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California Natural Gas Pipelines: A Brief Guide

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Stephanie Neuscamman, Don Price, Genny Pezzola, Lee Glascoe

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Introduction:

The purpose of this document is to familiarize the reader with the general configuration and operation of the natural gas pipelines in California and to discuss potential LLNL contributions that would support the Partnership for the 21st Century collaboration. First, pipeline infrastructure will be reviewed. Then, recent pipeline events will be examined. Selected current pipeline industry research will be summarized. Finally, industry acronyms are listed for reference.

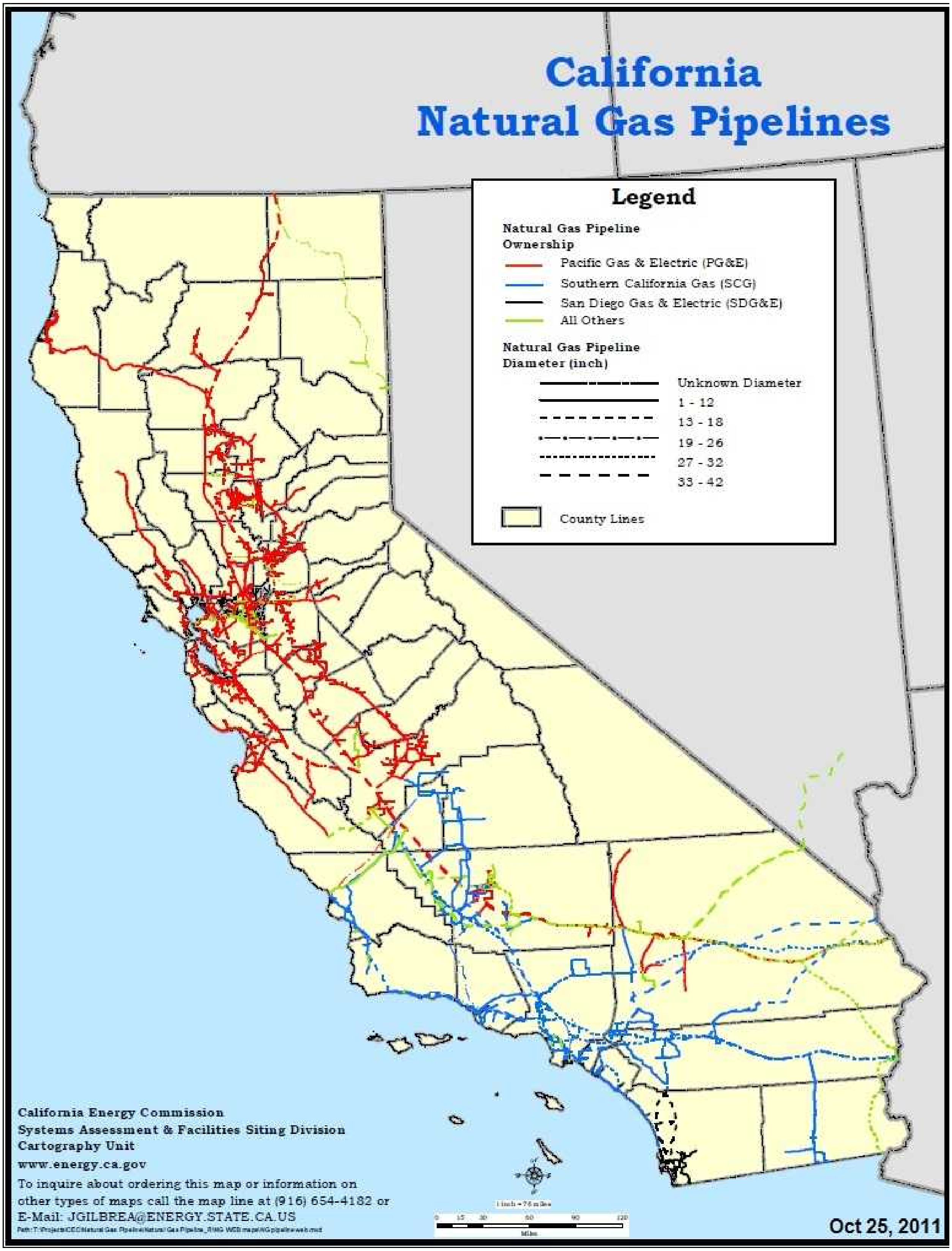
California Pipeline Infrastructure:

The main California natural gas utility companies are Pacific Gas and Electric (PG&E), Southern California Gas (SoCalGas), San Diego Gas & Electric (SDG&E), and Southwest Gas. Most of the natural gas used in California comes from out-of-state natural gas basins. In 2008, California customers received 46% of their natural gas supply from basins located in the Southwest, 19% from Canada, 22% from the Rocky Mountains, and 13% from basins located within the state. [1] Natural gas from out-of-state production basins is delivered to California via the interstate natural gas pipeline system. Most of the natural gas transported via the interstate pipelines, as well as some of the California-produced natural gas, is delivered into the PG&E and SoCalGas intrastate natural gas transmission pipeline systems (California's "backbone" natural gas pipeline system). [1] Natural gas on the utilities' backbone pipeline systems is then delivered into the local transmission and distribution pipeline systems, or to natural gas storage fields.

Natural gas pipelines are regulated by the Department of Transportation. The storage and sale of natural gas is monitored by the California Public Utilities Commission.

Gas flowing from higher to lower pressure is the fundamental principle of the natural gas delivery system. The amount of pressure in a pipeline is measured in pounds per square inch (psi).

From the well, the natural gas goes into "gathering" lines, which are like branches on a tree, getting larger as they get closer to the central collection point.


California
Natural Gas Pipelines
Legend
Natural Gas Pipeline Ownership
Pacific Gas & Electric (PG&E)
Southern California Gas (SCG)
San Diego Gas & Electric (SDG&E)
All Others
Natural Gas Pipeline Diameter (inch)
Unknown Diameter
1 - 12
13 - 18
19 - 26
27 - 32
33 - 42
County Lines
California Energy Commission
Systems Assessment & Facilities Siting Division
Cartography Unit
www.energy.ca.gov
To inquire about ordering this map or information on other types of maps call the map line at (916) 654-4182 or E-Mail: JGILBREA@ENERGY.STATE.CA.US
Oct 25, 2011

Gathering Systems

A gathering system may need one or more field compressors to move the gas to the pipeline or the processing plant. A compressor is a machine driven by an internal combustion engine or turbine that creates pressure to "push" the gas through the lines. Most compressors in the natural gas delivery system use a small amount of natural gas from their own lines as fuel.

Some natural gas gathering systems include a processing facility, which performs such functions as removing impurities like water, carbon dioxide or sulfur that might corrode a pipeline, or inert gases, such as helium, that would reduce the energy value of the gas. Processing plants also can remove small quantities of propane and butane.

The Transmission System

From the gathering system, the natural gas moves into the transmission system, which is composed of high-strength steel pipe ranging from 20 inches to 42 inches in diameter. These large transmission lines for natural gas can be compared to the nation's interstate highway system for cars. They move large amounts of natural gas thousands of miles from the producing regions to local distribution companies (LDCs). The pressure of gas in each section of line typically ranges from 200 psi to 1,500 psi, depending on the type of area in which the pipeline is operating. As a safety measure, pipelines are designed and constructed to handle much more pressure than is ever actually reached in the system. For example, pipelines in more populated areas operate at less than one-half of their design pressure level.

Many major interstate pipelines are "looped" – there are two or more lines running parallel to each other in the same right of way. This provides maximum capacity during periods of peak demand. The pipeline rights of way are usually 100 feet wide and are leased from landowners with restrictions on construction activities to minimize the potential for accidental damage.

Compressor Stations

Compressor stations are located approximately every 50 to 60 miles along each pipeline to boost the pressure that is lost through the friction of the natural gas moving through the steel pipe. Many compressor stations are completely automated, so the equipment can be started or stopped from a pipeline's central control room. The control center also can remotely operate shut-off valves along the transmission system. The operators of the system keep detailed operating data on each compressor station, and continuously adjust the mix of engines that are running to maximize efficiency and safety.

Natural gas moves through the transmission system at up to 30 miles per hour, so it takes several days for gas from the Southwest to arrive at a utility receipt point in California. Along the way, there are many interconnections with other pipelines and other utility systems, which offer system operators a great deal of flexibility in moving gas.

