Assessing the Fitness for Service of Distribution Pipelines
# Table of Contents

I. Executive Summary ........................................................................................................... 3

II. Overview of Development of Distribution Systems ......................................................... 4

III. Distribution Pipeline Design, Construction and Maintenance .................................... 6

IV. Performance Metrics ..................................................................................................... 15

V. Improving system reliability and pipeline safety ............................................................. 21

VI. DIMP ............................................................................................................................. 25

VII. Conclusion/Summary .................................................................................................... 27
I. Executive Summary

Natural gas is a clean burning and abundant energy source that cleanly fuels the life of 177 million Americans nationwide. Natural gas is delivered through pipeline systems of varying size and material type to customers for residential, commercial and industrial use. Natural gas pipelines, which transport approximately one-fourth of the energy consumed in the United States, are an essential part of the nation’s infrastructure. The distribution piping systems that comprise the natural gas infrastructure of this country have evolved primarily over the past century and continue to improve to help ensure that natural gas is delivered safely, reliably and efficiently. Natural gas utilities continually maintain, monitor and assess system performance to help ensure safe pipeline operations.

The term “fit for service” indicates that a pipeline facility performs as expected and carries an acceptable safety and reliability risk in its continued use. All companies are required to adhere to federal codes that address pipeline design, construction and maintenance activities to help ensure the safe and reliable delivery of natural gas to customers. Furthermore, most states, some municipal governments and the gas companies themselves require operating standards to be met that correspond with, and often exceed, federal codes. Over time, these governmental actions and standards have led to a steady decline in leaks and reportable incidents on the distribution pipeline system.

Operators continually work to identify and address pipeline facilities that need improvements. Natural gas utilities conduct engineering studies to define, prioritize and develop mitigation strategies to help reduce risks. In light of pipeline incidents that have occurred in recent years, companies are redoubling their focus to further improve data analysis.

The 2006 Pipeline Safety Act required the development of the distribution integrity management rule (DIMP), a far-reaching performance-based regulation that builds upon the infrastructure safety improvements previously achieved. DIMP, effective in August of 2011, requires operators to develop and implement a plan to formally document data gathering, analysis, risk ranking and mitigation activities associated with fitness for service studies. In conjunction with
existing regulations, DIMP will help formalize and document distribution pipeline systems’ fitness for service and will help improve the safety and reliability of the nation’s natural gas distribution systems.

II. Overview of Development of Distribution Systems

Natural gas is a clean burning and abundant domestic energy source that fuels America’s way of life. Natural gas is delivered directly from its source to customers for residential, commercial and industrial use through extensive pipeline systems. These pipeline systems vary in size, material type and pressure, depending on the amount of natural gas being transported and the location of the pipeline. A variety of equipment is used to monitor and control the pressure and flow in each section of the pipeline system.

Natural gas comes directly from a supplier or producer and is transported via high pressure transmission pipelines. Transmission pipelines are defined by federal and state regulations and are typically large in diameter, moving gas over long distances at high pressure. Transmission pipelines connect to more localized distribution pipeline systems for delivery to customers. Distribution systems, in contrast to transmission pipelines, typically operate at lower pressures and consist of two primary pipe components: mains and services. In general, a main may be defined as the piping that moves gas to points adjacent to customer properties. A service may be defined as the piping that delivers gas from the main to the customer meter location, typically at the property line or at the customer’s building.

The piping that makes up distribution systems in operation today is comprised of various material types operating at various pressures. Natural gas systems have grown as communities and cities, and their demand for gas, have grown. As systems grew and as technologies advanced, companies installed piping made of the latest materials available at the time, including cast iron, steel and copper. Today most companies use plastic piping. Each of these materials was joined using different methods, and installed using varying construction techniques, and each has its own advantages.

Early on, natural gas utilities typically supplied manufactured gas through a system of large diameter cast iron mains. These large supply mains connected to a network of smaller diameter cast iron pipes and ultimately supplied gas to homes. Pipe sizes ranged from two to 72 inches in diameter, were typically
installed in 12 foot long segments and were joined using bell and spigot joints\(^1\) sealed with lead or cement caulking. In general, cast iron piping has very thick walls that can withstand corrosion related metal loss better than thinner wall steel gas piping. Natural gas utilities monitor cast iron pipelines for specific issues such as activities that can cause the cast iron pipeline breaks and, in more rare instances, graphitization, which is essentially the degradation of cast iron.

As gas systems expanded after World War I, delivery pressures required to supply the demand of customers increased from lower to higher pressures. It was around this time that the preferred installation material of choice for gas systems became steel. Steel is a much stronger material than cast iron and is easily able to withstand higher distribution pressures. Early vintages of steel were installed in 20 or 40 foot lengths and were connected with mechanical couplings\(^2\). Improvements in welding technology eventually replaced many mechanical couplings for joining of steel pipes. Coating technologies and other protective measures reduce the potential for corrosion and significantly improved the life span of steel piping. Cathodic protection, which applies an electric potential to address any coating flaws, is currently the most effective method for protecting coated steel pipe from corrosion. In the early 1960s companies began to use these methods and, starting in 1970, the U.S. Department of Transportation required that all new steel gas pipelines be effectively coated and cathodically protected. When properly tested and maintained, cathodically protected steel can last for many decades.

