Pipeline Information for the Town of Atherton

December 9, 2013

Prepared by Pacific Gas & Electric Company

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 Atherton

San Mateo County Initiatives and Progress

The table below outlines the progress that has been made in San Mateo County since 2011 on various pipeline initiatives.

Pipeline Initiatives Progress Since 2011 for San Mateo County*	
Transmission pipeline MAOP validation complete	100 miles
Transmission miles being surveyed using high-precision GPS	100 miles
Transmission miles validated with existing strength test records	58.4
Transmission miles strength tested	41 miles
Transmission pipeline replaced	3.1 miles
Valves automated	16 valves
Distribution miles of cast-iron vintage steel replaced	49.5 miles (Peninsula division)**
Distribution miles of pre-1973 Aldyl-A replaced	In 2012: 0.06 miles In 2013: 2 miles
Emergency exercises with first responders	45
# Community open houses	25
2014 Planned Initiatives	
Transmission miles to strength test	1 test of a short section
Transmission miles to replace	9 miles
Valves to automate	11 valves
Aldyl-A distribution miles to replace	Continuing to replace on a prioritized basis

**Data valid as of September 30, 2013, unless stated otherwise. Numbers in this table are approximate.*

***PG&E does not track this data separately for San Mateo County; Peninsula Division includes all of San Mateo County and a small portion of Santa Clara County.*

PG&E Service in Atherton

PG&E serves customers from 2,558 gas meters and 2,723 electric meters in Atherton (as of November 30, 2013).

Transmission Lines

The following gas transmission pipelines run through Atherton.

Atherton Transmission Lines					
Lines	Operating Pressure	Install Year (s)	OD	%SMYS	Material
109	300 psig	1936, 1989	22 and 24 inches	21.15% to 50%	Steel
132	300 psig	1947	24 inches	48.81%	Steel

Distribution Mains

- Atherton has approximately 56 miles of gas distribution mains and service lines (47 miles of steel, 2 miles of Aldyl-A plastic, and 7 miles of other plastic.
- There are three Distribution Feeder Mains (DFM) in Atherton as shown in the table below.

Atherton Distribution Feeder Mains					
Lines	Operating Pressure	Install Year (s)	OD	%SMYS	Material
0201-01	120 psig	1927, 1987, 2005	6 and 8 inches	4.19% to 12.7%	Steel
0205-01	230 psig	1938, 1940, 1963, 1971, 1972, 2003, 2005, 2011, 2013	2, 3, 4 and 6 inches	5.07% to 28.15%	Steel
0217-01	175 psig	1987, 1989	6 and 8 inches	5.2% to 15.31%	Steel

Safety Overview

- There are no integrity concerns with transmission lines 109 and132 in Atherton
  - Line 109 was successfully strength tested in 2012 to a test pressure of 612 psig. The Maximum Operating Pressure (MOP) is 300 psig.
  - Line 132 was successfully strength tested in 2011 to a test pressure of 630 psig. The MOP is 300 psig.
- There are no integrity concerns with the DFMs in Atherton
  - The DFMs in Atherton have had successful strength tests performed at various times. Approximately 128 feet of DFM 0201-01 is untested, however the untested segments will be assessed under a future rate case to validate the current Maximum MOP of 120 psig. Approximately 54 feet of DFM 0205-01 is untested and is expected to be replaced along with Line 109 replacement work.
  - DFM 0201-01 has an MOP of 120 psig.
  - DFM 0205-01 has an MOP of 230 psig.
  - DFM 0217-01 has an MOP of 175 psig.
- In 2012, PG&E replaced 1.28 miles of pipe on Line 109. The remaining portion of Line 109 running through Atherton is planned for replacement in 2014. PG&E also

plans to replace approximately 20 feet of DFM 201-01 in 2014 as part of the replacement for Line 109.

- PG&E is working to replace certain Aldyl-A plastic distribution 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.

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.

