Blacksmith Group, LLC

A 2026 Evaluation of Natural Gas Distribution Pipeline Safety Performance in the United States

October 30, 2026

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Report Summary

Evaluation of Pipeline Safety Performance

In July 2026, the Future of Heat Initiative (FOHI) published a report entitled "Spending and Safety Outcomes in U.S. Gas Distribution Systems – An Assessment of DIMP & PHMSA's Call to Action." This report claims, among other things, that investment in replacing older, leak-prone (cast iron and bare/unprotected steel) natural gas distribution assets over the last 15 years has not resulted in industry-wide safety improvements.

The Blacksmith Group[1] examined FOHI's claims and conducted an evaluation using data collected by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and operator data. This report summary was prepared in early October and released publicly.

The following analysis identifies several areas where the FOHI report's interpretation of gas system performance data leads to conclusions that are not supported by the broader evidence. Left unanswered, these conclusions could inform policy decisions that increase the risk associated with aging, leak-prone infrastructure in the United States and the Northeast[2].

Key Findings:

- **Safety performance of the natural gas distribution system has in fact improved.** National and local gas system performance data show investment in replacing leak-prone pipe has prevented deterioration, mitigated emerging risks, and reduced the likelihood and severity of catastrophic events, rather than FOHI's conclusions, which rely solely on incident counts regardless of type.

- **Replacement of leak-prone pipe is the most effective and efficient long-term engineering solution to ensure gas system integrity.** FOHI argues that other methods are more cost-effective but do not reflect the pipe's actual condition, which often cannot be kept safely in service, even in the short term, with simple repairs.

- While FOHI claims most spending went to pipe replacement rather than leading risk drivers such as excavation damage, the **findings show that pipe replacement addresses multiple risk categories simultaneously and improves system integrity.**

- **Distribution Integrity Management Programs (DIMP) continue to evolve as an important, effective tool** to ensure gas system operators are addressing system risk, as demonstrated by a broad range of pipeline safety performance measures.

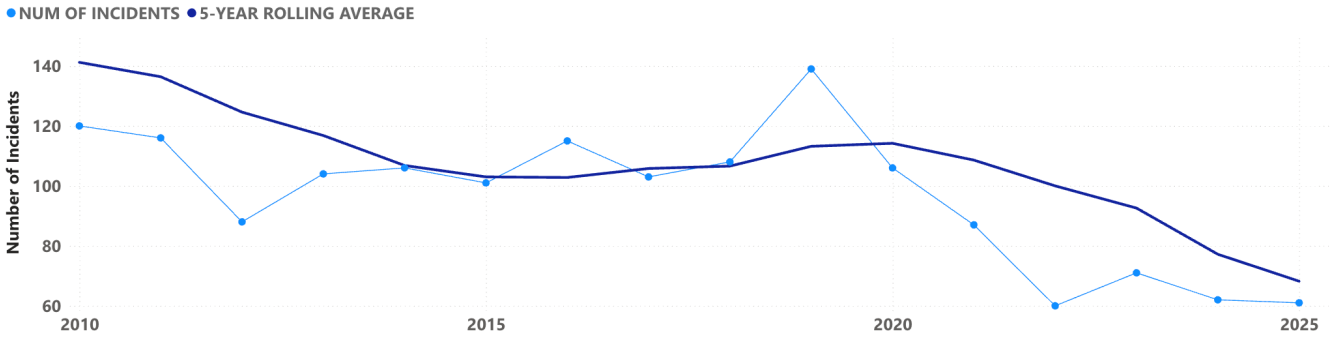
[1] The Blacksmith Group is an independent consulting firm formed in 2006 that provides expertise on energy pipelines and LNG. Our leadership and personnel bring deep industry knowledge and experience in design, construction, operations, maintenance, risk management, integrity and safety management systems. We have advised Boards and senior executives following major incidents to prevent recurrence, and many others proactively, to prevent failures.
[2] The Northeastern states used in this analysis include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, New Jersey, Pennsylvania, Rhode Island, and Vermont.

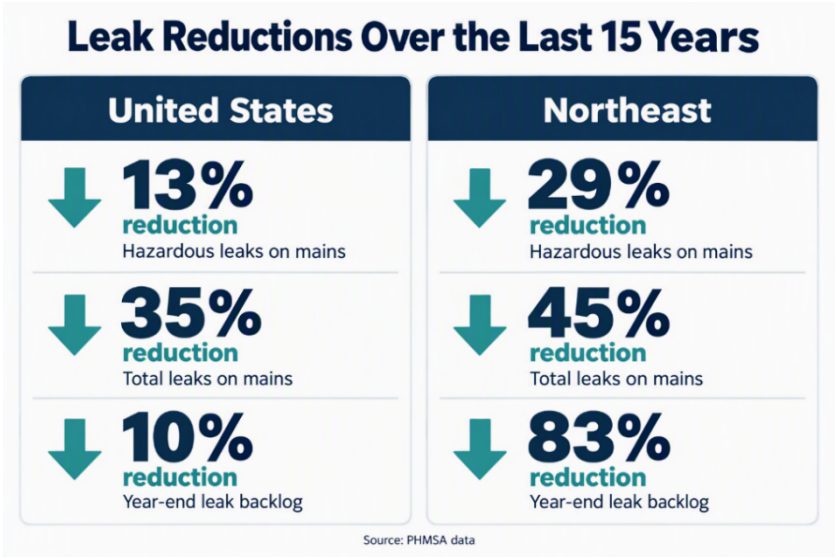
- FOHI's "low-replacement states" are actually states with lower leak-prone inventory. Between 2010 and 2025, these states actually replaced a higher percentage of their leak-prone inventory than Northeastern states, as baseline inventory levels varied by state. Furthermore, while FOHI highlights higher post-2011 incident rates in high-replacement states, **this metric is misleading as it includes incidents unrelated to asset failures and does not recognize the fact that high-replacement states started with older, riskier infrastructure that required replacement for long-term safety.**

Pipeline replacement is fundamentally preventive, risk-based work. Its effectiveness cannot be measured solely by counting incidents after the fact, particularly when the purpose of the investment is to address known vulnerabilities before they result in leaks, failures, or serious safety incidents. Managing pipeline safety is not a binary choice. Repair, leak detection, damage prevention, and replacement all play important roles, but they address different risks and are not interchangeable alternatives. Affordability, project prioritization, and the use of repair technologies or non-pipeline alternatives are all important considerations, but they must be evaluated against the asset's actual condition and the level of risk each option can effectively address. Specifically, the report shows:

Safety has improved significantly as a result of the investment over the last 15 years

Safety performance of the natural gas distribution system has, in fact, improved significantly over the last 15 years. The number of reportable incidents in the overall system based upon PHMSA data has decreased over the last 15 years, as demonstrated in the chart, which includes all reported incidents.