Copper has been used in gas distribution systems at various times dating back to the 1830’s. The use of copper pipe has varied widely over time and geography due to soil conditions, cost, and the quality of copper available. In the middle of the 20th century some operators renewed existing steel service lines by inserting copper inside the steel pipe. This technique was successful because the steel served as a physical barrier to various outside forces and a chemical barrier to corrosion. Although plastic has replaced copper as the state of the art pipe material for insertions and new services, copper remains a viable component of many distribution systems.

As gas utilities continued to take advantage of advancing technologies, plastic began finding its way into gas distribution systems as early as the 1950s. Since the 1970s, the predominant material of choice for gas distribution systems has been polyethylene. Advancements have rendered current polyethylene piping relatively maintenance-free, lightweight, highly resistant to corrosion, able to withstand pressures in

---

\(^1\) A bell and spigot joint can be defined as a pipe joint formed by the insertion of the spigot end of one length of pipe into the bell end of the next length.

\(^2\) A mechanical coupling can be defined as a fitting that is used for joining and pressure sealing two pipes together.
excess of 100 psig, and easy to join. Plastic piping is joined using fusion technology, which heats and melts the pipe together, or by using mechanical couplings. Since it is more susceptible to damage from excavators digging in the soil than steel pipe, excavation damage today accounts for the overwhelming majority of issues experienced on polyethylene piping systems.

To further strengthen the industry’s system enhancement and safety efforts, companies, along with the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration, supported the Pipeline, Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act). The PIPES Act built upon a wide variety of pipeline regulations previously implemented and the safety initiatives that were adopted by companies. Pipeline regulations in place include 49 CFR 190, 49 CFR 191, 49 CFR 192, 49 CFR 199 and operator qualification. In addition, many states have their own regulatory requirements that may be more restrictive than federal requirements. Industry continues to sponsor research to improve the performance of both existing and potential future materials for the gas system. Gas Distribution Pipeline Integrity Management, known as DIMP, is the most recent regulatory initiative to address natural gas distribution operations; natural gas operators will continue to build on these efforts.

III. Distribution Pipeline Design, Construction and Maintenance

Natural gas distribution companies, also known as local distribution companies (LDC’s), follow the Code of Federal Regulations (CFR) for pipeline design, construction and maintenance to provide safe and reliable gas service to customers. Title 49 of the CFR, Part 192 – Transportation of Natural and Other Gas by Pipeline: Federal Safety Standards detail the minimum requirements for design, installation, operation and maintenance of natural gas pipelines. In addition to these federal regulations, many states, counties and cities have additional or enhanced regulations that gas distribution companies must follow. Gas distribution companies also establish internal standards for construction and maintenance that meet, and often exceed, federal, state and local regulations. Companies are regularly audited by state and/or federal inspection personnel to confirm compliance with these regulations and operating procedures.

Operators address the following tasks when installing or replacing a segment of distribution piping: design, permitting, construction, inspection, testing, commissioning, and site restoration. The completion
of these tasks helps ensure the safety of the public is maintained and minimizes the impact to the environment and public infrastructure already in place.

Title 49 of the CFR Part 192 Subpart B enumerates federal regulations for material use. This section describes the manufacturing specifications for the following pipe materials currently used: steel, plastic (polyethylene) and copper pipe. Further design requirements can be found in Subparts C, D, E, F and H. These sections cover pipeline component design, valves and fittings, pipe joining methods, and customer meters, service regulators and service lines.

LDCs generally transport natural gas to the end user via distribution lines that operate sequentially from higher to lower pressures. Natural gas ultimately ends at a delivery, or utilization pressure, at the meter at the customer’s location, and then is transported to the customer’s gas appliances through the customer’s utilization pressure fuel line. Multiple stages of pressure control can be required in this process.

The design of new lines, replacement lines and pipeline services consider existing and future customer demand as well as the flow and availability of gas in the local network of distribution lines. Pipeline material and size are often determined based on the specific customer. For example, a large industrial customer may require a custom design and new pipelines installed in order to meet their needs. A residential installation, on the other hand, is generally a standard practice developed by the LDC that uses an approved standard installation of pipe types and fittings. Steel is commonly used for higher pressure applications and aboveground installations, such as bridge or water crossings, or other land areas subject to additional movement or excessive construction activity. Plastic pipe (PE) is more commonly used for the underground distribution systems. The design of new and replacement lines considers the routing, size and material to be used. The process can be as simple as applying existing company standards or as complex as developing a unique custom design.

Construction and permitting involves local regulators governing to the construction location. Natural gas utilities’ operations personnel review approved construction plans with the governing agencies to obtain the necessary permits. These permitting agencies may include municipal, county, state, federal and environmental applications.

Once the required permits are obtained, trained and qualified personnel are selected to construct the pipeline. Installing a pipeline is much like an assembly line production, with sections of the pipeline being completed in stages. The piping is installed by one of several means. New piping may be installed
using a direct burial process, which can be completed in two ways: 1) using a reciprocating plow to cut the ground and push the pipe into the ground or 2) excavating a trench in which the new piping is placed and covered. Piping can also be installed through various trenchless technologies, such as directional boring, which allows for minimal disturbance to the existing infrastructure and minimal inconvenience to the surrounding property. Finally, new piping may be inserted in the old pipe that is being replaced, a method of replacement that may take the pipe out of service while a new pipe with a smaller diameter is pushed through the old pipe.

