U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 30, 2024

The Honorable Maria Cantwell
Chair
Committee on Commerce, Science, and Transportation
United States Senate
Washington, DC 20510

Dear Chair Cantwell:

Enclosed is the Pipeline and Hazardous Materials Safety Administration's (PHMSA) report on "Integrity Assessment of Distribution Pipelines" as mandated by Section 122 of the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020" (PIPES Act of 2020; Pub. L. 116-260 at Division R).

Section 122 of the PIPES Act required the U.S. Department of Transportation to submit a report to Congress studying the availability of alternative methods to using direct assessment to assess pipeline integrity. The report provides details on the lack of available options for the assessment of distribution pipelines and includes an evaluation of alternative prevention methods as they relate to safety enhancement.

A similar letter has been sent to the Ranking Member of the Senate Committee on Commerce, Science, and Transportation; the Chair and Ranking Member of the House Committee on Energy and Commerce; and the Chairman and Ranking Member of the House Committee on Transportation and Infrastructure.

Sincerely,

Tristan H. Brown

Tristan H. Brown
Deputy Administrator

Enclosure

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 30, 2024

The Honorable Ted Cruz
Ranking Member
Committee on Commerce, Science, and Transportation
United States Senate
Washington, DC 20510

Dear Ranking Member Cruz:

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Deputy Administrator

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**Pipeline and Hazardous
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1200 New Jersey Avenue, SE
Washington, DC 20590

August 30, 2024

The Honorable Sam Graves
Chairman
Committee on Transportation and Infrastructure
U.S. House of Representatives
Washington, DC 20515

Dear Chairman Graves:

Enclosed is the Pipeline and Hazardous Materials Safety Administration's (PHMSA) report on "Integrity Assessment of Distribution Pipelines" as mandated by Section 122 of the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020" (PIPES Act of 2020; Pub. L. 116-260 at Division R).

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Deputy Administrator

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**Pipeline and Hazardous
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1200 New Jersey Avenue, SE
Washington, DC 20590

August 30, 2024

The Honorable Rick Larsen
Ranking Member
Committee on Transportation and Infrastructure
U.S. House of Representatives
Washington, DC 20515

Dear Ranking Member Larsen:

Enclosed is the Pipeline and Hazardous Materials Safety Administration's (PHMSA) report on "Integrity Assessment of Distribution Pipelines" as mandated by Section 122 of the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020" (PIPES Act of 2020; Pub. L. 116-260 at Division R).

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A similar letter has been sent to the Chairman of the House Committee on Transportation and Infrastructure; the Chair and Ranking Member of the Senate Committee on Commerce, Science, and Transportation; and the Chair and Ranking Member of the House Committee on Energy and Commerce.

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Tristan H. Brown

Tristan H. Brown
Deputy Administrator

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U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 30, 2024

The Honorable Cathy McMorris Rodgers
Chair
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Chair Rodgers:

Enclosed is the Pipeline and Hazardous Materials Safety Administration's (PHMSA) report on "Integrity Assessment of Distribution Pipelines" as mandated by Section 122 of the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020" (PIPES Act of 2020; Pub. L. 116-260 at Division R).

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Sincerely,

Tristan H. Brown

Tristan H. Brown
Deputy Administrator

Enclosure

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

August 30, 2024

The Honorable Frank Pallone, Jr.
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Ranking Member Pallone:

Enclosed is the Pipeline and Hazardous Materials Safety Administration's (PHMSA) report on "Integrity Assessment of Distribution Pipelines" as mandated by Section 122 of the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020" (PIPES Act of 2020; Pub. L. 116-260 at Division R).

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Enclosure

ORNL/SPR-2023/3188

Integrity Assessments of Distribution Pipelines

Ravi Krishnamurthy
Ryan Milligan
Scott Sluder

January 2024

Oak Ridge National Laboratory

ORNL IS MANAGED BY UT-BATTELLE LLC FOR THE US DEPARTMENT OF ENERGY

ORNL/SPR-2023/3188

Buildings and Transportation Science Division

INTEGRITY ASSESSMENT OF DISTRIBUTION PIPELINES

Ravi Krishnamurthy (Blade Energy Partners)
Ryan Milligan (Blade Energy Partners)
Scott Sluder (Oak Ridge National Laboratory)

January 2024

Prepared by
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UT-BATTELLE LLC
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US DEPARTMENT OF ENERGY
under contract DE-AC05-00OR22725

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1. Executive Summary

In response to Section 122 of the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) requested Oak Ridge National Laboratory through its subcontractor Blade Energy Partners to conduct a study of the methods, other than direct assessment (DA), that may be used in an integrity management (IM) program for distribution pipelines to provide a greater level of safety.

Blade Energy Partners reviewed past, current, and planned integrity technologies and methods available to assess the integrity of distribution pipelines. The study sought to identify whether any of these existing or emerging integrity assessment methods and technologies may provide a greater level of safety than DA for natural gas distribution systems.

This study found that robots and crawlers (robots/crawlers) appear to be the most promising technology to provide a level of safety equal to or greater than DA. Robots/crawlers can navigate the complexities of distribution networks, thus overcoming some of the challenges with multiple branches, changing diameters, and low to no flow. The feasibility of these technologies is limited by the capabilities of the platform and sensors and depends on whether the robots/crawlers can navigate the pipeline, given the diameters, material, pressure, and degree of branching.

The robots/crawlers deploy camera inspection that is an option for all materials—steel, cast iron, and plastic; however, camera inspections cannot provide a level of safety equal to DA. While not available for plastic pipes, caliper inspection can provide the same level of safety as DA in cast iron and steel pipelines. Finally, magnetic flux leakage sensors, the most predominantly used tool for in-line inspection in transmission pipelines, is applicable in steel distribution pipelines. There have been recent developments in NDE sensor technologies specific to small diameter plastic pipes that includes terahertz imaging, microwave imaging, and dry-coupled probe ultrasonic testing. These technologies require additional development prior to commercial applications in plastic gas pipelines.

Many other methods and technologies were considered during the research for this study, but they could not assess the integrity of pipelines and therefore did not meet the study objective. However, these methods and technologies enhance safety and promote integrity of distribution pipeline systems. Some examples of the other areas researched were those used in the performance of DA, integrity threat prevention, leak detection, and mitigation through repair. The integrity assessment methods that are the focus of this study address some of the distribution pipeline threats, but many threats are being addressed and proactively managed by other effective methods.

2. Introduction

Section 122 of the Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2020 amended Section 60109(c) of Title 49 USC, as follows:

(12) Distribution pipelines—

> *(A) Study.— The Secretary shall conduct a study of methods that may be used under paragraph (3), other than direct assessment, to assess distribution pipelines to determine whether any such method—*
>
> *(i) would provide a greater level of safety than direct assessment of the pipelines; and*
>
> *(ii) is feasible.*
>
> *(B) Report.– Not later than 2 years after the date of enactment of this paragraph, the Secretary shall submit to the Committee on Commerce, Science, and Transportation of the Senate and the Committees on Energy and Commerce and Transportation and Infrastructure of the House of Representatives a report describing—*
>
> *(i) the results of the study under subparagraph (A); and*
>
> *(ii) recommendations based on that study, if any.*

PHMSA requested Oak Ridge National Laboratory (Oak Ridge) to conduct the required study. Oak Ridge contracted with Blade Energy Partners (Blade) to complete the study.

Blade's approach to this study is described by the following steps:

- Review and identify affected pipeline infrastructure, including materials used, incident history, and threats specific to each material.
- Identify the differences in transmission and distribution integrity assessment methodologies.
- Identify integrity assessment methods available for distribution pipelines.
- Study the distribution integrity assessment methods through a review of available literature and discussions with vendors, suppliers, operators, and industry trade organizations.
- Evaluate the feasibility of the alternative integrity assessment methods identified.
- Compile, analyze, and integrate the data into a report.

Blade completed a detailed review of available literature and reached out to operators and vendors to gain insight into technologies in use or under development. The methods presented here represent an extensive list based on public information and data provided by operators and vendors.

Appendix A to this report details DA tools that are typically used to identify and evaluate integrity threats for mitigation. Appendix B details threats that are managed by proactive preventative methods that do not fall under the category of traditional integrity assessment. For example, leak detection is effective in identifying threats once a leak has occurred and is an important technique for distribution pipelines when traditional integrity assessment methods and techniques are impractical. The advances in leak detection and its efficacy are discussed in Appendix C. Finally, for cast iron, operators are focused on proactively replacing pipelines; however, there is the option of proactive repair that could be effective in preventing leaks, especially large diameter cast iron pipelines. These methods are discussed in Appendix D.

3. Gas Pipeline Infrastructure

As defined in 49 CFR § 192.3 of the federal pipeline safety regulations, a distribution line is a pipeline other than a gathering or transmission line. Distribution lines are the final step in the transportation of natural gas to commercial and residential consumers and small manufacturing and industrial plants. A distribution system typically begins when gas from the transmission line enters the local distribution company through a gate station (city gate, city border station, town station, or town tap). Here the pressure is reduced to a level typically at or below 200 psig, and an odorant is added to the gas to enable leak detection. The gas then moves from the gate station to a distribution main (main), ranging in diameters from 2 to 24 inches. Mains are separated into two categories based on operating pressure: (1) High-pressure mains are called *feeder mains*, *supply mains*, *interstation mains*, and *intermediate pressure mains*, operating at pressures between 60 and 200 psig. (2) Distribution or low-pressure mains typically operate at pressures lower than 60 psig, but, in specific scenarios, may operate as high as 125 psig. Service lines are the final stage transporting the gas from a common source of supply, typically a main, to an individual customer meter or connection to a customer's piping. In general, pipe sizes and pressures decrease as the distribution line approaches the customer.

Table 1 lists the miles of pipeline for gas distribution, gathering, and transmission systems in the United States. Gas distribution lines are further divided into main and service miles. The table indicates that at the end of 2021, distribution mains and services accounted for 52.1% and 36.7% of the total natural gas pipeline miles, respectively. In total, the distribution system represented 87.8% of natural gas pipeline miles.

Table 1. Gas pipeline length by system type in 2021. [1]

System type	System detail	Miles	Percentage of total miles
Gas distribution	Main miles	1,340,234	51.2
	Service miles	959,695	36.7
Gas gathering	Miles	17,076	0.7
Gas transmission	Miles	301,452	11.5
Total		2,618,457	100.0

PHMSA data were reviewed to determine the composition and size of the gas distribution system. Based on 2021 annual report data [2], gas distribution mains comprise 60.1% plastic and 34.4% coated steel with cathodic protection (CP). The remaining mains are constructed from coated steel without CP, bare steel with and without CP, ductile iron, copper, cast/wrought iron, and other materials. Service line data indicate similar composition: 75.2% of the lines are constructed from plastic and 16.8% constructed from coated steel with CP. These data are illustrated in Figure 1.