Gas Leak Survey For Atherton			
Lines	**Leak Survey Schedule**	**Last Leak Survey**	**Results**
109	Semi-Annual	10/17/2013	No leaks found
132	Annual Semi-Annual	5/16/13 10/24/2013	No leaks found
0201-01	5-year	10/7/2010	No leaks found
0205-01	5-year Semi-Annual	10/7/2010 10/28/2013	No leaks found
0217-01	5-year	10/7/2010, 10/8/2010	1 leak 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.

Transmission and DFM Cathodic Protection Surveys for Atherton			
Lines	**Date of last inspection**	**Results from most recent inspection**	**Frequency of inspection**
109	11/13/2013	No issues	Bi-Monthly
132	11/13/2013	No issues	Bi-Monthly
0201-01	10/2/2013	No issues	Bi-Monthly
0205-01	11/4/2013	No issues	Bi-Monthly
0217-01	11/8/2013	No issues	Bi-Monthly

Distribution Cathodic Protection for Atherton		
Dates of last inspection (multiple dates for multiple Cathodic Protection Areas covering Atherton)	**Results from most recent inspections**	**Frequency of inspection**
10/1, 10/4, 11/4, 11/7	No issues	Bi-Monthly

- 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. Lines 109 and 132 and the DFMs located in Atherton were last patrolled on 12/2/13 and everything was found to be normal.

Patrols for Atherton		
Lines	**Frequency of Patrol**	**Last Patrol**
109	Twice per month	12/2/2013
132	Twice per month	12/2/2013
0201-01	Twice per month	12/2/2013
0205-01	Twice per month	12/2/2013
0217-01	Twice per month	12/2/2013

Third-Party Damage

- Third-party dig-ins represent 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.
- In 2013, there have been four third-party dig-ins in Atherton on service lines through 11/8/13. Three of these dig-ins did not have valid USA tickets.

Atherton Pipeline Information

Gas Transmission Pipeline

The following gas transmission pipelines run through Atherton.

Atherton Transmission Lines					
Lines	Operating Pressure	Install Year (s)	OD	%SMYS	Material
109	300 psig	1936, 1989	22 and 24 inches	21.15% to 50%	Steel
132	300 psig	1947	24 inches	48.81%	Steel

Gas Distribution Mains

The following Distribution Feeder Mains (DFMs) run through Atherton:

Atherton Distribution Feeder Mains					
Lines	Operating Pressure	Install Year (s)	OD	%SMYS	Material
0201-01	120 psig	1927, 1987, 2005	6 and 8 inches	4.19% to 12.7%	Steel
0205-01	230 psig	1938, 1940, 1963, 1971, 1972, 2003, 2005, 2011, 2013	2, 3, 4 and 6 inches	5.07% to 28.15%	Steel
0217-01	175 psig	1987, 1989	6 and 8 inches	5.2% to 15.31%	Steel

Atherton has approximately 56 miles of gas distribution mains and service lines (47 miles of steel, 2 miles of Aldyl-A plastic, and 7 miles of other plastic.

Safety Overview

Safety considerations used to evaluate the gas system within Atherton is as follows:

- 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 – Low to moderate potential within city limits. However DFM 0205-01 has a moderate to high potential on certain sections.
- Fault Crossings – DFM 0217-01 is the only line within Atherton that crosses a fault, however this fault is considered inactive.
- Levee/Erosion Areas – No current locations of erosion have been observed within the city limits.

- Water Crossings – No water crossings within city limits.

PG&E monitors and takes appropriate actions based on Weather Related and Outside Forces (WROF) as described below:

- Aerial patrol: Aerial patrol is performed, at a minimum, quarterly. Most recent ground patrol was conducted on 10/28/13 and no findings have been reported. The next patrol will be conducted in December. A patrol performed on 9/17/13 found a construction site on once section of the line.
- Maintain Right of Way: Improved management of structures and vegetation (e.g., trees) was initiated in June of 2012. No encroachments within the city limits have been reported as part of the centerline surveys which were completed on 11/22/13 and the aerial patrols on 10/28/13.
- Installation of Automatic Shut-Off Valves (ASV's) or Remote Control Valves (RCV's): There are no ASVs or RCVs located in Atherton.
    - DFM 0201-01: An automated valve is installed on Line101 at MP 15.59 at Van Buren and Ringwood Station, which feeds this line.
    - DFM 0205-01: An automated valve is installed on Line 109 at MP 17.4 and Line 132 at MP 18.46 at Sand Hill Station and on Line 109 MP 24.59 and Line 132 MP 25.60 at Edgewood station. These valves are upstream and downstream of this line.
    - DFM 0217-01: An automated valve is installed on Line 101 at MP 15.59 at Van Buren and Ringwood Station, which feeds this line.
    - Line 109: No automated valves are installed on this mainline within the city limits. The closest automated valve is at MP 17.4 at Sand Hill Station.
    - Line 132: No automated valves are installed on this mainline within the city limits. The closest automated valve is at MP 18.46 at Sand Hill Station.
- 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 recent seismic events.

Direct Assessment

The most recent direct assessments are shown in the tables below.

	ECDA				
Lines	**Location of recent assessments**	**Date of recent assessment**	**Outcome of recent assessment**	**Corrective Action**	**Next Planned Assessment**
109	MP 18.61 - 19.00 (Runs parallel to Valley Road, near Sharon Heights Golf Club)	Mar-09	No intergity concerns identified, no digs were needed	No corrective action required since no integrity concerns were found.	2014
132	MP 19.93 - 20.05 (Runs parallel to Valley Road, near Sharon Heights Golf Club)	Mar-09	No intergity concerns identified, no digs were needed	No corrective action required since no integrity concerns were found.	2014

ICDA					
Lines	Location of recent assessments	Date of recent assessment	Outcome of recent assessment	Corrective Action	Next Planned Assessment
109	MP 18.61-19.55 (Runs parallel to Valley Road, near Sharon Heights Golf Club)	Oct-12	ICDA assessment showed no internal corrosion threat	No corrective action required since no internal corrosion threat found	N/A

In-Line Inspection

Line 109 is scheduled for in-line inspection in 2015 and Line 132 is scheduled for in-line in section in 2014.

Strength Testing (Hydrostatic Testing)

Strength testing has been performed on the transmission lines and DFMs as shown in the tables below.

Transmission Hydrotests for Atherton						
Lines	Date of Test	Tested Length (ft.)	Test Pressure	Spike Pressure	Outcome of Test	Purpose of Test
109	7/27/2012	2254.5 (entire length in Atherton)	612 psig	660 psig	Successful	MAOP validation
132	11/12/2011	2330 (entire length in Atherton)	630 psig	684 psig	Successful	MAOP validation

DFM Hydrotests for Atherton						
Lines	Date of Test	Tested Length (ft.)	Test Pressure	Spike Pressure	Outcome of Test	Purpose of Test
0201-01	3/26/1987 (water)	15	825 psig	N/A	Successful	Installation
	3/15/2005 (nitrogen)	65	620 psig			
		Appox. 128 feet is untested				
0205-01	11/12/2011 (water)	2	611 psig	684 psig	Successful	Installation, MAOP Validation
	9/13/2011 (water)	1	628 psig			
	9/6/2005 (nitrogen)	37	690 psig			
	8/15/2005 (water)	145	690 psig			
	10/30/2003 (water)	391	715 psig			
	8/25/2005 (water)	2	515 psig			
	8/29/2005(nitrogen)	4,650	350 psig			
		Approx. 54 feet is untested				
0217-01	1/20/1989 (water)	61	1035 psig	N/A	Successful	Installation
	3/27/1989 (nitrogen)	29	610 psig			
	3/7/1989 (nitrogen)	71	640 psig			
	3/26/1987 (water)	38	825 psig			
	3/7/1989 (water)	8	415 psig			
	3/26/1987 (water)	6712	825 psig			

Pipeline Replacement

In 2012, PG&E replaced 1.28 miles of pipe on Line 109. The remaining portion of Line 109 running through Atherton is planned for replacement in 2014. PG&E also plans to replace approximately 20 feet of DFM 0205-01 in 2014 as part of the replacement for Line 109. See table below.