Pipes and associated valves and fittings are all manufactured in accordance with national standards. Most steel pipe installations have welded joints, and each company maintains welding standards and procedures that adhere to welding requirements of national standards. If the material being installed is plastic, fusion technology is used either to directly heat the plastic joints butted together or to electrically heat couplings. This process is similar to welding, where a connection is formed by joining two segments utilizing heat. All materials and processes are required to meet or exceed the standards in 49 CFR 192. Operators may also use mechanical couplings in some applications.

New steel pipe installations require all pipes, joints and appurtenances to be coated and all coatings to be inspected for damage. All coating damages must be corrected prior to covering the pipe with backfill material. Steel pipes are required to be cathodically protected within one year of installation and the external coating of the steel pipe must be inspected to help ensure coating integrity. Plastic piping must be installed in a manner to prevent any gouging or nicks. A metallic tracer wire or other materials are installed with plastic pipe to allow for future locating of the piping. The last step in the construction process is to test piping for leakage. This is done by pressure testing the pipe to one and one half the system maximum allowable operating pressure by filling the installed pipe with air, an inert gas (such as nitrogen), or water (hydrostatic test). If any defects are identified, the defects are corrected and the pipe is retested. Regardless of which method is used, the test is documented for pressure, duration and type. Records for these new installations are maintained by the distribution companies for the life of the pipeline, in support of current regulations. Upon successful test results, the piping is then purged of the test medium and placed into service. Operators then restore the construction site. In many cases native soil is replaced with clean backfill to minimize impingement that may lead to a future pipeline failure.

**Operations and Maintenance Procedures**

Over many years of experience in gas operations and maintaining compliance with federal and other local regulatory requirements, gas distribution companies have developed individual operations and
maintenance procedures to promote safe and reliable operation of their gas systems. Natural gas companies employ preventative maintenance, damage prevention and leak management in their operations and maintenance procedures.

The Minimum Federal Safety Standards, Part 192, contain the regulatory code for Operations (Subpart L) and Maintenance (Subpart M), which details the requirements for operating activities such as leakage survey and related inspections, investigation of failures and damage prevention, emergency and public awareness plans. Individual states may require safety patrols that exceed federal mandates to detect encroachment and illegal or unsafe excavation activities.

All gas distribution facilities are surveyed for leaks on an established schedule based on pipe material, type of facility, location, operating history, local conditions and other risk threats. The surveys and inspections that LDC’s perform in accordance with regulatory requirements include:

- Annual leakage survey of facilities in locations where the public normally gathers (Business Districts).
- Three and five year surveys of metallic and plastic facilities.
- Atmospheric corrosion inspection of above ground facilities, such as customer meter sets and exposed bridge crossings are performed once every three years and all anomalies repaired.
- Additional leak surveys of facilities identified as higher risk threats, such as unprotected steel and cast iron.

### 3.1. Preventative Maintenance

As a part of their overall maintenance procedures, companies aggressively perform regularly scheduled maintenance activities on many assets and their appurtenances. These activities include, but are not limited to, regularly testing and maintaining pressure regulating equipment, regularly operating and maintaining critical valves, and maintaining adequate corrosion protection of steel assets in their systems. Each of these activities consists of site visits and inspections at regularly scheduled intervals. Testing and maintaining pressure regulation equipment consists of site visits to inspect equipment. Inspections include hands-on operation and observation to help ensure the equipment works as designed. If the operator observes improper operation, the appropriate parts are replaced or repaired. Valves also require hands-on operation to help ensure they can be accessed and operated. It is critical that valves are operational for emergencies as well as for normal operation of the system. Lubrication and sealants are used to keep the valves in good operating order.
All operators are required to apply cathodic protection to their coated steel pipelines as part of corrosion control programs and regular maintenance activities. Segments of piping are insulated from other parts of the system to create zones, similar to electric circuits at a residential home. Each zone is typically equipped with sacrificial metal anodes, which corrode at the expense of the steel pipe and, hence, protect the gas piping from corrosion. Operators also make use of rectifiers, devices which convert alternating current to direct current, to cathodically protect buried pipe. These systems are regularly tested, monitored and repaired in accordance with 49 CFR 192 Subpart I requirements to help ensure they are working as designed. In addition, leakage surveys are conducted utilizing tools capable of detecting extremely small amounts of gas present.

3.2. Damage Prevention

3.2.1 Overview
Excavation damage poses the most significant threat to safety and the integrity of distribution systems. These damages, generally, are not material dependent and historically have been the primary cause of distribution pipeline incidents. Excavation damage can be defined as any impact or unplanned exposure resulting in the need to repair or replace an underground pipeline or associated facility. Excavation damage includes direct damage to the pipeline as well as to the protective coating, lateral support, cathodic protection, tracer wire or the overpressure protection equipment. Locating pipelines and other assets prior to excavation activities is essential to preventing damage to underground facilities.

Damage is not a direct indicator of the fitness for service of a gas facility. Replacement or repair measures may result from external damages, but other leak/repair data is a better indicator of a distribution pipeline’s fitness for service. Other damage can occur though “natural forces” such as earth movement, floods, landslides and other weather related activities or “other outside forces” such as fire, heat or electric exposure, explosion or deliberate acts of vandalism.

