Pipeline Information for the City of Foster City

December 2, 2013

PG&E's Vision for Gas Operations

Become the safest, most reliable gas company in the nation

Our Goal

Enhance communication and build trust with our customers and the communities we serve

Executive Summary for Foster City

PG&E serves customers from 9,611 gas meters and 14,201 electric meters in Foster City (as of November 19, 2013).

Transmission Asset Overview

- No gas transmission pipelines run through Foster City. The closest gas transmission line is Line 101 in San Mateo.

Distribution Asset Overview

- Foster City has 75 miles of gas distribution mains and service lines (27 miles of steel, 15 miles of Aldyl-A plastic and 32 miles of other plastic).
- Distribution Feeder Main (DFM) 0214-01 runs through the Foster City in the vicinity of Redacted from Redacte to Redacted.

  Specifics on DFM 0214-01

  - Maximum Allowable Operating Pressure (MAOP): 180 psig
  - Normal operating pressure: 170 psig
  - Years installed: 1963, 1971 and 1997
  - Material: Steel
  - Pipe diameter: 6 inches and 8 inches
  - Percent of Specified Minimum Yield Strength (SMYS) range: 6.1% to 11.8% for all components
  - Number of main line valves: 3
  - Fed by transmission line L-101

Safety Overview

- PG&E has a comprehensive inspection and monitoring program to ensure the safety of its natural gas distribution system. PG&E regularly conducts leak surveys and cathodic protection (corrosion protection) system inspections for its steel gas distribution lines. Any issues identified as a threat to public safety are addressed immediately.
- Approximately 15 feet of DFM 0214-01 was pressure-tested in 1997 at installation. PG&E classifies DFMs as distribution pipe and as such this DFM was not tested as part of the Pipeline Safety Enhancement Plan (PSEP). As part of PG&E's long term plans, PG&E plans to perform hydrostatic tests on DFMs.
- There are no integrity concerns with DFM 0214-01.
- PG&E is working to replace certain Aldyl-A plastic mains. Replacement of Aldyl-A distribution main is based on factors related to the condition and surroundings of the pipe. The primary factor in determining if a main is to be replaced is leak

repair data, which indicates the potential of a material issue with the Aldyl-A plastic. Secondary factors include pipe vintage, operating pressure, the potential for ground movement, population density and areas of public assembly. Replacement projects are prioritized in order of the pipe with the greatest combination of consequence and likelihood for leakage.

PG&E has replaced or proposes replacement of the following Aldyl-A main around the Edgewater Park vicinity over the next 3 years:

Aldyl-A Replacement	
Year	Mileage
2013	2.8
2014	0.9
2015	3.5*

*Portions of projects are delayed due to street paving moratorium

- PG&E has worked with Foster City's Fire Department to provide first responder workshops and training to promote public safety and awareness.

Maintenance Overview

- PG&E regularly conducts leak surveys of its natural gas pipelines. Leak surveys are generally conducted by a leak surveyor walking above the pipeline with leak detection instruments. Distribution leak surveys are done at least every five years.
- DFM 0214-01 is on a 5-year leak survey schedule. The last leak survey was performed on 9/12/2010 and no leaks were found.
- PG&E utilizes an active cathodic protection (CP) system on its steel distribution pipelines to protect them against corrosion. PG&E inspects its CP systems every two months to ensure they are operating correctly. The CP system for DFM 0214-01 in Foster City was inspected on 11/1/13 and no issues were identified. The steel distribution mains within Foster City were last inspected on 11/1/13 and no issues were identified.
- PG&E patrols its gas transmission pipelines at least quarterly to look for missing pipeline markers, construction activity and other factors that may threaten the pipeline. Since DFM 0214-01 is a distribution facility (as defined by Federal code), patrols are not required. However, as a conservative measure, PG&E has chosen to include this DFM in its patrols of the gas transmission pipelines on the peninsula, which are currently done at least monthly. DFM 0214-01 was last patrolled on 10/28/13, and everything was found to be normal.