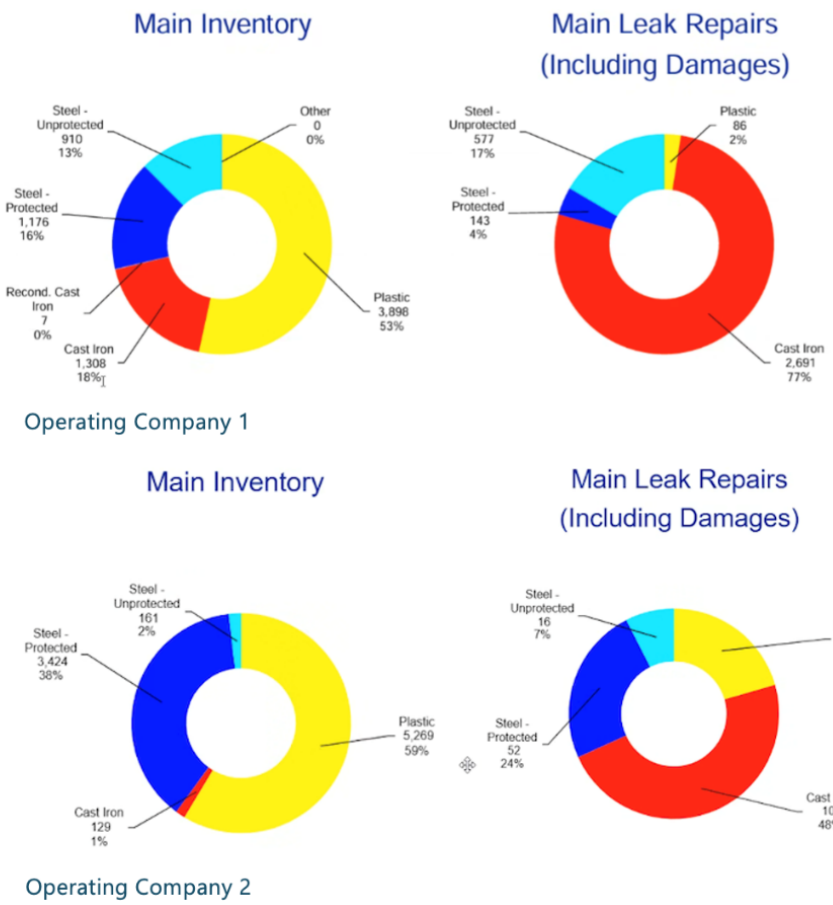


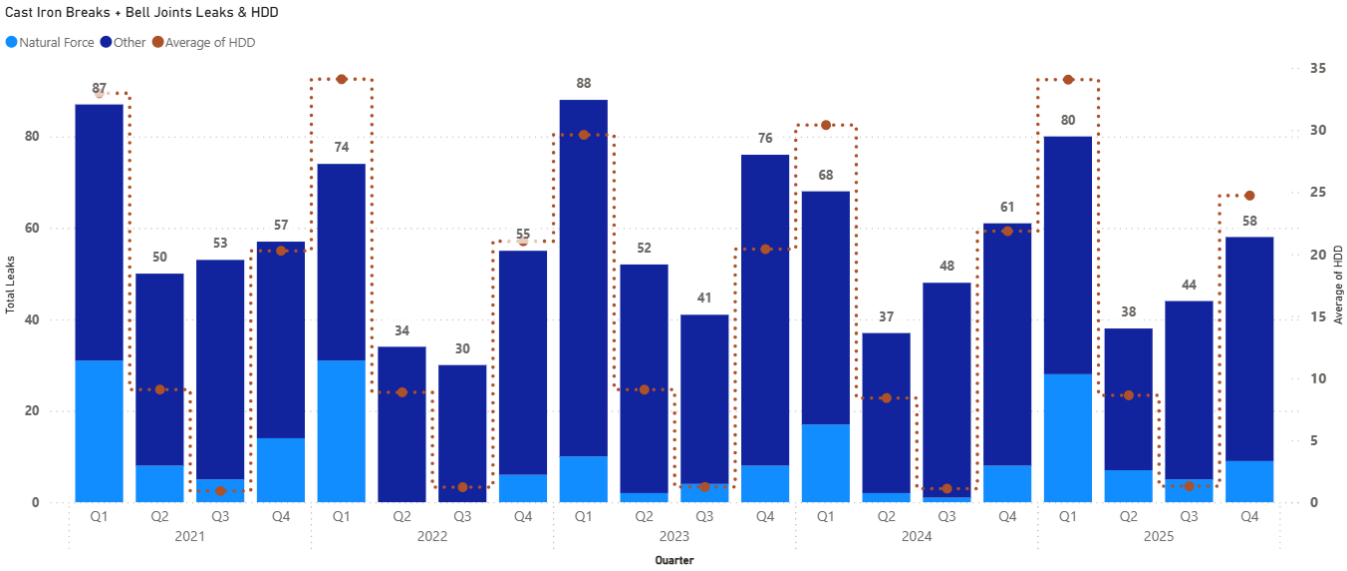
Also very importantly, leaks and associated emissions on natural gas distribution systems have decreased significantly over the last 15 years. Open, unrepaired leaks can turn into more serious situations. In addition, the decline in hazardous leaks (that must be repaired immediately) shows that replacement programs have in fact reduced higher-risk situations, especially in the Northeast where the leak-prone pipe inventory is large in comparison with other parts of the country due to the service years of the systems.

Safety issues occur disproportionately on leak-prone infrastructure

Leaks occur disproportionately more on leak-prone pipe compared to newer materials. As shown, cast iron is of particular concern. Cast iron was installed in the late 1800s and early 1900s, with bell-and-spigot joints every 12 feet. After a century of duty, these joints can leak extensively. In addition, subsurface movement from cold/frost, nearby excavation, and other ground movement can cause cast iron to break. This is especially risky in areas with full pavement or frost, which can prevent leaking gas from dispersing above ground and allow it to migrate into homes and businesses, posing a risk of explosion.

The occurrence of these leaks and breaks is more prevalent in cold climate areas such as the Northeast due to frost and resulting ground movement and stress induced on leak-prone pipe, as shown in the following chart, which relates them to higher Heating Degree Days (HDD) and resulting periods of colder weather, which generally impacts frost depth.

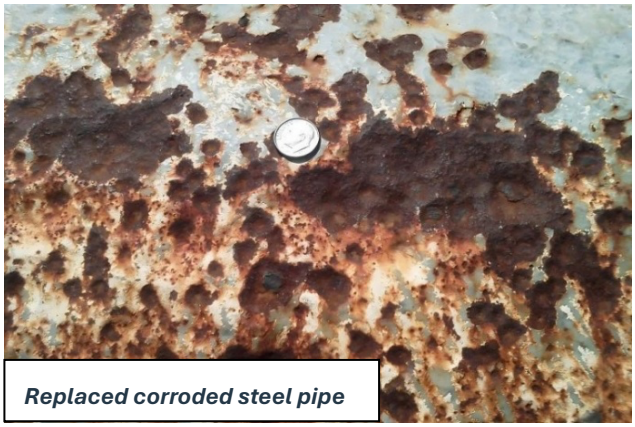




While the cast iron pipe inventory has decreased significantly, leaks and breaks have not decreased proportionately, indicating that the remaining cast-iron pipe is worsening, increasing safety risk and reinforcing the need to maintain the pace of addressing this concern.

Repair is appropriate for certain issues but is not a broad alternative to replacement or rehabilitation

Pipe replacement, rehabilitation, damage prevention, leak detection and classification, and repair each address distinct risks and operating conditions; therefore, they are not interchangeable alternatives.



Replaced corroded steel pipe



Replaced cast iron pipe

Repair is appropriate for immediate hazards and localized defects; rehabilitation can extend useful life where conditions and application permit; replacement is warranted when degradation is systemic, leaks recur, or rehabilitation is prohibited, such as when structural integrity is compromised. Repair or rehabilitation are not effective and have limited safety value when the pipe has deteriorated significantly. Replacement is the only reasonable method of mitigating safety risk when pipe has deteriorated significantly as depicted in the pictures above.

There are many additional safety benefits resulting from replacement programs that go beyond reduction of incidents and leaks

Replacement programs and, where appropriate, rehabilitation technology applications provide significant safety enhancements that go beyond incident and leak reduction. They fortify the system from an integrity standpoint and increase system resiliency and reliability, which provides multiple safety benefits, including:

- Excess flow valves installed, allowing for immediate shutdown of gas service in the event of unplanned high gas flow.
- Additional emergency sectionalizing valves installed, enhancing any needed emergency response.
- Gas service piping and meters/regulators moved outside, allowing for access for emergencies, inspection, and maintenance.
- Customer piping and equipment/appliances are checked for safety during the relight process.
- Improved gas facility records, which can significantly reduce facility damage and resulting consequences due to excavation. Vintage infrastructure may have records that are in excess of 100 years old and are not as accurate as records created today.

- Reduced chance of customer outages due to water intrusion in leak-prone low-pressure gas systems due to water main breaks, water leaks, or storm flooding.
- Reduced responses to and repairs of hazardous leaks.
- Elimination of vintage, sometimes unmapped appurtenances such as stubs that are at high risk for excavation damage.

All of these added safety benefits reduce the likelihood and consequence of excavation damage and other incidents, as well as reducing system-wide methane emissions.

Standards and Regulatory Requirements have continually evolved

Standards and regulatory requirements began as early as 1935. A broad group of stakeholders provided extensive input into standards and regulatory requirements over the years. The U.S. Congress sets direction and authorizes improvements through legislation. Standards developing organizations such as the American Society of Mechanical Engineers (ASME) and the American Petroleum Institute (API) have developed and improved standards that address legislation and provide the technical foundation for regulations developed and improved by the U.S. Department of Transportation (DOT), each State, the Pipeline and Hazardous Materials Safety Administration (PHMSA), along with their state partners, represented by the National Association of Pipeline Safety Representatives (NAPSR). Oversight of PHMSA is provided by the DOT Inspector General, the Government Accountability Office (GAO), and the National Transportation Safety Board (NTSB). Public input into regulatory proceedings is provided to the Gas Pipeline Advisory Committee (GPAC), and other interested parties through public comments.

Standards and regulatory requirements have continually improved over time as technical capabilities increased and lessons were learned. A recent example of this evolution is the creation of API 1173, a standard for Pipeline Safety Management Systems (PSMS), which the industry is adopting and implementing. Many state pipeline safety regulators currently require or encourage adoption of API 1173.

Asset Management and DIMP have improved investment prioritization

Operators use overarching asset management processes for addressing risk and for capital and expense planning. The advent of DIMP brought greater structure and transparency to the asset management process for the diverse assets that comprise distribution systems. DIMP was promulgated by PHMSA on December 4, 2009, establishing a systematic framework for gas distribution operators to identify, assess, and mitigate pipeline safety risks. DIMP assessment processes have evolved over the last several years. DIMP implementation resulted in significant improvements in asset data and qualitative as well as probabilistic methods, which combined with the deep operational experience of gas system operators are used to prioritize investment decisions needed to ensure the safe and reliable operation of the gas system.

Using DIMP, asset management processes continue to improve year over year. Assessment of system asset safety and emissions risks is done at both a strategic long-range goal-setting level and tactical shorter-range project level. Implementation planning is a key part of the asset management process. Implementation is not based solely on modeling output. Instead, work plans incorporate the realities and challenges of completing work, such as permitting requirements, paving moratoriums, system operation, resources, customer impacts, and opportunities for efficiency.

It is critical to continue to address risky, leak-prone pipe

> On April 30, 2026, Paul Roberti, Administrator of PHMSA and former Rhode Island Public Utilities Commissioner, wrote to the Chairman of the Massachusetts Department of Public Utilities:
>
> "*I…urge you to support the Massachusetts Gas System Enhancement Program for replacing cast-iron and other leak-prone pipe in natural gas distribution systems in the State of Massachusetts… Failing to support these replacement projects could increase the potential for pipeline incidents that may result in death, injury, or property damage.*"

Conclusion

Replacement programs take a proactive and preventive approach to managing and reducing risk on natural gas distribution systems so catastrophic incidents do not occur. Proactively replacing or, where practical, rehabilitating these pipes avoids future risk of catastrophic failure, helps to reduce methane emissions, and increases distribution system reliability, benefiting the customers and communities that utilities serve.