3.2.2 Damage Prevention Program
Current federal regulations require operators to have written programs to prevent damages from activities such as excavation, blasting, boring and tunneling. In 2008, the national “call-before-you-dig” phone number “811” was launched by the Common Ground Alliance (CGA) with the support of utilities, communities, emergency responders and government officials. This number allows anyone who plans to
excavate to dial “811” and be routed to the appropriate one call center in the area. Each “one call center” dispatches “locate requests” to all participating utilities, which in turn send representatives to mark the location of their facilities on the jobsite to ensure excavators know the location. In addition to the national “call-before-you-dig” number, companies are further enhancing their damage prevention programs through increased public education and communication with operators and excavators regarding the hazards of digging around natural gas pipelines.

Operators are required to provide temporary indication of all underground facilities prior to any excavation. To assist with locating gas facilities, tracer wire and electronic ball markers may be installed during construction. Advances in locating technology, such as GPS, ground penetrating radar, and the temporary injection of acoustic waves into the gas, have increased the accuracy of locating underground facilities. In some states operators are required to provide as-buils and other records to their contractors to facilitate in locating of underground gas facilities.

CGA is an association that is focused on public safety with respect to excavation damage prevention. This industry-led consortium of stakeholders was formed as the result of the Common Ground Study, sponsored by the U.S. Department of Transportation and completed in 1999. CGA was officially formed in 2000 to continue the study’s pursuit of excavation damage prevention and the protection of the public and underground facilities. The following chart shows that participation in the “call-before-you-dig” program, advances in technology and work by industry groups such as the CGA have contributed to reducing the number of third party damages since 1999.
3.2.3 Mitigation

Companies use data collected from damage prevention programs to identify areas that may have a heightened risk regarding potential damage. Operators utilize this analysis to develop mitigation strategies such as increased leak inspection, and to assign trained gas-operating personnel to oversee excavation activities. Other strategies to mitigate potential damage due to excavation include replacing gas facilities in conjunction with third party improvements, providing test holes for surveyors and requiring the placement of engineered low strength backfill material around the gas piping.

3.2.4 Repeat Offenders

Underground utilities sometimes experience “repeat offenders,” excavators who willfully disregard rules and regulations that require field markings to be in place prior to excavation, and who often damage underground facilities. Companies work continuously with excavators and operators to educate them on the consequences of not following the law, including employee injury/death, damage to equipment, lawsuits, and risks to the general public. Repeat offences generally occur due to one of two reasons: an interest in financial incentives that come with expedited completion of contracted work, and lack of enforcement. Some states have penalties in place that consistently enforce current laws, and operators
urge all states to apply similar consistent enforcement of “call-before-you-dig” laws. These penalties include, but are not limited to, shutting down the excavation site, fines and the revoking of the operational license of the excavation operator.

### 3.3 Leak Management

Leak management is a vital risk control practice used by gas distribution operators to maintain the integrity of the nation’s distribution system network. Operators locate leaks by various means, including visual inspection and leak survey equipment on a regular schedule. Leak surveys conducted may include walking, mobile and aerial surveys. Natural gas is odorless, so natural gas utilities add a strong odorant that makes natural gas smell like rotten eggs to allow the public to readily detect a natural gas escape. Operators educate employees and the public about what to do when a gas odorant is detected. Most people notice the odor long before the gas concentration becomes hazardous. Leak management procedures employed by operators take into account a wide variety of factors, including the pipeline material and the environment in which the pipeline is operating. Operators implement measures to address threats that are unique to their systems.

Current federal and state regulations require gas distribution operators to have procedures in place to evaluate the severity of the leaks according to the safety risk posed by the leak. Leaks are generally categorized as either hazardous or non-hazardous. A hazardous leak is a leak that represents an existing or probable hazard to persons or property. Examples would include blowing gas that can be seen, heard or felt, ignited gas, or any indication where gas has moved underground or traveled into or under a building or could likely migrate to the outside wall of a building. Some state regulations require operators to implement leak management activities that go beyond federal mandates. Examples of these state regulations may include the following:

- Targeted leakage survey of cast iron facilities during the cold weather (frost) periods
- Increased leak monitoring of existing/known leaks to determine if any have become more hazardous during the cold weather period
- Additional inspection of facilities subject to washout or movement
- Leakage survey of underground facilities before, during and after public works projects
- Patrols of higher pressure and critical facilities for adjacent construction

A non-hazardous leak is one where the condition is not likely to change into a hazardous leak. Examples of non-hazardous leaks include those that are small in volume, low concentrations, and away from
buildings. The use of the combined experience and knowledge of the professionals in the field, along with the work flow process, helps ensure that the suspect leak’s prioritization is driven by the highest priority of public safety and protection and still satisfies the regulatory requirements. Non-hazardous leaks that are not repaired are monitored to help ensure they do not become a threat to public safety.

When determining the priority of leak repair, natural gas operators consider criteria such as the amount and migration of gas, proximity of gas to buildings and subsurface structures, extent of pavement, and soil type and conditions. The vast majority of leaks on distribution systems are not hazardous. When leaks are identified as hazardous or potentially hazardous, immediate actions are taken to resolve the condition. Some non-hazardous releases of gas can be eliminated onsite by lubrication, adjustment or tightening. A leak that is nonhazardous at the time of detection can be scheduled for a repair if the operator determines there is a probable future hazard or, if the operator determines the leak can be reasonably expected to remain non-hazardous, the leak may be monitored. The non-hazardous releases of gas eliminated onsite do not require a return visit or trip.