Third-Party Damage

Third-party dig-ins represents the greatest threat to PG&E's buried pipelines and pipeline patrols provide a leading indicator that helps PG&E protect pipelines and improve safety. As stated above, DFM 0214-01 was last patrolled on 10/28/13, and everything was found to be normal.

In 2013, there have been two third-party dig-ins in Foster City on service lines through 11/8/13. Both had valid USA tickets.

Foster City Pipeline Information

Gas Transmission Pipeline

No natural gas transmission pipelines run through Foster City. The closest transmission pipeline is Line 101 in San Mateo.

Gas Distribution Mains

DFM 0214-01 runs through Foster City in the vicinity of Redacted from Redacte to Redacted with an operating pressure of 170 psig. The following table shows information about DFM 0214-01.

DFM 0214-01 - Foster City						
Year Installed	Outer Diameter (inches)	Length (feet)	Test Year	MAOP	% SMYS	Allowable % SMYS
1997	6	15	1997	180	7.10%	50%
1963	8	3206	Untested	180	6.1%-11.8%	50%
1971	6	107	Untested	180	10.92%	50%

Foster City has approximately 74 miles of gas distribution mains and service lines (27 miles of steel, 15 miles of Aldyl-A plastic and 32 miles of other plastic). The pressure of the distribution system is 50 psig.

There are no automated valves located in Foster City. However, there are three main line valves located within the city to facilitate routine maintenance and operations.

Automated valves are installed on L-101 at MP 21.54 and MP 26.72, which are located upstream and downstream of the DFM 0214-01.

Safety Overview for DFM 0214-01

- Landslide Potential – Low potential within city limits.
- Seismic Activity (Peak Ground Acceleration) – This measures the intensity of ground shaking from an earthquake. No earthquakes have occurred within the city limits that would have caused any structural or pipeline damage per USGS.
- Liquefaction Potential – Moderate to high potential within city limits.
- Fault Crossings – No fault crossing locations present within the city limits
- Levee/Erosion Areas – Centerline survey were conducted on 9/18/13 in Foster City and aerial patrols were conducted on 9/17/13. No observations of encroachments or land movement were identified.
- Water Crossings – No water crossings within city limits.

Weather Related and Outside Forces (WROF) Monitoring Actions

- Aerial patrol: Aerial patrol is performed, at a minimum, quarterly. Most recent patrol conducted on 10/28/13 and no findings reported.
- Maintain Right of Way: Improved management of structures and vegetation (e.g., trees) was initiated in June of 2012. The last ground investigation was performed on 9/18/13 and no issues within the city limits have been identified.
- Installation of Automatic Shut-Off Valves (ASV's) or Remote Control Valves (RCV's): Remote control valves are installed on gas transmission pipeline (L-101 at MP 21.54 & MP 26.72), which are located upstream and downstream of the DFM serving Foster City.
- Patrolling after a seismic event: Patrols have not been required within city limits consistent with PG&E's earthquake plan due to the lack of seismic events.

Strength Testing (Hydrostatic Testing)

Strength testing (hydrostatic testing) has been performed on segments of DFM 0214-01 installed in 1997. The remaining sections of pipe will be scheduled for future testing.

Strength Testing			
Route	Date of Assessment	Route Location of Assessment	MAOP/Test Pressure
0214-01	1997 (during installation)	15 ft	180/600

Maintenance Overview

Leak Survey/Repair

PG&E leak surveys its distribution facilities at least once every five years and annual surveys on distribution pipe in business districts or near public buildings. Also, the company performs additional leak surveys as determined by engineering needs.

In Foster City, PG&E's most recent five year distribution surveys were performed in 2009 and 2012. Together, these surveys encompassed all of the distribution facilities in Foster City. PG&E has also performed annual surveys in 2013 to cover the business districts and public buildings in Foster City. In August and October of 2013, PG&E performed additional leak surveys to collect data for distribution integrity management purposes. The table below shows the results of the leak surveys, and the number of current open leaks in Foster City.