Safety is not measured solely by the number of incidents that occur, but also by the effectiveness of the systems, processes, and risk mitigation provided by life cycle-based, prescriptive regulations in concert with DIMP and pipe repair, and where practical, replacement and rehabilitation that address all of the risks on the natural gas systems, preventing incidents from occurring in the first place.

Eliminating or even slowing the pace of replacement and rehabilitation programs will increase the risk of more incidents as the condition of remaining leak-prone pipe continues to worsen. Safety remains the industry's highest priority, and not addressing the riskiest assets in the distribution system would expose the customers and the communities that natural gas utilities serve to greater risk. We urge stakeholders to continue to work together to ensure these programs move forward to address these challenges, reduce these risks, and maximize safety value.

1. Introduction

The Blacksmith Group, in collaboration with Bay Utility Associates LLC, was engaged by the Northeast Gas Association to provide an evidence-based evaluation of natural gas distribution pipeline safety performance in the U.S., with a particular emphasis on the Northeastern U.S. It illustrates distribution system safety performance and how the industry, regulators, legislators, and other public representatives recognized the need for safety performance improvements and guided those improvements over five decades. Drawing primarily on PHMSA data[3] and supplemental operator information, it assesses how federal life-cycle safety standards, Distribution Integrity Management Programs (DIMP), and sustained repair, rehabilitation, replacement, damage-prevention, leak-detection, and operational programs have reduced risk. The evidence indicates that these complementary measures have materially improved safety and that replacement of vintage, leak-prone infrastructure remains an essential preventive strategy.

The central finding is that strong baseline regulation remains essential, but the greatest gains have come from combining those requirements with Distribution Integrity Management Programs (DIMP), including sustained repair, replacement, and rehabilitation of vintage infrastructure.

The report also responds to the Future of Heat Initiative's July 2026 assessment of DIMP and PHMSA's Call to Action. It concludes that comparisons of high- and low-replacement states must account for differences in starting inventory, infrastructure age, baseline condition, climate, incident cause, and the percentage of leak-prone assets removed. Without that context, incident counts alone do not establish whether replacement programs have been effective.

Risk and Decision Context

Incident counts alone do not fully measure safety performance. Incidents should be evaluated with hazardous and total leaks, leak backlog, breaks, excavation damage, near misses, and asset-condition indicators that enable an operator to act to prevent an incident. This is especially important because annual counts in individual causal categories can be small and volatile, particularly when evaluating the data on a threat basis. The purpose of distribution integrity work is to identify and mitigate causes and sub-causes before they produce failures, fires, explosions, injuries, or fatalities.

Remaining vintage assets may present greater risk per mile even as total mileage declines. Cast iron, bare steel, and certain older plastics have distinct failure modes, and cold-weather conditions can intensify frost movement, cast-iron breaks, joint leakage, and subsurface gas migration. Operator examples also show that cast iron can account for a disproportionate share of leak repairs relative to its share of inventory.

Implications and Priorities

Repair, rehabilitation, and replacement are complementary—not interchangeable—tools. Repair is appropriate for isolated defects where the surrounding pipe remains sound; rehabilitation may suit cases where the host pipe retains adequate structural integrity and operating compatibility; and replacement is warranted when recurring leakage, corrosion, graphitization, cracking, displacement, capacity limitations,

[3] Incident data used throughout this report are those reported to PHMSA under 49 CFR 191.9 found at https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data. Annual report data are found at https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

or interacting threats make other measures insufficient. DIMP and asset-management processes provide the framework for documenting and reevaluating these choices based on condition, consequence, feasibility, cost, customer impact, and expected useful life.

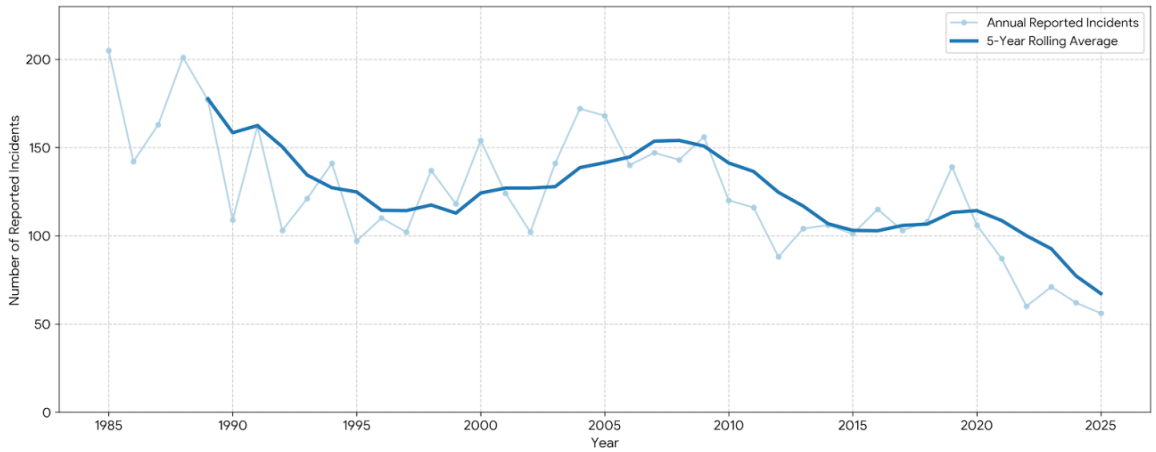
Modernization also produces broader benefits, including improved pressure control and emergency isolation, safer meter and regulator access, better records and traceability, lower methane emissions, fewer outages, and reduced exposure for employees, contractors, first responders, customers, and the public. Program pace must account for permitting, municipal coordination, paving restrictions, qualified resources, seasonal constraints, affordability, and future-system needs without compromising the obligation to operate existing systems safely.

Initial Federal Regulations

In 1968, Congress passed the Natural Gas Pipeline Safety Act, which established the first nationwide safety standards for gas pipelines. That same year, the federal government promulgated the first regulations, based on consensus standards developed and improved since 1935. In 1970, the U.S. Department of Transportation, through its Office of Pipeline Safety, promulgated a comprehensive set of life-cycle-based, prescriptive regulations. Industry initiatives, consensus standards, legislation, and regulations have been central to how safety performance has been evaluated and improved over decades.

High-Level View of Safety Performance Over Six Decades

At the highest level, safety performance is viewed through incidents, since reducing them is critical to protecting people, property, and the environment. Figure 1 shows a graph of U.S. incidents by year and a five-year rolling average. A rolling average accounts for fluctuations and helps reveal trends in data. As the graph shows, incidents trended downward into the early 1990s. Life-cycle-based, prescriptive, standards-based regulations drove improvement from the 1970s to 1990s; however, the improvement trend began to plateau in the early 1990s and into the early 2000s.



Source: PHMSA Gas Distribution Annual Report Data, 1985 through 2025[4]

Figure 1 – PHMSA Reportable Incidents from 1985 through 2025

[4] Incident data used throughout this report are those reported to PHMSA under 49 CFR 191.9 found at https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data. Annual report data are found at https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

Recognition of a Plateau in Safety Performance and the Advent of Risk Assessment

This report highlights the recognition of this plateau in incident reduction within PHMSA and among operators, and their trade associations, the American Gas Association and the Northeast Gas Association, and the actions taken to address it. These actions largely drew on early examinations of risk assessment in other industries and the gas industry's subsequent adoption of risk management principles. In 1993, the Research and Special Programs Administration (PHMSA's predecessor) formed a Gas Risk Assessment Quality Team and a Liquid Risk Assessment Quality Team (the Gas RAQT and Liquid RAQT, respectively). The RAQTs evaluated the state of the art for risk assessment in the respective sectors, including modeling methods and how risk models were used in planning operations, maintenance, and modernization work, and published individual reports and a joint public meeting presentation in 1995.

From 1996 through the end of the decade, PHMSA encouraged gas and liquid operators to develop demonstration projects to show the efficacy and value of risk-based approaches. The projects entailed adjusting inspection and maintenance intervals using risk to show equal or greater safety performance. With legislative support in 2000, the risk-demonstration program expanded.

A negative trend in safety performance, shown in Figure 1 in the early 2000s, accelerated the focus on risk-based methods. Broader use of risk in replacement and rehabilitation programs and learnings from gas and liquid transmission led the distribution industry and PHMSA, in concert with the National Association of Pipeline Safety Representatives (NAPSR), to commission the Gas Piping Technology Committee (GPTC) in 2005 to develop a framework for DIMP.

The Advent of Distribution Integrity Management and the Call to Action

With legislative support from Congress, PHMSA used the framework to create a performance-based regulation in 2009 known as distribution integrity management, under which operators adopt risk-based DIMPs.

In 2011, shortly after the DIMP regulations took effect, the Secretary of Transportation issued a Call to Action that placed additional emphasis on safety improvements. Although the Call to Action addressed all modes of pipeline transportation, the Secretary said gas distribution replacement and rehabilitation programs needed to accelerate. Later that year, the National Association of Regulatory Utility Commissioners (NARUC) sent a written response and action plan to Secretary Raymond H. LaHood detailing the commitments and resolutions passed by state utility commissioners to support accelerated replacement of vintage and leak-prone natural gas infrastructure.

DIMP strengthened ongoing operator repair, replacement, and rehabilitation programs by adding rigor to risk assessment and increasing transparency. Additionally, DIMP goes beyond mains and services assessment and considers all assets in a distribution system, including gate stations, district regulator stations, and meter and regulator stations. This broadens the focus and impact on managing all threats to distribution integrity and overall safety performance.