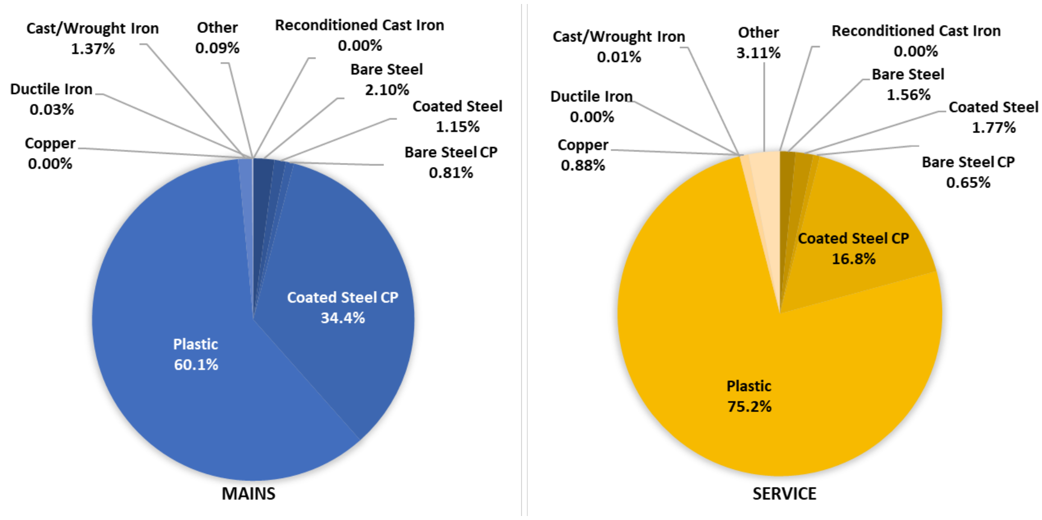


Figure 1. Gas distribution pipe materials in 2021 [2]

Based on the 2021 annual report data [2] submitted to PHMSA, gas mains primarily have diameters less than 12 inches. The distribution of gas main diameters is as follows: 60% are 2 inches or less, 24% are 2 to 4 inches, 13% are 4 to 8 inches, 2% are 8-12 inches, and 1% are greater than 12 inches. The distribution of gas service diameters is as follows: 88% are 1 inch or less, 10% are greater than 1 inch and less than or equal to 2 inches, and the remaining 2% are greater than 2 inches. These distributions are illustrated in Figure 2.

Integrity assessments using conventional transmission pipeline technologies pose an insurmountable challenge because 84% of the distribution pipeline systems have diameters less than 4 inches and operate at very low pressures. Furthermore, more than 60% of the systems are plastic or cast iron, and steel-based integrity assessments are not applicable. Plastic pipe integrity is managed through life prediction and replacement and possibly through repair, whereas cast iron issues are predominantly addressed through replacement.

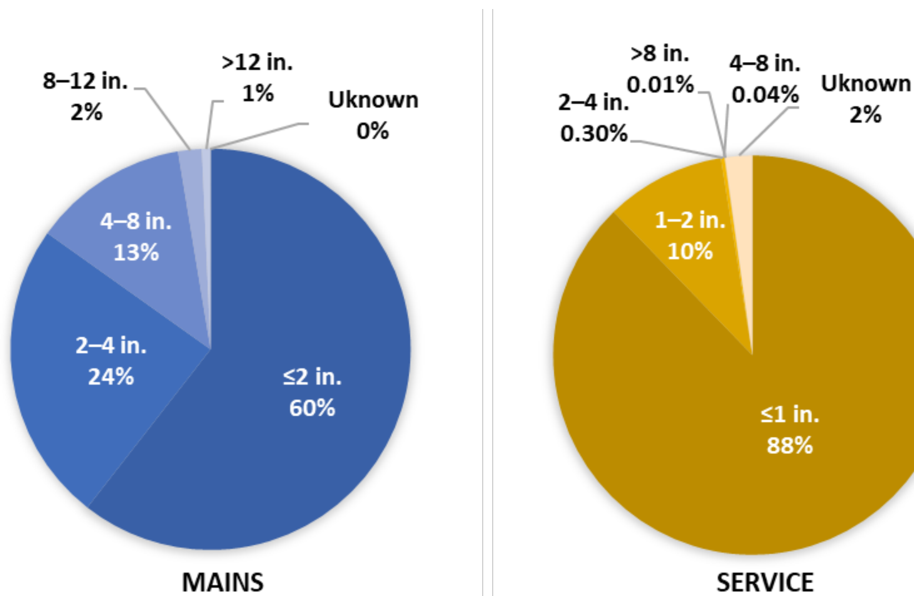


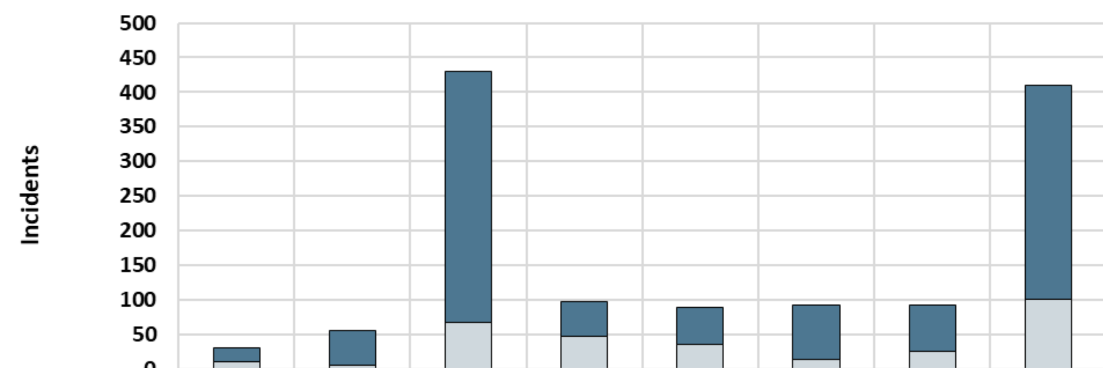
Figure 2. Distribution pipe diameters in 2021

3.1 INCIDENT DATA

PHMSA incident data were analyzed to determine which threats were most likely to cause an incident. Gas distribution threats, as reported to PHMSA from 2010 to 2021, are shown in Figure 3 and are as follows:

- Third-party excavation damage (33.2%)
- Outside force damage (31.5%)
- Incorrect operations (7.5%)
- Natural force damage (7.2%)
- Other causes (7.1%)
- Pipe or weld material failure (6.9%)
- Equipment failure (4.3%)
- Corrosion failure (2.4%)

The number of serious incidents are lower, however the distribution across causes are similar to the overall incidents.



	Corrosion Failure	Equipment Failure	Excavation Damage	Incorrect Operation	Material Failure of Pipe or Weld	Natural Force Damage	Other Incident Cause	Other Outside Force Damage
Incident Total	31	56	430	97	89	93	92	409
Incident % Total	2.4	4.3	33.2	7.5	6.9	7.2	7.1	31.5
Serious Total	10	6	68	48	35	14	25	101
Serious % Total	3.3	2.0	22.1	15.6	11.4	4.6	8.1	32.9

Figure 3. Incidents by cause category from 2010 to 2021

3.2 DISTRIBUTION PIPELINE MATERIALS AND INTEGRITY THREAT SUSCEPTIBILITY

The following sections discuss construction materials used for gas distribution pipelines. Each section provides a brief history and discusses the most common threats associated with each material.

3.2.1 Cast Iron

Cast and wrought iron pipelines were originally constructed to transport manufactured gas in the 1870s and 1880s, and cast iron became more popular in the early 1900s. Currently, approximately 1% of the total distribution pipelines are cast iron, and industry-wide efforts continue to reduce the miles of cast iron pipe by replacement with plastic pipe.

Cast iron is an alloy of carbon, silicon, and iron with more carbon present than can be retained in a solid solution in austenite, typically a high-temperature form of iron. Cast iron contains decomposition products such as free graphite or cementite (an iron carbide). The carbon content in cast iron is generally greater than 2%. The high percentage of carbon makes the cast iron brittle and not workable, except by casting. Cast iron groups include the following [3]:

- Gray cast iron
- White cast iron
- Malleable iron
- Ductile (nodular) iron
- Alloy cast iron

The natural gas industry historically used gray cast iron for distribution mains and fittings, and it is the most widely used of all cast irons. Gray cast iron generally has good compressive strength, castability, wear resistance, low notch sensitivity, and high damping capacity.

3.2.1.1 Threats and Solutions

Graphitic corrosion (leaching) is the most common and hazardous threat to cast iron pipes. It is a form of dealloying in which one constituent of an alloy is removed, leaving a residual structure. Graphitic corrosion is often referred to as *graphitization* [4]. However, graphitization is a different phenomenon that occurs when cast iron is exposed to elevated temperatures over a long period.

In addition to corrosion, ground movement is a common threat to cast iron gas distribution pipelines. Because cast iron is brittle, it can crack or break because of ground movement or overburden loads. Past cast iron installation practices have created shallow pipe conditions that are susceptible to distributed surface loads from vehicle travel or heavy equipment. Furthermore, cast iron's susceptibility to cracking increases with colder temperatures. Ground movement and external loading can also contribute to leaks in the bell and spigot joints by causing misalignment. Additionally, leaks often occur at joints because the sealing compound dries out. Cast iron was originally designed to transport manufactured gas, which contains more moisture than the natural gas transported today. The dry gas tends to dry out the sealant, which leads to leakage. During the literature review, a robot was identified that could inspect and repair cast iron joints. Details of this proactive repair technique are discussed in Appendix D.

3.2.2 Steel

In the early 1900s, distribution pipeline construction transitioned from cast iron to carbon steel (alloyed) with less than 0.2% carbon. Numerous studies have examined this transition in some detail [5] [6] [7] [8] [9] [10]. Of the 1.3 million miles of mains, nearly 34.4% are carbon steel, and of the less than 1 million miles of service, nearly 16% are carbon steel. The threats to steel pipes must be addressed through integrity assessment technologies and other proactive mitigation methods.

Carbon steel pipelines are characterized by low carbon, and with advances in manufacturing, alloying, and heat treatment, the industry continues to reduce carbon content while providing adequate yield and toughness. Pipe manufacturing was initially characterized by seamless pipes and later by welded pipes. Both processes have evolved and improved over time.

The practices of joining of steel pipe sections have also evolved from threaded collars and mechanical couplings during the early era (pre-1940) to flanged connections and automatic welding in the vintage (1940-1970) to modern eras (1970 onwards). During the early era, oxyacetylene welding was also an option and was discontinued during the vintage period.

The first version of API (American Petroleum Institute) 5L Standard was available in 1928, which was the start of the standardization of line pipe manufacturing. The initial pipeline grades were A (25 ksi) and B (35 ksi); later, X42, X52, and higher grades were developed.

3.2.2.1 Threats

The most common threats to steel pipelines include internal and external corrosion, gouges, dents, and buckles. Corrosion is caused by the surrounding environment and the condition of the steel pipe. For example, steel pipes without CP are susceptible to external corrosion. Without a coating to isolate the pipe from the environment or CP to slow the corrosive effects, bare steel will corrode. In contrast, coated steel is less susceptible to external corrosion because the coating prevents contact with the environment. Further protection for the coated pipe is provided by CP, especially in locations where there is a localized coating failure.

Gouges, dents, and buckling can be caused by many factors. For example, excavation damage can cause coating damage, gouges, and dents. Dents can also be caused by rocks buried in close proximity to the pipe and pipeline settlement. Cracking is a common threat to steel transmission pipelines; however, gas distribution lines operate at significantly lower stress, which reduces the probability of cracking and the likelihood of a leak or rupture.

3.2.3 Plastic Pipe

During the past 30 years, plastic pipe applications have increased for distribution pipelines operating at less than 100 psig. In 2003, plastic pipe accounted for half a million miles of distribution main [2] and this shift in increasing plastic pipe requires a different approach to pipe integrity. Plastic pipe is flexible, corrosion resistant, easy to transport, and relatively inexpensive to install, and it can often be inserted into existing pipelines or through the soil without traditional trenching along its entire route. Plastic pipe now accounts for [11] 60% of mains and 75% of all service lines.

Plastics are synthetic materials derived from organic products such as hydrocarbon fuels (coal, natural gas, and crude oil), salt, sand, and many other possible constituents.

Plastic materials that are currently or previously used for gas distribution include the following:

- Polyethylene (PE)
- Polyamide
- Polyvinyl chloride
- Fiber-reinforced plastic
- Cross-linked PE

Plastic has many advantageous characteristics for use in gas distribution pipelines, including the following:

- Resistant to corrosion
- Light weight and ease of handling during construction
- High flexibility, which allows the pipeline to be coiled and supplied in long lengths, avoiding frequent joints, and enabling insertion into older and leak-prone pipes

Resistant to ground movement from temperature fluctuation or instability

3.2.3.1 Threats and Solutions

There are three primary failure modes exhibited by plastic gas pipe materials [12]. The modes are as follows:

Ductile rupture failures occur because of the presence of high internal pressures. The failure mode is manifested in large, localized plastic permanent deformations of the pipe wall.