3.3.1 Root Cause and Preventative Measures
Operators maintain extensive records on the leaks identified and repaired, including the date and location. Records of the leaks and repairs are retained for future assessments to determine if further risk control practices (e.g. adjusting leak survey frequency) are needed to enhance the safety of the system. A gas leak can be caused by various situations, including corrosion, erosion, natural disasters like earthquakes and landslides, or excavation damage to the gas facilities. Both regulatory requirements and risk preventative measures implemented by operators address the aforementioned scenarios. Some of the mitigation actions include, but are not limited to: a systematic scheduled leakage survey program in accordance with U.S. Department of Transportation and/or state requirements, patrolling mains to determine the severity of the possible environmental conditions which could cause failure or leakage, the implementation of a written public education program that specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities and a written program to prevent damage to a pipeline from excavation activities such as blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations.

In addition, gas utilities develop and implement damage prevention, emergency response, and public awareness plans, often in conjunction with state or area emergency and management offices.
Implementation of these initiatives may require operators to promote their safe excavation messages through workshops or seminars.

IV. Performance Metrics

4.1. Background

Individual gas companies compile many metrics to track the performance of their operations and their gas distribution systems. Likewise, each state regulatory commission may have metrics they require for gas system operators in their state. These local metrics focus on performance and safety-related priorities. They are based upon many factors and can include the piping and other materials used by the individual operating companies, the environment and soils prevalent in the state, how developed the operating areas are, historical changes in the gas systems and local economics.

There are, however, a number of key metrics that the U.S. Department of Transportation (DOT) uses to monitor gas distribution systems across the United States. All operators in all states compile these metrics, and this compilation allows for trending at the national and state level. These metrics are submitted annually to DOT, or as certain issues arise. They are available to the public online at: http://www.phmsa.dot.gov/pipeline/library/data-stats.

4.2 Metrics Reported to U.S. DOT

The metrics submitted annually to DOT fall into four basic categories: distribution system components, failures, incidents and other safety-related measures. Historical trends in several of the key metrics will be discussed in a later section of this paper.

Distribution System Components
- Miles of main and number of services
  - by material
  - by material and diameter ranges
  - by decade of installation
Failures (Leak Repairs)
- Number of main leak repairs, by cause
- Number of service leak repairs, by cause
• Number of main and service hazardous leak repairs, by cause

Incidents
• All details of any significant or serious incident meeting specific criteria, including involved facilities, and consequences

Other Safety-related Measures
• Number of known system leaks at the end of the year scheduled for repair
• Failures of mechanical fittings
• Third-Party damage rate
• Installations of excess flow valves

In addition to required filings, a representative number of gas companies voluntarily compile information on issues seen with materials. For example, the industry voluntarily submits information on plastic pipe to the Plastic Pipe Data Collection group, a joint stakeholder group that shares findings with the industry, regulators, manufacturers and the public. The majority of operators also participate in industry benchmarking efforts to identify leading practices and share information.

4.2.1 Leak Metrics
Management of distribution systems requires a clear understanding of the causes of leaks on those systems. Leak causes fall into four general categories, and each are carefully defined to promote uniformity in reporting.

Outside Force-related Leaks (aka “Damages”)
• Excavation – A leak directly caused by underground physical damage (impact) that can be attributed to someone
• Natural Forces – A leak directly caused by a force of nature, including: undermining, earth movement, lightning, floods, washouts, frost heave, frozen components, etc.
• Other Outside Force – A leak directly caused by fire, explosion, vehicular damage to an aboveground facility, electrical/heat sources, or a deliberate/willful act such as vandalism

Leaks entirely related to material or construction methods
• Corrosion – A leak from a hole, crack or porosity in the pipe or other gas-carrying member AND that condition was caused by corrosion (or graphitization of cast iron).
• Equipment – A leak caused by non-pipe fittings or appurtenances
• Materials and Welds/Fusions – A leak caused by all material and construction defects, including welds on metal and fusions on plastic

Leaks caused by the company itself
• Operations – A leak caused by operator error, inadequate safety practices/procedures, or failure to follow procedures

All other leaks
• Other – Leaks whose cause is not specified above

4.3 Performance
The U.S. Department of Transportation Pipeline and Hazardous Materials Administration (PHMSA) and the industry track trends in metrics to help ensure ongoing improvement. During the past 19 years (1991 – 2010), the industry has improved its system’s performance and continues to replace inventories with state of the art materials. In addition, information concerning specific incidents is reported on a case-by-case basis and analysis of this data also shows that these have declined significantly over this time period. Improvements in safety since 1991 should continue and will likely accelerate with the implementation of Distribution Integrity Management Program rule (DIMP).