This report analyzes trends in DIMP adoption, alongside repair, replacement, and rehabilitation, to identify what changed over time and how those changes affected performance.

The remaining sections of this report will go into greater detail on the journey of pipeline safety initiatives, legislation and regulations, and the role that each played in safety performance. These include:

Section 2 – Life Cycle-Based Prescriptive Standards and Regulations

This section describes how regulations were first formulated and improved over the four decades that followed. The original pipeline safety regulations promulgated in 1970 were developed to address safety in each phase of the pipeline life cycle, with largely prescriptive requirements to ensure material selection and design based on consensus standards from ASME and API. The regulations established inspection and maintenance intervals based on experience with piping, valves, and pressure regulation in the pipeline industry, as well as in other process industries. The regulations were updated periodically through efforts undertaken by the consensus standards organizations, legislation, and regulation.

Section 3 – Repair, Replacement and Rehabilitation

This section describes the fundamentals of repair, replacement, and rehabilitation in managing gas distribution systems safety performance. It also describes how each method can be used and the factors considered in its application, resulting in the selection of methods to achieve the most appropriate and cost-effective outcome.

Section 4 – Distribution Integrity Management Programs

This section describes the advent of distribution integrity management. It occurred at a time when safety performance had plateaued. The life-cycle-based prescriptive regulations were insufficient on their own. They remain important today for providing data on asset condition and safety performance and for documenting compliance. Learnings from the focus on risk assessment in the late 1990s and work in developing integrity management in gas, crude oil, and petroleum product transmission in the early 2000s paved the way for adoption in the gas distribution industry. The section shows how DIMP, along with repair, replacement, and rehabilitation, has measurably improved gas distribution safety performance in the U.S.

Conclusions – This section provides conclusions related to the evaluation conducted.

Epilogue - The report ends with an epilogue describing the basis for continued improvement in gas distribution safety performance through the adoption of Pipeline Safety Management Systems (PSMS).

2. Life-Cycle Based, Prescriptive Regulations

As stated above, comprehensive pipeline safety regulations designed to ensure the safety of the gas system throughout its entire lifecycle have evolved over the last 50 years following a thorough and thoughtful process and with the involvement of a broad group of stakeholders. This section provides an important overview of the history of the natural gas industry and then describes the evolution of legislative and regulatory U.S. gas distribution pipeline safety standards, including "why" changes came about.

Although standards development began as early as 1935, this section includes a summary of the initial regulations' technical provisions promulgated in 1970, showing their comprehensiveness and breadth of coverage across the gas distribution system's life cycle. The technical provisions show that a piping system may appear simple on the surface (literally and figuratively) but is actually complex and relies on a myriad of requirements to ensure safety. The life cycle structure served as the foundation for the initial regulations and was updated as regulations changed in response to new technology, new safety performance goals, and most notably, lessons learned from incidents[5] and near misses. The rigor of the regulations and supporting consensus standards has been improved over the years, reflecting that complexity.

In the original consensus standard, developers tried to anticipate how failures would manifest and affect system safety and condition. Standards used the lifecycle framework to ensure inspection and maintenance occurred to properly manage asset condition.

This section also describes the role of federal oversight of pipeline safety. This includes federally sanctioned advisory committees, including the GPAC, which must provide perspectives on rulemakings PHMSA is considering. GPAC members are asked to consider the Technical Feasibility, Reasonableness, Cost-Effectiveness, and Practicability of each regulatory provision they review. It also examines oversight of PHMSA by the U.S. DOT Inspector General (IG), the Government Accountability Office (GAO), and the National Transportation Safety Board (NTSB).

It also includes a brief description of how the gas distribution industry and core piping and pressure-control infrastructure developed and evolved, establishing the foundation for the regulations and why they are lifecycle- and prescriptive-based.

Distribution System Terminology

To understand distribution system standards and regulations, including integrity management programs, it is important to understand the basics of distribution system components. A distribution system comprises mains, service lines, and associated appurtenances owned or operated by a gas distribution utility. These assets span a wide range of materials, operating pressure regimes, and functional components:

- **Distribution Mains:** Mains are the foundational pipelines running beneath streets, rights-of-way, and easements that transport gas throughout a service territory to supply individual service lines. Covered main materials include modern polyethylene plastic, cathodically protected coated steel, legacy bare steel, cast iron, ductile iron, and copper. Operating pressures range from low-pressure systems measured in inches of water column (for example, a pressure measured as 7 inches of

[5] Incident data used throughout this report are those reported to PHMSA under 49 CFR 191.9 found at https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data. Annual report data are found at https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

water column, which corresponds to approximately 1/4 pounds per square inch gage (psig)) up to high-pressure distribution mains operating below 20% of Specified Minimum Yield Strength (SMYS).

- **Service Lines and Appurtenances:** Service lines branch off distribution mains to deliver gas directly to individual residential, commercial, or industrial customers. The scope includes the underground service piping running to the meter set assembly, service tees or tapping tees, curb valves, and integrated safety devices such as Excess Flow Valves (EFVs), which automatically stop gas flow if a service line is severed.
- **Pressure Regulating and Overpressure Protection:** Pressure regulation consists of the control hardware required to reduce gas pressure from higher-pressure transmission pipelines at gate stations and district regulator stations to pressures suitable for safe operation in a distribution system. Covered equipment includes pressure-reducing valves, worker and monitor regulators, overpressure protection devices (such as relief valves and slam-shut valves), and associated telemetry and odorization monitoring equipment.
- **Customer Meter Assemblies and Regulators:** Service pressure regulators are generally installed at gas meter assemblies to reduce gas pressure to the utilization pressure of appliances.
- **Main Valves:** Sectionalizing and emergency valves distributed throughout the network to isolate pipeline segments during maintenance or emergency response.

The Era of Manufactured Gas

The gas distribution industry began in the early 1800s not with natural gas pulled from the earth, but with manufactured gas, commonly called "town gas." Developed primarily to provide lighting, town gas was produced locally by gasifying coal, and occasionally oil or wood, in airtight ovens at specialized manufactured gas plants (MGPs). This process produced a combustible mixture made up primarily of hydrogen, carbon monoxide, and methane.

From the early 1800s through the 1920s, town gas was the lifeblood of urban energy networks. Because it was manufactured locally, distribution systems were highly localized and radiated outward from the MGP. The gas was distributed at very low pressures—often just enough to keep a flame lit at a gas lamp or a primitive stove. The first distribution systems were built of cast iron. This low-pressure environment was necessary because the cast-iron mains, including the bell and spigot joints of the era, could not handle high pressures without leaking.

While town gas successfully modernized urban lighting and early cooking, it carried significant drawbacks. It was highly toxic due to its carbon monoxide content, soot-heavy, and had a relatively low heating value (roughly half the energy content of modern natural gas). Furthermore, the manufacturing process left behind heavy coal tar materials at the plant sites.

The Transition to Natural Gas

The transition from town gas to natural gas was not an overnight event, but an industrial shift spanning the 1920s through the 1950s that fundamentally reshaped energy infrastructure.

The catalyst for this transition began in the 1920s and 1930s with breakthrough advancements in pipeline engineering. The development of high-tensile steel pipe and electric arc welding allowed operators to build large-diameter pipelines that could withstand unprecedentedly high pressures. These were early vintage gas transmission systems. It became economically and physically viable to transport natural gas

discovered alongside oil deposits in places like Texas, Oklahoma, and West Virginia—thousands of miles to distant cities.

World War II temporarily paused civilian pipeline construction, but the post-war boom of the late 1940s and 1950s saw the rapid completion of major interstate transmission lines. Because natural gas was cheaper, cleaner, safer (non-toxic), and contained twice the heating value of town gas, distribution operators moved rapidly to convert their systems. By the mid-to-late 1950s, the transition was largely complete in North America, effectively rendering manufactured gas plants obsolete and setting the stage for higher pressure systems.

The Low-Pressure Baseline of Manufactured Gas

During the town gas era, pressure control was relatively rudimentary. Manufactured gas plants operated on a single-tier, low-pressure system. The gas was distributed directly from the plant's storage holders into the mains at just a few ounces per square inch—barely enough pressure to push the gas through the pipes and maintain a flame at a customer's appliance.

Because the entire network operated at this uniform low pressure, there was no need for individual service regulators at customer homes. The pressure in the street main was identical to the pressure entering the building. Control at the gas plant relied on simple, counter-weighted water-seal governors that manually throttled the gas flow into the town grid based on predictable time-of-day demand (such as evening lighting hours).

The Influx of High-Pressure Natural Gas

When interstate pipelines began delivering natural gas in the 1930s through the 1950s, it arrived at city gates at pressures measuring hundreds of pounds per square inch (PSI). The legacy cast iron and wrought iron street mains could not handle these pressures.

To safely integrate this high-pressure supply, the industry had to invent a multi-stage pressure-reduction framework as gas arrived at Town Border and City Gate Stations. Utilities built large-scale regulating stations at the edges of cities. These stations served as the first line of defense, using control valves to drop transmission pipeline pressures (often 400–800 PSI) to safer "intermediate" or "distribution" pressures (typically 15 to 60 PSI) entering urban areas.

Within the cities, utilities installed localized district regulator stations. These underground vaults or above-ground stations dropped the pressure a second time—taking the intermediate street pressure and lowering it to either a medium-pressure system or a traditional low-pressure system.

The Birth of the Customer Service Regulator

The most profound impact on individual properties was the introduction of the domestic service regulator. As utilities gradually upgraded street mains from low-pressure to medium-pressure (often initially using wrought iron and then steel), the gas traveling under the street was at a much higher pressure than household appliances could safely handle.