Linepack

A 50-mile section of 42-inch transmission line operating at about 1,000 pounds of pressure contains about 200 million cubic feet of gas. The amount of gas in the pipe is called the "linepack." By raising and lowering the pressure on any pipeline segment, a pipeline company can use the segment to store gas during periods when there is less demand at the end of the pipeline. Using linepack in this way allows pipeline operators to handle hourly fluctuations in demand very efficiently. Natural gas pipelines and utilities use very sophisticated computer models of customer demand for natural gas, which relate daily and hourly consumption trends with seasonal and environmental factors.

Gate Stations

When the natural gas in a transmission pipeline reaches a local gas utility, it normally passes through a "gate station." Utilities frequently have gate stations receiving gas at many different locations and from several different pipelines. Gate stations serve three purposes. First, they reduce the pressure in the line from transmission levels (200 to 1,500 psi) to distribution levels, which in California are approximately 40-80 psi. Then an odorant, the distinctive sour scent associated with natural gas, is added, so that consumers can smell even small quantities of gas. Finally, the gate station measures the flow rate of the gas to determine the amount being received by the utility.

The Distribution System

From the gate station, natural gas moves into distribution lines or "mains" that range from 2 inches to more than 24 inches in diameter. Within each distribution system, there are sections that operate at different pressures, with regulators controlling the pressure. Some regulators are remotely controlled by the utility to change pressures in parts of the system to optimize efficiency. Generally speaking, the closer natural gas gets to a customer, the smaller the pipe diameter is and the lower the pressure is.

The gas utility's central control center continuously monitors flow rates and pressures at various points in its system. The operators must ensure that the gas reaches each customer with sufficient flow rate and pressure to fuel equipment and appliances. They also ensure that the pressures stay below the maximum pressure for each segment of the system. Distribution lines typically operate at less than one-fifth of their design pressure.

As gas flows through the system, regulators control the flow from higher to lower pressures. If a regulator senses that the pressure has dropped below a set point it will open accordingly to allow more gas to flow. Conversely, when pressure rises above a set point, the regulator will close to adjust. As an added safety feature, relief valves are installed on pipelines to vent gas harmlessly, if a line becomes overpressured and the regulators malfunction.

Sophisticated computer programs are used to evaluate the delivery capacity of the network and to ensure that all customers receive adequate supplies of gas at or above the minimum pressure level required by their gas appliances. Distribution mains are interconnected in multiple grid patterns with strategically located shut-off valves, so the utility can perform maintenance of its lines without ever shutting off a customer.

Moving Natural Gas into the Home

Natural gas runs from the main into a home or business in what's called a service line. The line is likely to be a small-diameter plastic line an inch or less in diameter, with gas flowing at a pressure range of over 60 psi to as low as 40 psi. When the gas passes through a customer's gas meter, it becomes the property of the customer. Once inside the home, gas travels to equipment and appliances through piping installed by the home-builder and owned by the customer, who is responsible for its upkeep.

Most gas meters are connected to an inner or outer wall of a home or business. In some instances, however, meters are located next to the point where the service line meets the main line. In this case, the piping from the meter to the structure is the customer's property, not the gas company's. These are called "customer-owned" lines and their maintenance is the responsibility of the customer.

When the gas reaches a customer's meter, it passes through another regulator to reduce its pressure to under ¼ psi, if this is necessary. (Some services lines carry gas that is already at very low pressure.) This is the normal pressure for natural gas within a household piping system. When a gas furnace or stove is turned on, the gas pressure is slightly higher than the air pressure, so the gas flows out of the burner and ignites in its familiar clean blue flame.

Pipeline inspection methods:

Visual Inspection:

Currently, annual inspections of pipeline health are conducted via walking surveys, driving surveys, and visual aerial surveillance. These inspections look for obvious leaks, 3rd party encroachment on the pipeline (e.g. from farmers extending their fields or construction projects) and vegetation health within the right of way. Leaking gas may have an effect on the vegetation in the vicinity of the pipeline, so areas of poor plant health are indications of leaks. All indications of leaks detected by the aerial survey are inspected by a ground crew.

