4.3. Except as provided in paragraph (4.7), set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a); and

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

4.4.5. For steel pipelines whose MAOP is determined under §192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

4.5. Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

4.6. If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

4.7. If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (4.5) of this section.

5. INSPECTIONS

Inspection Scheduling

5.1. The SAP-PM (Plant Maintenance) application will create preventive inspection orders for regulators, valves, vaults and mainline filter equipment in regulator stations and power plants. The supervisor of region measurement functions is responsible for assuring all equipment is accounted for and inspected on time.

5.2. Regulator stations and power generating plants must be inspected at least once each calendar year. Inspections, including remedial work, are completed during the base inspection (anniversary) month, or within the "grace" period (defined as **one month** following the base inspection month for **customers** and **3 months** following the base inspection month for **District Regulator Stations**. Exceptions are:

5.2.1. **Customer** inspections with a base month for January must be completed in January or February.

5.2.2. **District Regulator Station** inspections with a base month for January must be completed in January, February, March or April.

5.2.3. December base month inspections must be completed in December.

5.2.4. Bi-annual inspections must be completed within their base month, and again during their 6-month anniversary (no "grace period").

5.2.5. Quarterly inspections must be completed within their base month, and again during each 3-month anniversary (no "grace period").

Note: Supervisor approval required if a Base Month is to be changed from original. Contact MRC staff for assistance.

5.3. Self-Audit

5.3.1. Supervisors and Leads will be able to verify all outstanding and completed orders through SAP-PM. SAP-PM will create and Click Schedule will issue work orders.

5.3.1.1. NOTE: With the roll out of OpEx, clerks, leads and supervisors will run daily reports against open notifications and orders in SAP for suspect non-compliance work. These reports are available via standard SAP or through SAP-BW. When Click Release 8 is rolled out, an exception report for preventive orders due and any orders near due date that will go into "*Jeopardy*" will be developed to allow the appropriate Supervisor to take immediate action. Reports should be run daily to ensure strict adherence to inspection intervals for compliance to CPUC and DOT rules and regulations.

5.4. Expansible Element and Diaphragm

5.4.1. MAXIMO or SAP-PM determines the interval, creates the preventive work order and, where applicable, **Click Schedule issues the order to perform** internal-parts-replacement (IPR) inspections for diaphragm or expansible elements at varying internals (depending on type and manufacturer) not to exceed fifteen (15) years.

5.4.2. Replace pilot diaphragms and valve seats etc., with associated mainline regulator IPR inspections.

> **NOTE: District Regulator Stations -** Internally inspect expansible element regulators every 2 years if used as a monitor with pilot that bleeds either to atmosphere or into another system. The SAP-PM maintenance plan must be updated manually for each regulator meeting the above criteria.
>
> **Customer MSA's -** Externally inspect expansible element regulators every 12 months if used as a monitor with pilot that bleeds either to atmosphere or into another system. The SAP-PM maintenance plan must be updated manually for each regulator meeting the above criteria.
>
> **Contact MRC – Measurement Technologies** to request updates to each regulator maintenance plan meeting above criteria.

6. DISTRICT REGULATOR STATION (DRS) SPECIAL INSPECTIONS

Special inspections require:

- Inspection of all regulators.
- Operation test of piston operated valves.
- Inspection of all mainline filters, pilot filters and screens/strainers.

> **NOTE:** DRS equipped with a mainline filter require only an external regulator inspection if filter inspection is found free of debris and liquids and the elements are intact.

6.1. Perform a special internal inspection on each regulator at regulator stations whenever there is a reason to suspect foreign materials/substance (wet or dry) in the gas stream.

- Enter appropriate condition code(s) on field orders.

7. CAPACITY CHECKS

7.1. Region Planning is responsible to determine:

7.2. The adequate capacities of district regulator stations.

7.3. The adequate capacities of pressure relieving devices. Special capacity checks are required prior to:

- Increasing inlet pressure to supply regulators.

- Reducing the Maximum Allowable Operating Pressure (MAOP) of area served.
- Increasing capacity of pipelines leading to the regulator.
- Increasing size of regulator or regulator orifice.
- Small relief valves (less than one inch) used as signaling devices recommended by **MRC** for pilot regulator overpressure protection are exempt from this review.

8. INSPECTION OF SURROUNDING AREA

8.1. The **supervisor**, his designate, **Instrument Tech** is responsible for field functions checks the area surrounding the station every unscheduled or scheduled inspection when a relief valve provides main regulator overpressure protection. The check is made to determine if blowing gas is safe or appropriate with consideration given to foot and vehicular traffic, buildings, power lines, etc.

- Use MAXIMO to record the field check results. If conditions indicate that relief protection is no longer desirable, contact Technical Services.

9. OPERATOR QUALIFICATION COVERED TASKS
(See GS G8113, *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 2.2 –** 49 CFR 192.461 – Properly applying external protective coatings for corrosion control
- **Task 2.13 –** 49 CFR 192.481 – Monitoring for atmospheric corrosion
- **Task 2.15 –** 49 CFR 192.487 – Recognizing general and localized corrosion, taking action: Distribution
- **Task 3.1 –** 49 CFR 192.503(d) – Leak Testing non-welded joints
- **Task 7.**1 – 49 CFR 192.629 – Purging Pipeline
- **Task 13.1 –** 49 CFR 192.739 – Inspection/testing of pressure limiting and regulating stations and devices
- **Task 15.1 –** 49 CFR 192.743 – Inspection/testing of relief devices
- **Task 16.3 –** 49 CFR 192.747 – Inspection operating, and maintaining distribution system valves
- **Task 17.1 –** 49 CFR 192.749 – Inspecting/maintaining vaults

10. EXCEPTION PROCEDURE
(See GS G7007, *Exception Procedure for Company Operations Standards*)

10.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

10.2. An exception from a standard shall not be allowed unless GS G7007, *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by G7007.

11. RECORDS

Forms/Reporting and Retention

11.1. Completed field order results including "preventive" (scheduled) and "corrective" (unscheduled) inspections are entered into MAXIMO or Click Mobile. For new facility installation data, enter information onto manual forms. Master facility (functional location) and equipment information is updated in SAP-PM.

11.1.1. **Regulator or Instrument Technician** — Reviews, signs and forwards all field orders to the M&R Section Clerk within one **(1)** day of the field order completion date when Click Mobile is not available.

11.1.2. **Data Entry Clerk** — Enters any orders not entered into Click Mobile into MAXIMO or SAP within three **(3)** working days of receipt, not to exceed five **(5)** work days of the field order completion date.

11.1.3. Forms Retention: See Records Retention Standards on Sempra Net, http://home.sempranet.com/rm/ reference OPS-20-04 and OPS-20-06.

12. APPENDICES

12.1. **APPENDIX A:** Regulator Station Inspection Requirement

12.2. **APPENDIX B**: Piston-Operated Valve Regulator Inspection Requirements

12.3. **APPENDIX C:** Power Generating Plant Inspection Requirements

APPENDIX A

REGULATOR STATION INSPECTION REQUIREMENT

Provide uniform guidelines when performing periodic and special inspections.

1. External Inspection (EXT)

   Complete the following requirements, if applicable, during each scheduled external inspection.

2. VAULT INSPECTION

   For detailed vault inspection requirements, STANDARD T8167, *Valve Inspection and Maintenance - Transmission.*

   Test vault with combustible gas indicator before entering. See STANDARD G8315, *Confined Space Operations and* STANDARD G8200, *GMI First Responder – Oxygas 500 SDGE Model Multigas Detector.*

   2.1. Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, and during all unscheduled inspections to ensure the vault is in good physical condition and adequately ventilated.

   2.2. Each vault cover must be inspected to assure that it does not present a hazard to public safety.

   2.3. All other vaults having a volumetric internal content less than 200 cubic feet are inspected each time the MSA is inspected to assure public and employee safety.

3. CHECK STATION PIPING FOR ELECTRICITY

   3.1. Check station for electricity using a company approved AC. (alternating current) voltage detector, when required to make physical contact with the station. See STANDARD D7131, Testing for Electricity at the Gas Meter Set Assembly.

4. CHECK STATION CONDITION

   4.1. Remove debris and weeds from area. Clean thoroughly around vault lid to avoid springing lid when opening.

   4.2. If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

4.3. Check for and remove water in vault.

4.4. The ventilating equipment must also be inspected to determine that it is functioning properly.

4.5. Check station for proper installation of piping and control lines. Repair as needed.

4.6. Inspect condition of the following as appropriate and repair where necessary, or issue follow-up order to have work done.

- Walls
- Fencing
- Buildings
- Barricades
- Vault Floor
- Vent stacks
- Vault covers
- Gauge houses
- Piping supports
- Overall Vault Condition
- Strain on piping due to ground settlement.
- Signage consistent with the requirements of §192.707(c, d)

4.7. Check station for existence of Intersection Drawing (I.D.) and verify accuracy of regulators, valves and related components. **Valves which are normally closed must be labeled 'CLOSED" on the station ID drawing.** If the station is incorrect, submit correction to Supervisor within one week of findings.

4.8. Check and record inlet and outlet pressures and ensure they are within MAOP/Authorized tolerances.

4.9. Monitor district pressure downstream from all valves throughout inspection and maintenance activities, and re-check pressure prior to departure.

4.10. Inspect Stop Valves.

4.10.1. Lubricate valves requiring lubrication, and when found hard to operate. Valves requiring lubrication do not necessarily need to be lubricated during each inspection. This includes all plug valves and the Rockwell Hypersphere TM (trunnion mounted) Valve and Grove Ball Valve (Model B-5) do not require lubrication for normal operation. See STANDARD T8167, *Valve Inspection and Maintenance - Transmission.*

4.10.2. Use two strokes of handgun or four pulses of pneumatic gun per inch of valve size.

4.10.3. Use one stick of sealant when installed with a lubricant screw. Verify that use of the screw has not changed the valve position.

4.10.4. Install a proper size button head lubricant fitting if valve is not so equipped. Install an extension high head with lubricant tube if the valve's depth will not permit the lubricating hose coupler to be attached to the button head. High head devices can be installed without excavating. Each cased plug valve should be left (install adapter if required) so as to permit the use of the standard 2-5/32" socket on the valve wrench.

4.10.5. If the valve is in a casing, test valve casing for leaking gas. If gas is detected and leak cannot be repaired by tightening the packing gland or lubricating the valve, complete the inspection and notify supervisor immediately to repair the leak. For Click Mobile users' note that additional follow-up work is needed in the remarks section on form 5110 District Regulator Station – Inspection.

4.10.6. Verify that valve tag is in place and identification number corresponds with the number on valve inspection order. If there is a discrepancy, immediately resolve the problem with the responsible **Supervisor**.

4.10.7. Hard to operate or inoperable valves must be repaired or replaced within the inspection and grace period for the **district regulator station**.
See STANDARD T8167, *Valve Inspection and Maintenance - Transmission.*

4.11. Check Regulator Operating Pressure

4.11.1. Operate and check all regulator settings using approved pressure standards that are in good working condition and possess a current calibration date.

4.11.2. Use manual bypass if needed. Compare actual settings with those listed on order, update as needed, and verify information on regulator identification tag is correct.

4.12. Check Regulator Lockup

4.12.1. Check all regulators, relief valves, and signaling devices for lockup and record lock-up difference.

- Enter lock-up difference for each spring-loaded regulator.
- If regulator is pilot loaded, post lock-up difference to associated pilot.
- For relief valves, shut-offs, and signaling devices enter difference between release point (setting) and closure/seal point.

4.12.2. Compare pressures with previous lock-up difference.

4.12.3. Metal-seated regulators do not require tight lockup, record-closing pressure in **MAXIMO** or **"Remarks"** section of **Click Mobile Form 5110 "DRS General Inspection".** Verify mainline regulator code as having "metal" seats.
See STANDARD T8174, *Regulator Lockup Tests*.

4.12.4. Regulator setting plus lockup difference must not exceed MAOP limits. See Section 4.4.5.

4.13. Check for Diaphragm Leakage

4.13.1. Place soap bubble over regulator vent.

4.13.2. Test for leakage at diaphragm chamber lip.

4.14. Check Control Piping

4.14.1. Drain all traps in control piping.

4.14.2. Clear any foreign objects from station piping or equipment.

4.14.3. Verify control piping is secure, protected and not installed in lower half of horizontal piping.

4.15. Check Pilot and Instrument Filter

4.15.1. Operate filter inlet sump blow off valve or make a visual internal inspection of pilot and instrument filters for cleanliness.

4.16. Check Relief Valves / Signaling Device

4.16.1. Check caps on all relief valves to make sure they are loose enough to open readily if relief valve operates.

4.16.2. Operate all relief valves and backpressure regulators used as relief valves and shutoff valves (except rupture disc type) to determine proper operation.

4.16.3. Test relief valve for leakage after operating test. Place soap bubble over outlet of relief valve, or test atmosphere in stack with gas indicator.

4.16.4. Verify information on identification tag is correct.

4.16.5. Check Signaling Device for operation.

4.17. Inspect Mainline Filter and Strainer/Screen

Filters**:**

4.17.1. If a mainline filter does not have a filter-monitoring device, then perform internal inspection

4.17.2. If the mainline dry gas filter has a filter-monitoring device and monitor indicator **exceeds** the pre-established **two-pound** differential limit, then an internal inspection is required. Some special filters may require differential pressures that exceed 2 psig. Establish unique requirements for those locations.

4.17.3. If a special inspection was performed on the filter prior to the scheduled inspection and dust/debris was found, then an internal filter inspection is required.

4.18. Screens and Strainers

4.18.1. Mainline strainers/screens require, at a minimum, blowing the purge valve to determine if any dust, dirt, or debris is present.

4.18.2. If a substantial amount of dust, dirt, or debris is found, (one 8 ounce cup or more), during and after blowing down the purge valve, an internal inspection is required to, (1) remove any additional material, (2) to verify that the strainer/screen remains structurally sound and (3) determine if a full sized filter is warranted.

4.18.3. On a newly installed mainline strainer/screen an internal inspection is required during its first scheduled inspection.

4.19. Check Deodorizer and Charcoal Filter

4.19.1. Make a “sniff" sampling of deodorizer or filter. Replace deodorizing material if odor of gas is evident at bleed outlet.

4.20. Check Electronic Pressure Recorder

4.21. Check Valve Position

4.21.1. Check stop valve under each relief valve to verify it is open and locked.

4.21.2. Check control line valves for proper position. For installations not in a vault or fenced enclosure, remove the valve handles or padlock valve.

4.21.3. Verify correct position of all valves inside station and shutoff valves outside station.

4.21.4. Lubricate valves requiring lubrication for normal operation. See *T8167* **-** *Valve Inspection and Maintenance — Transmission*

4.22. Check for Leaks

Soap test all connections loosened during inspection and leave station free of leaks.