To bridge this gap, utilities began installing a dedicated pressure regulator directly before the gas meter at every single home and business. This small, diaphragm-actuated device took medium pressure from the street service line and reduced it to a constant, low delivery pressure (typically about 0.25 PSI, or 7 inches of water column) required for residential stoves and furnaces. Low-pressure systems are often referred to as utilization pressure systems to denote the pressure "utilized" by appliances, boilers, and heaters.

Redundancy and Overpressure Protection (OPP)

Early safety systems included Overpressure Protection (OPP) systems designed to protect systems from over-pressurization. The first OPP methods used relief valves at receipt and intermediate points on the system. They are still in use today. Because they release gas to the atmosphere, staged monitoring systems were developed to manage pressure in a controlled fashion without releasing gas. The most common of these are Monitor Regulator Systems. District stations began utilizing "worker and monitor" setups—two regulators piped in series. If the active worker regulator failed open, the backup monitor regulator would instantly take control to prevent downstream over-pressurization. Service regulators had internal relief mechanisms that vented excess gas safely to the outside atmosphere if the regulator seat failed.

The Genesis of Pipeline Safety Regulations

Background

Federal regulation of natural gas distribution pipeline safety in the United States evolved from fragmented, state-level consensus standards to a risk- and performance-based federal oversight regime. Promulgated by the Office of Pipeline Safety (OPS) on August 19, 1970[6], under Title 49 of the Code of Federal Regulations (CFR) Part 192, the Minimum Federal Safety Standards are established for the life cycle of a pipeline with uniform baseline requirements for pipeline design, materials, construction, operation, and maintenance.

The OPS operates within the Pipeline and Hazardous Materials Safety Administration (PHMSA)[7]. PHMSA establishes federal pipeline safety regulations. States regulate and enforce gas distribution systems and intrastate pipelines. States must adopt federal regulations and may promulgate additional regulations. State public safety commissions approve funding through ratemaking for operations and maintenance, as well as design, construction, and testing of gas distribution systems. Operators define the scope and pace of work as part of their asset management programs. Ratemaking processes established in each state determine approved funding levels, including the scope and pace of work, and consider an operator's proposed work plans.

Over the subsequent five decades, PHMSA updated federal regulations in response to major Congressional reauthorizations, NTSB, IG and GAO recommendations, technological advancements, and lessons from incidents. This section examines the statutory drivers, regulatory updates, preamble contexts, and specific technical provisions governing gas distribution infrastructure from the development of the first consensus standards in the 1920s to the present.

Statutory Foundations and Pre-1970 Landscape

Before direct federal regulation, pipeline safety oversight rested with state utility commissions, which primarily adopted voluntary industry standards—most notably the American National Standards Institute - American Society of Mechanical Engineers (ASME) B31.8 Code for Pressure Piping[8]. State adoption was inconsistent, and compliance monitoring varied widely.

[6] 35 FR 13250, August 19, 1970.
[7] PHMSA was established within the U.S. Department of Transportation under the Norman Y. Mineta Research and Special Programs Improvement Act of 2004 (Pub. L. 108-426), which was signed into law on November 30, 2004. PHMSA officially began operations on February 20, 2005, taking over safety oversight of pipelines and hazardous materials previously managed under the Research and Special Programs Administration (RSPA). The Office of Pipeline Safety existed under these respective organizations since 1968.
[8] American Society of Mechanical Engineers (ASME) B31.8 Code for Pressure Piping, 1968.

ASME is a professional society that led the development of pipeline standards. ASME first established a standard for pressure piping in 1935, and it has been revised over the years through the ASME consensus standards development process. In 1955, members of the group working on the pressurized piping code agreed to develop and publish industry-specific sections as separate code documents. The standard for natural gas distribution and transmission pipelines is referenced as ASME B31.8. The standard includes provisions for material specification, design, welding, construction, testing, and operations and maintenance.

The ASME code for natural gas pipelines, B31.8, includes many provisions now considered essential to pipeline integrity management, including material specification, design, welding, construction, testing requirements, and operation and maintenance requirements.

The Natural Gas Pipeline Safety Act (NGPSA) of 1968

To establish consistent national oversight, Congress enacted the Natural Gas Pipeline Safety Act of 1968[9]. The Act granted the U.S. Department of Transportation (DOT) statutory authority to establish minimum safety standards for gas pipeline facilities. It created a federal-state partnership that allowed states to retain jurisdiction over intrastate distribution systems, provided they adopted standards at least as stringent as the federal baseline.

Many aspects of the ASME Code were codified into a set of Minimum Federal Safety Standards for Transportation of Natural and Other Gas by Pipelines (49 CFR Part 192) beginning in August of 1970. These regulations set requirements for materials, design of pipe and pipeline appurtenances, welding, construction, and operation and maintenance. Subsequent regulations added requirements for corrosion control in 1971.

A key provision of the NGPSA is that materials selection, design, construction, and testing requirements are not retroactive, meaning they cannot be applied to piping and components already in service as of the effective date of the 1970 regulations. This is referred to as the Nonapplication Clause.

Interim Final Rule in 1968

A newly formed Office of Pipeline Safety, within the U.S. Department of Transportation, issued *Interim Minimum Federal Safety Standards for the Transportation of Gas* on November 13, 1968, which became effective on December 13, 1968[10]. The interim standards were built using consensus standards developed and improved since the 1920s, described above. The rule was in direct response to the NGPSA of 1968 and was developed to rapidly implement requirements of the legislation.

Promulgation of 49 CFR Part 192 (August 19, 1970)

On August 19, 1970, the DOT's Office of Pipeline Safety (OPS) published the initial rule *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards* (35 FR 13248), establishing **49 CFR Part 192**.

[9] P.L. 90-481
[10] 33 FR 16500.

While the original regulations are often characterized as prescriptive, the Office of Pipeline Safety in the preamble stated:

> *"As indicated in the series of notices upon which this regulation is based, we intend to state the Federal safety standards in performance terms, rather than as detailed specifications, whenever it is possible to do so within the state-of-the-art and without lowering the required level of safety. Several commenters pointed out certain requirements that are stated in specification language and recommended that they be stated in the final rule in performance terms. As the discussion of this subject in the notices pointed out, the schedule within which this rulemaking action was accomplished did not give us time to develop adequate performance-type substitutes in all of the instances where such a standard would be appropriate. This is one of the areas to which future attention will be devoted and will be the subject of future rulemaking actions where performance-type requirements are appropriate."*[11]

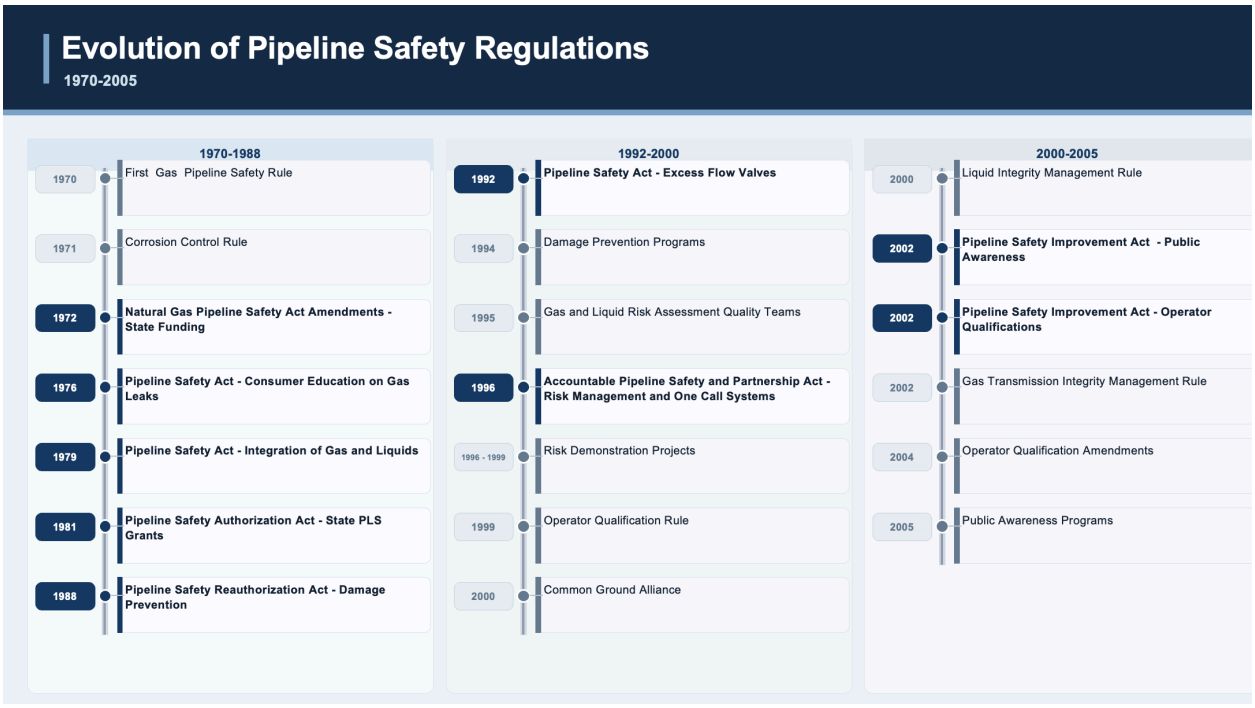
The initial rule began a practice that would serve as the core of pipeline safety regulations through the "incorporation of standards, by reference." The OPS provided the basis for using consensus standards and defined a process for making updates, to keep the basis for the regulations current.