Slow crack growth occurs over long periods at low loads below the material's yield point and is characterized by brittle (slit) fractures that exhibit minimal deformation.

Rapid crack propagation is manifested as a large-scale brittle crack that propagates at speeds exceeding 300 ft/s over long distances. Rapid crack propagation occurs because of an initial axial notch within the pipe wall.

Furthermore, plastics are susceptible to other failure modes, including multiple squeeze offs, bending, and rock impingement [12].

Another potential failure mode could result from improper fusion of pipe. The primary approach used by operators to mitigate threats is replacement. Traditional integrity assessment methods are not applicable for plastic pipe, and service life prediction is used to identify operational period.

4. INTEGRITY ASSESSMENT DIFFERENCES: DISTRIBUTION VS. TRANSMISSION

Significant differences exist in the design and construction of gas distribution pipeline systems compared with gas transmission pipelines. These differences significantly limit the applicability of assessment and inspection techniques used for transmission pipelines to distribution pipeline systems [13].

Federal pipeline safety regulations found in 49 CFR 192, Subparts M and O, prescribe requirements pertinent to the integrity assessment and management of gas transmission pipelines, in addition to other requirements. Subpart O was promulgated in 2003 and requires operators of gas transmission pipeline segments within high consequence areas to develop and implement integrity management plans for those segments.[1] Subpart M contains prescriptive maintenance requirements that are generally applicable to gas transmission and distribution pipelines. In 2019, Subpart M was amended to include requirements for integrity assessment of gas transmission pipelines outside high consequence areas. Consequently, § 192.710 (Subpart M) and § 192.921 and § 192.937 (both in Subpart O) now identify integrity assessment methods for initial assessment and periodic reassessment for gas transmission pipelines. These methods are as follows: pressure testing, internal inspection tools, direct examination, guided wave ultrasonic testing (GWUT), and DA. Presently, other than DA, the integrity assessment methods implemented for transmission pipelines have limited or no applicability for distribution pipelines because of differences in system design. These differences include the following:

- Distribution pipelines are constructed from smaller diameter pipes. Based on 2021 data reported to PHMSA [2] and as illustrated in Figure 3, 84% of gas distribution mains and 98% of service lines are 4 inches or less in diameter.
- In contrast, 73% of transmission pipelines are more than 12 inches in diameter, making them amenable to a multitude of inspection tools with high detection and characterization capabilities. These large diameter pipelines are made from steel to accomodate high pressures, normally exceeding 30% of the specified minimum yield strength to accommodate in line inspection tools.
- Distribution pipelines are predominantly plastic. Based on 2021 data reported to PHMSA [2] and as illustrated in Figure 2, mains and service lines are 60.1% and 75.2% plastic, respectively.
- Distribution pipelines are more complex than transmission lines because of the number of branches, taps, and valves used to establish the network of various pipe diameters and different pressure systems required to provide gas service to an area.
- Distribution pipelines have significantly higher mileage compared to transmission pipelines. Based on 2021 data reported to PHMSA [2], there were nearly 71 million service lines and approximately 1.34 million miles of mains in operation. Assuming that each service line is served from a distribution main, on average, there are 53 service lines per mile of main, which adds to the variability in product flow rates and flow direction. Depending on what portion of the system is being assessed, the test pressure and the test medium used can cause significant service outage to customers.
- Distribution systems have lower operating pressures and operate at hoop stresses that are less than 20% of the specified minimum yield strength. This results in low probabilities of integrity threats driven by hoop stress in the pipe, such as cracking (i.e., stress corrosion cracking). This also means that failure of a distribution pipeline will result in a leak and possibly

[1] See 49 CFR §192.903 for the definition of a high consequence area.

never a rupture. Although leak vs. rupture is advantageous in high-pressure transmission pipelines, which are often located in remote areas, the lower pressure of distribution pipelines can result in leaks being undetectable without specialized equipment. Odorization of the gas can reduce the likelihood that a leak goes undetected, but cannot completely eliminate this possibility. Since these pipelines are in more densely populated areas often buried beneath pavement and intermingled with other utilities, undetected leaks can result in gas migration into structures, including buildings, and have resulted in many gas incidents.

The following section reviews the effect of these differences on the feasibility of using existing assessment methods on distribution pipelines.

4.1 PRESSURE TESTING

Pressure testing is performed when installing new lines into the gas distribution system, as required by 49 CFR 192, Subpart J. Furthermore, pressure testing is used as a tool for assessing the integrity of transmission pipelines. Transmission lines are linear with no branching, so they can more easily be pressure tested. During a pressure test, the gas must be displaced by water and then dried following the test. For transmission pipelines, this integrity assessment method is feasible, unlike for distribution pipelines.

This integrity assessment method is not feasible for distribution pipelines because of the following:

- The high degree of branching will require many valves or stops to isolate the pipe test section.
- Significant service outage can result depending on which portion of the system is being tested (mains or services).
- Introducing and then removing test water in complex networks is difficult or impractical.
- Pressure testing is often meant for crack-like defects that are not a common threat to distribution pipelines.

4.2 INTERNAL INSPECTION TOOLS (ILI)

ILI tools are used in the gas transmission industry for identification and characterization of defects along the pipeline. Significant technological advances have occurred over the past 40 to 50 years in ILI technologies that enable effective integrity assessment of transmission pipelines. However, several factors such as the branching, low flow, lack of sensors for plastic and cast iron, and inability for ILI tools to enter and exit the distribution pipelines make integrity assessment by this method a challenge.

It should be noted that the industry has developed and adapted sensors used in for robots and crawlers that enable inspection of some of the distribution pipelines. This topic is further discussed in Section 5.1.

4.3 DIRECT ASSESSMENT (DA)

The third integrity assessment method is DA. DA is a four-step structured process for assessing the integrity of a pipeline. The steps include a preassessment, the selection and implementation of indirect aboveground technologies, data review (pipeline data, confirmation digs) and post-assessment evaluation data). The most common DA methods are external corrosion DA, internal corrosion DA, and stress corrosion cracking DA. Technologies that are part of a DA include GWUT, potential measurement (e.g., CP, close interval survey), and pipeline current mapping. These technologies are further discussed in Appendix A.

DA is an accepted assessment method for distribution pipelines, and the applicability of other technologies is qualitatively compared with DA in this report.

5. INTEGRITY ASSESSMENT METHODS AND TECHNOLOGIES FOR DISTRIBUTION PIPELINES

Distribution pipeline operators use different tools to anticipate, mitigate and manage integrity threats.

While the current technologies for assessment of distribution pipelines are limited; they include the following:

- Technologies listed in Appendix A are applied to steel pipelines and primarily enable identification of corrosion defects and anomalies. Furthermore, they enable mitigation by using improved CP, identifying stray currents, and ensuring connected pipes are appropriately insulated. Currently, DA is the primary tool for integrity assessment on distribution pipeline systems.

Methods and tools are also available to proactively mitigate threats to pipeline integrity and consequences of a loss of pipeline integrity. Those methods include the following:

- Preventative/proactive technologies (Appendix B): These technologies include many proactive measures to prevent, monitor, or manage many of the threats to distribution pipelines.
- Advanced leak detection (Appendix C): Following a failure, distribution pipelines may leak very small amounts of gas, and leak detection followed by mitigation is very effective. Progress in this technology provides one of the most effective means of ensuring distribution pipeline integrity.
- Cast iron repair and replacement (Appendix D). As noted approximately 1% of the total distribution pipeline miles are cast iron, and operators continue to replace them. Repair and replacement remain the most effective integrity assessment methods for cast iron.

As part of this study, the subcontractor performed a detailed literature review, conducted interviews, and discussions with ILI vendors and gas distribution operators. As a result, the inspection technology enabled by robots and crawlers, presents a possible alternative to DA.

As noted earlier, the intent of this report is to present integrity assessment methods that provide the same levels of safety as DA and those are described in the following subsections.

5.1 ILI USING ROBOTICS AND CRAWLERS

ILI tools have been used since the 1960s. They are equipped with a nondestructive evaluation sensor to detect various defects and anomalies. The tools are typically autonomous and propelled by the product in the pipeline as the tool inspects from inside the pipe. The first standards document related to ILI were published by the European Pipeline Operators Forum in 1998, *Specifications and Requirements for Intelligent Pig Inspection of Pipelines*, and the National Association of Corrosion Engineers in 2000, SOTA 35100, *In-Line Nondestructive Inspection of Pipelines* [14]. ILI tools have become more advanced with new sensors, better-designed platforms, improved accuracy and detection capabilities, and optimized data collection and interpretation.

Section 4 outlined the challenges of using ILI tools in gas distribution systems. Accessibility (launchers/receivers), diameter, pipe material, clearance (e.g., bends, tees, wall thickness changes), flow rates, and pressure are all challenges faced by distribution systems that limit the use of ILI as an integrity assessment method.

For distribution systems, conventional ILI tools are not an option. However, the sensors have been adapted for use with a crawler or a robotic platform. Some of these ILI tools are also tethered such that they can move down a pipeline and then be retrieved.

New ILI technology [15] has led to tools designed to navigate the complex paths of natural gas pipelines. These tools can operate in limited- or no-flow conditions. They can navigate through valves and unbarred tees, short-radius or mitered bends, back-to-back bends, cased pipelines, and pipelines without prebuilt tool launchers and receivers. Over time, the sensor electronics have become smaller, enabling tools for smaller diameter pipelines. These tools are classified as “unpiggable pipeline tools” and their applicability may be limited for distribution systems.

Crawlers/robots [16] [17] are a new commercial approach to inspecting pipelines and are typically self-propelled tools with various platform designs. The improvements to the platform and modifications to how the crawler or robot moves through the system have expanded the distribution pipeline systems that can be inspected. Crawlers and robots have the same functional goals as conventional ILI and often carry some of the same sensors and are primarily designed for distribution pipeline systems. Usually, crawlers and robotic systems require the pipelines to be shut down. However, at least one commercial system is operating on live distribution systems [16]. Depending on the complexity of their individual systems, operators use these tools to evaluate pipeline system integrity.

The choice of sensor is highly dependent on the pipeline material and the target defects. One challenge for sensor technology is that most sensors are designed for steel pipelines and cannot be used for nonmetallic (plastic) pipes or cast iron. No sensor packages appear to be specifically designed for plastic pipes. Visual inspection and geometric tools are available for plastic pipe inspections because the pipe size can accommodate the sensors. Another challenge with plastic pipelines is the risk of the tool scratching or damaging the pipe. Current efforts are to design crawlers and robots that are safe to traverse plastic pipes.

5.1.1 Sensor Types

5.1.1.1 Visual

A visual inspection is a standard method for inspecting pipelines constructed from any material (steel, plastic, or cast iron). A camera mounted to a crawler is carried through the pipeline, allowing the operator to inspect the pipeline internally. In some cases, the camera is mounted to the end of a cable fed through the pipeline. These inspections are typically called *closed-circuit television crawlers*. Recent research through NYSEARCH has led to the development of small- and large-diameter pipe crawlers that can inspect live gas lines. The crawlers, equipped with high-resolution cameras, enter the line through taps and can traverse a fixed distance from the entry point. [18] [19].

Additional advancements in the visual inspection of gas distribution lines include using artificial intelligence to identify damage during visual inspection runs. A PHMSA-funded project with Michigan State University is focused on an AI-enabled robotic platform with a structured light-based NDE inspection tool for the scanning of medium density polyethylene (MDPE) pipes used in natural gas distribution. The structured light is an optical sensor that can scan the pipe surface to measure the 3D shape of a defect and the AI-enabled shared control method combines autonomous decision support and high-level human commands to improve the safety and usability of robot control. The research into the nondestructive technologies and artificial intelligence has potential applications for the pipeline industry. The method is under development and is not commercially available. Continued research may lead to better detection and evaluation techniques using camera systems or other nondestructive techniques.