DOT tracks both “serious” and “significant” incidents. DOT defines a “significant” reportable incident as a pipeline incident that is reported by pipeline operators when any of the following specifically defined consequences occur:

1. Fatality or injury requiring in-patient hospitalization
2. Damage valued at $50,000 or more in total costs, measured in 1984 dollars
3. Highly volatile liquid releases of five barrels or more or other liquid releases of 50 barrels or more
4. Liquid releases resulting in an unintentional fire or explosion

“Serious” incidents are a subset of significant incidents and are considered serious due to harm to persons. DOT defines a “serious” incident as a pipeline incident that involves a fatality or injury that requires in-patient hospitalization.

4.3.1 Incident Trends
Over the last 19 years, the natural gas distribution industry has driven the number of incidents down. This trend is due to the efforts to manage the factors that are within operators’ control and also attempt to influence the factors not under operators’ direct control.

4.3.2 Leak Trends
Over the past 19 years, as noted by the following graphs, the industry has shown tremendous improvement in reducing overall leakage. The first graph included below demonstrates that the number of main leaks decreased by 43% from 1991 to 2009. The second chart included below captures service leaks. It indicates there was a jump in service leaks in 2009. It is important to note that this appears to reflect a change in the way many operators accounted for minor, non-hazardous above ground riser and meter set leak repairs, not a trend reversal. Based on an operator’s request for an interpretation from PHMSA on leak reporting and PHMSA’s response to this request, a number of operators started to report service leaks that were previously not considered reportable. This resulted in a significantly higher number of service leaks reported for 2009. Industry has started to use a definition of reportable above ground leaks that provides
consistency and focuses on leaks that represent a real hazard. The data that is included in both graphs below reflects the data that was made available by PHMSA in February 2012.
4.3.2 Infrastructure replacement

The industry has demonstrated a focus on modernizing its infrastructure. The following graph shows how the inventory of our nation’s infrastructure is largely composed of pipeline materials that continue to be installed by operators. The pipeline materials that are no longer being installed still perform well and may continue to do so over time. Operators perform risk-based analysis to determine what pipelines should be considered for modernization. These targeted replacements reduce the numbers of facilities or groups of facilities that may no longer be considered fit for service.
Due to replacements, the nation’s gas distribution mains are actually getting younger, on average, each year rather than getting older or remaining the same average age. The estimated average age of the nation’s gas mains is decreasing at the rate of about one year in every calendar year. Services are experiencing similar rejuvenation.

V. Improving system reliability and pipeline safety

5.1 Definition
An underperforming pipeline facility is one that is no longer performing as planned and carries an unacceptable safety and/or reliability risk in its continued use. There is no single “hard and fast” rule for identifying an underperforming distribution facility. This is because distribution systems consist of a wide variety of pipe, fittings and appurtenances with varying materials, sizes, construction methods and vintages, operating at different pressures in widely varying environments.

In general, an underperforming distribution pipeline segment will be either:
• one that has experienced performance-related hazardous leaks and can be reasonably expected to continue to experience such leaks or
• one that has been judged by operator or industry knowledge as being near the end of its useful life – based on evaluative technologies or known issues that may exist with very specific materials, vintages, manufacturers, lots, etc.

The identification of underperforming facilities can be complicated. To draw an analogy to a house or a car – you wouldn’t tear down and rebuild an old house if the roof leaked, but you might have to if the foundation was sinking. Likewise, you wouldn’t junk an older automobile that had clogged fuel injectors, but you might need to replace it if it had a seized engine. Some old bridges are maintained, while others need to be replaced. People make repair-replace decisions every day, and they will usually weigh many factors in doing so.

With distribution pipeline systems, a wide variety of information about the pipelines, fittings and appurtenances are gathered and integrated to form the basis of system knowledge. The information gathered may include, but is not be limited to, material, size, operating pressures, material failures, damages, repairs and different grades of leaks. Based on system knowledge, groups of facilities that are underperforming are identified with their root causes.

5.2 Prioritization
The results of leak surveys, patrols and inspections, and the resulting leak repair history are reviewed and analyzed to determine if additional maintenance is required, and/or to prioritize risk mitigation activities to maintain safe and reliable transportation of natural gas to consumers. After the subsets of underperforming facilities are identified, the risk posed by each cause/facility combination is evaluated and this becomes the basis for prioritization of mitigation actions. Because a multitude of factors contribute to making a facility underperform, the risk-based analysis is a better approach for indentifying such assets and the risks that they pose. Using a single factor such as age or material will lead to a very ineffective way of managing risk by potentially targeting facilities that pose little or no risk.

5.3 Risk Assessment
Risk assessment measures the probability and consequence of all the potential events that comprise a hazard. Risk assessment helps operators organize data and information to make decisions. Under the new Distribution Integrity Management Program regulations, operators have developed procedures for evaluating and ranking risk. Operators have additionally developed a formal plan to identify and define
the data necessary for the analyses. Operators validate data for accuracy, completeness and consistency and institute measures to improve upon future data collection efforts.

Risk assessment helps ensure that the appropriate attention is given to a potential failure of relatively low likelihood but significantly high consequence rather than only focusing on a failure with somewhat greater likelihood but very little consequence.