Remote sensing:

Subsequent to the gas pipeline explosion in San Bruno, a remote sensing approach was used to conduct a CPUC ordered survey of 6,500 miles of PG&E transmission line for leaks. The remote sensing technique used a mid-infrared Differential Absorption Lidar (DIAL) chemical sensor. The principle of DIAL relies on the selective absorption of laser light by different substances. The mid-infrared laser used was tuned to detect methane, ethane, and some volatilized liquid petroleum products. In operation, the laser beam is transmitted down from the aircraft to illuminate the area on the ground above and around the buried pipe. The light reflected from the ground is collected by the sensor's receiver, and the amount of received energy is measured. If the laser beam passes through a gas plume emanating from a pipeline leak, the received energy will be reduced due to the absorption of laser light by the gas plume. This absorption signature is used to locate the leak and to assess its magnitude.

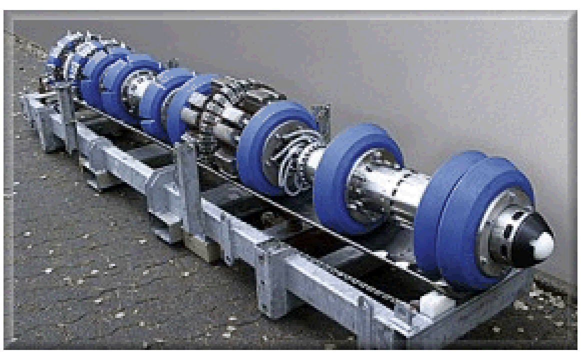
Hydrostatic Pressure Testing:

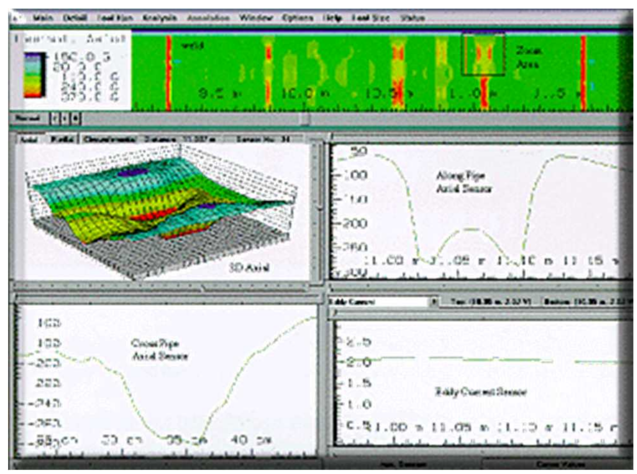
Hydrostatic pressure testing involves filling a section of pipeline with water at very high pressure to validate the safe operating pressure of the pipeline. The pipeline is drained of natural gas, cleaned and then filled with water at high pressures for a period of time (usually 8 hours). Gages along the pipe length monitor the uniformity of pressure within.

Pigging:

Pigging is a method of pipeline inspection that uses a device (the PIG – pipeline inspection gage) to make internal measurements of the pipe. Pigging is accomplished without stopping the flow of product in the pipeline; the pressure of the gas in the pipeline itself propels the device. “Smart” pigs use various technologies to measure internal details such as corrosion and thickness of the pipe. Some detect corrosion and surface pitting using magnetic flux leakage or detect pipe defects using electromagnetic acoustic transducers. Smart pigs are useful tools to monitoring pipeline health; however, current smart pigs are limited to larger diameter pipes and reasonably straight pipeline sections. Although the two most common requirements are for geometry/diameter measurement and for metal-loss/corrosion devices, the information which can be provided by these intelligent pigs covers a much wider range of inspection and diameter/geometry measurements:

- Curvature monitoring
- Pipeline profile
- Temperature / pressure recording
- Bend measurement
- Photographic inspection
- Crack detection
- Wax deposition measurement
- Leak detection
- Product sampling,
- Mapping
- Metal-loss / corrosion detection





Example inline inspection Smart PIG with an example output.

Leak Grades

Most state and federal agencies have adopted the Gas Piping and Technology Committee (GPTC) standards for grading natural gas leaks.

A Grade 1 leak is a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. Examples of a Grade 1 Leak are:

1. Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard.
2. Escaping gas that has ignited.
3. Any indication of gas which has migrated into or under a building, or into a tunnel.
4. Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building.
5. Any reading indicating an 80% Lower Explosive Limit (LEL), or greater, in a confined space[1].
6. Any reading of 80% LEL, or greater in small substructures (other than gas associated sub structures) from which gas would likely migrate to the outside wall of a building.
7. Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

A Grade 2 Leak is a leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.