4.23. Corrosion

Inspect for coating deterioration on all new and existing metallic gas piping, except stainless, installed above ground or piping exposed to atmosphere in a vault or curb meter box, clean and recoat as necessary with an approved coating to prevent corrosion and deterioration. See STANDARD **G8003,** *Design and Application of Cathodic Protection.*

4.24. Paint Station

Paint all new and existing metallic gas piping, except stainless, installed above ground or piping exposed to atmosphere in a vault or curb meter box with an approved paint as needed to prevent corrosion and deterioration. See STANDARD **G8003,** *Design and Application of Cathodic Protection.*

5. INTERNAL INSPECTIONS (INT)

Internal inspections are performed when station maintenance history, operating conditions, or the external inspection results indicate worn parts, damage or debris in the regulator. Any disassembly with or without parts replacement, short of a complete Internal with Parts Replacement Inspection is considered an Internal inspection.

6. INTERNAL WITH PARTS REPLACEMENT INSPECTIONS (IPR)

Internal with parts replacement inspections include all external requirements plus the following:

6.1. Replace soft parts (O-rings, disc, etc,) on inner valves. Replace expansible elements.

6.2. Replace diaphragms (leather or synthetic) in mainline regulators.

6.3. Replace or rebuild pilot regulators using new soft parts.

6.4. Replace filter elements in filters supplying pilot regulators and instruments.

6.5. Internal inspection and soft parts replacement is not required for the valve portion of a motor valve operated ball valve. Inspect and replace parts if inspection indicates a need.

7. SPECIAL INSPECTION

7.1. See **Section 6** District Regulator Stations (DRS), Special Inspections of this Standard.

7.2. See **Appendix A**, Section 4.17. Inspection Mainline Filter and Strainer/Screen applicable

> **NOTE:** If there is no mainline filter, disassemble and inspect the valve portion of all mainline regulators. (INT)

8. MALFUNCTION OF REGULATORS AND RELATED EQUIPMENT

8.1. Check regulators and related equipment to determine and record cause of malfunction, such as downstream pressure outside of normal tolerance, erratic operation or failure to control. Use MAXIMO or appropriate system condition and activity codes from the Click Mobile pick list Form 5460 “Regulation Inspection” and explain additional comments in Remarks section on Click Mobile **Form 5010** (MSA) or Click Mobile **Form 5110** (DRS) order.

8.2. Take corrective action to minimize possibility of a recurrence. Record appropriate activity codes and additional actions taken in Remarks section.

APPENDIX B

PISTON-OPERATED VALVE REGULATOR INSPECTION REQUIREMENTS

Provide guidelines while performing the following requirements for periodic inspections at district regulator stations and customer large meter sets.

1. External Inspection

1.1. Put installation on bypass if necessary. Stand clear of actuator movement at all times.

1.2. Shut off supply through piston-operated valve by closing its upstream or downstream mainline valve.

1.3. Check operation of controllers, air control or relay valves, positioners, other instruments and valve actuators. If controller has reset action, check to see that it is working properly.

1.4. Check and verify settings, and check and record lock-up differences of all control line devices (as applicable) and regulators associated with the piston-operated valve regulator. Verify equipment is tagged correctly.

NOTE: Lock-up difference for the piston-operated valve regulator is recorded as difference between controller (pilot) setting, and minimum induced closing pressure, required to fully close the main valve.

1.5. Three-Point Check on BPE regulators, perform the following:

1.5.1. Ball Valve Check

- Check mainline regulator for lock-up. In addition, check ball valve condition by blowing down body cavity while in the closed position. This check determines condition of both inner and outer seat rings.

1.5.2. If valve fails to shut down completely, lubricate valve per STANDARD T8167, *Valve Inspection and Maintenance - Transmission.*

NOTE: All Grove ball valves are designed not to require sealant. However, our Company's experience has identified the need to lubricate these valves under certain conditions. When lubrication is necessary use #47 Mobil lubricant or other lubricant recommended by manufacturer.

- If complete blow-down is not achieved by lubrication, determine which seat ring is bad by distinguishing whether the blow-by is created from the inlet or outlet pressure. Leakage due to erosion is a greater possibility when regulator is under throttling conditions rather than when as an on-off device.

NOTE: Notify **Technical Services** to develop a plan for valve repairs.

1.5.3. Pneumatic Cylinder Leak Test

Operate valve actuator several times to flex the piston seals. Check for piston seal blow-by. This is done by venting piston side without the pressure and placing a soap bubble on vented fitting. Check both sides of piston using this method. If the leak test indicates evidence of leakage, complete inspection and notify your Measurement Supervisor.

1.5.4. Cylinder Rod Linkage Check ("Lost Motion")

Operate valve actuator to inspect regulator for lost motion. When this is done, measure the travel indicator motion between cylinder movement and the start of ball valve rotation. This travel should be approximately 1/8-inch. Travel exceeding 1/4-inch is excessive and could affect control accuracy. Contact your Measurement Supervisor when this condition is discovered.

NOTE: A 10-to-20-psig signal should be used to operate actuator without moving ball when checking for lost motion

1.6. Operate all other valve actuators several times to flex the piston seals. It is the number of reversals of travel that is important.

1.7. Lubricate valve. If Grove ball valve, refer to item I.5.1 (a) Ball Valve Check.

1.8. Lubricate Ledeen valve actuators with automotive chassis grease.

1.9. Lubricate positioner linkage on valve regulators. Include pulleys on Foxboro's and ball joints on Baileys. Use Lubriplate or similar lubricant.

1.10. Lubricate Ledeen Spanseal positioner by turning lubrication fitting one full turn. Use Dow Corning #4 compound - special purchase item from Ledeen.

1.11. Check and report all other associated regulators and pneumatic equipment for lock-up and correct operation, i.e., positioners, controllers, no bleed pilots and pneumatic control valves.

1.12. Return equipment to normal operation. Verify that all valves, regulators, controllers set points, Valvair or Numatic valves, reset knobs, etc., are in correct position.

2. INTERNAL (VISUAL) INSPECTIONS

Internal inspections include all external inspection requirements plus the following:

2.1. Check oil level in body and oil dampening loop where applicable on plug and ball valve actuators. Oil level in body should be down a little and dampening loop should be full. Use SAE 50 or non-detergent motor oil 40 in body and rotary meter oil (Code 45-7800) in dampening loop.

2.2. Clean and lubricate the piston rod and rollers on operators that do not have an oil bath. Use Lubriplate or similar lubricant.

2.3. Check valves in controllers, positioners and other pneumatic control valves. Do not lubricate.

2.4. Check that valve positioner intake and exhaust screens are not plugged with foreign material.

2.5. Inspect all filters including built-in filters in Fisher 67F pilots and Bailey or Foxboro positioners. Clean or replace as necessary.

2.6. Blow all control and instrument supply lines.

2.7. Operate all valves equipped with valve actuators and record or verify the operating pressure. Reduce supply pressure to 24 psi and increase in 5-psi increments until valve operates. Compare with previous readings. If significant increase has occurred, lubricate or take other corrective action.

2.8. BPE regulators do not require an internal inspection if the three-point checks are performed on schedule. See **Section 1.5** of Appendix B.

2.9. Fisher Hi-Ball and V-Ball regulators do not require an internal inspection of the ball valve, except as indicated by operation tests.

3. INTERNAL WITH PARTS REPLACEMENT (IPR)

NOTE: When indicated by operation tests, an Internal with Parts Replacement **(IPR)** is required.

IPR inspections include all internal inspection requirements plus the following:

3.1. Internally inspect valve actuators, replacing soft parts as needed.

3.2. Replace controllers only when needed. Before inspecting or replacing the pressure controllers, **note proportional band, reset and set point.** (**"As Found"**) Condition.

3.3. Visually inspect and clean all Fisher 4100 controllers.

3.4. Replace malfunctioning internals of Bristol A/D's.

3.5. Bristol A/D units are cleaned and calibrated on test bench.

3.6. Replace and return controllers to Meter and Instrument Services for rebuilding.

NOTE: Adjust controllers in accordance with settings noted above in 3.2, **"as found"** condition.

3.7. Internally inspect and clean all positioners and pneumatically operated control valves. Leave all settings the same as before disassembly.

3.8. Rebuild or replace all pilot instrument supply and power gas regulators as needed. All setting should be left the same as before disassembly.

3.9. Replace all filter elements.

3.10. Lubricate all Bailey positioner supply and bypass valves with Bailey petcock lubricant - special purchase item from Bailey

3.11. Change grease in Bailey positioner gearboxes. Fill gearbox half full with Lubriplate or similar lubricant. Rotate gears to work grease into teeth.

3.12. BPE regulators **do not require IPR,** if the three-point checks are performed on schedule. See **Section 1.5** in Appendix B, *Three-point check for BPE Regulators*.

3.13. Fisher Hi-Ball and V-Ball regulators do not require an IPR on the ball valve portion of the regulator, except as indicated by operations tests.

APPENDIX C

POWER GENERATING PLANT INSPECTION REQUIREMENTS

1. General Requirements

    1.1. Notify Plant Control Room before attempting any work on meter runs.

    1.2. Provide means of maintaining service if meter run is taken out of service.

        1.2.1. Take no more than one run out of service at the same time.

        1.2.2. Operate manual bypass to carry a large portion of the load and let the standby run do the trimming if the facility has both manual bypass and automatic standby run. An operator must stay by the manual bypass valve and observe gauge during entire bypass operation.

2. OPERATING CHECK

    Operating Check includes the steps listed in **Appendix A** of this Standard for an external regulator inspection plus the following:

    2.1. Verify signal lights are functional, if installation is so equipped, while checking regulator operations.

    2.2. Check operation of differential limit controllers to see that control valves operated at high and low set points. Introduce false differential to check. If control valve is open, block open before testing.

    2.3. See **Section 1.** *External Inspection*, in **Appendix A** of this Standard for remainder of inspection requirements.

3. INTERNAL INSPECTION

    Internal inspections include the above operating check requirements, plus the following:

    3.1. Internally inspect all mainstream regulators.

    3.2. See **Section 4.** *Check Station Condition*, in **Appendix A** of this Standard for remainder of inspection requirements.

4. IPR (INTERNAL W/PARTS REPLACEMENT)

A rebuild includes the internal inspection requirements plus rebuild all regulators. This includes replacing all soft parts including diaphragms and expansible elements. There is no requirement to internally inspect or replace parts in the valve portion of a ball valve regulator. For ball valve regulators, replace parts only if inspection indicates a need.

5. SPECIAL INSPECTIONS

Perform a special inspection when unusual amounts of dust, dirt or debris are found, or when deemed necessary by the region. Inspect equipment as follows:

5.1. Disassemble and visually inspect all in-service regulators, mainline screens, filters, pilot filters and instrument filters. (INT)

5.2. Check regulators and piston-actuated valves for proper operation and satisfactory lockup.

5.3. Inspect valve actuators, valve positioners, flow controllers, pressure controllers and two-position (differential limit) controllers for proper operation – replace defective equipment.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Appendix A - Sections 4.2 and 4.4 were added. Other minor changes made for clarity. All new changes do not effect company operations, procedures or training. Example: newly added items 4.2 and 4.4 have been performed in the field, but now the GS includes written instructions.

Document Profile Summary	
Responsible Person:	[redacted]
Published On:	01/09/2019
Last Full Review Completed On:	07/15/2015
Writer:	[redacted]
Document Status:	Active
Document Type:	GAS
Category (Prior FCD system only):	
If Merged, Merged To Document Number:	
Utility:	SDG&E
Department:	Measurement, Regulation & Control
Number of Common Document:	184.0275
Confidential Sections:	
Part of SoCalGas O&M Plan:	No
Part of SDG&E O&M Plan:	Yes
Contains OPQUAL Covered Task:	Yes
OpQual Tasks	02.02 02.13 02.15 03.01 07.01 13.01 15.01 16.03 17.01
Last O&M Review date:	8/21/2019
O&M 49 CFR Codes & Impacted Sections of Document:	192.739(a): 4.4 192.739(b): 4.4.5 192.743(a): 4.5 192.743(b): 4.6 192.743(c): 4.7 192.749(a): 2.1 of Appendix A 192.749(b): 4.2 of Appendix A 192.749(c): 4.4 of Appendix A 192.749(d): 2.2 of Appendix A
Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	Yes
Part of Transmission IMP (TIMP)	Yes
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
GO112F Codes & Impacted Sections of Document	
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	DIMP2, GSSD, TIMP2

NOP Learning Module (LM) Training Code:	NOP01563

RMLD-CS™

Remote Methane Leak Detector Complete Solution

Recognize the potential for increased safety, significant productivity gains and time-savings with the new RMLD-CS. Remote detection allows utility services personnel and first responders to quickly scan an area for suspected gas leaks at a safe distance.

The HEATH Remote Methane Leak Detector - Complete Solution (RMLD-CS) is a highly advanced technology, capable of detecting methane leaks from a remote distance utilizing the same TDLAS (tunable diode laser absorption spectroscopy) technology as the current RMLD. This instrument eliminates the separate receiver and transceiver, combining them into one hand-held instrument that is lightweight, portable and field rugged. The RMLD-CS makes it possible to detect leaks without having to walk the full length of the pipe line, thus creating safer surveys in areas that may be difficult to reach such as busy roadways, yards with dogs, fenced off areas and other hard to access places. It operates under a variety of field conditions including a wide temperature range, light rain and fog. Its rugged design will stand up to normal field use and operating conditions and its sensitivity or range is not affected by reasonable amounts of dust on the instrument's window.

The RMLD-CS includes many new features including:

- ➡ Rechargeable and replaceable battery
- ➡ Dual battery charger
- ➡ Mobile App support
- ➡ Ergonomic housing
- ➡ Lightweight
- ➡ Graphical user interface
- ➡ Internal data logging
- ➡ WiFi
- ➡ GPS
- ➡ Bluetooth BLE
- ➡ Color camera
- ➡ Color display

HEATH CONSULTANTS

Your Safety...Our Commitment

9030 Monroe Road, Houston, TX 77061
www.heathus.com PH:713.844.1300

SPECIFICATIONS

Detection Method	Tunable Diode Laser Absorption Spectroscopy (TDLAS)
Measurement Range	0 to 99,999 ppm-m
Sensitivity	5 ppm-m at distances from 0 to 50 ft (15m)
Detection Distance	100ft (30m) nominal. Actual distance may vary due to background type and conditions.
Beam Size	Conical in shape with a 22” diameter at 100 ft (55 cm at 30 m)
Detection Alarms Modes	Digital Methane Detection(DMD): Audible tone relative to concentration when detection threshold exceeded Adjustable Detection Alarm Level 1 to 999 Real Time(RT): Continuous audio chirp relative to concentration.
System Fault Warning	Unique audible pitch and indication on the display.
Self Test & Calibration	Built-in Self Test and Calibration function verifies operation and adjusts laser wavelength for maximum sensitivity. Calibration results are stored on the device and can be downloaded by the user. Test gas cell integrated within carrying case.
Compliance	EMC (EN61000-6-2, EN6100-6-4)
Intrinsic Safety	Pending
Laser Eye Safety	IR Laser: Class I, Spotter : Class IIIa Do not stare into beam or view directly with optical instrument.
Communications	Bluetooth 4.2 BLE, WiFi, USB Dual Mode
Display	3.5” LCD
Operating Temperature	0° to +122° F (-17° to 50° C)
Humidity	5 to 95% RH, non-condensing
Enclosure (Inst.)	IP54 (Water Splash and Dust Resistant)
Instrument Weight	≈ 3 lbs.
Battery	Removable, rechargeable, Li ion battery pack, 12-15 VDC
Battery Run Time	8 hours at 32° F
Battery Charging	External, in-line, 110-240 Vac, 50/60 hertz, international
Charge Time, Maximum	2 - 3 hours
Charging Indicator	Integrated into dual battery charger
Survey Vest	Designed for Class 2, with multiple pockets, adjust-ability for both sides.