Cameras provide valuable data to engineers and operators and are essential sensors for crawlers and robot platforms. The use of cameras for visual inspections is feasible for all materials and pipe sizes, and cameras are in commercial use in various forms.

Alone, visual inspection does not provide increased safety compared with DA, because visual inspection is limited to identifying threats and does not provide data for assessment. For example, a visual inspection may identify internal corrosion or dents, but it cannot measure the size and depths of either. Furthermore, visual inspection will not provide insight into external corrosion; however, it can address some of the threats to distribution pipelines.

5.1.1.2 Caliper/Geometry

Geometry tools measure deviations in the internal surface from the ideal circular shape. The caliper tool is the most common deformation tool and uses many mechanical arms equally spaced around the tool to measure diameter changes. The design of the arms varies depending on the tool design; some options include wheels at the ends and arms mounted underneath the cup. The number of arms defines the resolution and sensitivity of the tool. Caliper tools are more common to conventional ILI platforms than robots and crawlers. Robots have been equipped with laser profilometry sensors capable of high-precision mapping and characterization of ID anomalies [16] [17]. Geometry tools can identify dents, ovalities, wrinkles, buckles, installations, ID changes, and girth welds. A current PHMSA project is prototyping and evaluating the use of multiple sensors for robotic platform integration, including a laser metrology scanner to identify and measure dents. [20]

Geometry tools such as caliper and laser profilometry are feasible for all pipe materials and sizes appropriate for the carrier platform. These tools can identify and measure all the features present and provide data for assessment, making them more effective than DA.

5.1.1.3 Magnetic Flux Leakage

Magnetic flux leakage (MFL) was first commercially used to inspect pipelines in 1964 and is the most used ILI method today. The basic principle of MFL tools is that a powerful permanent magnet is used to magnetize the steel pipe. Typically, the induced magnetic flux will remain within the pipe wall. However, in the presence of a metal loss defect, such as corrosion, the flux will leak from the pipe wall. MFL sensors based on the hall effect are placed between the permanent magnet poles to measure the amount of leakage caused by the defects. The hall effect is the production of a voltage difference across a conductor that is transverse to an electric current in the conductor and an applied magnetic field perpendicular to the current. MFL technology is available for distribution pipeline system applications through crawlers and robots. However, many of the operational challenges of distribution pipeline systems of branches, tees, valves, and other fittings might often make the use of crawlers and robots impractical.

MFL sensors can detect metal loss anomalies such as general corrosion, pitting corrosion, spiral weld metal loss, girth weld metal loss, circumferential cracks, and girth weld cracks. The sensors are commonly used for conventional ILI and have been mounted on crawlers and robots.

Like geometry tools, MFL sensors are feasible for metals and pipe sizes appropriate for the carrier platform. These tools can identify and measure all the features present and provide data for assessment, making them more effective than DA.

5.1.1.4 Electro Magnetic Acoustic Sensor (EMAT)

An EMAT is a noncontact method for generating acoustic waves within a conductive material. Like ultrasonic testing (UT) sensors, EMAT sensors create a pulse that travels through the pipe wall thickness. The methods are different in how the pulses are generated. An EMAT sensor induces eddy currents at the surface of the pipe wall using a coil and an alternating current (AC). A strong permanent magnet is positioned so the magnetic field is perpendicular to the pipe surface. The combination of the magnetic and electric forces creates a Lorentz force that changes with time according to the AC. The periodic movement of the Lorentz force generates acoustic waves that travel through the pipe wall.

In the presence of a defect, the waves are reflected earlier, generating a signal that the analyst can interpret. The concept is similar to the pulse-echo method used by UT sensors. The most apparent advantage of EMAT sensors is that they do not require a couplant, a material (usually liquid) that facilitates the transmission of ultrasonic energy from the transducer into the test specimen, which allows EMAT to be used in gas pipelines, whereas UT sensors are more suited for oil and liquid pipelines. EMAT-mounted crawlers and robotic tools are commercially available.

Like geometry tools and MFL sensors, EMAT sensors are feasible for metals and pipe sizes appropriate for the carrier platform. These tools can identify and measure coating defects and intended features and provide data for assessment, making them more effective than DA.

5.1.1.5 NDE Sensors for Small Diameter Plastic Pipe

A recent PHMSA project conducted through NYSEARCH [21], investigated the feasibility of various NDE sensor technologies for robotic systems on small diameter plastic pipe. The scope of the work was defined based on input from the natural gas industry personnel on the project team. The team investigated many variables including parameters such as pipe material, pipe diameter, operating pressure, and the robot's range. The team concluded that the research should include HDPE and MDPE for pipe diameters 2 inches and larger.

The research team investigated many NDE sensor types including radiography, eddy current, magnetic particle, EMAT, shearography, thermography, ultrasound, microwave imaging, and terahertz imaging. As discussed in previous sections, several of the sensors (eddy current, EMAT, and magnetic particle) only work on ferrous materials and are not applicable to plastics. Other technologies (radiography, shearography, and thermography) work on plastics but are not feasible in small diameter pipe. Therefore, the project team investigated three feasible NDE techniques for use on small diameter plastic pipe: terahertz imaging, microwave imaging, and ultrasonic inspection.

Terahertz imaging (THz) uses electromagnetic energy radiated in the frequency range from 50 GHz to 10 THz, which allow it to penetrate non-conducting materials such as ceramics, glass, and plastics. The NYSEARCH-funded project showed that THz can detect and size indications of 0.5 mm diameter or smaller embedded in the pipe wall. The project also found that miniaturization of THz sensors is possible and could work inside of pipe of 4-6 inches.

Microwave imaging use electromagnetic signals in the frequency range of 300 MHz to 300 GHz, corresponding to a wavelength range of 1000 mm to 1 mm. Microwave signals can penetrate dielectric materials such as HDPE and can detect various defects including delamination, gauges, and the presence of foreign materials. A disadvantage of microwave imaging is that it struggles to discriminate objects attached to the outer surface. The research team concluded that microwave imaging is a viable option for plastic pipe and that current technology could be reduced to fit in pipes as small as 4 inches.

Ultrasonic testing (UT) is a common technique used by ILI tools for liquid lines. UT is not typically used in gas pipelines due to the need for a couplant such as water. Three types of UT were investigated as part of the NYSEARCH research: air-coupled ultrasound, captured water ultrasound, and dry-coupled probe ultrasound. The research team determined that the dry-coupled probe was the best approach for conducting UT in a gas pipeline.

The feasibility study conducted as part of the Phase 1 work showed that sensors exist for inspecting plastic pipes and that they can be miniaturized to fit in pipes as small as 4 inches. These NDE sensors are not currently commercially available on robotic platforms. Additional work is required to develop and deploy the NDE technologies for the inspection of plastic pipelines.

6. CONCLUSION

The analysis presented in this report found that robots and crawlers are the most promising integrity assessment technology to provide a level of safety equal to or greater than DA in gas distribution systems. Robots and crawlers can navigate the complexities of distribution networks, thus overcoming the challenges of multiple branches, changing diameters, and low to no flow. The feasibility of this technology is limited by the capabilities of the platform and sensors. The current platforms cannot navigate all pipelines due to number branches, diameter changes, or other fittings that may obstruct movement; consequently, they require a review by the inspection vendor to confirm feasibility.

The platform determines whether a robot or crawler can move through a gas distribution system, and the sensors determine what the robot or crawler can detect. The sensor technologies used by robots and crawlers include cameras, caliper, geometry tools, MFL sensors, and EMAT sensors. Table 2 lists sensors and their feasibility based on the material. In all cases, the feasibility depends on whether the robot or crawler can navigate the pipeline, given the diameters, material, pressure, and degree of branching.

Table 2 indicates that visual inspection of pipelines is feasible for most pipelines regardless of material. Small robots can inspect pipelines with diameters as small as 2 inches. However, visual inspection alone does not provide a level of safety equal to or greater than DA. Cameras can detect internal features only but cannot characterize them quantitatively. Sensors such as MFL and EMAT, are designed for steel pipelines and cannot be applied to cast iron and plastic pipelines. Similarly, there are sensors specific to plastic pipe that have been developed and are feasible such as Terahertz and microwave imaging, and dry coupled UT probes.

The two primary challenges for ILI, robots, and crawlers are sensor capabilities and pipeline size limitations. Distribution systems consist of many miles of small diameter pipe that traditional ILI and robotic platforms cannot traverse. Additionally, many sensors are designed for detecting defects in steel, whereas many distribution pipe systems are plastic.

Research and development effort in ILI and robotic platforms for small diameter pipe could expand the miles of distribution pipe that can be inspected. Recent research [21] identified and tested NDE techniques for detecting flaws in plastic pipe. Additional research to further miniaturize and assess smaller pipe diameters, more specifically plastic pipelines would significantly benefit integrity assessment of gas distribution systems.

Table 2. Robotic and crawler technologies and feasibility

Material	Sensor type	Technically feasible*	Level of safety
Cast iron	Visual	Yes	Less than DA
	Caliper/geometry	Yes	Greater than or equal to DA
	MFL	No	—
	EMAT	No	—
Steel	Visual	Yes	Less than DA
	Caliper/geometry	Yes	Greater than or equal to DA
	MFL	Yes	Greater than or equal to DA
	EMAT	Yes	Greater than or equal to DA
Plastic	Visual	Yes	Less than DA
	Caliper/geometry	Yes	Greater than or equal to DA
	MFL	No	—
	EMAT	No	—
	Terahertz Imaging	Yes	Greater than or equal to DA
	Microwave Imaging	Yes	Greater than or equal to DA
	Dry-Coupled Probe UT	Yes	Greater than or equal to DA

*Technology may still be limited based on the capabilities of the carrier platform and the design of the gas distribution pipelines (e.g., size, flow, degree of branching). Some are commercial and some still require further development.

7. ABBREVIATIONS

Term	Definition
AC	alternating current
CGI	combustible gas indicator
CP	cathodic protection
CRDS	cavity ring-down spectroscopy
DA	direct assessment
DFOS	distributed fiber optic sensing
EMAT	electromagnetic acoustic transducer
FID	flame ionization detector
FTIR	Fourier transform infrared
GIS	geographic information system
GPR	ground-penetrating radar
GTI	Gas Technology Institute
GWUT	guided wave ultrasonic testing
HDD	horizontal directional drilling
ICOS	integrated cavity output spectroscopy
ILI	in-line inspection
IM	integrity management
IRT	infrared thermography
MFL	magnetic flux leakage
MMM	metal magnetic memory
OGI	optical gas imager
ORFEUS	Optimized Radar to Find Every Utility
PE	polyethylene
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020
RMLD	Remote Methane Leak Detector
TDLAS	tunable diode laser absorption spectroscopy
UT	ultrasonic testing
WMS	wavelength modulation spectroscopy

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APPENDIX A. Existing DA Methods and Technologies

The DA methods and technologies discussed in this appendix can be used for integrity assessment and to increase the safety of distribution pipelines.

GWUT

GWUT is a nondestructive evaluation method that employs acoustic waves propagating along the pipeline being guided by its boundaries; the waves can travel long distances with little loss in energy. GWUT is also commonly known as *guided wave testing*, *ultrasonic guided waves*, and *long-range UT*. GWUT is used worldwide to inspect and screen pipelines and uses lower ultrasonic frequencies than conventional UT, typically between 10–100 kHz.

All conventional inspection methods (e.g., ultrasonic thickness gauging, eddy current, digit radiography, alternating current field measurement) inspect a component's volume under the search device's footprint. Contrary to conventional ultrasonics, GWUT uses a ring of piezoelectric or EMAT transducers clamped around the pipe to transmit a symmetrical circular wave. The sound waves travel in each direction down the pipe. When the waves encounter a cross-sectional change (e.g., corrosion, damage), part of the wave is reflected. The reflected waves are analyzed to determine defect locations and severity and separate them from standard features.

GWUT transducers generate a dead, near, and far zone. The dead zone exists beneath the transducer and is an area where defects cannot be identified. The near zone is an area ahead of the transducer where the signal amplitude varies spuriously, mainly with high and low amplitudes. The far zone is where the signal has attenuated to a point where damage detection is effective.