> *"Incorporation by reference. In the proposed rulemaking it was stated that, while the editions of the documents incorporated by reference in the notice were based on the B31.8 Code, the final regulation might be updated to incorporate the most recent edition of the referenced standard or specification. Specific comments were requested on whether the use of the newer editions would cause a significant change in the impact of the regulations involved. The comments in general indicated that use of the latest published edition would not create any problems. However, some commenters questioned how future edition changes would be handled, since pipe and materials built to a new specification could not be used if that specification were not referenced in the regulations. New editions of referenced documents will be reviewed as soon as they are available and, if found to be acceptable, will be included in the referenced documents."* [12]

The initial regulations included initial versions of risk-based thinking. ASME B31.8 used a risk-based approach for design of pipe and to establish allowable operating pressures based on the relative density of the population surrounding the pipeline. The OPS incorporated these provisions into the Minimum Federal Safety Standards in 1970. The approach, known as "Class Location," applies a safety factor for gas transmission pipelines that reduces the maximum allowable operating pressure based on surrounding population density. The greater the population density, the greater the safety factor, and therefore the lower the allowable operating pressure or required increased pipe wall thickness. The risk-based approach using class design factors served as the basis for establishing design and construction requirements, as well as intervals for inspection and operations and maintenance work on transmission pipelines.

[11] Ibid.
[12] Ibid.

Figure 2 shows the timeline of development of legislation, regulations and standards from this point onward.



Source: Developed by Blacksmith personnel reflecting standards, legislative and regulatory publication dates.

Figure 2 – Evolution of Pipeline Safety Regulations – 1970 Through 2005

Technical Provisions for the Original Regulations

The technical provisions of the initial regulations are described in detail below to demonstrate their comprehensiveness and breadth of coverage across the gas distribution systems' life cycle. The detail provided also shows that what appears simple on the surface is actually quite complex. The rigor of the regulations and supporting consensus standards has been developed and improved over the years, reflecting that complexity. The life cycle structure served as the foundation for the initial regulations and was updated as regulations changed in response to new technology and lessons from incidents and near misses.

General – (Subpart A)

The 1970 regulations established **General Requirements (Subpart A),** which defined the regulations' applicability and definitions, introduced an early method for addressing risk, and included a section that incorporated consensus standards by reference. There were seven standards incorporated into the regulations by reference, developed by the American Petroleum Institute (API), 18 by the American Society of Testing and Materials (ASTM) for pipe and fittings; 11 by the American Society of Mechanical Engineers (ASME), three by the Manufacturers Standardization Society of the Valves and Fittings Industry (MSS) for valves and fittings; and three by the National Fire Protection Association (NFPA).

Class location, a surrogate for population density, and corresponding design factors provided a risk-based approach to establishing safety factors for design and material specifications, and inspection and maintenance intervals for operations and maintenance work.

Materials (Subpart B) and Pipe Design (Subpart C)

In its 1970 regulations, the Office of Pipeline Safety established explicit material specifications and qualifications, as well as design standards in **Subpart B (Materials)** and **Subpart C (Pipe Design)** for pipelines after the effective date of the rule. Operators were required to ensure that all steel and plastic piping materials met strict manufacturing standards, design formulas, and yield strength limitations before installation in gas distribution systems.

Steel Welding & Joining Requirements (Subparts E & F) and Construction (Subpart G)

When the original **49 CFR Part 192** standard was promulgated on August 19, 1970, the Department of Transportation (DOT) Office of Pipeline Safety laid out construction, joining, welding, and pressure testing mandates in **Subpart E (Welding)**, **Subpart F (Joining)**, and **Subpart G (General Construction)**.

The regulations established requirements for welding, qualification of welding procedures, personnel, welding preparation and preheating, visual inspection, nondestructive evaluation and repairs. While welding technologies, including NDE methods, have improved, the framework of procedure and personnel qualification, preparation, and inspection have endured and provided sound welding practices. Plastic joining methods included solvent cements, heat fusion, adhesives, and mechanical joints. Construction requirements addressed use of construction specifications, inspection, protection of pipe when placing it in trench, protection from hazards such as ground movement, washouts, and flooding, as well as repairs for damage during construction.

Post-Construction Pressure Testing Requirements (Subpart J)

Before putting any new, replaced, or relocated distribution line into service, operators were required to conduct a post-construction leak test as well as a strength test for certain higher-risk pipelines to ensure that it was leak-free.

Operations (Subpart L) and Maintenance (Subpart M)

The regulations established a framework for managing **gas distribution pipeline operations and maintenance**. The regulations addressed operations and maintenance for assets in service when promulgated, as well as for newly installed pipelines. The primary operations and maintenance (O&M) requirements are defined under **Subpart L (Operations)** and **Subpart M (Maintenance)**.

Corrosion Control Mandates (1971) and Early Statutory Reauthorizations

Subpart I – Requirements for Corrosion Control (June 30, 1971; 36 FR 12297)

While Part 192 initially included general requirements, OPS promulgated comprehensive corrosion control rules under Subpart I in 1971.

Pipeline Safety Act of 1979 (P.L. 96-129)

Congress amended the NGPSA to unify gas and liquid pipeline statutory frameworks, expanding DOT's enforcement authority, increasing civil penalties, and directing clearer safety mandates for distribution systems in populated areas.

Expansion of Plastic Pipe Use & Third-Party Damage Prevention (1980s–1990s)

During the 1980s and 1990s, local distribution companies (LDCs) shifted rapidly toward Polyethylene (PE) plastic piping. Concurrently, data showed excavation damage by third parties was the leading cause of distribution system incidents.

Plastic Pipe Joining Qualifications (1983)

Following incidents related to plastic pipe joining, OPS promulgated technical provisions **(§192.273–§192.287).** These included standardized qualification requirements for joining plastic pipe (butt fusion, socket fusion, electrofusion, and mechanical fittings). They also mandated written joining procedures and hands-on qualification testing for personnel (§192.285).

Pipeline Safety Reauthorization Act of 1988 (P.L. 100-561) & Damage Prevention

The Act required establishment of state one-call notification systems and directed DOT to mandate operator participation. It also included requirements to establish **Mandatory Damage Prevention Programs (§192.614 - Sept 21, 1994; 59 FR 48588):** Required distribution operators to establish written damage prevention programs, participate in public "One-Call" centers (later standardized nationwide as **811**), mark buried facilities prior to excavation, and inspect pipe exposed during digging.

The Transportation Equity Act for the 21st Century (TEA-21)

The law enacted on June 9, 1998 (Public Law 105-178) was a landmark surface transportation authorization act. In the context of pipeline safety and underground infrastructure, TEA-21 made significant contributions to damage prevention by establishing **National "One-Call" Program Incentives:** TEA-21 established federal grant and incentive programs to encourage states to establish, upgrade, or enhance robust One-Call notification systems. The goal was to mitigate excavation and construction damage—historically one of the greatest threats to pipeline and utility integrity—by streamlining communication between excavators and underground facility operators.

TEA-21 established a mandate to improve damage prevention. The RSPA/OPS initiated a study in **1998**. They assembled a diverse stakeholder working group of industry professionals, regulators, excavators, and public safety advocates to evaluate existing one-call systems and compile national damage-prevention best practices. The study's final findings and its catalog of best practices were ultimately published in **June 1999**.

The Common Ground Alliance (CGA) was officially formed in **2000**. Today, a 4,000-member nonprofit trade association, it was established to continue the collaborative work started by the U.S. Department of Transportation's **Common Ground Study[13]. This congressionally mandated study** was completed in 1999 to identify industry best practices for preventing damage to underground utilities. Approximately 160 participants in the study included pipeline and other utility operators like telecom, excavators, locators, railroads and federal and state government agencies. This consensus approach to this study laid the foundation for the practice of shared responsibility, which is critical today to the safe protection of pipelines and other underground utilities. It also led to the creation by the FCC of 811, one national number to call before digging to prevent damage to pipelines and underground utilities.

[13] **Common Ground Study** (*Study of One-Call Systems and Damage Prevention Best Practices*), which was mandated under the Transportation Equity Act for the 21st Century (TEA-21), August 1999.

Operator Qualification (OQ) Rule (August 27, 1999; 64 FR 46853)

Promulgated under Subpart N to address human error, OQ shifted safety focus from general job experience to verified capability. The regulations relied on a Four-Step Covered Task Test to define tasks that directly affect pipeline safety. The rule also established required evaluation via written/oral tests or practical demonstrations to verify an individual's ability to perform covered tasks and recognize and react to Abnormal Operating Conditions (AOCs).

Risk-Based Safety and Integrity Management (2000s–2010s)

Pipeline Safety Improvement Act of 2002 (P.L. 107-355) & PIPES Act of 2006 (P.L. 109-468)

Congress directed the creation of integrity management frameworks. While the 2002 Act focused primarily on high-pressure transmission lines in High Consequence Areas (HCAs), the 2006 PIPES Act directed PHMSA to create a specialized integrity program for gas distribution systems.

The 2002 Act was driven by lessons from incidents on transmission systems such as Olympic Pipeline in Bellingham, Washington, in 1999, and El Paso Natural Gas in Carlsbad, New Mexico. It focused on improving regulatory and consensus standards, building on the work of the risk assessment quality teams of the 1990s and the Risk Demonstration Projects.

Following numerous public meetings which led to a national consensus about the foundation of key principles, integrity management rulemaking followed over the years, with the first Hazardous Liquids rule on December 1, 2000, for operators owning or operating 500 or more miles of hazardous liquid pipelines, and it took effect on May 29, 2001. On January 16, 2002, OPS promulgated a follow-up final rule expanding the requirements to cover operators of fewer than 500 miles of hazardous liquid pipelines, which became effective February 15, 2002.