ORDERING DETAILS

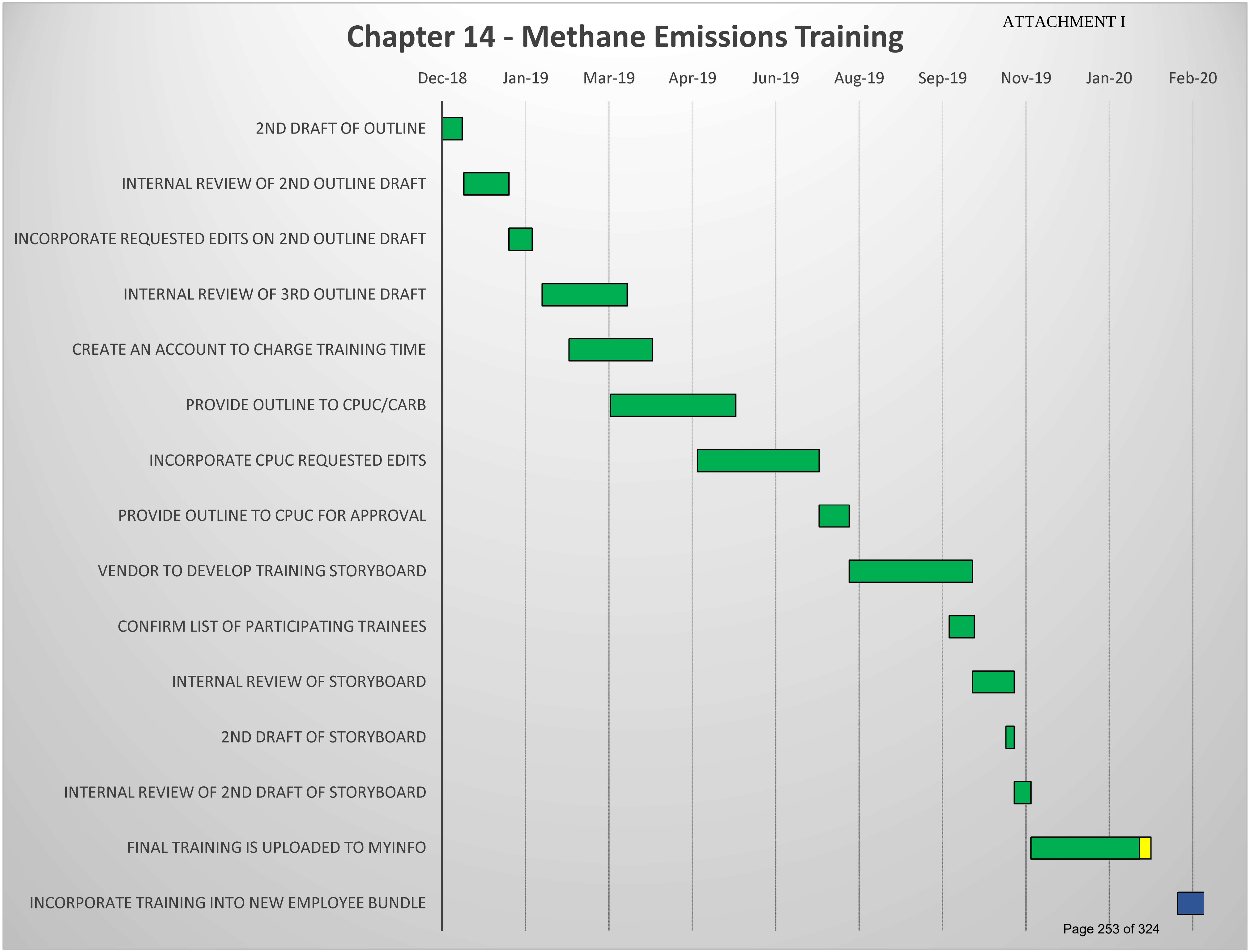
RMLD-CS - HPN 105301
Includes carry strap, case, battery charger, power supply, USB cable, one battery pack, gas calibration test cell.

Battery Pack - HPN 105384
Li-Ion replacement battery.

Battery Charger - HPN 105358
Charges two batteries at a time.

Survey Vest - HPN 105357 (M/L)
Survey Vest - HPN 105406 (L/XXL)
Class 2, multiple pockets for equipment, maps or water pack.

HEATH CONSULTANTS
Your Safety...Our Commitment
9030 Monroe Road, Houston, TX 77061
www.heathus.com PH:713.844.1300


Chapter 14 - Methane Emissions Training
Dec-18
Jan-19
Mar-19
Apr-19
Jun-19
Aug-19
Sep-19
Nov-19
Jan-20
Feb-20
2ND DRAFT OF OUTLINE
INTERNAL REVIEW OF 2ND OUTLINE DRAFT
INCORPORATE REQUESTED EDITS ON 2ND OUTLINE DRAFT
INTERNAL REVIEW OF 3RD OUTLINE DRAFT
CREATE AN ACCOUNT TO CHARGE TRAINING TIME
PROVIDE OUTLINE TO CPUC/CARB
INCORPORATE CPUC REQUESTED EDITS
PROVIDE OUTLINE TO CPUC FOR APPROVAL
VENDOR TO DEVELOP TRAINING STORYBOARD
CONFIRM LIST OF PARTICIPATING TRAINEES
INTERNAL REVIEW OF STORYBOARD
2ND DRAFT OF STORYBOARD
INTERNAL REVIEW OF 2ND DRAFT OF STORYBOARD
FINAL TRAINING IS UPLOADED TO MYINFO
INCORPORATE TRAINING INTO NEW EMPLOYEE BUNDLE

Research & Development Templates

Best Practice Addressed	R&D Project	Subject
16	16	Special Leak Surveys & Predictive Methodologies
17	17-1	Aerial Methane Detection
17	17-2	Sub-Surface Modeling
17	17-3	Evaluation of New Instruments for Leak Detection, Localization, and Speciation
18	18	Evaluation of Stationary Methane Detectors
20	20a-1	Develop Distribution Mass-Balance Leak Detection and Quantification Methodology
20	20a-2	Develop Improved Measurement Methods for Buried Leaks
20	20a-3	Develop Company Specific Emission Factors
20	20a-4	Model Leak Growth Rates from Polyethlene Plastic Piping Slow-Crack Growth Failures
20	20a-5	Quantification of Through-Valve Leakage on Large Compressor Valves
20	20b	Geographic Emissions Tracking & Evaluation
22	22	Investigate Specifications, Tolerances and Sealing Compounds for Threaded Fittings
23	23-1	Evaluation of Technologies to Mitigate Vented Emissions and Gas Blowdowns
23	23-2	Evaluate Component Emission Reductions Opportunities
23	23-3	Alternative Fuel Substitution Strategy

2020 Leak Abatement Plan R&D Summary #16
Special Leak Surveys & Predictive Methodologies

1) **BEST PRACTICE ADDRESSED**

- Best Practice 16: R&D for Special Leak Surveys & Predictive Methodologies. Utilities shall utilize enhanced technologies, such as artificial intelligence, to predict and provide spatial analysis of leak threats near pipelines.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**

- Evaluation of Special Leak Surveys & Predictive Methodologies.
    - Improve understanding of current factors that contribute to system leakage (such as pipeline materials and operating environment variables) that can be used to predict system leakage.
    - Emission reductions through predictive models and early leak detection.

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**

- The research objective is to achieve emission reductions by evaluating different strategies for predictive spatial analysis of leakage threats. Predict and prevent system leakage by leveraging machine learning/artificial intelligence.
- Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
			F				

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
    - Gather input from subject matter experts
    - Develop models or algorithms
    - Conduct special field survey pilots to validate models

4) **ANTICIPATED OR EXPECTED RESULTS**

- Determine effective strategies to predict leakage threats.

Emission reductions through predictive models and early leak detection

5) **EMISSIONS IMPACT**

- SoCalGas anticipates emission reductions through predictive models and early leak detection; however, it is difficult to anticipate or estimate potential emissions reductions.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS

- **CEC- NATURAL GAS PIPELINE INTEGRITY SAFETY AND INTEGRITY MANAGEMENT (GFO-15-506) AND CEC-STORAGE RESEARCH PROJECT (GFO-16-508)**
  - Anticipated End Date: Q4 2020

b. PROPOSED PROJECTS

- Develop leak prediction models leveraging prior and on-going project related to evaluation and development of leakage risk models and predictive methodologies, such as projects in correlation to leak rates as associated with steel and PE piping leakage:
  - Tapping Tee Cap
  - Tree Root Damage
  - Rocky Soil Threats
  - Leak migration models
    - Anticipated Start Date: Q1 2021
    - Anticipated End Date: Q1 2023

7) **DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT**

a. CURRENT PROJECTS

- Projects related to this Best Practice that are currently in progress are scheduled to be completed by the end of 2020.

b. PROPOSED PROJECTS

- Predictive Methodologies Projects
  - Gather input from subject matter experts
    - Data gathered from subject matter expert is used to characterize or identify areas of interest.
  - Develop models or algorithms

    - Data gathered during inspection of leak damage reports and special leak surveys will be used in model development and evaluation of machine learning/artificial intelligence.
    - Data output from model or algorithm will be utilized to schedule/identify the special field survey pilots.
  - Conduct special field survey pilots to validate models.
    - Data output from special field surveys are used by machine learning to update models.

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$288,181	$340,800

SDG&E	2021	2022
	$25,936	$30,672

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$774,129

SDG&E	Total Loaded Costs
	$69,672

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

Tools for Predicting Gas Migration and Mitigating its Occurrence/Consequence. (n.d.). Retrieved from https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=748

https://ww2.energy.ca.gov/2017publications/CEC-500-2017-036/CEC-500-2017-036.pdf

2020 Leak Abatement Plan R&D Summary #17-1
Aerial Methane Detection

1) **BEST PRACTICE ADDRESSED**

- Best Practice 17: Enhanced Methane Detection
  Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**

- Aerial Leak Detection and Quantification Technologies.
- Reduce emissions and improve efficiencies by detecting, differentiating, and rapidly responding to large leaks.
- Pilot studies to validate actual costs and leak detection, pin-pointing, and system capabilities.

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**

- The research objective is to continue advancing aerial emissions detection technologies and to better understand actual capabilities of new technologies and methods available for detecting and locating methane emissions by aerial means (Satellite, Manned and Unmanned Aircraft) and the relative benefits, shortcomings, costs and short-notice availability of each application.
- Areas targeted

Transmission			**Distribution**			**Storage**	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F,v	F,v	F,v	F,v	F,v	F,v	F,v	F,v

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v – Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
  a) Manufacturer Demonstration
     - Facilitate demonstrations of unmanned vehicles, methane sensors, and/or payload components (cameras, instrumentation, black box) for the purpose of determining capability and applicability to the gas infrastructure in both SCG and SDGE.
  b) Laboratory Evaluation
     - Establish baseline performance for sensors and other quantification instruments.
  c) Comparative evaluation to manufacturer specifications.
     - Evaluate the sensors and other quantification instruments to Company requirements for intended applications.

d) Simulated Field Evaluation (Controlled Environment)
   - Evaluate each prototype system, sUAS with payload, in a simulated field environment utilizing controlled natural gas releases. Compare against Company's specifications for the intended application, and test for repeatability.

e) Field Demonstrations
   - Demonstrate aerial systems in actual field environments. May include controlled natural gas releases and evaluation for false positives and false negatives.

f) Pilot Study
   - Conduct pilot studies of viable aerial technologies for specific intended applications. Evaluate implementation costs and calculate potential emissions reduction.

4) **ANTICIPATED OR EXPECTED RESULTS**

- Using acquired understanding, determine the usefulness of each application to both small scale and large-scale needs in the practical applications of gas utility routine or emergency operations.
- Using acquired understanding, determine the feasibility of applying these technologies to both routine operations in difficult-to-access locations or for emergency response.
- Develop capability for quick response to assess emissions from the natural gas system during routine operational requirements or emergency response.

5) **EMISSIONS IMPACT**

- It is difficult to estimate the reduction in emissions that could result from applying aerial methodologies. Aerial technologies facilitate more rapid deployment possibilities and access to locations restricted from the ground and will likely result in better leak detection and reduced duration between detection and repair.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS (2018 Compliance Plan)

1. NYSEARCH- sUAS Technology (M2014-001)
   - Project Close Out: Q1 2020
2. Aerial (sUAS) Leak Detection Research (SCG-2016-001)
   Prior and current research and demonstrations will be leveraged to support aerial leak detection. This includes ongoing development of payload systems such as sensor platforms and software, Gas Mapping LiDAR™ systems and image recognition technologies, and sUAS technology
   - Anticipated Project Close Out: Q4 2020
3. Aerial (sUAS) Leak Detection Research Projects (BP17 Z-3)
   This SoCalGas project has been executed in parallel with, and been used in support of, the progressive development of drone and sensor instrument by the respective manufacturers. Specific to this project are the Pergam sensor and the Microdrones MD4-1000 sUAS, which were selected as the best

candidates at the time out of several sensor and sUAS combinations. (See video in References). The methane concentration data collected by the Pergam sensor (~100 ft height limit) coupled with GPS flight data has been demonstrated to provide locations of elevated methane levels that can be utilized for leak detection and leak localization. The system can closely inspect pipelines, bridges, and other facilities that may be difficult to access. Develop sensor platform for UAS deployment and associated software for data postprocessing to perform emission quantification (BP17 Z-3)

- Anticipated End Date: Q4 2020

4. Aerial (Manned) Leak Detection, Pin-Pointing of Emission Source, and Quantification using Bridger Photonics Gas Mapping LiDAR™ system.
   - Anticipated End Date: Q4 2020

b. PROPOSED PROJECTS

1. Evaluate Optical Gas Imaging (OGI) on UAV using Southwest Research Institute image recognition software.
   - Anticipated Start Date: Q1 2021
   - Anticipated End Date: Q4 2021
2. Satellite methane detection technologies for super emitters (appx. 100+ cfh)
   - Anticipated Start Date: Q1 2021
   - Anticipated End Date: Q4 2022
3. Evaluate various manned aircraft systems to detect large leaks (appx. 10+ cfh) system-wide
   - Anticipated Start Date: Q1 2021
   - Anticipated End Date: Q4 2022

7) **DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT**

CURRENT and PROPOSED PROJECTS:

- Manufacturer Demonstration
- Data gathered during manufacturer demonstration is used to identify potential capabilities that can be leveraged for Company specific applications.
- Laboratory Evaluation
- If possible, data gathered during laboratory evaluation is used to demonstrate capability of sensors and instruments for intended applications. (Go/No-Go Decision).
- Use results of laboratory data to guide simulated field-testing plan.