Leak Survey	Leak Indications Found	Leak Indications Resolved*	Leaks Repaired	Leaks Remaining (Current Open Leaks)
5 Year	58	33	19	6
1 Year	0	NA	NA	NA
Additional Surveys in 2013	7	0	0	7

*Leak indications that, upon further investigation, are not identified as actual gas leaks

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Leaks can also be found and reported by customers and PG&E employees, however, there are currently no open leaks reported through these channels. The leaks that are currently open in Foster City are non-hazardous and pose no threat to people or property; PG&E will continue to monitor these leaks to determine if they will require further action.

For DFM 0214-01, leak surveys are performed once every five years. The last leak survey on DFM 0214-01 was on 9/12/10 and no leaks were identified.

Pipeline Replacement

From 2013 through 2015, PG&E will replace approximately 43,192 feet of gas distribution main in Foster City. Approximately 9,610 feet were replaced in 2013.

Distribution Pipeline Replacement	
Year	Feet
2014	9,082
2015	24,500

Patrols

The table below provides pipeline patrol information for DFM 0214-01.

Patrols		
Route	Frequency	Date of Last Patrol
0214-01	Monthly	10/28/2013

Cathodic Protection Inspections

DFM 0214-01 in Foster City had its last CP inspection on 11/1/2013, and no issues were identified.

The distribution lines within the city had their last CP inspection on 11/1/2013, and no issues were identified.

General Pipeline Information

Assessing Risk

Pipeline threats are grouped into three main categories: Loss of Containment, Loss of Supply and Service, and Inadequate Response and Recovery. As part of PG&E's evaluation of pipeline safety relative to Loss of Containment, potential threats are organized into three main categories:

1) Time-dependent threats (which are threats that potentially increase over time, such as corrosion).
2) Stable or "resident" threats (which are threats that are present, or inherent in the pipeline such as manufacturing or construction defects, but do not pose a threat unless acted upon by outside forces).
3) Time-independent threats (which are threats such as third-party excavation damage, incorrect operations, or weather-related and outside forces such as land movement or terrorism).

Mitigation programs are identified for each potential threat area as shown in the table below.

	Time-Dependent Threats *"The threat level may grow over time if unchecked"*			**Resident Threats** *"The threat is inherent but does not grow over time unless acted*			**Time Independent Threats** *"The threat exists outside of the continuum of time"*		
	External Corrosion	Internal Corrosion	Stress Corrosion Cracking	Manufacturing Related	Construction / Fabrication Related	Equipment Related	Excavation Damage	Incorrect Operations	Weather & Outside Forces
Primary CAUSES	Coating Degradation and Inadequate Cathodic Protection	Gas Quality	Coating Degradation, Pipe Surface Condition, Environment, Stress & Fluctuations, Discharge Temperature	Long-seam Defects, Pipe Defects	Girth Welds, Coupled Pipe, Wrinkle Bends, Branch Connections	Gaskets Relief Values / Regulators	1st, 2nd and 3rd Party	Human Error, Inadequate Training, Failure to Follow Procedures	Weather-Related Events, Ground Movement, Terrorism
Primary PREVENTION PRACTICES	Cathodic Protection	Gas Quality Monitoring	Cathodic Protection	Pipe Specification	Construction Practices	Preventative Maintenance	Excavation Observation and Patrolling	Operating Procedures	Continuous or Event-based Surveillance
	Close Interval Survey	Site-Specific Plan	Field Inspections	Inspection During Manufacturing	Inspection During Construction	Inspection During Maintenance	Use of One Call System	Training & Development	
MITIGATION PRACTICES (Assessment technology)	In-line Inspection	Operational Pigging	Pressure Testing	Mill Pressure Testing	Pressure Testing	Patrolling	Locating & Marking	Operator Qualification	Emergency Preparedness
	Direct Assessment	In-line Inspection	Direct Assessment	Pressure Testing	Patrolling	Monitoring Pressure & External Loads	Excavation Monitoring	Audits	Slope Monitoring & Stablization
	Pressure Testing	IC Direct Assessment	Coating Surveys (DCVG and ACVG)	Monitoring Pressure & External Loads	Monitoring Pressure & External Loads		Public Awareness	SCADA/Network Visibility	Local land movement evaluation
	Coating Surveys (DCVG and ACVG)	EM Coupon Monitoring	In-Line Inspection	In-line Inspection	In-line Inspection		In-line Inspection		In-line Inspection
		Pressure Test	Discharge Temperature						Cybersecurity

The results of the integrity assessments described above are used to identify and prioritize the work that is performed on the transmission system as part of the Transmission Integrity Management Program described below.