Advantages of GWUT include the following:

- High-productivity inspection with long-range coverage and rapid screening
- 100% screening coverage of pipe wall, 360° around the pipe circumference
- Ability to scan pipes with limited access, such as coated, insulated, buried, road-crossing, and through-wall pipes
- Cost reduction for excavation, scaffolding, and insulation removal
- Cost-effective solution for pipe integrity assessment programs
- In-service inspection (no production shutdown)

A major drawback of GWUT is that it can only be used as a screening tool because it cannot accurately determine the corrosion profile (e.g., depth, length). Conventional nondestructive testing techniques are required to size defects accurately, which is needed to assess the carrying capacity of a pipeline.

Remote Magnetic Monitoring

Remote magnetic monitoring is a category of nondestructive evaluation that detects corrosion and metallurgical defects in the pipe wall from above the ground without removing the soil cover. Technologies in the remote magnetic monitoring category of pipeline nondestructive evaluation are based on the principles of the metal magnetic memory (MMM) technique developed in 1997.

MMM is a nondestructive testing method that detects stress concentration regions for ferromagnetic materials. Researchers in the early 1980s first observed stress-induced magnetic fields on defective areas of boiler pipes in a power station. In 1994, A. A. Doubov introduced the “magnetic memory of metal” concept, which led to the development of the MMM technique.

MMM is based on inverse magnetostriction, which is the change in magnetic properties of the material when subjected to mechanical stress. James Joule first established magnetostriction in 1842 using an iron bar and mechanical levers to show that a bar expands in the direction of applied magnetization. In 1865, Emilio Villari showed that tensile stress on a steel bar would alter the magnetic field around the bar, known as *inverse magnetostriction* or *the Villari effect*. This early research showed that the magnetic field surrounding a structure such as a pipeline is affected by the stress state of the material and that stress concentration zones create signals different from the nondamaged pipe [22].

Significant research has been conducted since the invention of the MMM technique. It has led to the development of new and improved technologies, and in particular large standoff magnetometry (LSM). This and similar technologies identify stress concentration zones by measuring the self-MFL signals of ferromagnetic materials generated under the influence of operational or residual stresses. The primary advantage of large standoff magnetometry is that most pipeline threats occur in areas of high stress, such as corrosion, cracking, and mechanical damage, which makes the method ideal for pipeline surveys. However, the technology cannot provide accurate sizing data and is sensitive to interference from other buried metallic cables or structures. The influence of metallic cables and structures limits their use for gas distribution pipelines, which are often in urban settings. This technology provides valuable data to the operator that can be implemented in DA.

Potential Measurement and Pipeline Current Mapping

CP

CP is an electrochemical means of corrosion control for steel and cast iron pipelines. Two types of CP systems are used in distribution systems.

Galvanic Anode CP

In galvanic anode CP, the material’s corrosion current is the steel pipeline’s CP current. The current flows through the electrolyte onto the steel, controlling its corrosion. The current returns to the anode in the metallic circuit. The anode materials are alloys of either zinc, aluminum, or magnesium. Onshore, short pipelines are often protected using magnesium anodes. The anodes are connected to the pipe either individually or in a group. Galvanic anodes are limited in current output by the anode-to-pipe driving voltage and the electrolyte resistivity.

Impressed Current Anode Protection

Impressed current CP is provided by connecting a direct current source (e.g., rectifier, generator, or solar panels and batteries) between the pipeline being protected and the CP anodes. In contrast to galvanic anode CP, in this system, the CP current is supplied by the direct current power source and not by corrosion of the anode itself.

Impressed current anodes can be materials such as graphite, high-silicon cast iron, lead-silver alloy, precious metal, and steel. They are connected with an insulated cable either individually or in groups (groundbed) to the positive terminal of a direct current source. The pipeline is connected to the negative terminal of the direct current source.

Criteria for CP Performance

External corrosion control can be achieved at various levels of cathodic polarization depending on the environmental conditions. However, in the absence of specific data that demonstrate that adequate CP has been achieved, one or more of the three primary criteria for CP of underground or submerged steel or cast iron pipelines listed in Section 6 of the National Association of Corrosion Engineers Standard RP0169 can be applied:

A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half-cell. Determination of this voltage must be made with the protective current applied.

A minimum negative (cathodic) polarization voltage shift of 100 millivolts.

Of these primary criteria, the first is likely the most widely used for determining whether a buried or submerged steel or cast iron structure has attained an acceptable level of CP.

Measurement of CP system performance is critical. The voltage drops through the soil must be neglected to assess the CP performance; consequently, the CP is interrupted for the impressed current systems. The instantaneous measurement does not have an IR drop and can be used for monitoring purposes. However, for an anode bed system, a certain amount of IR drop voltage (possibly 200 mV) should be added to assess the system.

AC Current Attenuation Survey

AC current attenuation surveys are typically used to assess coating quality and to detect and compare discrete coating anomalies. The coating condition is assessed by measuring the current attenuation of an applied AC signal. If a coating has a uniform dielectric strength and electrically isolates the pipeline from the surrounding ground at all points, then the strength of the signal produced from the injected current will attenuate logarithmically.

The attenuation rate depends on the coating's conductance in contact with the ground per unit area of the pipe and the frequency of the applied AC signal. If there are any coating holidays, the current will attenuate rapidly. The strength of the AC signal remaining on the pipeline is determined at discrete points along the pipeline, and standard mathematical formulas are used to calculate the rate of attenuation for each surveyed section.

Also, this survey is typically used to locate electrical shorts in distribution networks. By tracing current flow and magnitude, unintended shorts or contacts between pipelines and other metallic structures can be found.

AC current attenuation surveying is performed using equipment such as the Pipeline Current Mapper. The survey equipment comprises a transmitter/signal generator and a detector/receiver unit. The transmitter is a signal generator conductively attached to the pipeline under survey and a suitable remote ground. The transmitter injects AC into the pipeline, generating an electromagnetic field with a signal strength proportional to the applied current to the coated pipeline.

A receiver measures the radiated electromagnetic field's strength around the pipeline. Depending on this strength, the current flowing through the pipeline is measured, and the current attenuation of the coated pipeline section is calculated.

APPENDIX B. Preventative Methods and Technologies

This appendix summarizes preventative methods that are utilized for ensuring the safety of distribution pipeline systems. These methods proactively prevent events that could compromise the integrity of the pipelines. They are not integrity assessment methods, but they complement the integrity assessment methods in proactively preventing integrity incidents.

Technologies and Methods to Prevent Excavation Damage

Excavation damage accounted for 33.2% of all reportable incidents and 22.1% of all serious incidents in the United States in 2021 [23], thus representing the highest cause category for reportable incidents and the second highest cause category for serious incidents (behind other outside force damage). The challenge to operators is that most damage occurs because of third-party excavation or parties not directly controlled by the operators.

Construction companies and the public must be educated about excavation risks, and a simple method must be developed for disseminating information about buried gas pipelines to excavation projects. This need led to the adoption of the national *8-1-1* number.

When operators receive a notification of a new dig, they first must determine whether the project is near a gas facility or buried pipeline. Up-to-date maps or geographic information systems (GISs) are needed to ensure that the locations of buried pipelines are known. If the excavation work is close to a gas pipeline, operators will send crews to the site to physically locate and mark the pipeline. Locating a buried line can be challenging, especially for distribution lines. Gas distribution pipelines are often in urban settings with many sources of interference (e.g., other utility cables, conduits, sewage lines).

Developments continue in improving pipeline location technologies and right-of-way encroachment surveys; some development has occurred in locating plastic pipes, expediting right-of-way encroachment surveys, and designing new technologies to monitor excavation equipment.

One-Call System and Education

In 2005, the FCC made *8-1-1* the national “call before you dig” number. Before 2005, one-call programs existed for most states; however, the numbers were different across states. Simplifying the method by having one number was an attempt by many stakeholders to reduce the number of incidents involving excavation damage.

This integrity approach remains one of the first lines of defense against injuries and fatalities involving excavation projects. Education programs sponsored by operators and government agencies have aimed to notify the public about the risks of buried gas pipelines and the proper steps that should be taken to avoid disasters. For example, PHMSA introduced 811 Day to publicize the importance of calling *8-1-1* before any excavation project. According to PHMSA, research reveals that calling *8-1-1* before digging provides a 99% chance of avoiding an incident, injury, environmental harm, and even death [24].

Distribution operators identified internal programs designed to identify nonreported excavations near pipelines actively. Furthermore, operators have sent personnel to construction companies to provide training and education about safe digging practices.

Pipeline Location Technologies

The most common method for locating natural gas utilities relies on the electromagnetic properties of the materials. The locating equipment sends an electromagnetic radio frequency into the ground and reads the resulting signal from conductive materials in the subgrade utilities. This method is commonly used to detect gas, electric, telephone, cable, propane, water, sewer, storm, and irrigation lines.

Traditional pipeline location technologies operate using active or passive methods. These methods rely on the electromagnetic behavior of the metals typically used for most utility lines. However, most gas distribution mains and services are constructed from plastic (most have tracer wires for location), which is nonmetallic and consequently nonmagnetic. New technologies have emerged to detect both metallic and nonmetallic (plastic) utility lines, including natural gas mains and services.

Location technologies include the following:

- Geomagnetic surveying
- Electromagnetic induction
- Electrical resistivity
- Tracer wires
- Infrared thermography (IRT)
- Ground-penetrating radar (GPR)
- Detectable markers

Most of these technologies have been well developed, especially for metals. However, the current advancements in pipeline locating technologies are in nonmetallic pipeline detection, such as IRT and GPR.

Geomagnetic Surveying

The Earth's magnetic field extends from the North and South Poles and surrounds the planet, creating a pattern like a standard magnet. The magnetic field interacts with items on the surface. When the magnetic field interacts with a conductive object, a new magnetic field is formed that extends from the object. Magnetometers can measure changes in the magnetic field surrounding the sensors. Typically, two sensors are placed a set distance apart. The strength of the magnetic field is measured at each sensor and compared to determine the field gradient. The two sensors will not indicate a difference in the Earth's magnetic field, but a buried conductive object will create a field gradient, causing the sensor to send an alarm to the user.

Many types of magnetometers are on the market, and magnetometers are a standard tool for locating conductive gas pipelines (steel lines). This technology, though widely used, cannot identify plastic or other nonconductive pipelines.

Electromagnetic Induction

Electromagnetic induction, or electromagnetic induction spectroscopy, works on the principle that an electrically conductive or magnetically permeable object exposed to a low-frequency electromagnetic field produces a secondary electromagnetic field. The system includes a receiver and transmitter. The receiver is held by the technician and used to read the secondary electromagnetic field from the buried pipeline. The secondary field can be generated by a few methods. The preferred method is the direct connection method, where leads from the transmitter are attached to an exposed part of the pipe and a stake in the ground. The transmitter propagates a signal along the pipe that the receiver can detect on the surface.

If a direct connection cannot be made, a ring is attached to the pipe that induces a current. This option is not preferred but will work if the direct current is not feasible. Finally, the transmitter can propagate an electromagnetic field through the soil to generate the secondary field. This method is the least preferred but may be necessary when surveying an area where the pipe's location is entirely unknown.

Another method is to use a sonde, which is a line-locating transmitter that generates a signal as it is pushed through a line. A receiver can track the sonde as it moves through the pipe, allowing the technician to mark the pipe's location. This method requires access inside the pipeline and cannot be used when the line is in service. This option is not used very often.

High-Density Resistivity Method

The high-density resistivity method is a geophysical method based on the electrical difference between the buried target and surrounding media, also known as *electrical resistivity tomography*. This technique is often used for geophysical surveys to locate transitions in soil types and to locate underground water. This method measures the potential difference at specific locations while injecting current at other locations.