Transmission and DFM Pipeline Replacement for Atherton			
Lines	**Location of Pipeline Replaced**	**Date of Replacement**	**Footage of Replacement**
109	Replaced 1.28 miles of pipe along Sand Hill Road from Menlo Park to Atherton	2012	1.28 miles was replaced, with 6,742 feet of new pipe installed
109	Remaining pipe in Atherton along Valley Road	Planned for 2014	1.29 of the current pipe will be replaced, with 6,810 feet of new pipe planned. Part of a larger planned pipeline replacement project on Line 109
0205-01	About 20 feet of DFM 0205-01 will be replaced as part of the replacement job on Line 109	Planned for 2014	About 20 feet will be replaced

Maintenance Overview

Leak Survey/Repair

PG&E leak surveys its transmission and 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.

The most recent leak surveys performed on transmission lines and DFMs in Atherton are shown in the table below.

Gas Transmission and DFM Leak Survey For Atherton			
Lines	**Leak Survey Schedule**	**Last Leak Survey**	**Results**
109	Semi-Annual	10/17/2013	No leaks found
132	Annual Semi-Annual	5/16/13 10/24/2013	No leaks found
0201-01	5-year	10/7/2010	No leaks found
0205-01	5-year Semi-Annual	10/7/2010 10/28/2013	No leaks found
0217-01	5-year	10/7/2010, 10/8/2010	1 leak found

- Line 109 is leak surveyed semi-annually. The last leak survey was performed on 10/17/13 and no leaks were identified.
- Line 132 is leak surveyed semi-annually. The last leak survey was performed on 10/24/13 and no leaks were identified
- DFM 0201-01 is leak surveyed every five years. The last leak survey was performed on 10/7/13 and no leaks were found.
- DFM 0205-01 is leak surveyed every five years however there are some portions that are surveyed semi-annually. The last five year leak survey was performed

on 10/7/13 and the last semi-annual survey was performed on 10/28/13. No leaks were found.

- DFM 0217-01 is leak surveyed every five years. The last leak survey was performed on 10/7/13 and 10/8/13. During the 10/8/13 survey, one leak was found and repaired on a valve on DFM 0217-01.
- Leaks can also be found and reported outside of leak surveys, such as during routine maintenance work. In 2013, two leaks were identified on DFM 0205-01 outside of routine leak survey, one on a valve, and one on a section of pipe. The valve was replaced, and the pipe was replaced with a new section of pipe.

In Atherton, PG&E's most recent five year distribution surveys were performed in 2010 and 2011. Together, these surveys encompassed all of the distribution facilities in Atherton. PG&E has also performed annual surveys in 2013 to cover the business districts and public buildings in Atherton. The table below shows the results of the leak surveys, and the number of current open leaks in Atherton.

Gas Distribution Leak Survey for Atherton				
Leak Survey Schedule	**Leak Indications Found**	**Leak Indications Resolved***	**Leaks Repaired**	**Leaks Remaining (Current Open Leaks)**
5 Year	22	7	14	1
1 Year	0	0	0	0

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

The leak currently open in Atherton is non-hazardous and poses no threat to people or property. PG&E will continue to monitor this leak to determine if it will require further action.

Patrols

The table below provides pipeline patrol information for transmission lines and DFMs running through Atherton.

Patrols for Atherton		
Lines	**Frequency of Patrol**	**Last Patrol**
109	Twice per month	12/2/2013
132	Twice per month	12/2/2013
0201-01	Twice per month	12/2/2013
0205-01	Twice per month	12/2/2013
0217-01	Twice per month	12/2/2013

Cathodic Protection Inspections

The table below shows the dates and results of the last cathodic protection (CP) inspections performed on the transmission lines and DFMs in Atherton. No issues were identified.

- The CP systems for lines 109 and 132 in Atherton were inspected on 11/13/13 and no issues were identified.
- The DFMs in Atherton were last inspected in October and November of 2013 and no CP issues were identified.
- The distribution CP system is broken out into Cathodic Protection Areas (CPAs). Each CPA is inspected every two months. The results of the latest inspections are shown in the table below.