Transmission Integrity Management Program (TIMP)

PG&E's Transmission Integrity Management Program (TIMP) assesses the risk related to different segments of pipe on the system and identifies the appropriate action to prevent or mitigate these risks.

Three methods of integrity assessment are utilized: In Line Inspections (ILI), strength testing and direct assessment. PG&E uses a combination of all three of these federally approved integrity assessment methods depending on the threats identified on a pipeline segment. In addition to these assessment methods, PG&E continues to reduce risk both in HCAs and non-HCAs using a host of additional monitoring and assessment methods and technologies, such as leak survey, radiography, cathodic protection monitoring, aerial patrol, fault crossing pipe replacements and monitoring, pipeline surveillance, and geotechnical monitoring.

- **In-Line Inspection**

  In-Line-Inspections (ILI) determines the thickness of a pipe's remaining wall and, with some newer technologies, improves the ability to locate and assess cracks and other potential weaknesses. A "Pig" travels inside the pipe to measure and record irregularities that may indicate corrosion, cracks, laminations, deformations (dents, gouges, etc.) or other defects. Some "pigs" use high-resolution video to assess the internal condition of the pipeline, its welds and components, such as valve seals. Many of these "pigs" also provide GPS data that is usefuly in not only improving PG&E's knowledge of its pipeline locations for use in third party damage risk reduction, but is also useful in determining bending strains on the pipeline that may be caused by localized land movement.

- **Strength Testing**

  Strength testing or hydrostatic testing measures a pipeline's strength using water that is raised to a pressure higher than standard operating pressures to ensure the pipeline is operating at a safe pressure.

  The effectiveness of hydrostatic testing is based on an engineering concept that if a pipe can successfully hold pressure at a high operating pressure, it can safely hold pressure at a lower operating pressure.

  As part of Phase 1 of PG&E's Pipeline Safety Enhancement Plan (PSEP), pipeline segments that are in highly populated urban areas, have vintage seam welds that do not meet modern manufacturing, fabrication or construction standards or were "grandfathered" under previous regulations, and have not been strength tested will be hydrostatic tested. Urban areas are defined as Class 2, 3 and 4 and Class 1 in high consequence Areas (HCA).

- **Direct Assessment**

Direct Assessment integrates a pipeline's operational records with known variables of the immediate surface environments when exposed to corrosive electrolytes. Excavations are then performed on areas of concern to conduct a direct examination of the pipe as required by federal regulations.

Direct examinations help us evaluate the possibility of time-dependent threats using:

- External corrosion direct assessment (ECDA)
- Internal corrosion direct assessment (ICDA)
- Stress corrosion cracking direct assessment (SCCDA)

Direct Assessment involves first predicting the expected performance of the cathodic protection (described below) system at spots with the highest potential for corrosion or stress corrosion cracking (ECDA or SCCDA) and also analysis of data to determine the highest likelihood for internal corrosion (ICDA) to occur. Next, excavations refine and corroborate the predictive process. These excavations also provide opportunities to mitigate or prevent future corrosion through cathodic protection system upgrades, coating replacement or other appropriate repair responses

Pipeline Maintenance

PG&E also performs routine maintenance activities, including:

- Cathodic Protection
- Leak Surveys
- Leak Repair

Cathodic Protection

PG&E's steel gas pipe have a natural tendency to corrode. To manage corrosion, steel gas lines are coated or wrapped before installation, and then cathodic protection is applied in order to prevent corrosion of the metal surface in soil by applying a direct current from an anode to the pipe being protected.

PG&E sends corrosion mechanics to physically visit each "pipe-to-soil" location at least six times per year to identify and repair cathodic protection areas (CPA) that are not working properly.