Examples of a Grade 2 Leak are:

A. Leaks Requiring Action Ahead of Ground Freezing or Other Adverse Changes in Venting Conditions. Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building.

B. Leaks Requiring Action within Six Months

1. Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak.
2. Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak.

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[1] **Lower Explosive Limit** (LEL): The lowest concentration (percentage) of a gas or a vapor in air capable of producing a flash of fire in presence of an ignition source (arc, flame, heat). At a concentration in air below the LEL there is not enough fuel to continue an explosion. Concentrations lower than the LEL are "too lean" to explode but may still deflagrate. Methane gas has a LEL of 4.4% (at 138 degrees C) by volume, meaning 4.4% of the total volume of the air consists of methane. At 20 degrees C the LEL is 5.1 % by volume. If the atmosphere has less than 5.1% methane, an explosion cannot occur even if a source of ignition is present. When methane (CH_4) concentration reaches 5.1% an explosion can occur if there is an ignition source. LEL concentrations vary greatly between combustible gases.

3. Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard.
4. Any reading between 20% LEL and 80% LEL in a confined space.
5. Any reading on a pipeline operating at 30 percent SMYS, or greater, in a class 3 location (area with 46+ buildings intended for human occupation within 220 yards of 1 mile of pipeline or an area within 100 yards of the pipeline where 20 or more people routinely gather – such as a playground or theater)[2] or a class 4 location (area where 4+ story buildings are prevalent)[2], which does not qualify as a Grade 1 leak.
6. Any reading of 80% LEL, or greater, in gas associated sub-structures.
7. Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

A Grade 3 Leak is a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

Examples of a Grade 3 Leak are:

1. Any reading of less than 80% LEL in small gas associated substructures.
2. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the out-side wall of a building.
3. Any reading of less than 20% LEL in a confined space.

<u>Pipeline Incidents</u>:

The European Gas Pipeline Incident Data Group (EGIG) collected data for the period from 1970 to 2007 and found that the majority of pipeline incidents were caused by 3rd party interference (50%). Other significant factors were construction defects and material failures (16%) and corrosion (15%). [2]

San Bruno:

On September 9, 2010, a 30-inch Pacific Gas and Electric Company (PG&E) natural gas transmission pipeline in San Bruno exploded, claiming the lives of eight residents, injuring numerous others, and destroying many homes. As the state agency charged with overseeing the operation of the state's utilities, the CPUC immediately had an inspector on-site in San Bruno, and has since been working

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[2] **Code of Federal Regulations Title 49: Transportation**
PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS
Subpart A—General

> *closely with the National Transportation Safety Board (NTSB) to investigate the cause of the explosion, and take other actions in the interest of public safety.* [3]

The NTSB released a Pipeline Accident Report on the San Bruno incident on September 26, 2011. After a thorough investigation the NTSB determined that the probable cause of this accident was PG&E's inadequate quality assurance and quality control during its Line 132 relocation project in 1956, in which a substandard and poorly welded pipe section with a visible seam weld flaw was installed. Over time it grew to a critical size and caused the pipeline to rupture during an increase in pressure due to "poorly planned electrical work" and PG&E's inadequate pipeline integrity management program, which did not detect and repair the defective pipe section. [16] In the investigation into the San Bruno incident, the NTSB found that the installed pipe in the line that ruptured was not consistent with the as-built drawings. The as-built drawings claimed the line in question was constructed of 30" diameter seamless steel pipe, but the ruptured pipe segment found to be constructed with longitudinally seam-welded pipe. CPUC ordered an investigation into the state of transmission pipelines of PG&E. During the course of this investigation, PG&E determined that it could not locate pressure records to support the MAOP it is using for 8% of its natural gas transmission system. As a result, the company is being ordered to search out the construction, testing, maintenance and other records for this portion and "determine the valid maximum allowable operating pressure, based on the weakest section of the pipeline or component to ensure safe operation." [4]

The San Bruno incident highlights many of the issues that utility companies face today in their natural gas pipelines: aging infrastructure, the consequences of increasing demand up to and past operational limits, external interference with the pipelines, record keeping and data management issues and how to monitor for safe conditions in vast pipeline networks.