- Simulated Field Evaluation (Controlled Environment)
- Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, to develop Standard Operating Procedures, and provide feedback to manufacturers for required enhancements to performance.
- Data gathered during simulated field evaluation will be used to demonstrate that the sUAS system can meet Company specifications and FAA regulations. (Go/No-Go Decision)
- Use results of simulated field evaluation data to guide pilot study plan.
- Evaluate integration of instrument data into Enterprise Data Management Systems and business process workflows.
- Evaluate Cost of Implementation
- Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
- Pilot Study
- Data gathered during pilot studies will be used to demonstrate the capability of the sUAS system for intended applications, and that the system can meet Company specifications and FAA regulations. (Go/No-Go Decision)
- Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	**2021**	**2022**
	$550,346	$551,294

SDG&E	**2021**	**2022**
	$49,531	$49,616

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	**Total Loaded Costs**
	$1,356,046

SDG&E	**Total Loaded Costs**
	$122,044

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**
No other Advice Letter costs directly related to this template.

11) **REFERENCES**

a. **NYSEARCH 2014-001 Project Report**
b. **Microdrone Video: https://www.youtube.com/watch?v=fSveg51lcDo**
c. **UgCS Data Logger: https://www.ugcs.com/news-entry/detecting-a-methane-leak-faster-and-more-safely**
d. **UgCS Case Study: https://industrial.ugcs.com/methane-detector#case-studies**
e. **Percepto: https://percepto.co/oil-gas-drones/**
f. **Seek-Ops: https://www.seekops.com/**
g. **Satelytics: www.satelytics.com**
h. **Kairos: http://kairosaerospace.com/methane-detection/**
i. **Ball Aerospace: https://www.ball.com/aerospace/Aerospace/media/Aerospace/Downloads/D3242-Methane-Monitor_0518.pdf?ext=.pdf**
j. **LASEN: http://www.lasen.com/technology.aspx**
k. **JPL: https://www.jpl.nasa.gov/news/news.php?feature=6192**
l. **PRCI Multi-sensor platform: Report Title:**
PR-271-173903-R01 Evaluation of Current ROW Threat Monitoring, Application & Analysis Technology – website:
https://www.prci.org/Research/SurveillanceOperationsMonitoring/SOMProjects/ROW-6-2/56648/171730.aspx
Title:
PR-680-183907-R01 Use of Aerial LiDAR for Geohazard Assessment
Website:
https://www.prci.org/Research/SurveillanceOperationsMonitoring/SOMProjects/GHZ-1-01/101481/169042.aspx

2020 Leak Abatement Plan RD&D Objective Summary #17-2
Sub-Surface Methane Modeling

1) **BEST PRACTICE ADDRESSED**

- Best Practice 17: Enhanced Methane Detection
  Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**

- Sub-Surface Methane Modeling
  - Improve understanding natural gas migration in system territory operating environments including soil types to gain an understanding of leakage migration threats to pipelines and possibly anticipate hazardous operating conditions to better predict hazardous leaks.
  - Understanding of sub-surface methane behavior may result in better understanding of leak behavior and validation of current practices for below-ground methane threshold(s), resulting in increased leak detection efficiency.

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**

- The research objective is to study the sub-surface methane environment and determine factors that contribute to leak migration. Understanding of these factors will be used to develop numerical models to predict gas migration behavior below ground.
- The research objective is also to determine the appropriate below-ground methane concentration threshold(s) that should trigger creation of leak record and investigation.
- Areas targeted

Transmission			**Distribution**			**Storage**	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F			F			f	

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that include one or more of the following:
    - a) Collect Leak Response Survey Data
        - a. Leak data and borehole samples
    - b) Analytic Method Development
        - a. Simultaneous and iterative analysis of:
            - i. Statistical Analysis of Leak Response Survey Data
            - ii. Controlled Field Experiments
            - iii. Numerical Modeling
            - iv. Develop Analytic Tool
    - c) Field Validation of Analytic Method (PHMSA)
    - d) Field Validation of Analytic Method (Company)
    - e) Evaluate the methodologies in a Company specific field environment.

4) ANTICIPATED OR EXPECTED RESULTS

- Using acquired understanding, determine appropriate below-ground methane concentration threshold(s) that should trigger creation of leak record and investigation.
- Using acquired understanding, enable pipeline operators to determine if below-ground methane emissions are due to a leak from the natural gas piping system.

5) EMISSIONS IMPACT

- Knowledge of the below ground methane threshold may reduce both false positives (recording a leak when there is no leak) and false negatives (not recording a leak when one exists), which increases operational efficiency and resulting in overall shorter leak duration and emissions reduction.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- Tools for Predicting Gas Migration and Mitigating its Occurrence/Consequence (PHMSA - #748).
  This project is managed by PHMSA with Academia as the performer and includes involvement and participation of selected Utilities. The project includes data collection and analysis plans for each stage of the R&D approach.
    - Actual Start Date: Q4 2018

- Anticipated End Date: Q2 2021

- Below Ground Methane "Background" Concentration Study Research Projects (SoCal Gas).
  - Actual Start Date: Q4 2019
  - Anticipated End Date: Q2 2021

b. PROPOSED PROJECTS

- Field Validations of Analytical Model – Company Specific
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q3 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

- Field Validations of Analytical Model – Company Specific
  - Leak Survey
    - Data gathered during leak survey is used to roughly confirm output of analytical tool.
  - Map Surface Concentrations and Flux
    - A grid of surface concentration measurements is used to demonstrate capability of analytical tool and provide feedback to developers for required enhancements to performance.
    - Surface flux measurements (using Hi Flow Sampler ™ or equivalent) will be used to demonstrate capability of analytical tool and provide feedback to developers for required enhancements to performance.
  - Soil Measurements
    - Measurements of the gas concentration in the soil (barhole) will be used to demonstrate capability of analytical tool and provide feedback to developers for required enhancements to performance.
  - Excavation and Direct Measurement
    - Direct measurement of the emission rate, after excavation, (using Hi Flow Sampler ™ or equivalent) will be used to demonstrate capability of analytical tool and provide feedback to developers for required enhancements to performance
    - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision for further Field Validations).
  - Evaluate Cost of Field Validation
    - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision for further Field Validations

2020 Leak Abatement Plan RD&D Objective Summary #17-2
Sub-Surface Methane Modeling

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$250,157	$125,294

SDG&E	2021	2022
	$22,514	$11,276

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$462,408

SDG&E	Total Loaded Costs
	$41,617

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

- Tools for Predicting Gas Migration and Mitigating its Occurrence/Consequence: https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=748

2020 Leak Abatement Plan R&D Objective Summary #17-3
Evaluation of New Instruments for Leak Detection, Localization, and Speciation

1) BEST PRACTICE ADDRESSED

- Best Practice 17: Enhanced Leak Detection and Speciation.
  Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Evaluation of New Instruments for Leak Detection, Localization, and Speciation.
- Improve efficiency and reduce cost of operation.
- Reduce emissions by improving detection efficiency.
- Conduct Pilot studies to be initiated based on results of instrument evaluations. Pilot studies will provide basis for implementation cost and emissions reductions estimates.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- This research objective is to identify instruments and/or methods to improve the efficiency and output of the leak detection processes.
- Evaluate the performance and features of new instruments and/or methods and perform comparative analysis to existing methods for leak detection, source localization, and speciation of natural gas.
- Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F	F	F	F	F	F	F	F

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
  1) Manufacturer Demonstration
- Facilitate demonstrations by manufacturers of new technologies, methods, and/or practices for leak detection, localization, and speciation.
  2) Laboratory Evaluation
- Establish baseline performance for instruments that are evaluated.
- Comparative evaluation to manufacturer specifications and currently approved devices.
- Evaluate the instruments to Company requirements for intended applications.
  3) Simulated Field Evaluation (Controlled Environment)
- Evaluate instruments and technologies in a simulated field environment utilizing controlled natural gas releases.
- Compare to currently approved devices, practices, and/or procedures.

4) Pilot Study

- Obtain and evaluate multiple devices against Company's specifications for the intended application, and test for repeatability.
- Evaluate instruments and technologies in an actual field environment, including controlled natural gas releases.
- Compare to currently approved devices, practices, and/or procedures.

4) ANTICIPATED OR EXPECTED RESULTS

- Identify more accurate, precise, or reliable instruments and methods for leak detection, localization, and speciation processes.

5) EMISSIONS IMPACT

- Reduce emissions by improving detection, leak localization and quantification efficiency. Leaks detected and repaired earlier in the lifecycle will result in a reduction of emissions, leak detection and localization efficiency will reduce operational costs.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS (2018 Compliance Plan)

- Back Pack & Handheld Methane Detection Tools (Sensor) & Systems Research Projects (a.k.a. Next Generation Walking Leak Survey) (BP 17 AC-2)

  Exploratory work has been completed by the Company to evaluate the addition of open-path laser analyzers to enhance the Company approved walking leak survey technology, DPIR. Exploratory work in the laboratory, simulated field conditions, and actual field scenarios has been executed. Ongoing work includes similar exploratory investigations of a variety of PPB-sensitive laser analyzers used to monitor atmospheric methane concentrations in addition to traditional methods for inspecting ground level and below-ground methane levels based on the Company approved survey methodologies.
  - Actual Start Date: Q1 2019
  - Anticipated End Date: Q1 2021

- NYSEARCH T-784 First Pass Leak Detection Optimization:
  Optimize Walking Leak Survey for buried Distribution pipelines (performed on a single pass) using instrumentation and data acquisition techniques to maximize the rate of leak detection for traditional leak survey methods. A second goal of this project is to determine what improvements can be achieved using an integrated technology approach between traditional instruments performing drawn samples from the ground surface with part-per-million sensitivity combined with atmospheric monitoring instruments with parts-per-billion sensitivity.

  - Anticipated End Date: Q4 2020

- Integrate Mobile Methane Mapping w/Mobile Leak Survey Research Project: Evaluate possibility of integrating GIS and wind (speed & direction) data into traditional mobile leak survey applications where mobile leak survey is conducted directly over the pipeline right-of-way. Increase the leak detection capabilities of mobile methane mapping by integrating multiple methane detection systems to increase lower detection limit and minimize false-positive indications.

    - Anticipated End Date: Q4 2020

- Evaluate Aeris MIRA PICO Responder™ advanced mobile leak detection system:

    The MIRA PICO analyzer with 1 PPB sensitivity for Methane and 0.5 PPB sensitivity for Ethane. System includes software application and analytics for visual integration of emissions detection with wind and GPS data, plus potential ability for emission source speciation to distinguish petrogenic sources from common biogenic and vehicle emission sources.

    - Anticipated End Date: Q4 2020

- Optical Gas Imaging (OGI) Cameras and associated leak quantification algorithms:

    The development or demonstration of leak quantification using OGI or estimation of leak size based on IR camera imaging and algorithms could provide rapid estimates of the size of leaks and result in better prioritization of leak repairs (i.e., repair largest leaks first and reduce emissions). In 2019 SoCalGas investigated two currently available and viable IR camera algorithms to categorize leak rates and determined that neither technology is suitable for categorization of underground pipeline leaks at that time.

    - Actual Start Date: Q4 2018
    - Anticipated End Date: Q1 2020

b. PROPOSED PROJECTS

- Evaluate new leak detection, localization, and speciation technologies.
    - Anticipated Start Date: Q1 2021
    - Anticipated End Date: Q4 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a. CURRENT PROJECTS

- Back Pack & Handheld Methane Detection Tools (Sensor) & Systems Research Projects (a.k.a. Next Generation Walking Leak Survey) (BP 17 AC-2).
  1. Manufacturer Demonstration
     - Data gathered during manufacturer demonstration is used to identify potential capabilities that can be leveraged for Company leak detection, speciation, and localization.
  2. Laboratory Evaluation
     - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
     - Use results of laboratory data to guide simulated field-testing plan.
  3. Evaluate Cost of Implementation
     - Estimate cost to conduct simulated field evaluation.
     - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
  4. Simulated Field Evaluation (Controlled Environment)
     - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
     - Use results of simulated field evaluation data to guide pilot study plan.
     - Evaluate integration of instrument data into Enterprise Data Management Systems and business process workflows.
     - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
  5. Pilot Study
     - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
     - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

- NYSEARCH T-784 First Pass Leak Detection Optimization
  1. Solicit information from funding members as to existing practices for leak survey and for combining techniques

- Select Instrumentation and Technique Combinations

2. Model Leak Detection Comparative Techniques. Use statistical Design of Experiments (DOE) to define data collection parameters and evaluate test results.
    - Perform Field Testing
    - Conduct Statistical Analysis.

b. PROPOSED PROJECTS

1. Manufacturer Demonstration
    - Data gathered during manufacturer demonstration is used to identify potential capabilities that can be leveraged for Company leak detection, speciation, and localization.

2. Laboratory Evaluation
    - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
    - Use results of laboratory data to guide simulated field-testing plan.
3. Evaluate Cost of Implementation
    - Estimate cost to conduct simulated field evaluation.
    - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).