Recognizing the safety value of explicitly addressing known threats using a risk-based approach adopted from the transmission integrity standards development and rulemaking processes, OPS moved to develop integrity management regulations for gas distribution systems. As had been the practice since the 1970s, the regulations were built on a strong foundation of consensus standards and research, including, in the case of gas distribution, organizations such as the Gas Research Institute and NYSEARCH.

NYSEARCH was originally formed as the Research, Development, and Demonstration (RD&D) committee of the New York Gas Group (NYGAS), which was founded in 1973. In 1996, NYSEARCH transitioned its RD&D model into an all-voluntary, project-by-project program, allowing gas distribution utilities to co-fund specific research initiatives. In the early 2000s, it expanded beyond New York to include gas operators across North America. On January 1, 2003, NYGAS merged with the New England Gas Association to form the Northeast Gas Association (NGA). NYSEARCH became a voluntary research and development sub-organization of NGA, managing natural gas technology projects across North America.

Public Awareness Programs

Prompted by major pipeline incidents, including the 1999 Olympic Pipeline, Bellingham and 2000 El Paso Natural Gas, Carlsbad accidents, and mandates in the Pipeline Safety Improvement Act of 2002, the Pipeline and Hazardous Materials Safety Administration (PHMSA) overhauled § 192.616. The final rule incorporated API Recommended Practice (RP) 1162 (*Public Awareness Programs for Pipeline Operators*), transforming high-level "public education" into detailed, formal, and enforceable "public awareness" standards on May 19, 2005.

The Advent of Risk Assessment

The transition from prescriptive "one-size-fits-all" regulations to proactive, risk-based requirements represents one of the most significant evolutions in federal pipeline safety. RSPA formed Gas Risk Assessment Quality and Liquid Risk Assessment Quality Teams (referred to as the Gas RAQT and Liquid RAQT, respectively) in 1993. The RAQTs evaluated the state of the art of risk assessment in the respective sectors, including modeling methods and how risk models were used in planning operations, maintenance and modernization work.

The Gas RAQT efforts were informed by work conducted by The Hartford Steam Boiler Inspection and Insurance Company (HSB) for the Gas Research Institute (GRI). At that time, HSB was the largest insurer of process equipment in the world including oil and gas. They not only brought deep knowledge of the industry but also an insurer's view of risk management. GRI published a four-volume set of documents developed by HSB, entitled, ***Natural Gas Pipeline Risk Management***[14]***,*** that examined the state of risk assessment and risk management in the natural gas pipeline industry, and documented the extent of its application in other industries. The primary goal of these reports was to inform the natural gas industry's transition from rigid, historical prescriptive rules to **risk-based, reliability-centered frameworks** for pipeline safety, integrity management, and design.

From 1996 through the end of the decade, PHMSA encouraged gas and liquid operators to develop demonstration projects to show the efficacy and value of risk-based approaches. The projects involved adjusting inspection and maintenance intervals based on risk to demonstrate equal or better safety performance. With legislative support in 2000, the program expanded. While risk assessment was expected to better allocate resources and consider regulatory alternatives, a negative trend in safety performance shown in Figure 1 in the early 2000s accelerated the focus on risk-based methods. Broader use of risk in replacement programs and learnings from gas and liquid transmission led the distribution industry and PHMSA, in concert with the National Association of Pipeline Safety Representatives (NAPSR), to commission the Gas Piping Technology Committee in 2005 to develop a framework for Distribution Integrity Management.

With legislative support from Congress, PHMSA used the framework to create a performance-based regulation in 2009 known as distribution integrity management, where operators would adopt risk-based Distribution Integrity Management Programs (DIMP). Even with recent legislation and DIMP regulations in effect, in 2011 the Secretary of Transportation issued a Call to Action that placed additional emphasis on safety improvements. Although the Call to Action addressed all modes of pipeline transportation, the Secretary said gas distribution replacement and rehabilitation programs needed to accelerate. Later that year, the National Association of Regulatory Utility Commissioners (NARUC) sent a written response and action plan to Secretary LaHood detailing the commitments and resolutions passed by state utility commissioners to support accelerated replacement of vintage and leak-prone natural gas infrastructure.

Distribution Integrity Management Program (DIMP – Subpart P)

Congress reauthorized PHMSA with the PIPES Act of 2006 (P.L. 109-468), establishing funding for and the basis for development of regulations for distribution integrity. Figure 3 shows the regulations developed for DIMP and those that followed, strengthening DIMP and overall pipeline safety.

[14] Hartford Steam Boiler Inspection and Insurance Company, Radian Corporation, & Gas Research Institute. (1995). *Natural Gas Pipeline Risk Management: Final Report* (4 vols., Report No. GRI-95/0228). Gas Research Institute.



Source: Developed by Blacksmith personnel reflecting standards, legislative and regulatory publication dates.

Figure 3 – Evolution of Pipeline Safety Regulations – 2006 through 2026

A Distribution Integrity Management Program (DIMP), mandated under 49 CFR Part 192, Subpart P (§ 192.1001–192.1015), establishes a systematic framework for gas distribution operators to identify, assess, and mitigate pipeline safety risks. DIMP is structured around seven core element steps. PHMSA promulgated a rule on December 4, 2009 (74 FR 63905), codified under Subpart P (§192.1001–§192.1015). The rule required all gas distribution operators to develop and implement a written DIMP plan by August 2, 2011, incorporating seven core elements as shown below in Table 1.

Table 1 – DIMP Core Elements

Core element	Description
System Knowledge	Maintain records of pipe materials, age, operating pressures, and failure histories.
Identify Threats	Evaluate eight threat categories (corrosion, natural forces, excavation damage, outside force, material/weld failure, equipment failure, incorrect operation, and other concerns).
Evaluate and Rank Risk	Prioritize risk profiles across distribution mains and service lines.
Implement Mitigation	Execute preventive/mitigative measures, such as replacement of higher-risk vintage materials (cast iron, unprotected bare steel, Aldyl-A plastic).
Measure Performance	Track key safety performance indicators (e.g., hazardous leaks repaired by cause).
Periodic Evaluation	Perform program updates at intervals not exceeding five years.
Reporting	Submit performance metrics annually to PHMSA and state regulators.

DIMP and how safety performance has improved when it is combined with repair, rehabilitation, and replacement is discussed in greater detail in Section 4.

Excess Flow Valve (EFV) Expansion Rules

- 2009 Rule: Mandated EFV installation on new or replaced single-family residential service lines operating at ≥ 10 psig.
- 2016 Rule[15]: Expanded EFVs to multi-family residential lines, small commercial services, and mandated manual curb valves where EFVs are technically infeasible.

Modern Statutory Mandates and Regulatory Updates (2020s–Present)

PIPES Act of 2020 (P.L. 116-260) and Post-Merrimack Valley Mandates

Following the September 2018 over-pressurization incident on the Columbia Gas distribution system in Merrimack Valley, MA, Congress enacted the PIPES Act of 2020, directing enhancements to gas distribution safety and environmental controls.

Technical Provisions

- Over-pressure Protection Redundancy: Proposed secondary safety controls (e.g., monitor regulators, automatic shut-off/slam-shut valves) on low-pressure distribution systems to prevent single-point regulator failure over-pressurization.
- Management of Change (MOC): Mandated formal MOC processes for distribution system modifications, regulator station adjustments, and pressure setpoint changes.
- Leak Detection and Repair (LDAR): Required operators to deploy advanced leak detection technologies, reclassified Grade 3 leaks, and established mandatory repair timelines to reduce fugitive methane emissions.

Regulatory Reform and Technical Updates (2021–2026)

- Farm Taps (§192.740): Streamlined regulatory oversight of farm taps, moving their maintenance under dedicated operational requirements while preserving safety checks.
- Plastic Pipe Technical Amendments: Updated allowable design factors and temperature limits for high-density polyethylene (HDPE) and polyamides (PA-11/PA-12).
- Incorporation by Reference (IBR): Adopted updated consensus standards from ASME, ASTM, and API to align Part 192 with modern materials testing, joint inspection, and quality assurance methods.

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[15] Expanding the Use of Excess Flow Valves in Gas Distribution Systems to Applications Other Than Single-Family Residences, 81 FR 70987, October 14, 2016, corrected 81 FR 72739, October 21, 2016.

PHMSA's Office of Pipeline Safety Rulemaking in Response to PIPES Act of 2020 (P.L. 116-260) and Post-Merrimack Valley Recommendations by the NTSB

PHMSA published the Notice of Proposed Rulemaking (NPRM) for the Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives in the Federal Register on September 7, 2023[16].

During the May 28, 2026 meeting of the Gas Pipeline Advisory Committee (GPAC), the 15-member advisory body reviewed PHMSA's Notice of Proposed Rulemaking (NPRM) on the Safety of Gas Distribution Pipelines. The rulemaking stems from the congressional mandates in the PIPES Act of 2020 following the 2018 Merrimack Valley incident.

The committee endorsed every core proposal submitted by PHMSA but attached specific conditions to each voting motion to better align implementation timelines and ensure regulatory precision with PIPES Act mandates.