Risk = Probability of Incident * Consequence of Incident
Probability of Incident is the likelihood that a pipeline failure event will occur and lead to an incident.
Failures include:
1. Loss of Integrity
2. Failure to perform
3. Failure of the asset resulting in a leak
Consequence of an incident is the potential loss of life, injury, or property damage caused by pipeline failure

5.4 Mitigation
There are five basic types of action that an operator can take to mitigate risk and/or improve performance of an existing pipeline facility, these are: Monitor, Respond, Reduce, Remedi ate, and Replace. The particular actions of each operating company are as varied as the operating environments. Each gas distribution system requires a unique strategy which is determined through both experienced and detailed risk analysis and prioritization. Risk prioritized replacement is a proven concept in the industry and has been repeatedly demonstrated to increase safety and system reliability more quickly than arbitrary replacement of a pipeline facility. This principle is inherent in all the mitigation strategies discussed in this section.

5.4.1 Monitor
For pipeline facilities that have historically performed well, monitoring provides early warning to future performance issues. For pipeline facilities with declining performance, monitoring reduces risk by finding problems early on and gathering data to determine additional mitigation action. For example, when abnormalities are detected in the cathodic protection system, it can trigger further inspection of the pipe and alteration or repair of the cathodic protection system. Other types of monitoring include system-wide leak surveys and corrosion inspections of meters, pressure regulators and other above ground assets. In some cases special circumstances may be identified that lead an operator to inspect an asset more
frequently, such as in business districts. In addition, certain external factors, such as weather and large community events, can lead operators to make precautionary inspections of assets.

5.4.2 Respond
Whether discovered through self-monitoring or customer reports, leaks sometimes occur on gas distribution systems. Operators maintain personnel to respond to these instances 24 hours a day 365 days a year. In the event of hazardous situations operators mobilize any and all necessary resources to help ensure public safety. After the immediate hazard is removed, operating companies use their leak management program to perform permanent repairs to their systems and restore any customers that lose service. The record of the issue adds to the data monitored for future consideration.

5.4.3 Reduce
Once the performance of a pipeline facility is brought into question, one action that an operator may consider is to reduce the operating pressure of that pipeline facility. Lowering the pressure can reduce both the likelihood of failure and potential consequence of a failure if it occurs. In some cases, it is possible to shutdown the asset (i.e. reduce the pressure to zero). This is generally temporary and, when utilizing this option, operators make every effort to avoid adversely impacting customers while further testing, remediation or repair is performed.

5.4.4 Mitigate
Sometimes the data gathered in inspections indicate that more action is required. There are a variety of methods available to mitigate risk and/or improve the performance of an asset by physically altering the asset. The specific actions depend on geography, asset material, local population density and many other factors. In general, most non-replacement mitigation activities involve the remediation of a single component of a pipeline. For instance, it is a common practice to encapsulate a leaking cast iron joint, or place a leak sleeve over an isolated corrosion pinhole on a steel pipe.

5.4.5 Replace
Replacement is generally reserved for pipeline facilities with poor and/or declining performance histories and is a solution to the fitness of service question. These replacement programs are worked into the operators’ multi-year capital plans. Operators work closely with third party improvements such as governmental road projects or utility replacement projects. To account for the extensive costs associated with large scale replacement programs, operators utilize ratemaking, a process by which a pipeline operator, its customers, and the operator’s regulatory body determine a fair price for the pipeline’s
services. It’s important to note that, although replacement programs are highly effectual, they are also the most costly mitigation measure to ratepayers and it can be disruptive to continuity of service, the community (including traffic) and the environment.

VI. DIMP

In 2002 the U.S. Department of Transportation published a rule that required operators of transmission pipelines to develop "integrity management" programs to help ensure the safety of their systems. This rule required transmission pipeline operators to collect detailed information about their systems, identify threats to their systems, assess the risk posed by the threats identified and take the needed actions to avert a pipeline incident. As transmission natural gas operators began to implement the "integrity management" requirements, operators became better informed of areas of their pipeline system that were potentially susceptible to rupture, allowing them to repair these sections of pipe and continually improve pipeline safety.

Due to the findings and extensive work completed for the 2002 rule, the U.S. Department of Transportation, natural gas operators and many other interested parties began to research how a similar initiative could be applied to distribution pipeline systems. Transmission pipeline operations are distinctly different from distribution pipeline operations, but natural gas operators were focused on developing a similar initiative to effectively improve pipeline safety and reliability. It’s also important to note that distribution systems are many times larger, more complex and more diverse than transmission systems and all of these characteristics make an assessment-based approach impractical.

In preparation for the development of an integrity management program rule specific to distribution pipeline systems, the American Gas Foundation (AGF) began developing a report in 2003 to assess distribution pipeline safety from 1990 to 2002. This report was finished in 2004 and compared incidents on natural gas transmission pipelines with incidents on natural gas distribution pipelines. This report determined that both distribution and transmission pipelines had good safety records, but distribution pipelines could also benefit from regulations that required integrity management actions.
Beginning in 2005, the U.S. Department of Transportation began working with distribution pipeline industry experts and other stakeholders on a joint group tasked to identify key considerations to help ensure the safety of distribution pipelines and, based on those considerations, the regulatory requirements that should be expected for distribution pipeline operators. This group focused on topics such as excavation damage, corrosion and the attributes of a variety of pipeline materials. Following the assessment and path forward provided by this joint stakeholder group, the Gas Piping Technology Committee, a technical committee comprised of individuals with extensive experience with distribution pipeline operations, developed guidance in 2006 for the rule requirements and improving pipeline safety.