Recently researchers at Boston and Duke Universities found 3,356 separate natural gas leaks under the streets of Boston, associated with old cast-iron underground pipes. The gas leaks were mapped using GPS-equipped car installed with a new high-precision methane analyzer. At least six of the locations analyzed had gas concentrations that exceeded the LEL. Any city with aging pipeline infrastructure may be susceptible to hazardous natural gas leaks. [17]

Other recent pipeline events in this country are displayed in the table below.

Table 1: Recent Pipeline Events

Date	Location	Pipe Diameter	Year Installed	Cause	Company Involved	Reference	NOTES
8/19/2000	New Mexico	30"	1950	Severe internal pipe erosion led to significant reduction in pipe thickness	El Paso Natural Gas	NTSB	12 people were killed; $998,300 in damages
9/7/2000	Abilene, Texas	12"		Bulldozer		Statesman.com	1 person was killed
3/22/2001	Weatherford, Texas	12"	1979	unknown	Mitchell Gas Services	Hazards Intelligence	
8/11/2001	Arizona	24"		unknown	El Paso Natural Gas	PHMSA	
3/15/2002	Michigan	36"	1968	unknown	Great Lakes Gas	DoTransportation	
6/11/2002	Eston, CA	400mm		Bulldozer	PG&E	Hazards Intelligence	
8/5/2002	Lanham, West Virginia	750mm		shifting earth	Columbia Gas Transmission		Failure to take precautions against fire or explosions and "record keeping violations" led to fines
2/2/2003	Illinois	24"	1949	unknown	ANR Pipeline	DoTransportation	
7/2/2003	Wilmington, Delaware			Excavation Damage		NTSB	at least $300,000 in damages
8/21/2004	DuBois, Pennsylvania			fracture of defective butt-fusion joint	National Fuel	NTSB	2 fatalities
5/13/2005	Marshall, Texas	36"	1967	stress corrosion cracking	Natural Gas Pipeline of America	DoTransportation	
7/22/2006	Kentucky	24"	1944	external pitting corrosion	El Paso Natural Gas	DoTransportation	wet shale area known to cause corrosion, Class 2 location area
8/28/2008	Stairtown, Texas	36"		external corrosion		PHMSA	$2,000,000 in damages
8/29/2008	Missouri	24"	1937	external corrosion led to longitudinal rupture	Panhandle Eastern Pipeline Co	PHMSA	
9/14/2008	Virginia	30"	1955	unknown (possibly corrosion)	Williams Gas Pipeline-Transco	DoTransportation	nearby lines were recently internally inspected with MFL
5/4/2009	Florida	18"	1959	unknown (possible seam manufacture defect)	Florida Gas Trans Co	DoTransportation	did not ignite
5/5/2009	Indiana	24"	1940	unknown	Panhandle Eastern Pipeline Co	DoTransportation	
11/5/2009	Bushland, Texas	24"	1948	unknown (may involve connection assembly at abandoned tap)	El Paso Natural Gas	DoTransportation	
11/14/2009	Philo, Ohio	42"	2009	girth weld failed at a transition from straight pipe to bend	Kinder Morgan Energy	DoTransportation	

6/7/2010	Johnson County, Texas	36"		construction workers installing poles		Texas Observer	
6/8/2010	Darrouzett, Texas	14"		construction workers/bulldozer	DCP Midstream	Texas Observer	
11/30/2010	Natchitoches, Louisiana	30"	1948	straight circumferential crack, strain from operational stresses/original construction	Tennessee Gas Pipeline Co	DoTransportation	No fire, explosions or injuries. ILI had been performed in 2010 with MFL with no problems found
2/9/2011	Allentown, Pennsylvania	12"	1928	unknown; aging cast-iron pipe	UGI Utilities	Huffington Post	5 people were killed
2/10/2011	Hanoverton, Ohio	36"	1960's	unknown	El Paso Natural Gas	cleveland.com	no injuries, automatic shutoff systems functioned as intended
11/21/2011	Batesville, Mississippi	24”	1946	Failed at sleeve over a wrinkle bend	Tennessee Gas Pipeline Co	PHMSA	No injuries, 20 homes evacuated
12/11/2012	West Virginia	20”/30”	unclear	Unknown; material of pipe unknown as well	NiSource, Columbia Gas	Statejournal.com	No fatalities, freeway shut down, at least 4 homes destroyed

<u>Current Industry Research Efforts</u>:

The focus of this section is on projects pertaining to natural gas pipelines. Subjects such as natural gas engines, natural gas storage, processing plants and LNG transport and gasification, though active areas of research, are not addressed in this report.