4. Simulated Field Evaluation (Controlled Environment)
    - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
    - Use results of simulated field evaluation data to guide pilot study plan.
    - Evaluate integration of instrument data into Enterprise Data Management Systems and business process workflows.
    - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
5. Pilot Study
    - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
    - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$960,604	$851,999

SDG&E	2021	2022
	$86,454	$76,680

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$2,231,417

SDG&E	Total Loaded Costs
Methane Detection Sensor & Systems Research Project (handheld and mobile devices)	$200,828

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

- Southern California Gas Company – Pico Rivera. "Southern California Gas Company's Verification Study of the Methane Mapping of Four California Cities by the Environmental Defense Fund and Colorado State University" Southern California Gas Company. Southern California Gas Company, August 2016. https://www.socalgas.com/regulatory/documents/r-15-01-008/EDF_4-Cities_Methane_Mapping_Report_Final_081916.pdf
- https://primis.phmsa.dot.gov/rd/mtgs/091118/Ed%20Newton.pdf
- "Mobile Guard Advance Mobile Leak Detection." Https://Heathus.com/Wp-Content/Uploads/MobileGuard.pdf
- Leifer, I., and I. MacDonald. 2003. Dynamics of the gas flux from shallow gas hydrate deposits: Interaction between oily hydrate bubbles and the oceanic environment. Earth and Planetary Science Letters 210(3/4):411-424.
- Leifer, I. and J. Clark. 2002. Modeling trace gases in hydrocarbon seep bubbles. Application to marine hydrocarbon seeps in the Santa Barbara Channel. Russian Geology and Geophysics 43(7):613-621.
- University of California - Santa Barbara. "Methane emissions higher than thought across much of U.S.." ScienceDaily. ScienceDaily, 15 May 2013. <www.sciencedaily.com/releases/2013/05/130515165021.htm>.

- "Improving Methane Emissions Estimates for Natural Gas Distribution Companies, Phase II - PE Pipes." *OTD*, 23 Nov. 2013, https://www.otd-co.org/reports/Documents/710c_OTD-14-0001-Improving-Methane-Emission-Estimates-NG-Distribution-Companies-PE-Pipes-FinalReport.pdf.RKI HH Tech/Data sheet – Website.
- Aeris MIRA PICO Hand-Held and Mobile Leak Detection Systems (LDS) Responder™ Advanced Mobile LDS System
- http://aerissensors.com/pico-series/
- http://aerissensors.com/wp-content/uploads/2019/12/MIRA-Responder-LDS_191208_FINAL_quartz.pdf
- Pergam Technologies: http://pergamusa.com/lmm/

2020 Leak Abatement Plan R&D Objective Summary #18
Evaluation of Stationary Methane Detectors

1) BEST PRACTICE ADDRESSED

- Best Practice 18: Stationary Methane Detectors for Early Detection of Leaks

Utilities shall utilize Stationary Methane Detectors for early detection of leaks. Locations include: Compressor Stations, Terminals, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). Methane detector technology should be capable of transferring leak data to a central database, if appropriate for location.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Evaluation of Stationary Methane Detectors
- Reduce emissions by quicker leak detection and repair.
- Pilot studies to be initiated based on results of instrument evaluations. Pilot studies will validate actual costs and emissions reductions.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to develop and/or evaluate stationary methane sensors for early detection of leaks.

- Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F,V	F,V	F,V	F,V	F,V	F,V	F,V	F,V

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v – Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
  a) Manufacturer or Prototype Demonstration
     - Facilitate demonstrations of research prototypes or by manufacturers of methane sensors
  b) Laboratory Evaluation
     - Establish baseline performance for sensors that are evaluated.

- Comparative evaluation to manufacturer/prototype specifications and currently approved sensors.
- Evaluate the sensors to Company requirements for intended applications.

c) Simulated Field Evaluation (Controlled Environment)
- Evaluate sensors in a simulated field environment utilizing controlled natural gas releases.
- Compare to currently approved sensors.

d) Pilot Study
- Obtain and evaluate multiple sensors of a single type against Company's specifications for the intended application, and test for repeatability.
- Evaluate sensors in an actual field environment, including controlled natural gas releases.
- Compare to currently approved sensors.

- Blind studies and validation of actual costs and emissions reductions

4) ANTICIPATED OR EXPECTED RESULTS

- Accurate assessment of the performance of stationary sensors enables field deployment leading to quicker leak detection and repair and emissions reductions.

5) EMISSIONS IMPACT

- The reduction and quick repair of leaks as detected by stationary sensors represents various size leaks at n as yet unknown quantity for various applications. Therefore, the emissions reduction cannot be estimated at this time.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS (2018 Compliance Plan)

- Stationary Methane Sensor Evaluation BP 18 AE-3.3 - complete

  The Company executed an evaluation of stationary methane sensors under laboratory conditions and simulated field conditions. Sensors included three open path lasers and one closed path laser, capable of detection to 2ppm-m, and two-point sensors capable of detection to 1% and 2% LEL. Key findings included better understanding of specific use applications for the various sensors and sufficient information to select best performing sensors and/or eliminate certain candidates.

  - Anticipated End Date: Q1 2020

- Methane Sensors State-of-the-Art Investigation (OTD 7.16.f) BP 18 AE-2

  This study provided a high-level review of the current state of the art in "point" methane sensors and how they are used in the utility industry. However, the project did not provide comprehensive quantitative data on sensor performance (accuracy, sensitivity/detection limit, methane or methane + ethane, repeatability/precision, range, survey speed, response time, passive or active sampling, etc.) in comparable engineering units.

  - Project close out: Q4 2019

- Residential Methane Detector (BP 18 AE-3.1 NYSEARCH M2010-002)
  The objective of this project is to develop a 10% LEL methane sensor. Prototype detectors are currently undergoing a one-year pilot field study to assess performance and reliability.
  - Project close out: Q4 2020
- Stanford MEMS sensor development project (BP 18 AE-1)(NGI-2018-001)
  A multi-layer silicon-based sensor approximately 1 cm x 1.5 cm in size was developed and results published (P.A. Gross et al. Analytical Chemistry, 2018). Improvements to the sensor to fulfill field deployment requirements include adjustments in hydration, method of manufacture, temperature stability, and sensitivity. The Company is currently expecting the receipt of a 1st Prototype to commence controlled laboratory evaluation
  - Project close Out – Q1 2021
- PHMSA #851 / OTD (7.20.a) Develop Remote Sensing and Leak Detection Platform with Multiple Sensors
  The main objective is to demonstrate a sensing platform permanently deployed at discrete locations in the ROW. These locations are wirelessly connected to a software back-end that performs sensor data fusion to identify integrity threats in the ROW. These leading indicators can be used to prevent damage or leakage. A single prototype of this system has been deployed on a live utility site. This work would address needed improvements and deploy the system to additional utility sites.
  - Start Date: Q4 2019
  - Anticipated End Date: Q3 2021

b. PROPOSED PROJECTS

- Evaluate New and/or prototype methane sensor technologies.
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q4 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

A) **CURRENT PROJECTS** (2018 Compliance Plan)

- Stanford MEMS sensor development project (BP 18 AE-1)
  1. Stanford Demonstration
     - Data gathered during Stanford demonstration is used to identify potential capabilities that can be leveraged for Company leak detection, speciation, and localization.
  2. Laboratory Evaluation
     - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
     - Use results of laboratory data to provide feedback to Stanford Researchers to improve Prototype.
     - Repeat Lab Evaluation with new Prototype.
  3. Evaluate Cost of Implementation
     - Estimate cost to conduct simulated field evaluation.
     - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
  4. Simulated Field Evaluation (Controlled Environment)
     - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
     - Use results of simulated field evaluation data to guide pilot study plan.
     - Evaluate integration of instrument data into Enterprise Data Management Systems and business process workflows.
     - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
  5. Pilot Study
     - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
     - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

2020 Leak Abatement Plan R&D Objective Summary #18
Evaluation of Stationary Methane Detectors

B) **PROPOSED PROJECTS**

- Evaluate available CH4 sensors that could be used for stationary CH4 detection use-cases at company facilities. The project will involve one or more of the following steps:
  - Manufacturer or Prototype Demonstration
    - Data gathered during manufacturer or research demonstration is used to identify potential capabilities that can be leveraged for Company leak detection, speciation, and localization.
  - Laboratory Evaluation
    - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
    - Use results of laboratory data to guide simulated field-testing plan.
  - Evaluate Cost of Implementation
    - Estimate cost to conduct simulated field evaluation.
    - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
  - Simulated Field Evaluation (Controlled Environment)
    - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
    - Use results of simulated field evaluation data to guide pilot study plan.
    - valuate integration of instrument data into Enterprise Data Management Systems and business process workflows.
    - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
  - Pilot Study
    - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
    - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$239,150	$479,124

SDG&E	2021	2022
	$21,524	$43,121

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$883,666

SDG&E	Total Loaded Costs
	$79,530

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

PA Gross, T Jaramillo and B Pruitt, Cyclic-Voltammetry-Based Solid-State Gas Sensor for Methane and Other VOC Anal. Chem. 2018, 90, 10, 6102-6108

www.fullmoonsensors.com

https://www.newcosmos-global.com/news/2701/

https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=851

2020 Leak Abatement Plan RD&D Objective Summary #20a-1

Develop Distribution Mass-Balance Leak Detection and Quantification Methodology

1) **BEST PRACTICE ADDRESSED**

- Best Practice 20a: Quantification

Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks to assist demonstration of actual emissions reductions.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**

- Develop Distribution mass-balance leak detection and quantification methodology
- This project is a continuation of the R&D project from the prior compliance plan.
- Objective - early detection of system leaks, reduced system emissions, reduced cost of leak management, better measurement of leak duration.
- Pilot studies will be executed to evaluate implementation costs and actual efficiencies of the mass-balance methodology(s).

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**

- The R&D objective is to develop and evaluate methodologies to detect and quantify gas leaks in a defined Distribution area using flow measurement data and mass-balance algorithms. Using available gas metering data, unbalanced Distribution segments are identified, which may provide an indication when system leaks initiate and provide a direct measurement of leakage flow rate.
- Areas targeted

Transmission			**Distribution**			**Storage**	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
			F		F		

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v – Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
  a) Mass Balance Model Development
     a. The mass balance approach compares the gas supplied to the gas consumed for a defined service area. The deviation from a net-zero mass balance is an indicator of possible system leakage.
     b. Mass-balance model development includes identifying and characterizing all gas supply and gas consumption (i.e., customer) meters in the study service area and considering the impacts of pack and draft and other variables.
  b) Pilot Study
     a. Identify candidate gas service areas with newer generation plastic pipe and a sufficient number of customer meters and appropriate gas supply and customer meters (e.g., meters with high accuracy with advanced analytics)
     b. Identify and repair or quantify the flow rate of leaks in the service area
     c. Use measurement data from installed gas supply meter(s) and customer meters to establish baseline mass balance model
     d. Measure flow rates of any actual system leaks and test sensitivity to leak flow rates after leak repair. Simulate system leakage by performing controlled experiments with monitoring activity on the system (added/subtracted load, changes in customer count through close orders, leak repairs, etc.)

4) **ANTICIPATED OR EXPECTED RESULTS**

- The expected R&D benefit is early detection of system leaks resulting in more rapid leak detection and mitigation resulting in reduced emissions.
- Detecting leaks using a mass-balance algorithm approach, combined with active monitoring for leaks, could potentially reduce “unknown” leaks and theoretically reduce the need for leak surveys. This could reduce detection times to potentially years sooner (in 5-yr survey areas) and provide a means for calculating overall emissions from leaks.

5) **EMISSIONS IMPACT**

- Earlier detection of system leaks are expected to result in a reduction in leak emissions; however, the magnitude of this emissions reduction cannot yet be determined.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

A. **CURRENT PROJECTS**
- System Emissions Using Mass Balance with Advanced Meter Technology Research Project (BP 20a AF-1) – Phase 1
    - Actual Start Date: Q3 2019

B. **PROPOSED PROJECTS**
- System Emissions Using Mass Balance with Advanced Meter Technology Research Project (BP 20a AF-1) – Phase 1 (continued)
    - Anticipated End Date: Q4 2022

7) **DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT**

a) **CURRENT PROJECTS:**
- System Emissions Using Mass Balance with Advanced Meter Technology Research Project (BP 20a AF-1) – Phase 1
    - Mass Balance Model Development
    - Data collection includes accuracy specifications for the gas supply and customer meters in the study service area
    - Data collection includes historical gas consumption for the study service area
    - Data analysis includes development of the mass-balance model including the estimated uncertainty in the mass balance calculation
- Pilot Study
    - Data collection includes the quantification of the flow rate of unrepaired leaks in the service area
    - Data collection includes gas flowrates/volumes measured by the gas supply and customer meters during baseline tests
    - Data collection includes gas flowrates/volumes measured by the gas supply and customer meters during controlled experiments with simulated leakage. Simulated leak rates are directly measured.
    - For the baseline tests, data analysis includes calculation of the system mass balance and estimation of the uncertainty in the mass balance calculations.
    - For the controlled experiments with simulated leakage, data analysis includes calculation of the system mass balance and the leak rate. The minimal detectable leak rate is determined and the uncertainties in the mass balance and simulated leak rate calculations are estimated.

b) **PROPOSED PROJECTS:**
- System Emissions Using Mass Balance with Advanced Meter Technology Research Project (BP 20a AF-1) – Continuing project

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$266,167	$267,623

SDG&E	2021	2022
	$23,955	$24,086

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$658,718

SDG&E	Total Loaded Costs
	$59,285

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**
No other Advice Letter costs directly related to this template.

11) **REFERENCES**
Attachment G – Advanced Meter Analytics Algorithm: Business Case Estimation
Attachment H – Advanced Meter Analytics Algorithm: Advanced Meter Presentation

2020 Leak Abatement Plan RD&D Summary #20a-2
Develop Improved Measurement Methods for Buried Leaks

1) BEST PRACTICE ADDRESSED

- Best Practice 20a: Quantification
  Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks to assist demonstration of actual emissions reductions.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

Evaluate new or revised tools, technologies and methods to develop improved leak flow measurement methods for system leaks.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The R&D objective is to develop and evaluate technologies and methods to quickly and accurately quantify emissions from underground leaks that spread over large areas.
  - Reduce leak emissions by improving prioritization of leaks for repair
  - Improve leak measurement efficiency and reduce cost of operation
  - Pilot studies to be initiated based on results of method evaluations. Pilot studies will evaluate actual costs and efficiency improvements.
- Areas targeted

	Transmission			**Distribution**			**Storage**	
	Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
Belowground	F			F			f	
Aboveground	f	f	f	f	f	f	f	f

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

2020 Leak Abatement Plan RD&D Summary #20a-2
Develop Improved Measurement Methods for Buried Leaks

- The R&D approach to meet the objective will involve a series of planned evaluations, of the technologies and methods of interest that can include one or more of the following:

    a) Laboratory Evaluation

    - Evaluate technologies and methods in a laboratory environment utilizing controlled natural gas releases to assess their capabilities
    - Compare to existing buried leak measurement methods
    - Determine operating range
    - Determine leak rate measurement accuracy and precision over operating range
    - Determine ancillary equipment requirements

    b) Simulated Field Evaluation (Controlled Environment)

    - Evaluate technologies and methods in a simulated field environment utilizing controlled natural gas releases
    - Compare to existing buried leak measurement methods
    - Determine leak rate measurement accuracy and precision over operating range
    - Determine ancillary equipment requirements
    - Identify practical implementation issues and refine technologies and methodologies

    c) Pilot Study

    - Evaluate technologies and methods in an actual field environment.
    - Compare to existing buried leak measurement methods
    - Identify practical implementation issues and refine technologies and methodologies

4) **ANTICIPATED OR EXPECTED RESULTS**

- The expected R&D benefit is to develop more accurate and efficient methods to quantify emissions from underground leaks that spread over large areas. More accurate measurements would produce a more accurate emission inventory and better prioritization of system leaks for repair (i.e., repair largest leaks first and reduce emissions). More efficient methods would reduce cost of operation and allow measurement of isolated leaks.