Leak Survey

Pipeline safety regulations require PG&E to conduct periodic or routine leak surveys on its distribution and transmission systems to find gas leaks. The frequency depends on the local conditions where the pipe is installed and the material or operating condition of the pipe itself. Leak surveys are performed by gas field technicians using both vehicle-mounted and handheld leak detectors to identify leaks. Surveyors check gas facilities line by line, from one end of a pipeline facility to the other, on regular intervals.

PG&E's current leak survey cycles are shown in the table below.

Facility Type	Survey Frequency
All Company facilities within business districts and at public buildings	Annual
Distribution maximum allowable operating pressure (MAOP) less than or equal to 60 psig	
Business district and public buildings	Annual
Buried metallic facilities not under cathodic protection and not covered by an annual requirement.	3 years
Balance of underground distribution facilities	5 years
Distribution Feeders (MAOP greater than 60 psig)	5 years
Transmission	
DOT Transmission All Odorized Transmission with the exception of Non-HCA pipe within a Class III & IV location.	Annual
DOT Transmission - Non-HCA Class III & IV	Semi-Annual
Un-Odorized DOT Transmission	
Class I & II	Annual
Class III	Semi-Annual
Class IV	Quarterly
Gathering	
Class I, II, III & IV	Annual
Transmission Stations	
Class I & II	Annual
Class III & IV	Semi-Annual

Leak Repair

All gas leaks are graded based on a number of factors, including the amount of gas present, the proximity to structures, whether the below ground leak is covered wall-to-wall by concrete or other permanent covering, and whether or not the leak is above or below ground. PG&E personnel classify leaks into four grades based on the severity and location of the leak, the hazard the gas leak presents to persons or property, and the likelihood that the leak will become more serious within a specified amount of time.

Leaks are graded according to regulatory standards set by PHMSA and the CPUC :

- **Grade 1 Leak** – Existing or probable hazards to person or property; requires immediate repair or continuous action – Repaired within 24 hours.
- **Grade 2+ Leak** – Priority Grade 2 leak. No immediate risk, but still requires a priority scheduled repair – Repair within 90 days.
- **Grade 2 Leak** – No immediate risk, but still requires a scheduled repair – Repaired within 15 months..

- **Grade 3 Leak** – No immediate risk and can reasonably be expected to remain non-hazardous – On-going monitoring.

PG&E's grading rules exceed industry standards, as set by the ASME GPTC Guide for Gas Transmission and Distribution Piping systems, in that PG&E uses a Grade 2+ category with a scheduled priority repair within 90 days.

Distribution Integrity Management Program

The Distribution Integrity Management Program (DIMP) evaluates the risks to PG&E's gas distribution system and proposes mitigation strategies. DIMP evaluations rely on leak history to determine pipeline performance and prioritization of pipeline replacement work.

Gas Pipeline Replacement

For more than 20 years, PG&E's Gas Pipeline Replacement Program (GPRP) has focused on replacing cast-iron and pre-1940s' steel distribution pipelines. External factors, like seismic susceptibility and potential impact to the public are used to prioritize the highest risk pipe for replacement. PG&E has replaced nearly all cast-iron pipe.

Aldyl-A Replacement

The manufacturer of Aldyl-A plastic piping, DuPont, identified quality issues with a portion of its product manufactured between 1970 and 1972. This specific type of Aldyl-A is susceptible to failure under stressed conditions. Consequently, the life expectancy varies based on operating and environmental factors, such as pressure and soil type. Replacement of Aldyl-A distribution main is based on factors related to the condition and surroundings of the pipe. The primary factor in determining if a main is to be replaced is leak repair data, which indicates the potential of a material issue with the Aldyl-A plastic. Secondary factors include pipe vintage, operating pressure, the potential for ground movement, population density and areas of public assembly. Replacement projects are prioritized in order of the pipe with the greatest combination of consequence and likelihood for leakage.

Sewer Lateral Inspection (Cross Bore Program)

Video inspecting sewer laterals to confirm gas pipeline replacement work has not damaged sewer lines. In 2012, we inspected approximately 10,000 sewer laterals and we plan to inspect 25,000 sewer laterals by the end of 2013.