In the area of pipeline inspection, several current research efforts warrant attention. PRCI, Blade Energy Partners and PHMSA recently assessed the performance of current ILI technologies for detecting mechanical damage in pipes. The research included magnetic flux leakage (MFL) technology, ultrasonic transducers (UT), electromagnetic acoustic transducers (EMAT), and caliper methods and categorized the capabilities and limitations of each. The ILI technologies were tested for several pipe defect configurations. The project resulted in improved protocols for the measurement methods used in actual pipe inspections.

PRCI completed testing for the “Full-Scale Experimental Validation of Mechanical Damage Assessment Models; testing in modern steels”, providing experimental data needed for improving the mechanical damage models for fatigue and burst failure. Five separate dent and gouge defects were created for testing of burst and fatigue failure modes using controlled conditions and the GDF Suez Pipe Aggression Rig (PAR). Work has begun on improving both failure models in modern steels. PRCI will be performing a similar test for vintage steels (to simulate pipeline construction pre-1970s). PRCI plans to continue the project to fill in existing gaps in their "Mechanical Damage Research Roadmap." [10]

An example of using modeling to advance the understanding of ILI techniques is a recent effort employing finite element analysis to study magnetic flux leakage. [10] MFL tools are sensitive to both pipe wall geometry and pipe wall stresses, making them well suited to locating and characterizing mechanical damage in pipes. However, the signals from dents and gouges can be difficult to interpret. Magnetic finite element analysis can be applied to model MLF signals from mechanical damage for varying configurations. These models included geometry effects, contributions due to elastic strain and magnetic behavior changes due to severe deformation. Model results were compared with experimental MFL signals from measurements on laboratory dents and gouges, as wells as under field conditions.

In a project combining inspection, modeling, and experiments, Germanischer Lloyd (GL) collaborated with PRCI and PHMSA to assess the remaining strength of corroded pipelines and generate guidelines on the safe operating pressure (if any) of such pipes. Currently, by federal regulation, remaining strength of corroded pipe is evaluated using models ASME B31G or RSTRENG. The performance of these models in predicting failure pressures for six sensitivity studies was compared against a database of pipe burst test results. Each case represented different flow stress definitions and material properties. GL determined that a sufficiently conservative estimate of safe operating pressure of corroded pipes is obtained through establishing the accuracy of the chosen prediction model, using specified minimum material properties and nominal values for pipe diameter and wall thickness, and using an additional factor of safety. [10]

PRCI recently performed research on the use of composite materials to reinforce mechanically-damaged pipelines and found that properly designed composite repair systems could restore integrity for a range of pipeline anomalies so that they could continue to operate in the conditions they were originally designed for. This research provides design guidelines and fatigue curves for the repair of pipelines using composite materials. [10]

PRCI developed an "in-the-ditch" SCC identification and characterization protocol using magnetic particle inspection and metallography to identify surface breaking cracks. PRCI has also been working on a project to improve models to select sites for stress-corrosion cracking excavations and hydrostatic testing using ILI data. A comprehensive study of vintage girth weld defect assessment was also recently performed by PRCI, including a literature review, surveys of pipeline operators, and subject matter experts. Girth weld integrity, welding consumables, weld inspection, testing, quality assurance, and other areas were the main focus of this work. PRCI also conducted research on pipe material properties including the stress-strain curve shape as well as the degree of anisotropy. It was found that the shape of the stress-strain curves is a more important factor in pipe strain demands than the degree of anisotropy. [10]