5) **EMISSIONS IMPACT**

- More timely and/or accurate quantification of buried leak emissions may result in reducing the time to repair leaks, and improve the operational efficiency of the process thereby reducing implementation costs.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS

- Standardization of Surface Expression Equipment and Protocol (NYSEARCH M2019-002) Phase 1 and 2
    - Actual Start Date: Q2 2019
    - Anticipated End Date: Q3 2021
- SoCalGas/IES Surface Expression Measurement System

  SoCalGas is currently working with IES to design a next-generation Surface Expression measurement system that can measure a larger range of leak flowrates with improved accuracy over currently employed leak rate measurement instruments. The accuracy of this next-generation HFS instrument will be +/- 10% or less, compared to the currently employed instrument accuracy of +/- 20%. Through a test matrix in a controlled laboratory environment-controlled gas rates will be introduced directly into the HFS sample line to isolate the HFS performance, and into different regions of the gas leak enclosure for further characterization. Simulated field environment testing will evaluate the practical considerations.
    - Actual Start Date: Q2 2019
    - Anticipated End Date: Q4 2021
- Laser-scan method to measure/classify underground pipeline gas leak rates

  SoCalGas has devised a laser-scan method that would allow leak measurements/classifications of underground pipeline gas leaks to be conducted more rapidly and accurately than current methods. The proof-of-concept will determine the method accuracy and whether the method provides an accurate “measurement” of the true leak rate (i.e., low measurement uncertainty) or whether the method results have a high uncertainty and should more appropriately be used to “classify” or “bucket” the leaks (e.g., as small, medium, or large).

- Anticipated Start Date: Q2 2020
- Anticipated End Date: Q4 2021

- Optical Gas Imaging (OGI) Cameras and associated leak quantification algorithms

  The development or demonstration of leak quantification using OGI or estimation of leak size based on IR camera imaging and algorithms could provide rapid estimates of the size of leaks, and result in better prioritization of leak repairs (i.e., repair largest leaks first and reduce emissions). In 2019 SoCalGas investigated two currently available and viable IR camera algorithms to categorize leak rates and determined that neither technology is suitable for categorization of underground pipeline leaks at that time.

  - Anticipated Start Date: Q3 2020
  - Anticipated End Date: Q4 2021

b. PROPOSED PROJECTS

- Currently, there are no new proposed projects for this Best Practice.

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

- Standardization of Surface Expression Equipment and Protocol.
  - Data collection and analysis conducted by NYSEARCH
- SoCalGas hi-flow sampler; Laser-scan method to measure/classify underground pipeline gas leak rates; and OGI Cameras and associated leak quantification algorithms
  a) Laboratory Evaluation
     - Data collection includes replicate measurements over a wide range of controlled leak rates to determine range of operation
     - Data analysis to determine accuracy (bias) and precision (repeatability) over the range of operation
     - Data analysis to compare performance to existing buried leak measurement methods

- Document equipment functionality and determine ancillary equipment requirements/areas for improvement

b) Simulated Field Evaluation (Controlled Environment)

- Data collection includes replicate measurements over the range of operation determined during the Laboratory Evaluation
- Data collection includes replicate measurements by different test teams to estimate reproducibility
- Data analysis to determine accuracy (bias) and precision (repeatability and reproducibility) over the range of operation
- Data analysis to compare performance to existing buried leak measurement methods
- Document equipment functionality and determine ancillary equipment requirements/areas for improvement (e.g., leak enclosure construction and implementation)
- Document time required to conduct measurements
- Data analysis to estimate cost to conduct measurements

c) Pilot Study

- Data collection includes measurements of real-world leaks in typical settings
- Data collection includes replicate measurements by different test teams to estimate reproducibility
- Data analysis to determine precision (reproducibility)
- Data analysis to compare performance to existing buried leak measurement methods
- Document equipment functionality and determine ancillary equipment requirements/areas for improvement (e.g., leak enclosure construction and implementation)
- Document time required to conduct measurements
- Data analysis to estimate cost to conduct measurements

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$330,208	$264,621

SDG&E	2021	2022
	$29,719	$23,816

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$732,328

SDG&E	Total Loaded Costs
	$65,910

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

https://www.mybacharach.com/wp-content/uploads/2015/08/0055-9017-Rev-7.pdf

2020 Leak Abatement Plan R&D Objective Summary #20a-3
Develop Company Specific Emission Factors

1) **BEST PRACTICE ADDRESSED**

- Best Practice 20a: Quantification
  Utilities shall develop methodologies for improved quantification, geographic evaluation, and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall also work together, with CPUC and ARB staff, to develop a similar methodology to improve the emissions quantification of leaks in order to demonstrate actual emissions reductions.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**

- Develop Company Specific Emission Factors (EFs).
- Company specific EFs will result in more accurate quantification of emissions than current methods.
  - In support of Company specific EFs, develop "Above Ground Leak Quantification Method Using Soap Test"
  - Facilitates reduction of emissions through defining leak-based emission factors and reduction in time to repair and increased frequency of leak survey.
  - Pilot studies to evaluate and advance above ground methane quantification technologies.

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**

- The research objective is to develop Company-Specific emission factors based upon SCG and SDGE data. These emission factors will replace current "Facility" or "Population" based Emission Factors.
  Current Facility-based emission factors for Meter Set Assemblies, Distribution Regulating Stations, and potentially Transmission M&R stations will be replaced with a set of leak-based emission factors. Methane emissions from above ground leaks on facilities operating at 60 psi or less are categorized using a soap test and correlated with estimated leak rates. Transmission pipeline leaks may also be evaluated for use of a Company-specific emission factor or engineering estimate methodology.

- Areas targeted

Transmission			**Distribution**			**Storage**	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F	F, V		F	F, V	F, V		

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the Company-specific emission factors will involve a series of planned evaluations, that can include one or more of the following:
  a) Gather Equipment and Operating Data
     - Transmission M&R Facilities
     - Distribution M&R Stations
     - Customer Meters
  b) Categorize Equipment (Emissions Sources)
     - M&R Stations
     - Customer Meters
  c) Determine statistically significant number of samples needed based on population of facilities and annual number of leaks as well as conduct leak measurements on a statistically random basis
  d) Statistically Analyze Leak Data
  e) Develop Company-specific Emission Factors

- The R&D approach to meet the soap-test based emission factors objective will involve a series of planned evaluations, that can include one or more of the following:
  a) Laboratory Evaluation
     - Establish baseline performance testing for threaded above ground asset leaks.
     - Evaluate the test matrices to Company requirements for intended applications
  b) Simulated Field Evaluation (Emissions Sources)
     - Evaluate each test matrix, in a simulated field environment utilizing controlled natural gas releases
     - Compare to currently approved Gas Standards
  c) Pilot Study
     - Evaluate leak quantification method in an actual field environment, which may include controlled natural gas releases
  d) Develop Emission Factors
     - Using leak rates with bubble characteristics develop leaker-based emission factors.

4) **ANTICIPATED OR EXPECTED RESULTS**
- Emission factors based upon present day conditions and local leak measurements will improve emission estimates and support better strategic decisions.
- A defined relationship between soap bubble formation and leakage rates will be determined based on the results of a field leak measurement study of above ground leaks. The results from this study will be used to develop Leak-Based emission factors.

5) **EMISSIONS IMPACT**
- Leaker based emission factors will enable more accurate emissions reporting. Accurate emissions inventory also facilitates proper planning and resource allocation to the emissions sources that provide for greater emissions reductions.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS

- Develop Company-Specific Leak-Based Emission Factors for Distribution Main & Services (SCG & SDG&E) (BP 20a AI-4.5)
  - Anticipated End Date: Q4 2020

- Develop Company-Specific Leak-Based Emission Factors for Customer Meters (SCG & SDG&E) (BP 20a AI-4.6 & 4.7)
  - Anticipated End Date: Q4 2020

- Develop a detailed inventory of the different categories of M&R stations operated by SoCalGas & SDG&E (BP 20a AI-4.5)
  - Anticipated End Date: Q4 2020

- Quantification of Leaks and Define Practical Lower Emission Threshold Research Project (OTD 7.17.d) (BP 20a AH-1)
  Initial testing on above ground assets at 60 psig or less demonstrated that good correlation exists between soap bubble size and leak flow rate; and that practical bubble size categories could be used to develop leaker-based emission factors.
  - Anticipated End Date: Q4 2020

b. PROPOSED PROJECTS

- Distribution Main & Services additional analysis to refine DT model and investigate additional parameters (SCG & SDG&E)
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q4 2022

- Customer Meters additional sampling (SCG & SDG&E)
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q4 2022

- Develop Company-Specific Leak-Based Emission Factors for Transmission M&R Station Facilities
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q4 2022

- Develop Company-Specific Leak-Based Emission Factors for Above Ground Leaks Using Soap Test Method
    - Anticipated Start Date: Q1 2021
    - Anticipated End Date: Q4 2022

7) **DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT**

- Company-specific emission factors
    - Gather Equipment and Operating Data
      Gather necessary operating data (e.g., pressure) and equipment characteristics (e.g., number of components by type and size) that can impact emissions.
        - Transmission M&R Facilities
        - Distribution M&R Stations
        - Customer Meters
    - Categorize Equipment (Emissions Sources)
      Use data from task No. 1 to develop equipment categories.
        - M&R Stations
        - Customer Meters
    - Develop Equipment Sampling Plan
      Leak measurement samples must be representative of the facility population to be statistically valid for the entire population of leaks in the service area. Samples must be collected randomly in order to meet this requirement.
    - Conduct Leak Measurements
      Conduct leak measurements on a statistically random basis. Measure the emission rate of detected leaks in the field and document each leak source (component type and size). Measure emission rate from pneumatic devices and document each device.
    - Statistically Analyze Leak and Emissions Data
    - Develop Emission Factors
        - “Leaker” and/or “Component Population” emission factors based upon data analysis and “Fugitive” or “Vented” type of emissions
- Quantification of Small Leaks and Define Practical Lower Emission Threshold Research Project (OTD 7.17.d) (BP 20a AH-1).
    - Final results will be analyzed for capability to meet company specifications.
- Develop Company-Specific Emission factors for Above Ground Leaks Using Soap Test Method**.**
    - Laboratory Evaluation
        - Data gathered during laboratory evaluation is used to demonstrate capability of soap test method for intended applications. (Go/No-Go Decision).
        - Use results of laboratory data to guide simulated field-testing plan.
        - Evaluate Cost of Implementation
        - Estimate cost to conduct simulated field evaluation.
            - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).

- Simulated Field Evaluation (Controlled Environment)
  - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications. (Go/No-Go Decision). Use results of simulated field evaluation data to guide pilot study plan.
- Pilot Study
  - Verify soap test method capability for intended applications, and that the method can meet Company specifications (Go/No-Go Decision).
  - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
- Develop Emission Factors
  - Data gathered during pilot studies will be used to calculate emission factors.

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$793,499	$806,693

SDG&E	2021	2022
	$71,415	$72,602

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$1,600,192

SDG&E	Total Loaded Costs
	$177,783

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**
No other Advice Letter costs directly related to this template

11) **REFERENCES**

- GHG Emission Factor Development for Natural Gas Compressors, PRCI Catalog No. PR-312-16202-R02, April 18, 2018.
- Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data, PRCI Catalog No. PR-312-18209-E01, October 17, 2019.

2020 Leak Abatement Plan RD&D Objective Summary #20a-4
Model Leak Growth Rates from Polyethylene Plastic Piping Slow-crack Growth Failures

1) **BEST PRACTICE ADDRESSED**

- Best Practice 20a: Quantification
  Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks to assist demonstration of actual emissions reductions.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**

- Model Leak Growth Rates from Polyethylene Plastic Piping Slow-crack Growth Failures.
  - This is a continuing Research & Development project to advance the understanding of how leaks evolve over time on various pipeline materials.

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**

- The research objective is to advance industry understanding of how leak rates tend to grow over time on Polyethylene (PE) pipe once the leak has initiated. Prior to this project industry research in this area was focused on the process of crack initiation up until a leak occurred. This knowledge will assist in improving system leakage estimate and emission factors and help to optimize leak survey intervals based on projected emissions growth rates.
- Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
			F				

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
  a) Laboratory Testing

- Multiple pipe samples are placed on test in multiple soil types in known conditions for an extended time period.

b) Modeling
- Using data and conditions from laboratory tests, develop a model to estimate emissions growth rate from cracks in PE pipe.

c) Model Verification
- Verify the model with field leak measurements between time detected and at point of repair.

4) **ANTICIPATED OR EXPECTED RESULTS**

- Increased understanding of the impact on methane emissions from the leak growth rate due to cracks in the Polyethylene (PE) pipeline.

5) **EMISSIONS IMPACT**

- The knowledge gained from this study will assist in management and estimation of methane emissions from PE pipelines. Leak rates can be projected from the time of discovery and repairs can be prioritized using this knowledge to prevent leaks from developing into large emitters.
- This knowledge can also be applied to future methane emissions studies in the development of improved Emissions Factors and methane emissions inventory reporting.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS

- PE Leak Growth Rate from Slow Crack Growth Research Project (OTD 7.15.c, BP 20a AK-1)
  - Actual Start Date: Q1 2016

b. PROPOSED PROJECTS

- PE Leak Growth Rate from Slow Crack Growth (continuing) (OTD 7.15)
  - Anticipated End Date: Q4 2022

7) **DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT**

- PE Leak Growth Rate from Slow Crack Growth Research Project (OTD 7.15.c, BP 20a AK-1)
  - Laboratory Testing
    - Data gathered during laboratory testing is used as inputs to develop the model. Measurement data includes pressure, leak rate, temperature, soil type, etc. Analysis will be performed to determine relationships among the variables and the leak rates.
  - Modeling
    - During the development of the model there is no new data collection.
    - Model development will incorporate and analyze data collected from laboratory testing.
  - Model Verification
    - Demonstrate model capability for intended applications, which meet Company specifications (Go/No-Go Decision).
    - Gather field leak measurement and leak duration data
    - Correlate with leak repair data and types of plastic leaks
    - Test statistical validity of the model
    - Re-Evaluate/update the model and repeat verification if needed
    - Go/No-Go Decision

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

- Incremental Cost Estimates (Provided in 2017 Dollars and Direct Costs (No Loaders))

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$66,042	$67,158

SDG&E	2021	2022
	$5,944	$6,044

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	**Total Loaded Costs**
	$163,957

SDG&E	**Total Loaded Costs**
	$14,756

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

OTD Project No. 7.15.c Summary Report

2020 Leak Abatement Plan R&D Summary 20a-5
Quantification of Through-Valve Leakage on Large Compressor Valves

1) **BEST PRACTICE ADDRESSED**
- Best Practice 20a: Quantification
  Utilities shall develop methodologies for improved quantification, geographic evaluation, and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall also work together, with CPUC and ARB staff, to develop a similar methodology to improve the emissions quantification of leaks in order to demonstrate actual emissions reductions.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**
- Quantification of Through-Valve Leakage on Large Compressor Valves.
  - Improve quantification of through-valve leaks on large natural gas compressor valves prone to leakage (i.e., blowdown valves and isolation valves) by identifying and/or developing appropriate measurement methods (i.e., instruments and measurement procedures).
  - Reduce natural gas emissions by identifying and repairing large through-valve leaks on large compressor valves.
- The evaluation of promising measurement methods for through-valve leakage emissions will be conducted on full-scale compressor valves under controlled conditions. Pilot studies will follow as deemed necessary to further evaluate emissions reductions and/or cost efficiency.