In 2006 Congress passed the Pipeline Safety Act, requiring the U.S. Department of Transportation to develop a distribution integrity management rule. The U.S. Department of Transportation published a proposed integrity management rule for distribution pipelines in June of 2008 and, following a review of comments from the gas industry, local regulators, other experts as well as the public, published the final rule in December of 2009. This rule took into account the diverse and complex nature of the nation’s gas distribution systems and reflected the six years of extensive efforts undertaken by the U.S. Department of Transportation to continually identify opportunities to improve pipeline safety. The final rule requires distribution pipeline operators to develop a plan that assesses the safety of their system and taking into account:

1. Demonstrate knowledge of the system
2. Identify threats
3. Evaluate and rank risk
4. Identify and implement mitigative measures
5. Measure performance, monitor results and evaluate effectiveness
6. Evaluate and improve periodically
7. Report results

In addition to data analysis and subject matter expert opinions on specific portions of their pipeline systems, operators are required to submit reports to the U.S. Department of
Transportation on an annual basis for the following performance measures: number of hazardous leaks eliminated/repaired (by cause), number of excavation damages, number of excavation tickets from one-call centers and total number of leaks eliminated/repaired (by cause). As a result of this rule, distribution pipeline operators will become more data-driven and build upon previously implemented efforts to manage leaks and reduce risk. Data collection, granularity and analysis leads to better decisions using both new and previously available data. With DIMP now in place, companies have been able to formalize their process to achieve this goal and gain an even better understanding of their systems. Operators were required to have a distribution integrity management plan in place by August 2, 2011 and will be required to implement the plan by August 2, 2012.

VII. Conclusion/Summary

Natural gas is a clean burning and abundant fuel that is delivered through pipeline systems of varying size and material type to customers for residential, commercial and industrial use. Unlike transmission pipeline systems, distribution pipeline systems operate at lower pressures and are comprised of two primary pipe components, namely mains and services. Common piping materials utilized in today’s distribution pipeline systems include cast iron, copper, steel and plastic. Each material type has its own unique strengths and challenges, and each was installed utilizing varying techniques available at the time of construction.

Early gas companies installed cast iron mains in its distribution pipeline system, which were typically installed in 12 foot lengths and joined using bell and spigot joints. As companies started increasing delivery pressure to meet the increasing customer demand of natural gas, steel piping became the material of choice because it could better withstand the higher pressures and was a stronger material. Early vintages of steel were installed in 20 or 40 foot lengths and were connected with mechanical couplings. The modern pipe material of choice is a plastic material known as polyethylene. Polyethylene is a lightweight material that is highly resistant to corrosion, can withstand high pressures and is easily joined using fusion technology or
mechanical couplings. Most local distribution companies, or LDCs, employ multiple materials in its distribution system, which often is the result of its unique history and geographic conditions.

Regardless of the material type used in distribution systems, all LDCs must adhere to federal codes to help ensure the safe and reliable delivery of natural gas to customers. These codes govern the process of pipeline design, construction and maintenance activities. Most of the federal requirements are contained within CFR, Title 49, Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. In addition to federal requirements, most states and some municipal governments have enacted rules and regulations that govern the design, operation and maintenance of distribution pipeline systems. LDCs set internal standards for their pipeline construction and maintenance activities that meet and often exceed CFR, Title 49, Part 192, as well as other state and municipal regulations.

One of the primary means of ensuring a safe pipeline operation is performing leakage surveys. Effective leak management is a vital risk control practice used by LDCs to maintain the integrity of the nation’s distribution system. LDCs perform these surveys in accordance with regulatory requirements. In addition to following the minimum standards for leak survey inspections, many LDCs exceed this standard when warranted by additional factors, such as the pipe material in use, pipeline location, operating history, local conditions or other identified risks.

In addition to monitoring the pipeline system for leaks, LDCs perform regularly scheduled maintenance activities on their pipelines and other facilities. These activities include, but are not limited to, regular inspection and testing of pressure regulating equipment, regular operation and maintenance of valves, and inspection and maintenance of corrosion protection systems for steel assets.

Another factor LDCs must consider when maintaining a safe and reliable pipeline system is the prevention of third party damages. Excavation damage is a leading cause of natural gas related pipeline incidents, and consequently has garnered much attention from both regulators and gas companies. LDCs have developed written programs to prevent damages caused not only by excavation, but other activities such as blasting, boring and tunneling. LDCs have also supported
the enactment of a national “call-before-you-dig” number, and have enhanced their damage prevention activities by developing public education and communication plans aimed at increasing the awareness of hazards associated with digging around natural gas pipelines.

Employing effective leak management techniques, performing regular inspections, performing preventative maintenance activities, and developing outreach campaigns and other damage prevention measures have led to a steady decline in leaks and incidents considered significant or serious on the nation’s distribution pipeline system. A federal integrity management rule was recently enacted for distribution operators to continue this positive trend and help ensure public safety. The federal Distribution Integrity Management Program rule, or DIMP, requires operators to develop and implement a plan to assess the safety of their system based on several criteria. The pipeline material type and age are only two of many factors that LDCs will consider when assessing the safety of their pipeline system. Depending on other factors under consideration, pipeline material and age may prove to be low risk factors for LDCs and other factors, such as the prevention of third party damages, could present more risk to the pipeline system and the safety of the public.