Modeling has also been used to determine acceptance criteria for mild ripples in pipeline field bends. Field bends are often used in gas and oil pipelines. Mild ripples can often occur at these bends, especially in pipes with high yield strength. The application of acceptance standards for such features is inconsistent, leading to variable inspection standards and possible scrapping of still serviceable pipe. Finite element analysis was used to estimate the effect of ripple magnitude and spacing on stresses due to pressure and bending. Stress concentration factors predicted by the model were combined with a fatigue damage rule to estimate the effect of ripples on service life. The model was benchmarked against available test data. The study determined that middle or shallow ripples of up to 2% of the diameter of the pipe would not be expected to be harmful for gas transport. It also found that the presence of ripples could eventually be harmful to long-term pipe integrity when severe cyclic loading conditions (pressure, thermal expansion, flow-induced vibrations) were present or when earth or soil movement could take place. [10]

The Pipeline and Gas Journal describes an effort by researchers at Beihang University in Beijing studying drag-reducing inner coating for gas pipelines. Internal coating technology is applied to reduce the friction between the natural gas flow and the wall of the pipe; it also protects against corrosion of the pipe. The researchers studied the effect of a biomimetic lining that replicates the behaviors of shark skin. First, an epoxy resin coating reduces the average absolute roughness of the pipe to create a hydraulically smooth pipe. Then, groves are etched into the surface such that the tips of grooves stick out of the viscous sublayer in order to improve the drag reduction still further. The effectiveness of the lining was investigated with direct numerical simulation of the pipe flow. The results showed a drag reduction due to the grooved surface of 6.32%. [11]

The Gas Technology Institute (GTI) and its manufacturing partners develop new technologies to improve efficiencies and productivity in the utilities industry. Examples of products that allow for trenchless inspection (which is less destructive and less expensive) of pipes are the micro-excavation system and the keyhole pipeline inspection camera system. [12] The micro-excavation system uses fluid lance technology to excavate small-diameter openings in soil, even rocky or otherwise difficult to penetrate soil. The fluid lance employs compressed water and air to create holes between four to six inches in diameter. Another inspection tool developed by GTI and its collaborators is a small and flexible keyhole camera that enables inspection of pipeline through a small access hole of 18 inches. [12] The camera can maneuver through tight bends, reducing the necessity of additional access holes.

GTI also describes interesting new technology used to repair aged or damaged pipelines. One example is the “clock spring” sleeve – a system of fiber-glass and resin material that can repair dents and defects in high- and low-pressure pipeline, arrest ductile fractures and protect pipe at its support locations. Another example is “Cured in Place (CIP) liners” which are used to rehabilitate structurally sound pipelines with localized defects such as weakened welds, loose joints, or localized corrosion. The liners are seamless polyester circular-woven hose with plastic coating that can quickly be inserted into pipeline and bonded to the interior with a solvent free adhesive. [12]

The Department of Energy’s Fossil Energy program is also developing technology to improve the safety and performance of America’s gas delivery infrastructure. In June 2004, DOE demonstrated a self-powered, remote controlled robot called EXPLORER. “The robot successfully inspected a mile of an 8-inch diameter live natural gas distribution main and delivered real-time pictures of the pipeline's interior over a wireless connection.” [13] Since EXPLORER can inspect smaller pipelines, it could eliminate the need to dig holes to inspect pipes in urban areas. The next generation of EXPLORER robot is being developed by Carnegie-Mellon University and the Northeast Gas Association to utilize advances in sensor technology. Other DOE projects include developing advanced compressor technology to increase the capacity of the nation’s infrastructure without the addition of more compressor units, and investigating the use of unmanned aerial vehicles to conduct remote-sensing of gas leaks from high altitude.

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Acronyms:

CPUC – California Public Utilities Commission
DIAL – Differential Absorption Lidar
EGIG – European Gas Pipeline Incident Data Group
GPTC – Gas Piping and Technology Committee
GTI – Gas Technology Institute
ILI – Inline inspection
LEL – Lower Explosive Limit
LNG – Liquefied Natural Gas
MAOP – Maximum Allowable Operating Pressure
MFL – Magnetic Flux Leakage
NTSB – National Transportation Safety Board
OPS – Office of Pipeline Safety (Dept of Transportation)
PHMSA – Pipeline and Hazardous Materials Safety Administration
PIG – Pipeline Inspection Gages (backronym)
PRCI – Pipeline Research Council Institute
SCADA – Supervisory Control and Data Acquisition
SCC – Stress corrosion cracking
SMYS – Specified Minimum Yield Strength