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**
- The research objective is to evaluate current and new through-valve leakage emissions measurement methods and determine the best method(s) for accurate quantification.
- Areas targeted:

Transmission			**Distribution**			**Storage**	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
		F, V					F, V

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series planned evaluations, that can include one or more of the following:
  a) Screening evaluation of measurement methods for through-valve leakage emissions.
  b) Identify most promising measurement methods from the screening study and evaluate these methods under controlled conditions over a range of valve types and sizes, operating pressures, leak configurations, leak sizes, etc.
  c) Identify the best practice measurement method(s) and/or need for further evaluation.

4) **ANTICIPATED OR EXPECTED RESULTS**

- Accurate through-valve leakage measurements will lead to the ability to prioritize repair of large through-valve leaks on large compressor valves.

5) **EMISSIONS IMPACT**

- The current method to measure through-valve leakage emissions from compressor blowdown valves and isolation valves is an acoustic technology, which historically measures with a low bias (often measures a false zero)[A]. Evaluation of the SoCalGas 2015 baseline emissions data indicates a low bias in the blowdown and isolation valve measurements, and an adjustment of the 2015 emissions using best available data is appropriate. The identification and implementation of best method(s) for accurate measurements will allow quicker mitigation of previously undetected or under-quantified large leaks.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS

- Evaluate current measurement methods for through-valve leakage emissions to determine bias and precision
  A 2019 PRCI Project, funded in part by SoCalGas, "Scoping Study on Unit Isolation Valve Gas Leakage at Natural Gas Compressor Stations" compiled valve population, leakage, and O&M information for more than 1,000 isolation valves. In addition, in 2019 a Companywide survey of every compression facility and corresponding compressor isolation valves was completed. Subject matter experts at each facility were interviewed and the results are summarized in an internal report. The lessons learned from these two projects are used to guide this evaluation of measurement methods for through-valve leakage emissions.
  - Anticipated End Date: Q4 2020

b. PROPOSED PROJECTS

- Identify best practice methods and procedures to identify effective emission measurement methods
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q4 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a. CURRENT PROJECTS

- Evaluate current measurement methods for through-valve leakage emissions to determine bias and precision.
  - Screening Evaluation/Manufacturer Demonstrations
    - Data will be gathered during manufacturer/user demonstrations of IR cameras, acoustic methods, ultrasonic methods, insertion flowmeters, and new methods.
    - Data analysis will include identifying measurement methods/instruments with a propensity for measuring false negatives (i.e., measurement of zero emissions when emissions are known to exist).
    - Isolation valves are installed on various pipe sizes from 1” to 24” in diameter at varying pressures up to 3,000 psi. Blowdown valves are installed on various pipe sizes from about 1” to 4” in diameter at varying pressures up to 3,000 psi. These parameters and the results of the screening evaluation will be considered to select measurement methods for further evaluation in the Controlled Study of Full-Scale Valves.
    - Go/No-Go Decision. A Go/No-Go Decision will be based on the estimated cost to conduct the Controlled Study of Full-Scale Valves as well as estimates of emission reductions and the cost impacts of implementing the measurement methods.
  - Controlled Full-Scale Valve study (Controlled through-valve leakage tests)
    - This study will assess selected measurement methods over a matrix of key parameters (e.g., operating pressure, valve type and size, leak configuration, and/or leak rate) typical of actual field conditions.
    - Data analysis will include estimation of the bias/accuracy and precision (i.e., repeatability and reproducibility) of the different measurement methods. Test results will be used to evaluate whether the measurement methods demonstrate capability for intended applications and can meet Company specifications (Go/No-Go Decision).

b. PROPOSED PROJECTS

- Identify best practice methods and procedures on preferred measurement methods
  - Data gathered during the evaluations of measurement methods for through-valve leakage emissions is used to develop best practices and procedures as applicable to specific pipe size/pressure/valve type combinations. The need to develop and/or evaluate additional methods will be determined.

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$132,083	$134,315

SDG&E	2021	2022
	$11,887	$12,088

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$327,915

SDG&E	Total Loaded Costs
	$29,512

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

A. GHG Emission Factor Development for Natural Gas Compressors, PRCI Catalog No. PR-312-16202-R02, April 18, 2018.

B. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, GRI-94/0257.25, EPA-600/R-96-080h, June 1996.

2020 Leak Abatement Plan RD&D Objective Summary #20b
Geographic Emissions Tracking & Evaluation

1) BEST PRACTICE ADDRESSED

- Best Practice 20b: Geographic Tracking
  Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together with CPUC and ARB staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emissions reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census track.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Geographic Tracking and Evaluation of Leak Data
- Increase efficiencies through error reduction and work bundling.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to integrate emissions related data from different operating organizations; develop strategies to gather and store field data electronically minimizing data error; and spatially identify facilities that fall into different categories to support data analytics.
  Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F			F		F		

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v – Vented

- The R&D approach to meet the objective will involve a series of planned evaluations that can include one or more of the following:
  a) Gather input from subject matter experts
  b) Develop Strategies for field collection and storage
  c) Develop methods to spatially identify facilities

d) Incorporate into data analytics

4) **ANTICIPATED OR EXPECTED RESULTS**

- Reduction of electronic data error from manual data entries of field data.
- Capturing of additional data points, currently unrecorded, from field leak measurements.

5) **EMISSIONS IMPACT**

- The direct impact on emissions is difficult to quantify as the major benefit is the improves efficiencies from both work bundling and data entry error reduction.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS

- Prior research may be leveraged to support this objective, such as GIS Platform & Data Model for Mobile Data Collection (OTD 8.17 e)
  - Anticipated End Date: Q2 2020

b. PROPOSED PROJECTS

- Gather and Store Field Data
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q4 2021
- Spatially Identify Facilities
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q4 2021

7) **DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT**

a. CURRENT PROJECTS

- There are no projects in conjunction with the Best Practice.

b. PROPOSED PROJECTS

- Gather input from subject matter experts

  - Data gathered from subject matter experts is used to guide strategies to gather and store field data.
  - Data gathered from subject matter experts is used to categorize facilities
- Develop strategies for field data collection and storage
  - Data gathered during strategic planning will be used and analyzed to determine efficient methods of field data collection and acceptable methods of data storage that meet Company specifications. (Go/No-Go Decision)
  - Estimate cost to implement field data collection and storage
- Develop methods to spatially identify facilities and system components
  - Data gathered during the spatial identification and categorization of facilities will be evaluated for usefulness towards data analytics and work bundling.
  - Estimate cost/efficiency of facility categorization.

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$46,029	$94,048

SDG&E	2021	2022
	$4,143	$8,464

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$173,017

SDG&E	Total Loaded Costs
	$15,572

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

OTD Project No. 8.17.e Summary Report

2020 Leak Abatement Plan RD&D Summary #22

Investigate Specifications, Tolerances and Sealing Compounds for Threaded Fittings

1) **BEST PRACTICE ADDRESSED**

- Best Practice 22: Pipe Fitting Specification & Tolerances
  Utilities shall eliminate or greatly reduce emissions from metal pipe and fitting threaded connections most commonly used on aboveground facilities, such as on customer meter set assemblies and meter and regulation stations. This is accomplished with improved quality control inspection of supplier's threaded products and the application of high-performance thread sealant compounds during construction.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**

- Investigate Specifications, Tolerances and Sealing Compounds for Threaded Metal Pipe and Fittings
- Reduce emissions by reducing fugitive gas loss at threaded connections.
- Pilot studies to be initiated based on results of sealant evaluations. Pilot studies will validate actual costs and emissions reductions.

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**

- Evaluate the sealing performance of pipe thread sealants (spray-on, brush-on, putty, or epoxy leak sealant products) that can be applied externally to threaded metal connections to lock and prevent gas leakage under varying environmental conditions, internal pressures and external loading.
- Identify the high-performance thread sealant products that can seal low pressure (7 IWC or 2 PSIG) thread leaks on existing MSAs and conduct a thorough evaluation of these products.
- Areas targeted

Transmission			**Distribution**			**Storage**	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
f	f	f	F	f	F	f	f

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
  a) Laboratory Evaluation
     a. Establish baseline performance for sealants that are evaluated.
     b. Comparative evaluation to manufacturer specifications and currently approved sealants.
     c. Evaluate the sealants to Company requirements for intended applications.
  b) Simulated Field Evaluation (Controlled Environment)
     a. Evaluate sealants in a simulated field environment utilizing controlled natural gas releases.
     b. Compare to currently approved sealants, practices, and/or procedures.
  c) Pilot Study
     a. Obtain and evaluate multiple sealants against Company's specifications for the intended application, and test for reliability.
     b. Evaluate sealants in an actual field environment, including controlled natural gas releases.
     c. Compare to currently approved sealants, practices, and/or procedures.

4) **ANTICIPATED OR EXPECTED RESULTS**

- Company use of high-performance thread sealants may help eliminate fugitive methane emissions.
- Revising Company pipe thread specifications to ensure tighter tolerance and better-quality threads will help reduce fugitive methane emissions.
- Implement a threaded fitting replacement program for threaded components identified to have significant thread leaks.
- The project will identify the most economical thread sealants that resist leakage when exposed to varying combinations of pipe size, pressure, and temperature changes; movement; and general environmental conditions, and that provide an emissions cost-benefit when considering implementation costs of any required changes to operational practices. For example, Spray-on and brush-on type sealants will blow off by the force of the low-pressure leaks. The putty type sealants will take more time to apply but will stop low-pressure leaks. Ease of application, amount of time to apply, minimum surface preparation, and no service disruption are advantages over standard MSA dismantle and reassembly.
- Leak testing of NPT and ANPT quality pipe and fitting threads will provide performance data that will determine if company pipe fitting specifications need to be revised.

5) **EMISSIONS IMPACT**

- Reduce or eliminate fugitive methane emissions from aboveground threaded connections on Customer MSAs and Meter and Regulation Stations.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. **CURRENT PROJECTS**
- Study Quality of Existing Pipe Fitting Inventory Research Project (NYSEARCH M2018-001)
  Final Report Review and Phase 2 (Go/No-Go Decision) Q1 2020:

b. **PROPOSED PROJECTS**
- NYSEARCH: Phase 2 - Evaluate thread sealants to reduce emissions from pipe fittings.
  Anticipated Start Date: Q1 2021
  Anticipated End Date: Q3 2022
- Low pressure sealants – Identify possible spray-on, brush-on, putty, or epoxy leak sealants to seal low pressure (7IWC or 2PSIG) thread leaks on existing MSAs
  Anticipated Start Date: Q1 2021
  Anticipated End Date: Q3 2022

7) **DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT**

a. **CURRENT PROJECTS**
- Study Quality of Existing Pipe Fitting Inventory Research Project (NYSEARCH M2018-001). Data gathered during the environmentally controlled testing is used to compare the effects of thread form, lubricant and torque as a function of temperature and pressure on leak rate. A baseline for NPT and ANPT is established.
- SPEC project and report

b. **PROPOSED PROJECTS**
- Laboratory Evaluation
  - Data gathered during laboratory evaluation will be utilized to establish performance baselines and to determine which sealants proceed to the field evaluation.
- Simulated Field Evaluation (Controlled Environment)
  - Data gathered during field evaluation will be used to compare to Company specifications and guide the Pilot Study.
- Evaluation Cost of Implementation
  - Estimate cost to conduct pilot studies
  - Estimate emissions reduction cost reduction, and cost avoidance benefits (Go/No-Go Decision)
- Pilot Study
  - Data gathered during pilot study will be utilized to determine candidates for implementation.

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$141,089	$142,334

SDG&E	2021	2022
	$12,698	$12,810

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$348,873

SDG&E	Total Loaded Costs
	$31,399

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**
No other Advice Letter costs directly related to this template.

11) **REFERENCES**
NYSEARCH Project M2018-001 Project Report

2020 Leak Abatement Plan R&D Summary #23-1
Evaluation of Technologies to Mitigate Vented Emissions and Gas Blowdowns

1) **BEST PRACTICE ADDRESSED**

- Best Practice 23: Emissions from Operations, Maintenance and other Activities Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**

- Evaluation of Technologies to Mitigate Vented Emissions & Gas Blowdowns
- This is an emissions reduction effort through mitigation of natural gas release which is currently part of the operation. This will also result in operational efficiencies.
- Perform pilot projects to demonstrate effectiveness and establish basis for cost estimates of technology implementation.

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**

- The research objective is to:
  - Evaluate the effectiveness of various technologies (new or as discovered during records search) to mitigate vented emissions and gas blowdowns.
  - Review relevant operating procedures where gas is currently released as part of the operation to identify opportunities to reduce methane emissions by changing current practices and utilizing new technology, tools and equipment, and/or practices.
  - Perform pilot projects to demonstrate effectiveness and establish basis for cost estimates of technology implementation.
- Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F	F			F		F	F

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective for technology, tool or equipment will involve a series of planned evaluations, that cam include one or more of the following:
    - a) Manufacturer/In-house Demonstration
        - a. Facilitate demonstrations by manufacturers or set-up in-house prototypes of new technologies, tools or equipment.
    - b) Laboratory Evaluation
        - a. Establish baseline performance for technologies, tools or equipment that are evaluated.
        - b. Comparative evaluation to manufacturer specifications and currently approved methods.
        - c. Evaluate the technologies, tools or equipment to Company requirements for intended applications.
        - d. Simulated Field Evaluation (Controlled Environment)
        - e. Evaluate technologies, tools or equipment in a simulated field environment
        - f. Compare to currently approved technologies, tools or equipment
    - c) Pilot Study
        - a. Evaluate technologies, tools or equipment in an actual field environment, including controlled natural gas releases.
        - b. Compare to currently approved technologies, tools or equipment.
- The R&D approach to meet the objective for procedural evaluations includes:
    - a) Identify relevant operating procedures where gas is currently released as part of the operation.
    - b) Review Procedures
        - a. Identify opportunities to reduce methane emissions
    - c) Evaluate cost of implementation and prioritize opportunities
    - d) Execute demonstrations/evaluations on prioritized opportunities

4) **ANTICIPATED OR EXPECTED RESULTS**

- The evaluation of various technologies to mitigate gas blowdowns and vented emissions will result in recommendations to reduce blowdown events and a reduction in vented emissions.
- Opportunities that are identified in the operating procedure review may result in an evaluation and subsequent recommendation to change existing practices or to utilize new practices, tools and equipment or technology.