Damage Prevention

Damage Prevention is an end-to-end process that includes the field location of underground facilities as requested through the USA One-Call system, USA ticket management, investigations associated with dig-ins, and damage claims. The marking of underground utilities is governed by California Government Code 4216 and the process is driven by industry best practices.

Damage Prevention consists of multiple processes working together to help prevent damages from third party excavation activities as described below. PG&E's Damage Prevention processes are reviewed annually.

Public Awareness

Public Awareness consists of educating customers and other key audiences regarding excavation rules, laws and best practices. Efforts include, but are not limited to, sending bill inserts in the mail, making education links available on email bill pay, sending individual separate mailers, running ads in newspapers and on the radio, conducting companywide campaigns for ***Call 811 Before You Dig*** and attending ***USA S.A.F.E.*** events that involve educating excavator companies of safe digging practices and recommendations.

Dig-In Mitigation

PG&E's Damage Prevention Program is focused on determining the root causes of excavation damage to PG&E facilities and identifying process improvements to reduce damages, including training and communications with external parties.

Locate and Mark

Federal pipeline safety regulations and California state law require that the PG&E belongs to, and shares the costs of, operating the regional "one call" notification system. Builders, contractors and others planning to excavate use this system to notify underground facility owners, like PG&E, of their plans. The company then provides the excavators with information about the location of its underground facilities. Information is normally provided by having company personnel visit the work site and place color coded surface markings to show where any pipes and wires are located. Because of its large service territory, PG&E belongs to two regional one call systems which share a common toll free, three digit "811" telephone number. The California one call systems are commonly referred to as Underground Service Alert (USA).

Pipeline Patrols and Monitoring

Pipeline Patrol and Monitoring consists of patrolling transmission pipelines to provide continuing surveillance including evaluating any significant activities on or near the pipeline and within the right-of-ways. One of the important patrol activities is monitoring that there are no unauthorized excavations taking place close to transmission pipelines. Patrols are performed with a mix of fixed-wing aerial, helicopter aerial and ground patrol methods on a quarterly basis at a minimum, which exceeds the federally mandated patrol standards.

In 2013, PG&E began a comprehensive survey (Centerline Surveys) of all 6,750 miles of gas transmission pipeline using GPS mapping technology to improve our ability to identify and prevent risks to our pipelines, and ensure better access to inspect, test and maintain pipelines.

Pipeline Markers

CFR 192.707 requires PG&E to provide pipeline markers and warning information for gas facilities. Pipeline markers are used to indicate the approximate location of the respective pipeline along its route. The markers are signs on the surface above or near the natural gas pipelines located at frequent intervals along the pipeline right-of-way. The markers can typically be found at various points along the pipeline route including highway, railway or waterway intersections and other such prominent locations. These markers display the name of the operator and a telephone number where the operator can be reached in the event of an emergency.

Appendix

Maps

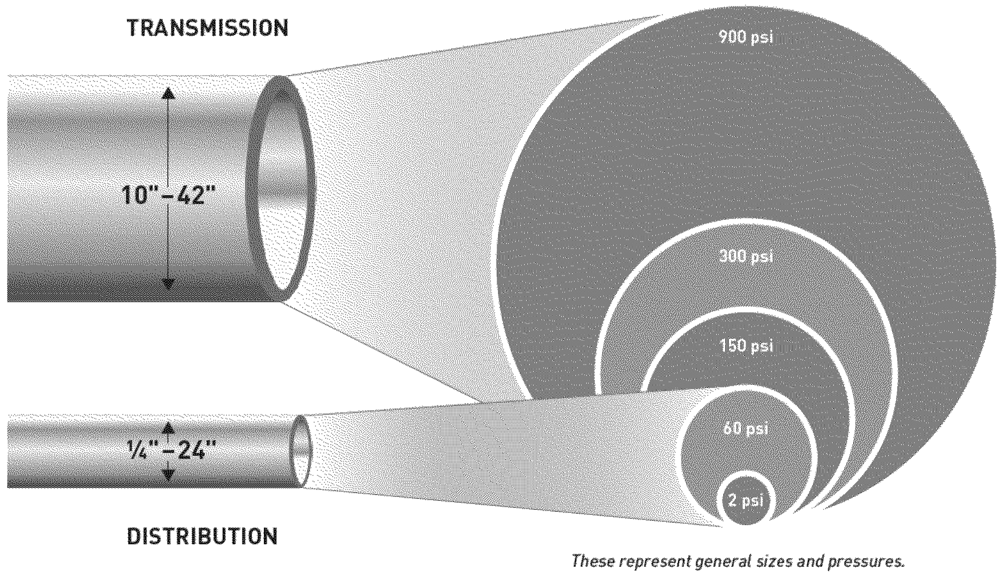
Map 1: Pipeline and Station Location Map