The apparent resistivity of the soil is determined and used to identify buried objects. This technique requires careful placement of the electrodes and depends on the soil conditions of the site. An array of depths is measured according to the spacing of the electrodes. Spacing is important because it controls the depth of penetration and resolution. Some disadvantages of the technology are its susceptibility to interference and location accuracy, especially for smaller diameter pipelines.

Tracer Wires

The technologies discussed so far require conductive materials for proper detection, which excludes plastic pipes. Tracer wires are conductive wires buried with utilities to enable operators to locate the lines later. The wires are typically accessible at the surface, so a signal can be sent along the wire and detected at the surface using a handheld receiver. The challenge with tracer wires is that they corrode or break over time. This issue makes tracer wires unreliable, especially for old pipes. In addition, the accuracy of the location is based upon the proper installation of the tracer wire over the pipe and at the connection points.

Infrared Thermography (IRT)

Different materials have different thermal characteristics that affect the rate of energy flow through and from the material. IRT uses an infrared sensor/camera (see Section 0) to measure the variations in thermal energy around an object, which is converted into a thermographic image. This technique applies to pipelines carrying hot media such as petroleum or steam because a temperature differential is needed at the soil surface to identify the pipe [25]. However, this technology's use for gas distribution lines is unlikely.

Ground Penetrating Radar (GPR)

GPR has been used for countless applications. The technology works by sending a radar pulse into the ground. The pulse propagates through the medium and is reflected by buried objects or other boundaries with different electromagnetic properties. The reflected signal is received by an antenna and recorded. GPR works with many materials, including plastics; can pinpoint the object's depth; and has good resolution.

GPR is often used concurrently with other techniques and is ideal for situations with nonmetallic utilities, broken tracer wire, underground storage tanks, concrete storm and sewer systems, and nonutility structures. GPR is sensitive to the soil conditions at the site location. The system can be used over asphalts or pavements to identify underlying utilities, and new technological advances have included GPR systems mounted on drones [26]. Current research efforts [27] attempt to improve GPR technology, specifically for identifying nonmetallic pipes. This technology is currently used for distribution systems and will continue advancing as research improves its accuracy and expands its capabilities.

Detectable Marker System for PE Pipe

Research has been conducted to design and implement tracking tags for plastic pipes. One area of research involves RFID tags. These tags utilize radio frequency technology to communicate information to a receiver. The tags can be active (battery) or passive. Passive tags use energy transmitted by the receiver to power the tag and are considered for PE pipe installations. The current research is in the development phase [28]. The challenge with RFID tags is that they require different readers because the technology is not unified; their durability in buried conditions is another concern. The research aims to create a single receiver unit that can reliably locate all RFID tag types.

NYSEARCH [29] has investigated using a resonant magneto-mechanical electronic marking system for plastic gas pipes. The research team has completed the development and concept testing phase with much success. The markers are protected by a low-profile housing fused to the outside surface of the pipe. The marker/housing design is rugged enough to handle the installation rigors.

Marker technologies for buried pipe are primarily in the early stages of development but can potentially reduce the efforts required to locate PE pipe.

3D Mapping Tool for PE Pipe

A recent project with the Gas Technology Institute (GTI) [30] introduced technology for mapping PE pipes. The work combined knowledge from gas operations, GIS technology, 3D inertial measurement unit–based mapping probes, and cable pushers to develop a system for inserting and propelling a mapping probe into a live gas pipe to collect accurate 3D data. The technology is intended to prevent third-party excavation and cross-bore damage. Cross-bores occur when a gas line is installed through another utility (typically a sewage line) using trenchless or HDD techniques. The output is a 3D map of the pipe, which includes the depth—a limitation with most technologies. This technology is applicable to distribution lines and has potential to improve the locating of PE pipes. The advantage for the distribution system is that the mapping tool can be used in lines as small as 2 inches and used while the pipe is in service.

Encroachment Surveys

Encroachment surveys are a common method for distribution operators to monitor unauthorized excavation operations near their pipelines, often in conjunction with leak surveys. Most of the research in this area is on aerial platforms that can quickly and safely survey the operators' right-of-way. Additionally, sensor technology, in conjunction with artificial intelligence or machine learning algorithms, is being used to help automate the detection of pipeline encroachment [31].

Airborne synthetic aperture radar is one such technology that has been studied under US Department of Transportation funding [31]; it detects the presence of excavation equipment obscured from visual inspection. The Pipeline Damage Prevention Radar project leverages previous experience with the US Department of Defense and NASA; it shows significant promise but may require further research and testing to prepare for commercialization.

Excavator Monitoring Device

The California Energy Commission released a report in 2018 outlining its developmental work of a GPS excavation encroachment notification system [32]. The project intended to develop a tracking and monitoring device for excavators that could communicate with a real-time GIS-enabled database using cellular networks. The system can notify the excavator operator and other stakeholders of potential threats to buried gas pipelines based on utility geofencing on the GIS maps. Desktop and mobile apps were designed to track excavator movement and locations and enable email and mobile alerts when the system detects threats to gas pipelines.

The work was inspired by the need to reduce accidental damage to natural gas pipelines caused by digging, grading, trenching, and boring. The California Public Utilities Commission reported in 2016 that 50% of natural gas incidents in California were caused by third-party excavation damage [32]. The pilot program tested the system by sending devices to PG&E (150 units) and SoCalGas (20 units). The devices were installed on utility-owned excavators for monitoring. The pilot program results were positive and have led to the development of a commercial device that can be implemented with third-party excavators. The advantage of the technology is that it is independent of the pipeline characteristics by shifting the monitoring to the excavators, the source of the damage [32] [33]. This approach should be applicable to distribution systems but requires further investigation, mainly regarding the lack of GIS or GPS data for distribution systems.

Technologies and Methods to Prevent Cross Bores

Horizontal Directional Drilling GPR Device

Optimized Radar to Find Every Utility in the street (ORFEUS) is a novel cross-bore prevention technique developed for horizontal directional drilling (HDD). A PHMSA project is underway to advance the technology and develop a commercial application for HDD equipment. A GPR device is attached to the head of the drill string for real-time monitoring of obstructions. The system was evaluated in April 2017 at PG&E facilities in Livermore, California, using purposely built buried utility targets. The testing confirmed that ORFEUS borehead GPR could detect obstructions ahead of the drill string, such as plastic and steel pipe utilities. The technology is applicable to gas distribution lines and has the potential to significantly reduce cross-bores associated with HDD installation methods [34].

Technologies and Methods to Prevent Material Failures

Phased Array Inspection of Plastic Fused Joints

PolyTest is an inspection system designed and optimized specifically for the volumetric nondestructive testing of electrofusion and butt fusion joints in PE pipes. The system uses phased array ultrasonic probes, operating at the optimal frequencies for PE pipes of wall thicknesses between 10 and 60 mm. A modular, flexible design allows the tool to accommodate pipes with outside diameters ranging from 100 to 800 mm. Membrane water wedges permit full coverage of the weld fusion zone. Key advantages of the PolyTest system include the following [35]:

- Inspection of both electrofusion and butt fusion joints in a single system
- Ability to inspect welded joints between pipes and reducers, elbows, and tee fittings
- Critical flaw sizes and acceptance criteria determined for butt fusion and electrofusion welds in various PE pipe materials
- Proven consistent detection of particulate contamination, lack of fusion, cold fusion, and pipe underpentation in electrofusion joints

In 2013, TWI conducted inspections of 25 electrofusion and eight butt fusion welds in Milan, Italy. No fault indications were detected in most of the pipes; however, anomalies were detected in a few. Destructive testing on some of the inspected joints confirmed the flaws correlated with the ultrasonic data [36].

APPENDIX C. Detection Methods and Technologies

Accessibility is a significant challenge for distribution pipelines, which operate at very low pressures and may be buried or located under pavement. Leak detection is crucial to identifying the leak and mitigating the event that caused it.

Leak Detection Methods and Technologies

PHMSA currently defines a *leak* as an unintentional escape of gas from the pipeline (76 FR 5496, referring to Annual Report instructions), and a *hazardous leak* as a leak that represents an existing or probable hazard to persons or property (49 CFR 192.1001).[2] Leaks range in size from small to a complete separation of the gas line (i.e., a rupture). Natural gas transmission lines operate at high pressures that can result in a rupture, whereas in natural gas distribution lines, damage will often result in a leak rather than a rupture.

The challenge with leaking gas is that it might not vent to the surface at the leak location. Instead, the gas can migrate along other paths, such as sewage lines, and collect in empty spaces, such as manholes and buildings. If the methane concentration is between approximately 5% and 15% (lower and upper explosive limits) in an air mixture, the gas can ignite and explode. A commonly referenced example of this scenario is the 2008 natural gas explosion in Plum Borough, Pennsylvania, that killed one man and seriously injured a 4-year-old girl [37].

A 2 inch natural gas line was damaged with a backhoe when a master plumber was hired to install a new sewage line. The excavator stripped the pipe's protective coating and made the pipe susceptible to corrosion and failure. A circumferential crack was identified on the 2-inch line where gas had leaked through a porous backfill into the home. The gas reached an ignition source (pilot light or light switch) and exploded [38].

Gas leaks can be categorized using several criteria. Some studies have categorized leak detection systems based on human monitoring requirements (automated, semi-automated, and manual), and others have classified methods as direct or indirect. Direct methods patrol along the pipelines and detect leaks by measuring gas emanating from the pipeline.

With advancements in patrolling technology, sensors are now mounted on vehicles, drones, and aircraft to perform direct leak detection. Most of the advancements in leak detection are in the direct measurement category.

Indirect methods infer a leak by detecting parameter changes within the pipeline. Indirect leak detection often involves output from the sensor monitoring the conditions of the pipeline (flow rate, pressure, and temperature). These techniques are typically used for transmission lines.

Leak detection methods are typically classified by the nature of the measurement technology. The two main categories are (1) hardware- and software-based and (2) externally and internally based methods. Sometimes a third category is presented: biological or nontechnical methods. For completeness, all three

[2] PHMSA issued a Notice of Proposed Rulemaking (PHMSA-2021-0039) on May 18, 2023, titled: "Pipeline Safety: Gas Pipeline Leak Detection and Repair." to amend the definition as follows "*Leak or hazardous leak* means, for the purposes of all subparts of part 192 except § 192.12(d) and subparts O and P, any release of gas from a pipeline that is uncontrolled at the time of discovery and is an existing, probable, or future hazard to persons, property, or the environment, or any uncontrolled release of gas from a pipeline that is or can be discovered using equipment, sight, sound, smell, or touch."

methods are presented here. Nontechnical techniques are commonly used to detect leaks. Research is not conducted in this category and nontechnical techniques are typically used as the first indicator of a leak.

Hardware-based methods use sensors that rely on different physical phenomena to detect gas leaks. The subcategories for hardware methods are acoustical, optical, and vapor sampling [39].

The category selection is based on past works and was chosen as an intuitive means of presenting the technology developments in the detection of natural gas leaks. Other combinations of categorizing the methods are possible and equally acceptable.

The following discussion is on leak detection sensors, which are often mounted on ground or aerial vehicles; mitigation will require identifying and validating the specific leak. The advantage of vehicular-mounted sensors is the ability to cover a large region with low effort.

Nontechnical Methods

Nontechnical methods involve using the senses (smell, sight, and sound) to identify signs of a leak. The most common tool for leak detection is odor. Natural gas is inherently colorless and odorless, preventing detection by sight and smell. However, per regulation, operators must add odorants to the gas before delivering it to businesses and residents such that a person with a normal sense of smell can detect a gas leak.

Odorization of natural gas is a simple, effective method for detecting leaks. Most odorants used in the United States are mercaptans or mercaptan–sulfide blends, which contain tertiary butyl mercaptans as their main component. Humans can detect mercaptans at 1 ppb. The explosive concentration range of methane is between 5% and 15% or (50,000 and 150,000 ppm), indicating a high safety factor between detection and explosive levels.

Specially trained dogs have also been used to detect and locate small natural gas leaks. A dog's sense of smell is highly sensitive compared with that of humans, allowing them to locate small pinhole leaks, even leaks occurring underground.