Transmission and DFM Cathodic Protection Surveys for Atherton			
Lines	Date of last inspection	Results from most recent inspection	Frequency of inspection
109	11/13/2013	No issues	Bi-Monthly
132	11/13/2013	No issues	Bi-Monthly
0201-01	10/2/2013	No issues	Bi-Monthly
0205-01	11/4/2013	No issues	Bi-Monthly
0217-01	11/8/2013	No issues	Bi-Monthly

Distribution Cathodic Protection for Atherton		
Dates of last inspection (multiple dates for multiple Cathodic Protection Areas covering Atherton)	Results from most recent inspections	Frequency of inspection
10/1, 10/4, 11/4, 11/7	No issues	Bi-Monthly

General Pipeline Information

Gas Control

PG&E has recently opened a new state-of-the-art gas control facility to monitor and manage its entire gas system. The co-located facility combines Gas Transmission Control Center, Gas Distribution Control Center and Gas Dispatch functions into a single facility operating 24 hours a day. The Transmission Gas Control Center monitors and controls system pressure, flow and operation status utilizing a Supervisory Control and Data Acquisition (SCADA) system that utilizes alarms to warn of changing conditions that could escalate to abnormal or emergency conditions. Since 2011, PG&E has significantly enhanced and expanded its SCADA visibility and control capabilities to assist in predicting and proactively managing abnormal events on the transmission and distribution system.

When the MOP of a pipeline is exceeded, immediate action is taken to reduce the operating pressure of the line below MOP and an engineering evaluation is performed to determine further remedial action. An over-pressure notification is provided to PHMSA and the CPUC SED for over-pressures greater than 10% above MOP that meet the reporting criteria.

Since the San Bruno incident, PG&E has been striving to reduce operating pressures and, consequently, alarm set-points to reduce and ultimately eliminate pipeline over-pressure events. PG&E has also standardized alarm margins where feasible to attain consistency across the gas system.

The automated valves being installed under PG&E's PSEP program are set to close in no more than ½ second per inch diameter of the valve size. For example, a 30 inch valve closes in 15 seconds.

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 upon by pressure or external load"			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 Direct Assessment	Operational Pigging	Pressure Testing	Mill Pressure Testing	Pressure Testing	Patrolling	Locating & Marking	Operator Qualification	Emergency Preparedness
		In-line Inspection	Direct Assessment	Pressure Testing	Patrolling	Monitoring Pressure & External Loads	Excavation Monitoring	Audits	Slope Monitoring & Stabilization
	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						Cyber security

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

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 device known as 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 useful 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 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 strength tested. Urban areas are defined as Class 3 and 4 and Class 1 and 2 in high consequence Areas (HCA). Class location designation is based on the definition included in the federal regulations and is determined by the density of buildings intended for human occupancy in close proximity to the pipeline.

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 which meet or exceed federal regulation requirements.

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 at the federal level and the CPUC at the state level:

- **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 amongst other variables 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 pipes.

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 and can last well over 100 years if it is not 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)

Sewer lateral inspection involves video inspecting sewer laterals to confirm gas pipeline replacement work has not damaged sewer lines. In 2012, we inspected approximately 10,000 sewer laterals with plans to inspect 18,000 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.

Emergency Response and Public Awareness

PG&E has applied the lessons learned from the San Bruno incident to improve its emergency response plans. These include:

- Improving internal procedures
- Changes to organizational structure
- Establishing clear responsibility and accountability during emergencies
- Greater collaboration with first responders
- Broadening training activities

PG&E's Public Awareness Plan addresses the need for communication about pipeline safety to key stakeholders and incorporates a process to ensure that PG&E continuously improves the effectiveness of its program. On an annual basis, PG&E conducts an internal self-assessment of its Public Awareness Plan. This assessment evaluates whether the Plan is implemented according to standard API RP-1162 (Public Awareness Programs for Pipeline Operators) and how effectively the Plan is reaching key stakeholders. In response to the assessment, PG&E develops an action plan to make changes and improvements to the program.