Map 2: PSEP Valve Automation Map

Map 3: Diameter, Install Date and Hydrotest Maps

Map 4: Class Location and MAOP Maps

Pipelines: Transmission vs. Distribution



Pipelines are defined as transmission or distribution based on the stress level the pipeline operates and the functionality of the pipeline. Generally, transmission lines operate between 150-900 psi and range between 10”-42”. All pipelines not defined as transmission are considered distribution.

Definitions

Class Location

Class 1: 0 – 10 buildings intended for human occupancy

Class 2: 11 – 45 buildings intended for human occupancy

Class 3: 46+ buildings intended for human occupancy or an area in close proximity to public place of assembly (e.g. playground, recreation area, etc.)

Class 4: 4+ story buildings are prevalent

Maximum Allowable Operating Pressure (MAOP)

MAOP is the maximum pressure at which a pipeline segment or component is qualified to operate in accordance with the requirements of CFR Title 49, Part 192 based on the design pressure of the weakest element in the pipeline segment. MAOP of a pipeline is established by two methods. Pipelines constructed prior to July 1, 1970 had the MAOP established by the highest recorded operating pressure between July 1, 1965 and July 1, 1970. Pipelines installed after July 1, 1970 have a pressure test performed on the pipeline or pipeline components for a specified length of time to establish the MAOP. Pipelines are tested at the time of construction and components are tested when manufactured. MAOPs of existing pipelines can also be increased or "uprated" by performing a pressure test of that pipeline in accordance with CFR Title 49, Part 192.

High Consequence Area (HCA)

An HCA in PG&E's service territory includes any pipeline locations where the Potential Impact Circle/Radius (which is "the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property" includes 20 or more buildings or an "identified site" in any class location (1, 2, 3 or 4). An "identified site" includes parks, recreation areas, campgrounds, outdoor theaters, stadiums, or any buildings, including offices, stores, factories, community centers or religious facilities occupied by twenty or more persons on at least 50 days per year.

Specified Minimum Yield Strength (SMYS)

SMYS means the specified minimum yield strength for steel pipe manufactured in accordance with a listed specification. This is a common term used in the oil and gas industry for steel pipe used under the jurisdiction of the United States Department of Transportation. It is an indication of the minimum stress a pipe may experience that will cause plastic (permanent) deformation.

Test Safety Margin – Test Pressure/MAOP

Pipelines are strength tested to a higher pressure than which they will operate. This test proves the pressure containing capacity of the pipeline beyond the MAOP. The Test

Safety Margin quantifies the pressure above MAOP that pipeline has been tested to. Pipelines are purposefully built much stronger than needed for normal usage to allow for emergency situations, unexpected loads, misuse, or degradation.

Design Safety Margin

Design Pressure/MAOP – Design pressure is calculated based on pipeline specifications and the allowable SMYS for the population density. This is what the pipeline can operate at from a design perspective. If you divide this value by the MAOP, you get an incremental Safety Margin because the class location safety margin has already been incorporated in the Design Pressure calculation.

Distribution Feeder Main

Distribution Feeder Main (DFM) refers to pipelines built off of PG&E's trunk transmission lines, which were assigned line numbers such as L-101, L-109 and L-132. DFM's have a MAOP above 60 psig, and provide gas to district regulator stations. The first two digits referred to the operating division in which the line originated and the last four digits are uniquely assigned to distinguish the pipeline from others. As an example, the Foster City feeder was assigned the DFM number 0214-01 (all DFM's originating in Peninsula Division start with 02).