5) **EMISSIONS IMPACT**

- Reduce planned facility blowdown or venting of natural gas to the atmosphere and/or other operational venting by employing one or more viable options.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS

GFO-19-502 Group 2: Smart Shutoff Technology for Residential and Commercial Buildings

A meter valve has been identified that is a normally closed mechanical gas valve that is installed on the service and upstream of the meter-set assembly. It provides automatic and remote shut-off in the event of fire (and optionally flood, over-pressure, seismic activity) or utility initiated disconnect.

- Anticipated Start Date – Q1 2020

b. PROPOSED PROJECTS

- **Field demonstrations and evaluation of mitigation technologies**
  - Anticipated Start Date Q1 2021
  - Anticipated End Date Q4 2022
- **Evaluate impact of utilizing new technology, tools and equipment on practices and procedures**
  - Anticipated Start Date Q1 2021
  - Anticipated End Date Q4 2022

7) **DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT**

- Data collection and analysis for technology, tool or equipment evaluations includes:
  1. Manufacturer/In-house Demonstration
     - Data gathered during demonstrations is used to identify potential capabilities that can be leveraged for Company reduction of planned gas release.
  2. Laboratory Evaluation
     - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, tool or equipment can meet Company specifications (Go/No-Go Decision).
     - Use results of laboratory evaluation to guide simulated field-testing.

3. Evaluate Cost of Implementation
   - Estimate cost to conduct simulated field evaluation.
   - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
4. Simulated Field Evaluation (Controlled Environment)
   - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, tool or equipment can meet Company specifications (Go/No-Go Decision).
   - Use results of simulated field evaluation data to guide pilot study plan.
   - Evaluate integration of instrument data into Enterprise Data Management Systems and business process workflows.
   - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
5. Pilot Study
   - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision)
   - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	**2021**	**2022**
	$146,092	$147,346

SDG&E	**2021**	**2022**
	$13,148	$13,261

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	**Total Loaded Costs**
	$361,200

SDG&E	**Total Loaded Costs**
	$32,508

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

https://www.energy.ca.gov/solicitations/2019-10/gfo-19-502-storage-monitoring-smart-shutoff-and-3d-mapping-technologies-safer

2020 Leak Abatement Plan R&D Summary #23-2
Evaluate Component Emission Reductions Opportunities

1) **BEST PRACTICE ADDRESSED**

- Best Practice 23: Minimize Emissions from Operations, Maintenance, and Other Activities
  Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

2) **NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT**

- Evaluate Component Emission Reductions Opportunities
- Reduced emissions from component leaks and potential operational efficiency improvement through improved monitoring systems, improved performance, and changes in practices, designs, materials or novel solutions.
- Pilot studies to be executed on successful areas of improvement to validate actual costs and emissions reductions

3) **R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?**

- The research objective is two-fold:
  - Evaluate the maintenance history of Compressor and M&R Station components to identify components prone to leakage (valve stems, through-valve in closed positions, lube port, etc.). Identify opportunities to improve leak detection through monitoring systems and/or improve system performance through changes in maintenance practices, component designs, new materials, or novel solutions.
  - Evaluate emissions from system components designed to have vented emissions. Identify opportunities to reduce vented emissions through monitoring systems or improved maintenance practices, component designs, new materials, or novel solutions.
- Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
V	F,v	F,v	V	F,v	f,v	F,V	F,V

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
  a) Evaluate maintenance histories to identify components prone to leakage
  b) Implement lessons learned regarding valve maintenance and improved leak detection.
  c) Evaluate emissions from system components with vented emissions
  d) Identify opportunities to reduce vented emissions
  e) Select opportunities based on emissions reductions and cost efficiency and evaluate on site.
  f) Create Standard Operating Procedures, training programs, tracking plans
  g) Develop materials, novel solutions as identified.

4) **ANTICIPATED OR EXPECTED RESULTS**

- Reduce methane emissions by improved valve maintenance practices and/or replacing existing equipment/materials/components with new designs that reduce emissions.

5) **EMISSIONS IMPACT**

- This research objective is estimated to result in emissions reduction; however, the magnitude of this emissions reduction cannot yet be determined.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS

- Methane Oxidation Catalyst Research Project (NYSEARCH M2017-004) (BP 23 AP-1)
  - Actual Start Date: Q4 2017
  - Anticipated End Date: Q1 2021
- Compressor Isolation Valves Maintenance Best Practices (SoCalGas R&D)
  - Actual Start Date: Q2 2019
  - Anticipated End Date: Q1 2021

b. PROPOSED PROJECTS

- Study alternatives to reduce component leakage (Bellows valves, secondary containment, etc.)
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q3 2022
- Evaluate and revise current practices and utilize new technology, tools, equipment, and practices and procedures
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q3 2022
- Evaluation of electrohydraulic devices to replace pneumatic to replace intermittent bleed devices
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q3 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a. Current Projects

- Methane Oxidation Catalyst Research Project (NYSEARCH M2017-004) (BP 23 AP-1).
  - Proof of Concept
  - Prototype Design
  - Prototype Development
  - Lab-Scale Prototype Demonstration
- Compressor Isolation Valves Maintenance Best Practices (SoCalGas R&D) - Implement lessons learned regarding valve maintenance and improved methods to detect through-valve leakage
  - Compile existing data (e.g., make, model, size, age) regarding the population of SoCalGas compressor blowdown valves and isolation valves
  - Utilize information gathered ("lessons learned" and maintenance practices for valve systems) during interviews of SoCalGas subject matter expects to develop a draft SOP.
  - Determine Baseline Leak Conditions
    - Identify and measure through-valve leakage on a sub-population of SoCalGas compressor blowdown valves and isolation valves
  - Utilize data gathered during determination of baseline to develop better methods to detect through-valve leakage (BP 20a.5)
  - Tracking
    - After the SOP has been implemented, periodically measure through-valve leakage on the population SoCalGas compressor blowdown valves and isolation valves to determine the impact (i.e., expected emissions reduction) of the SOP implementation
- Evaluation of electrohydraulic devices to replace pneumatic intermittent bleed devices.
  - Manufacturer Demonstration
    - Data gathered during manufacturer demonstration is used to identify potential capabilities that can be leveraged for Company requirements for intermittent bleed devices.
  - Laboratory Evaluation
    - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the intermittent bleed devices can meet Company specifications (Go/No-Go Decision).
    - Use results of laboratory data to guide simulated field-testing plan.
  - Evaluate Cost of Implementation
    - Estimate cost to conduct simulated field evaluation.
    - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).

- Simulated Field Evaluation (Controlled Environment)
  - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the intermittent bleed devices can meet Company specifications (Go/No-Go Decision).
  - Use results of simulated field evaluation data to guide pilot study plan.
  - Evaluate integration of instrument data into Enterprise Data Management Systems and business process workflows.
  - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
- Pilot Study
  - Verify capability for intended applications, and that the intermittent bleed devices can meet Company specifications (Go/No-Go Decision).
  - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

b. Proposed Projects

- Study alternatives to reduce component leakage (Bellows valves, secondary containment, etc.) for T&S.
  - Compile existing data (e.g., make, model, size, age) regarding the population of SoCalGas components
  - Interview SoCalGas subject matter expects to document “lessons learned” regarding maintenance practices for components, develop draft SOP
  - Determine Baseline Leak Conditions
    - Identify and measure component leaks on a sub-population of SoCalGas components
  - Implement Lessons Learned/SOP regarding valve maintenance
  - Tracking
    - After the SOP has been implemented, periodically monitor components for leakage to determine the impact (i.e., expected emissions reduction) of the SOP implementation
- Evaluate current practices to utilize new technology, tools, equipment, and practices and procedures
  - Compile existing data regarding current practices and the associated population of SoCalGas components
    - Interview SoCalGas subject matter expects to document “lessons learned” regarding the current practices, develop draft SOP
    - Determine Baseline Leak Conditions - Identify and measure emissions from a sub-population of the associated SoCalGas emission sources
    - Implement Lessons Learned/SOP
    - Tracking - After the SOP has been implemented, periodically measure from a sub-population of associated SoCalGas emission sources to determine the impact (i.e., expected emissions reduction) of the SOP implementation

- Compile existing data regarding new technology, tools, equipment, and practices and procedures and the associated population of SoCalGas components
  - Interview SoCalGas subject matter expects to document "lessons learned" regarding the current practices, develop draft SOP
  - Determine Baseline Leak Conditions - Identify and measure emissions from a sub-population of the associated SoCalGas emission sources
  - Implement Lessons Learned/SOP
  - Tracking - After the SOP has been implemented, periodically measure from a sub-population of associated SoCalGas emission sources to determine the impact (i.e., expected emissions reduction) of the SOP implementation

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$340,214	$342,804

SDG&E	2021	2022
	$30,619	$30,852

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$840,746

SDG&E	Total Loaded Costs
	$75,667

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**
No other Advice Letter costs directly related to this template.

11) **REFERENCES**

A. GHG Emission Factor Development for Natural Gas Compressors, PRCI Catalog No. PR-312-16202-R02, April 18, 2018.
B. Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data, PRCI Catalog No. PR-312-18209-E01, October 17, 2019.

2020 Leak Abatement Plan R&D Objective Summary #23-3
Alternative Fuel Substitution Strategy

1) BEST PRACTICE ADDRESSED

- Best Practice 23: Minimize Emissions from Operations, Maintenance, and Other Activities
  Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Alternative fuels substitution strategy to reduce methane emissions by changing the Gas composition resulting in a reduced petrogenic methane concentration. Reduce emissions of petrogenic methane from gas leaks (i.e., fugitive emissions) and gas venting by blending alternative fuels.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to revise the current gas composition specification to achieve a reduction in petrogenic methane emissions.
- Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F, V	F, V	F, V	F, V	F, V	F, V	F, V	F, V

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
  a) Feasibility Study
- Identify the “best” fuel substitution strategies; that is, the strategies that have the potential to reduce petrogenic methane emissions and be cost-effective.
  b) Small Scale Demonstration and Evaluation of Reliability and Safety
- Execute testing and research to address data and technology gaps identified in the Feasibility Study and verify that any potential identified fuel substitution strategies will not impact system reliability and safety.

4) ANTICIPATED OR EXPECTED RESULTS

- The potential benefit is reduced emissions of all releases of petrogenic methane sources within the supply chain.

5) **EMISSIONS IMPACT**

- Petrogenic methane emissions reductions are expected to differ for the different fuel substitution strategies, and reduction estimates will be an output of the Feasibility Study.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS

Prior research where investigations into gas composition has been performed may be leveraged to support this project, such as GTI Low-Carbon Renewable Natural Gas (RNG) From Wood Wastes (see Section 11 REFERENCES).

b. PROPOSED PROJECTS

- Phase 1 Feasibility Study
  - Evaluate the system gas petrogenic methane reductions associated with different fuel substitution strategies, which could include hydrogen, propane, ethane, and methane from existing biogenic methane sources
  - Evaluate other possible impacts including, but not limited to: possible impact on combustion VOC and/or NOx emissions and other criteria pollutant emissions; impact on system gas Wobbe index and existing specifications/tariffs for SoCalGas system gas; GHG emissions from fuel substitution system implementation and substitute fuel transport; and costs of fuel substitution system implementation (i.e., equipment and operating costs) and substitute fuel transport. (Go/No-Go Decision)
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q3 2021
- Phase 2: Small Scale Demonstration and Evaluation of Reliability and Safety
  - Perform small scale laboratory demonstration(s) to evaluate the impact on combustion equipment and emissions. (Go/No-Go Decision)
  - Anticipated Start Date: Q1 2021
  - Anticipated End Date: Q3 2023

7) **DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT**

- Phase 1 Feasibility Study – gather data and make calculations to support the feasibility analysis of each alternative fuel substitution strategy identified through input of industry and subject-matter experts.
- Determine if the potential alternative fuel substitution strategy complies with existing specifications/tariffs for SoCalGas system gas or could comply with potential revised specifications/tariffs for system gas.
- Collect data to estimate GHG emissions (e.g., as petrogenic methane equivalents) from the fuel substitution system strategy implementation and substitute fuel transport.
- Collect data to estimate emissions of criteria pollutants and hazardous air pollutants, and other possible ancillary impacts, from the fuel substitution system strategy implementation and substitute fuel transport

- Collect data to estimate the cost of the fuel substitution system strategy implementation (i.e., capital and operating costs) and substitute fuel transport.
- Calculate estimates of net petrogenic methane emissions reductions (e.g., as petrogenic methane equivalents).
- Calculate estimates of cost-effectiveness (e.g., $/yr for implementation / change in emissions of petrogenic methane equivalents (Δ ton/yr)).
- Alternative fuel substitution strategies that 1.) are estimated to result in net reductions of petrogenic methane equivalents emissions; 2.) have favorable (i.e., low $/Δ ton) estimates of cost-effectiveness; and 3.) do not have significant adverse ancillary impacts (e.g., criteria pollutant emissions) would be considered for Phase 2.
- Phase 2: Small Scale Demonstration and Evaluation of System Reliability and Safety - – gather data and conduct analyses to further evaluate whether alternative fuel substitution strategies should be implemented. Specific data collection, testing and analyses will be determined after the completion of Phase 2 and could include:
- Data needed to refine Phase 1 feasibility analysis
- Combustion stability testing
- Review and evaluation of existing safety systems and practices
- Analysis of the impact on system reliability

8) **EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).**

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	$100,063	$100,235

SDG&E	2021	2022
	$9,006	$9,021

9) **RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	$246,554

SDG&E	Total Loaded Costs
	$22,190

10) **OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.**

No other Advice Letter costs directly related to this template.

11) **REFERENCES**

GTI Low-Carbon Renewable Natural Gas (RNG) From Wood Wastes
https://www.cpuc.ca.gov/uploadedfiles/CPUS_Website/Content/Utilities_and_Industries/Energy_Programs/Gas/Natural_Gas_Market/GTI.pptx