Odor is not always a reliable detection method. Odor can change and even disappear when traveling through soil or sewers. Therefore, other technologies are deployed for patrols. PHMSA has identified various common nontechnical signs of a natural gas leak, including the following:

1. Odor
2. Vegetation
3. Insects (e.g., flies, roaches, spiders)
4. Fungus-like growth
5. Sound
6. Unaccounted-for gas
7. Soap solutions

Soap solutions are an effective technique for identifying a pinhole gas leak. After the leak is detected by another method, soap solutions can be implemented to pinpoint the exact leak location.

Acoustic

Constant release of natural gas from a pipeline results in sound waves emanating from the source. Acoustic sensors detect sound waves generated from a leak using acoustic sensors, microphones, accelerometers, and dynamic pressure transducers. Acoustic sensors have been around since the 1930s and have improved significantly over time. These sensors can be used in handheld devices for patrols, installed on ILI tools for detection within a pipe, or used as an area sensor for well sites and facilities. Handheld devices are the most applicable to distribution systems. Workers patrolling the lines can use handheld acoustic sensors to assist with leak detection. However, the acoustic signature of gas escaping from a low-pressure distribution line may be more difficult to detect than the high-pressure leaks associated with transmission lines.

Sensors installed on ILI tools are promising but have limited application in distribution systems because of the challenges faced by ILI. Finally, area monitors are ideal for single locations such as a facility. The sensors are spaced out according to coverage and sensitivity and will continuously monitor the site for leaks. However, distribution systems cover extensive areas and are often surrounded by ambient noises, making area sensors an expensive option for distribution operators.

There have been many advancements in acoustic sensors and the systems that implement them. Artificial neural networks have been used to assist with processing sound data to block out ambient noises and isolate leak signatures. Despite improvements, acoustic sensors have limited application for distribution pipelines.

Optical

Optical methods are often divided into active and passive categories. Active methods illuminate the target area using a radiation source, whereas passive methods rely on the background radiation of surrounding objects. Most optical methods utilize the fact that gases absorb or scatter radiation when a source travels through the gas. The received signal can then be analyzed to determine whether a leak is present and, in some cases, its concentration. GTI released a report in 2021 [40] that discussed recommended practices for leak detection. Many of the optical methods discussed there are summarized in this section. Table 3 is extracted from the GTI report and shows the various optical methods for leak detection and the applicable platforms.

Table 3. Aligning methods, platforms, and technologies [40]

External LDS Platforms	Technology Classes	Commonly Used Instrument Types
Above Ground Stationary	Ranged Laser	OPFTIR, TDLAS
	In-Plume Laser	WMS, CRDS, ICOS, TDLAS, MCS
	In-Plume Point Sensor	CNT
	Catalytic Combustion/Pellistor	Catalytic Pellistor
	Metal Oxide Senor	MOS
	Nondispersive IR	NDIR
Vehicle Mounted Sensors	Ranged Laser	TDLAS
	In-Plume Laser	WMS, CRDS, OA-ICOS
	Etalons	CIPS
	IR Imaging	OGI
Foot Patrol (Handheld) Sensors	Ranged Laser	TDLAS
	In-Plume Laser	Miniature OPLAS
	Etalons	CIPS (ex. DPIR, OMD)
	Nondispersive IR	NDIR
	Flame Ionization (FI)	FID
	Photo Ionization	PID
	Thermal Conductivity	Thermal Conductivity
	IR Imaging	OGI
	Catalytic Combustion/Pellistor	Catalytic Pellistor
Unmanned Rotary (Drone) Mounted Sensors	Ranged Laser	TDLAS, LiDAR
	In-Plume Laser	Miniature OPLAS
Manned Rotary (Helicopter) Mounted Sensors	Ranged Laser	TDLAS, DIAL
Unmanned Fixed Wing (Drone) Mounted Sensors	In-Plume Laser	TDLAS, OA-ICOS, WMS, Miniature OPLAS
Manned Fixed Wing (Drone) Mounted Sensors	Ranged Laser	DIAL
	In-Plume Laser	CRDS, OA-ICOS, WMS
	IR Imaging	Imaging Spectrometer (Hyperspectral)
Satellite	IR Imaging	Imaging Spectrometer (Hyperspectral)

Ranged Lasers

Tunable Diode Laser Absorption Spectroscopy

Many laser-based detectors use tunable diode laser absorption spectroscopy (TDLAS) for detecting methane. Tunable diode lasers utilize a laser diode and a frequency-selective element, such as a grating for laser frequency selection. TDLAS can detect methane concentrations as low as 5 ppm-m and estimate whether a gas leakage has occurred. Methane molecules absorb energy in narrow bands of specific wavelengths in the electromagnetic spectrum. The laser wavelength can be calibrated (i.e., tuned) to the narrow band of methane so that any methane molecules in the measurement path attenuate the signal according to the Beer–Lambert relationship.

The Remote Methane Leak Detector (RMLD)–IS or the newer RMLD-CS is a commonly used technology that implements TDLAS for leak detection. The portable system consists of a laser emitter, a receiver subsystem, and a signal processing/user interface controller. RMLD is designed for personnel to conduct methane foot surveys. The main advantages of RMLD-IS are that it is intrinsically safe and can detect leaks up to 100 feet away. The technology is useful for surveying difficult-to-reach places such as busy roadways, yards with pets, locked gates, and compressor stations [41].

Lidar and Differential Absorption Lidar

Lidar first became popular in the 1960s and 1970s when NASA used laser-based remote sensing technology in the development of exploratory spacecraft. The technology continued to advance over the years. With the introduction of GPS and inertial measurement units, the technology could be used for topographic mapping of the Earth's surface. Lidar can be used with laser absorption spectrometry techniques to determine gas concentrations. Differential absorption lidar uses two different wavelengths. One wavelength is on-resonance and the other is off-resonance of the molecular absorption of the target gas (methane in the case of natural gas leaks). The difference between the signals can be correlated to the concentration of the tested gas.

New aerial-based systems [42] use frequency-modulated continuous-wave lidar and continuous-wave laser absorption lidar to create topographic maps that are correlated with gas concentration data. Frequency-modulated continuous-wave uses the frequency of the laser light to determine distance and velocity rather than time of flight, which can only measure distance. Laser absorption lidar uses the ground to scatter the laser light back to the lidar system, allowing the measurement of gas concentration based on the laser absorption spectroscopy technique or TDLAS. The SoCal Gas study reported that a gas mapping lidar sensor attached to a helicopter could operate with a sensitivity of 0.5 kg/h or 26.8 scfh with a 90% probability of detection in typical conditions with an unobstructed view [43]. This approach has shown promise and has received much interest from distribution operators for detecting gas leaks in complicated distribution systems.

Open Path Fourier Transform Infrared

Open path Fourier transform infrared (FTIR) has been implemented since the 1970s for measuring atmospheric gases. The core of FTIR instrumentation is the interferometer. An interferometer consists of an IR source, beam splitter, stationary mirror, and moveable mirror. Open path FTIR devices can be either active or passive. Active sensors use an IR source to help excite molecular vibration modes in higher wavenumber ranges. Active devices can operate in two modes. In the first mode, bistatic, the source and detector are separate devices placed in line of sight of each other. In the second mode, monostatic, the system uses a single telescope as the IR source and detector. The different active configurations have advantages and disadvantages.

Passive sensors are single devices that use ambient infrared radiation. The spectroscopy technique measures absorbance or emission pattern spectra and is often used in stationary systems because of the size and weight of the equipment.

In-Plume Lasers

Cavity Ring-Down Spectroscopy (CRDS)

Cavity ring-down spectroscopy (CRDS) was pioneered by O'Keefe and Deacon, building on a technique previously used to measure mirror reflectivity. CRDS devices use a high-speed laser and a cavity with two or more highly reflective mirrors to measure gas absorption many times over a few microseconds. A photodetector senses the amount of light leaking through one of the mirrors to produce a signal directly proportional to the intensity in the cavity. After the laser is turned on, the cavity fills up with the laser light. Once a particular intensity is reached, the laser is turned off. The light reflects around the sensors and decays over time. The intensity decay over time is known as the ring down. In an empty cavity, the only energy loss occurs because the mirrors are not 100% reflective. If gas is introduced into the chamber, additional energy is lost because of absorption.

This method is both precise and sensitive. However, the high sensitivity has led to increased false positives. The technology has been primarily applied to vehicles [44]. The challenge with using other platforms, such as aerial, is that the device must be in the gas plume to take measurements.

Integrated cavity output spectroscopy (ICOS) and off-axis ICOS are the next-generation versions of CRDS. Essentially, these sensors operate using the same principles with slight changes to how they are applied. The laser enters the cavity at an angle (off-axis) to handle cavity vibrations. The configuration is less sensitive to component alignment and local temperature and pressure variations. Off-axis ICOS has been applied to vehicle surveys [45].

Wavelength Modulation Spectroscopy

Wavelength modulation spectroscopy (WMS) is a TDLAS technology that is specific to in-plume applications. WMS works by simultaneously modulating the laser wavelength at a high frequency while linearly scanning the laser wavelength across the absorption profile. This method shifts the absorption information to harmonics of the modulation signal, which can be extracted using digital lock-in filters. The resulting spectra are then measured and converted to gas concentrations using WMS models. The main advantage of the WMS over direct absorption techniques is the noise reduction due to the high-frequency modulation [46].

Miniature Open Path Laser Absorption Spectroscopy

Miniature open path laser absorption spectroscopy is a sensor designed initially by the NASA Jet Propulsion Lab to find methane on Mars. The lab has worked with a drone company [47] to use the sensor for natural gas leak surveys; however, these sensors are also applicable to foot patrols. Data are limited on the working principles of the sensor technology. The working principle relies on radiation absorption similar to the other technologies. Generally, the technology uses multiple mirrors and a laser for measuring methane concentrations.

Nondispersive Infrared

Nondispersive infrared gas detection, similar to other laser technologies, measures gas concentration based on the absorption of infrared radiation at particular gas-specific wavelengths based on the Beer–Lambert law. The devices use two thermopile or pyroelectric sensors to detect the laser light, an infrared source, and gas-specific narrow-band optical filters. One detector reads the absorbed wavelength (active channel) and the other reads the non-absorbed radiation (reference channel). The device compares the two signals to determine the concentration of the gas. Multiple gases can be detected simultaneously, but additional channels must be added to the sensor. Nondispersive infrared devices are used for foot patrols and aboveground stationary devices.

Distributed Fiber Optic Sensing

Distributed fiber optic sensing (DFOS) enables continuous monitoring of pipelines by sending pulses of laser light along a fiber optic cable close to the pipeline. DFOS systems were originally designed for intrusion detection or third-party interference but have since been developed to act as an early warning system for pipeline leaks. Fiber optic cables are standard equipment for transmitting voice, video, and other data. They are frequently installed along pipelines and are often used to enable communication between and remote control of individual stations of the system (SCADA data and control signals) [48] The existing fiber optic cables for communications and data transmission can be converted into a DFOS system based on the interpretation of backscattered laser light caused by changes in temperature and strain. Additionally, sound and vibration can also be detected by the system.

DFOS systems comprise the interrogator and fiber optic cable. The interrogator sends pulses of laser light down the fiber optic cable and processes the resulting backscatter. The fiber optic cable consists of strands of glass, the center of which is known as the core. Light travels through the core and is reflected inward by the surrounding glass or cladding. There are several advantages to fiber optic cables, including large bandwidth, reduced susceptibility to electrical interference, and travel distance.

Fiber optic cables are designed to minimize scattering effects to maximize the transmission distance and data rate. However, the scattering of injected laser light depends on the cable's temperature and strain. Detection of these physical changes has led to systems that can detect the sources of the change, such as third-party intrusion (changes in strain) and leaks (temperature changes). Even though standard communication cables can be used for DFOS systems, specially designed cables are often more sensitive and, consequently, more effective at identifying third-party interference or leaks.