The Emergency Preparedness team within Public Safety and Integrity Management is actively engaged in various facets of emergency preparedness planning. Responsibilities of this team include maintenance of the Gas Emergency Response Plan (GERP); GERP assists PG&E personnel in responding safely, efficiently and in a coordinated manner to emergencies affecting the gas transmission and distribution systems. The GERP outlines the roles and responsibilities of PG&E's emergency response personnel and includes a single person that assumes command and designates specific duties for SCADA staff and all other potentially involved company employees.

The GERP requires training and exercises to ensure its response procedures are effectively put into action should an emergency occur. Training activities include: read-through exercises; table-top exercises; games; drills; and functional and full scale exercises. Annual events include joint exercises involving PG&E personnel and public first responders for each gas storage and gas regulation facility, and exercises at each of PG&E's 18 divisions. Gas Dispatch, Gas Control and PG&E Emergency Response personnel train on dispatch and emergency response procedures annually.

Additionally, PG&E personnel with a role in an emergency operation train on the GERP. Completed training activities include:

- Exercises with public officials and first responders to simulate gas curtailment scenarios and build understanding of how to prepare for potential events
- Educational and interactive sessions, including practice drills, with first responders to prepare for gas-related emergencies
- First responder pilot training program with the City and County of San Francisco and the City of Fremont focused on sharing critical emergency response information
- Incident Command System training (this training is an ongoing effort and PG&E is currently improving controls to continually identify employees required to complete the training)
- California Independent System Operator (CAISO) Gas Curtailment Exercise

Appendix

Maps

Map 1: Pipeline and Station Location Map

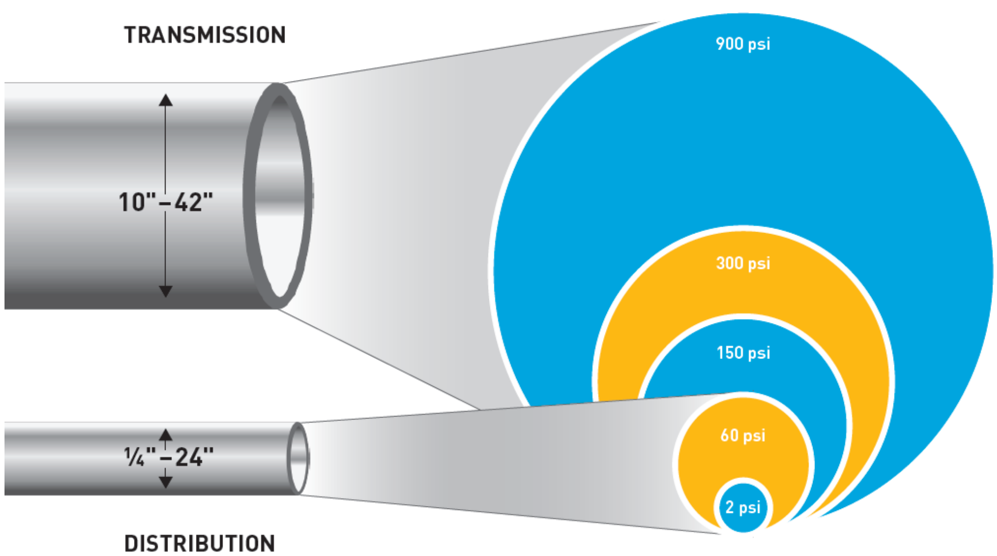
Map 2: PSEP Valve Automation Map

Map 3: Diameter, Install Date and Hydrostatic Test Maps

Map 4: Class Location and MOP Maps

Map 5: Distribution Map

Pipelines: Transmission vs. Distribution



These represent general sizes and pressures.

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 Operating Pressure (MOP)

The maximum pressure a gas pipeline system may operate in accordance with the requirements of CFR title 49, Part 192 definition of maximum allowable operating pressure for a system.

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.

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. DFMs 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 Atherton feeders were assigned the DFM numbers 0201-01, 0205-01, and 0217-01 (all DFMs originating in Peninsula Division start with 02).