Available detection modes for a DFOS system include orifice noise, negative pressure pulse, local strain changes, and temperature change. The detection modes or sensing technology are typically classified as Rayleigh, Raman, and Brillouin scattering systems, depending on which type of scattering is used for sensing.

Distributed acoustic sensors use the information from optical fiber Rayleigh backscatters to detect sound in the environment surrounding the fiber optic cable. These systems rely on the backscatter change caused by cable strain changes when subjected to sound vibrations. Most distributed acoustic sensor systems are based on phase-sensitive optical time domain reflectometry. Brillouin fiber sensing can measure the temperature and strain distribution along the optical fiber and can obtain a high spatial resolution for long sensing distances. Raman optical fiber sensing is used in distributed temperature sensing and can monitor a large-scale distributed temperature. Unlike Brillouin fiber sensing, Raman optical fiber sensing is not sensitive to strain.

Fiber optic systems are not typically used for distribution systems. The technology is more applicable to long stretches of pipe, such as in transmission lines.

Infrared Imaging/Optical Gas Imagers

An optical gas imager (OGI) is a specialized infrared camera that uses optical imaging to screen inaccessible locations or remote facilities. The camera has a filter and detector to create a thermal image. The filter is a band pass filter that only allows certain wavelengths of infrared radiation to the detector. The selected bands are based on the absorption frequency of the target gas. The cameras use quantum detectors that require cooling to significantly lower temperatures to operate.

The detector has a mixture of electrons that can conduct electricity (free electrons) and others that cannot (valence electrons). At sufficiently low temperatures, free electrons are frozen in place, preventing current flow. Photons that pass through the filter strike the detector and stimulate electrons in the valence band, causing them to move up into the conduction band. The freed electrons carry a current that is proportional to the incident radiation.

OGIs allows technicians to detect gas plumes that are invisible to the naked eye. [49] Patrols use this technology to quickly investigate pipelines and equipment for leaks. The challenge of OGIs is acquiring a high contrast to recognize the plume. However, the motion of the plume makes identification easy.

Hyperspectral Imagery or Imaging Spectroscopy

Hyperspectral imaging collects and processes electromagnetic spectral data and maps them to spatial data. The technology has been around since the 1980s; however, it has grown significantly over recent years because of technological advancements and cost reductions. The spectral data extend well beyond the visible spectrum, collecting wavelengths from the infrared to the shortwave infrared, and can be used to identify specific objects based on their spectral signature. Hyperspectral imagery sensors can be stationary [50] or mounted on aircraft, drones, and even satellites that can monitor methane leaks in all sectors of the oil and gas industry (upstream, midstream, and downstream) [51] [52].

Vapor Sampling

Flame Ionization Detectors (FIDs)

The natural gas industry has used flame ionization detectors (FIDs) since the late 1950s. FIDs internally combust hydrogen gas, producing a small flame. A pump draws air samples over the flame where hydrocarbon vapors are burned. The unit analyzes the combustion products and calculates the total hydrocarbon concentration in parts per million. One disadvantage of FIDs is that they cannot differentiate between methane and other hydrocarbons. Therefore, detecting hydrocarbons does not necessarily indicate a methane leak. However, a negative reading from the FID means that no hydrocarbons are present, so there are no gas leaks. FIDs are still used but have mostly been phased out by newer technologies.

Electrochemical Gas Sensors

Developed in the 1950s to monitor oxygen, electrochemical gas detectors measure a specific gas's concentration by oxidizing or reducing the gas to an electrode, generating a positive or negative current flow. The main components of an electrochemical sensor are the working electrode, a counter electrode, and a reference electrode. The gas diffuses into the sensor and through a membrane to the working electrode. Oxidation or reduction will occur depending on the gas type, generating an electric current between the electrodes. The signal is amplified and scaled according to the device's calibration, and the gas concentration is reported in parts per million.

Combustible Gas Indicators (CGIs)/Catalytic Sensors

Catalytic sensors measure the methane concentration based on the change in resistance of a filament wire. The wire, typically platinum, is coated with a catalyst specifically designed for the target gas (methane). When hydrocarbons pass over the heated filament, they react with the oxygen in the air and oxidize. The chemical reaction is exothermic, causing the filament to heat and the wire resistance to increase. A Wheatstone bridge converts the change in resistance into a voltage that is processed and analyzed to determine the gas concentration. Typically, a second platinum wire is used as a compensating element. The second wire is isolated from the test gas volume and used to account for slight changes in resistance independent of the tested gas. Higher methane concentrations result in higher voltage output signals.

Most combustible gas indicator (CGI) devices output the percentage of flammable gas in the air (percent gas scale) and the percentage of the lower explosive limit scale. The CGI is designed for quantifying gas concentrations below ground, in confined spaces, and is not suitable for aboveground surveys. The CGI was intended primarily for use inside buildings, testing the atmosphere in the soil for confirmation of a leak on a buried pipeline, and checking for flammable atmospheres in trenches and confined spaces. The technology requires oxygen and will not function in environments with oxygen concentrations of 10 vol % or less. The CGI is often used with bar holes (i.e., small holes driven into the ground adjacent to a pipeline) to locate a pipeline leak. The intent is to release the leaking gas traveling through the soil so it can be measured with the CGI.

Metal Oxide Sensors

Metal oxide sensors are based on a chemiresistor material that reacts to the surrounding environment. Chemiresistors bridge the gap between two electrodes. The resistance of the material changes based on the presence or absence of an analyte. For gas leak detection, n-type metal oxide nanostructures are used as the chemiresistor material. Metal oxide is a porous assembly of grains that, when exposed to an atmosphere, will absorb oxygen on the grains of the material. The oxygen molecules react with the free electrons and increase the resistance of the metal oxide material.

The increased resistance causes a reduction in the flow of electrons (current). This occurs at the outer layer where the material is in contact with the test atmosphere. If the test atmosphere contains a reducing gas, such as methane, the oxygen reacts with the gas and is removed from the metal oxide surface. The reduced oxygen liberates electrons that were bound to the oxygen, lowers the resistance, and increases the current.

Carbon nanotubes as a chemresistor were first introduced in 2000. Carbon nanotubes change resistance in the presence of various gases; however, they are less selective than other chemiresistor materials. Recent research [53] has designed carbon nanotubes targeting a particular gas using dopants, coatings, and nanoparticles. Machine learning has been incorporated to train the system for high sensitivity and selectivity of low–molecular weight hydrocarbons. The advantage of carbon nanotubes is their low cost, quick response times, and low detection limits.

Cross-Bore Detection Technologies

Cross-bores occur when a gas line is installed through another utility (typically a sewage line) using trenchless or HDD techniques. HDD requires launching and receiving pits on both sides of the installation and a drill rig. A pilot hole may be drilled depending on the pipe size. Once the pilot hole is drilled, the string is fitted with a back ream to enlarge the hole to the diameter required for the pipe installation. Often, the gas line is unknowingly installed through the utility, creating a hazardous situation.

The cross-bore remains undetected until the sewage line becomes blocked, and a plumber is called to perform a repair. When the plumber attempts to remove the blockage, often with a root cutter, the gas line is ruptured, causing a leak and creating the possibility of ignition. Gas from the broken line can leak into the home and ignite from sources such as a pilot light or light switch. Improved technologies are needed for preventing and detecting cross-bores.

Visual (Closed-Circuit Television) Inspection (Pre- and Post-Construction Inspection)

The current method for locating cross-bores is with cameras attached to sondes. Camera technology has improved significantly over time. However, a camera system cannot access all laterals. One approach is to conduct a preinstallation inspection to locate the sewer mains and laterals. Another approach is a post-inspection to confirm that the sewer lines are free of cross-bores. Pre-inspection can prevent cross-bores; however, post-inspections ensure that no cross-bores exist once the project is complete.

Acoustic Sensors

Acoustic sensor technology works by sending a unique acoustic pattern into sewers from two manholes. The frequency of the sound pattern was carefully selected to avoid interference from outside sources such as traffic. A sensor is run through the newly installed pipe and detects sound traveling through the sewer mains and laterals. Soil attenuates the acoustic signal and prevents the sensor from detecting the sound if the gas line and sewer are far apart. A cross-bore is located by identifying where the signal is the strongest. The crew marks the location of the cross-bore on the surface for repair crews. This approach works for plastic and steel pipes and does not require navigating mains and laterals with a camera [54].

APPENDIX D. Cast Iron Repair and Replacement

Cast iron replacement by using plastic pipe increases safety and mitigates failures. Additionally, joint inspection and repair are applied to proactively prevent leaks. These options are discussed in this appendix.

Replacement

The most effective integrity method for cast iron is replacement programs. Cast iron material poses many integrity risks. Cast and wrought iron pipelines were used from the early days of energy transportation through the 1940s. Since then, cast iron has been replaced by new materials such as steel and plastics. In 1991, the National Transportation and Safety Board recommended that PHMSA (then Research and Special Programs Administration) require pipeline operators to implement a program to identify and replace cast iron pipelines that may threaten public safety. PHMSA issued two advisory bulletins (RSPA Alert Notice 91-02 and 92-02) related to cast iron replacement programs [55].

In the 1970s, PHMSA began collecting data about gas pipeline mileage categorized by pipe material type. In 1984, operators began submitting merged data for cast and wrought iron pipes. A review of the PHMSA data for cast iron mains and services shows that there were 34,592 miles of cast iron in 2010 and 18,316 in 2021—a decrease of 16,276 miles. Using the PHMSA data, Figure 4 shows the wrought iron gas distribution pipelines data by year. The mains and services curves clearly show a decreasing trend since 2005. Replacement programs implemented by gas distribution operators are the primary force driving the decrease. Replacement is the long-term solution to ensure pipeline integrity. Until replacement is complete, mitigation methods are available.

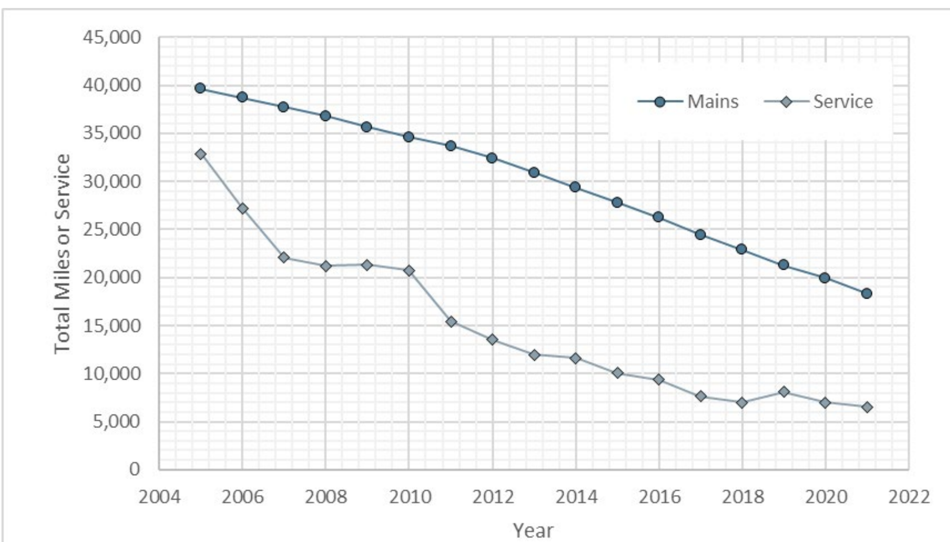

Figure 4. Wrought iron gas distribution pipelines by year (2005–2021)

Joint Inspection and Repair

Some large-diameter natural gas pipelines may need to continue to operate and therefore require interim measures to operate. Many of these cast iron pipelines are used to transport wet natural gas, and since the transition to dry natural gas, the cast iron joints may leak. The joint sealant dries out because of the dry natural gas and requires repair. A crawler has been developed [56] to inspect and repair cast iron joints. The crawler capabilities include the following:

- Inspection and repair of mains 15 inches or greater
- Sealing of jute and mechanical joints
- No disruption of gas service
- Access up to 110 joints from one excavation