Key voting items and outcomes included:

- Over-pressurization Protection for Low-Pressure Systems: Evaluated requiring secondary overpressure protection and remote pressure monitoring for new, replaced, or modified regulator stations. GPAC members supported providing longer compliance windows for upgrading existing stations, allowing operators access to a range of effective alternative protection methods, and accepting mechanical pressure devices alongside remote monitoring on legacy lines.
- Management of Change (MOC) & Emergency Response: The GPAC voted to adopt formal MOC requirements for significant pressure control modifications—extending formal MOC standards beyond gas transmission operators to distribution systems for the first time. They also backed requirements for written procedures to investigate over-pressurization events and immediately notify 911 centers (Public Safety Answering Points) during emergencies.
- On-Site Pressure Monitoring During Construction (§ 192.640): Voted to support the proposal as written, requiring an operator-qualified individual (Subpart N) to be present and monitor pressure during high-risk construction activities capable of causing over-pressurization.
- Traceable & Verifiable Pressure Control Records (§ 192.638): Endorsed mandates for operators to maintain complete records detailing regulator station set-points, sensing line locations, and overall system configurations.
- Distribution Integrity Management Program (DIMP) Threat Updates: Approved explicitly adding over-pressurization to DIMP threat models, along with mandatory risk evaluations covering cast iron.

The GPAC's conditional approvals now serve as recommendations for PHMSA as the agency prepares to issue the final rule.

Risk remains a focus area for PHMSA. During his July 16, 2025 confirmation hearing before the Senate Committee on Commerce, Science, and Transportation, PHMSA Administrator Paul Roberti made comments supportive of the use of risk in managing systems and advancing technology.

[16] 88 FR 61746

State Pipeline Safety Regulation

PHMSA develops and enforces pipeline safety regulations at the federal level. States must incorporate the federal regulations and may add requirements for gas distribution and intrastate transmission through state legislative actions.

Some states added provisions to address lessons learned from the Columbia Gas Incident in the Merrimack Valley, even though PHMSA had already undertaken regulatory development in response to the PIPES Act of 2020 and NTSB Recommendations. Examples include Massachusetts, Connecticut, and New York.

Following the 2018 Columbia Gas incident, state utility commissions and legislatures across the United States implemented regulatory shifts. State-level regulatory changes fell primarily into two buckets: direct legislative and administrative reform, and multi-state operational enforcement actions targeting Columbia Gas subsidiaries.

States Implementing Legislative and Regulatory Reforms

The National Association of Pipeline Safety Representatives (NAPSR) maintains a document referred to as "The Compendium[17]," which provides details on legislative background and regulatory requirements within each state. Examples of recent legislative and regulatory actions are summarized below.

- **Massachusetts:** Enacted Chapter 208 of the Acts of 2018, mandating licensed Professional Engineer (PE) review and stamping for gas infrastructure projects affecting pressure. The Department of Public Utilities (DPU) subsequently promulgated regulations requiring secondary overpressure protection, enhanced Management of Change (MOC) protocols, and standardized methane leak reporting (220 CMR 115.00).
- **Pennsylvania:** The Pennsylvania Public Utility Commission (PAPUC) eliminated the use of incremental uprates for converting low-pressure distribution systems to elevated pressures. PAPUC also enforced stricter mapping accuracy standards, mandatory service-line tap verification, and enhanced quality control protocols across gas utilities.
- **Vermont:** The Vermont Public Service Department and Public Utility Commission reviewed NTSB recommendations and eliminated administrative exemptions for public utilities, requiring utility operators (such as VGS) to ensure licensed PE stamps on system design plans.
- **Maine:** The Maine Public Utilities Commission (MPUC) instituted heightened operational review requirements for natural gas utilities regarding low-pressure system modifications, emergency communications with local first responders, and asset mapping accuracy.

In Ohio, Indiana, Virginia, Maryland, and Pennsylvania, state utility regulators issued administrative orders requiring:

- **Removal of Regulatory Exemptions:** Phasing out public utility engineering exemptions to enforce independent PE oversight for pressure-regulating station modifications.
- **Mandatory Management of Change (MOC):** Standardizing formal MOC safety evaluations before performing work on sensing lines, regulator stations, or main cut-outs.

[17] https://www.napsr.org/compendium.html

- **Traceable Pressure Records:** Ordering comprehensive audits to ensure system drawings and sensing line configurations are traceable, verifiable, and complete.

The Role of Federally Sanctioned Advisory Committees

The OPS utilizes Federal Advisory Committees chartered under the Federal Advisory Committee Act (FACA) as a core peer-review and stakeholder consensus mechanism for rulemaking. For gas pipelines, the Technical Pipeline Safety Standards Committee (TPSSC), commonly referred to as the Gas Pipeline Advisory Committee (GPAC), anchors this process.

Statutory Mandate & Legal Authority

Under **49 U.S.C. § 60115**, OPS/PHMSA is required by federal statute to submit proposed pipeline safety standards—and any associated risk assessments or cost-benefit analyses—to a technical advisory committee prior to finalizing rules.

Because GPAC is governed by **FACA (5 U.S.C. Ch. 10)**, OPS must ensure:

- Meetings are open to the public, transcribed, and made available on public dockets.
- Committee charters are renewed every two years through DOT and the General Services Administration (GSA).

Tripartite Composition of Advisory Committees

To ensure balanced representation and prevent regulatory capture, GPAC consists of **15 members** appointed by the Secretary of Transportation, divided equally into three representative sectors:

1. **Government:** Federal and state regulators (e.g., state utility commissions, PHMSA officials).
2. **Industry:** Technical experts representing the natural gas transmission, distribution, and underground storage sectors.
3. **Public:** Representatives from safety advocacy groups, environmental organizations, academic institutions, or the general public.

Key Functions in Gas Pipeline Rulemaking

OPS utilizes GPAC as a mandatory review body during the notice-and-comment rulemaking process:

A. Peer Review of Proposed Standards

Before OPS can issue a final rule for natural gas pipelines, GPAC must review any Notice of Proposed Rulemaking (NPRM). The committee evaluates whether the proposal is:

- Technically feasible
- Reasonable
- Practicable
- Cost-effective

B. Review of Regulatory Impact Analyses (RIA)

GPAC assesses the validity of the economic data, risk assessments, and cost-benefit methodologies OPS uses to justify new rules. Members vote item-by-item on whether the agency's evaluations are supported by available data.

C. Voting and Consensus Building

During GPAC meetings, members debate specific provision-by-provision language of complex rules. GPAC votes on whether proposed regulatory language is technically sound and cost-effective. The meeting transcript, along with presentation slides and recorded votes, constitutes the official advisory report.

D. Incorporation into Rulemaking Preambles

OPS is legally required to include GPAC's recommendations—and minority views, if applicable—in the preamble of the Final Rule published in the *Federal Register*. If PHMSA rejects a majority recommendation from GPAC, the agency must explicitly state its reasons in the public preamble.

Significant Examples of the GPAC Role in Gas Pipeline Safety

OPS has relied heavily on GPAC to navigate landmark gas pipeline regulations, including:

A. Gas Integrity Management Program (IMP) Rules (49 CFR Part 191/192): GPAC reviewed and helped define High Consequence Areas (HCAs) and the use of risk assessment to prioritize work. The GPAC also considered integrity assessment technologies to evaluate system condition, the need for repairs, and preventive and mitigative measures, as well as assessment intervals for HCAs.

B. Original Gas Distribution Integrity Management Program (DIMP) Rule[18]: When PHMSA (and its predecessor RSPA) originally developed the 49 CFR Part 192 Subpart P regulations for gas distribution integrity management, the GPAC met on December 12, 2007, to conduct initial peer reviews and discuss the framework for distribution integrity management regulations. On May 28, 2008, GPAC met formally to review the proposed DIMP Notice of Proposed Rulemaking (NPRM) before its publication in the *Federal Register*. GPAC reconvened on December 9, 2008, to review public comments, cost-benefit analyses, and finalize voting recommendations on the proposed DIMP standards before PHMSA issued the Final Rule in December 2009.

C. The "Mega Rule" (Safety of Gas Transmission Pipelines): GPAC held a series of extensive, multi-day public meetings between 2017 and 2019 to dissect massive regulatory changes, including maximum allowable operating pressure (MAOP) reconfirmation, material verification, and non-destructive testing requirements.

D. Leak Detection and Repair (LDAR) and Valve Installation Regulations: GPAC held a series of meetings to consider and deliberate on OPS's proposed approach to leak detection and repair for gas transmission and distribution. The meetings followed a broader public stakeholder meeting on Leak Detection, Leak Repair, and Methane Emission Reductions on May 5–6, 2021, which informed early rulemaking development. The GPAC met to evaluate PHMSA's proposed Gas Pipeline Leak Detection and Repair (LDAR) rule (Docket No. PHMSA-2021-0039) across two major multi-day public sessions, a first session on November 27 – December 1, 2023 and a second session from

[18] *Docket No. PHMSA-RSPA-2004-19854 / PHMSA-2004-19854*

March 25 – March 29, 2024. PHMSA has yet to promulgate a final LDAR rule. It is a priority that the current administration intends to address. The GPAC will continue to serve as the critical forum as PHMSA continues work on the LDAR rulemaking in 2027 and beyond.

E. Gas Distribution Rule Enhancements: As described above, GPAC held a full-day public meeting on May 28, 2026 in Washington, D.C. (and virtually) dedicated specifically to discussing and voting on the proposed Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives rule. During this session, the committee evaluated core proposals regarding secondary overpressure protection on low-pressure systems, remote pressure monitoring, and integrity management updates, guided by Congressional mandates following the 2018 Merrimack Valley incident. PHMSA issued a Notice of Proposed Rulemaking (NPRM) on September 7, 2023.

PHMSA Oversight

PHMSA and its Office of Pipeline Safety (OPS) are collectively overseen by the Department of Transportation (DOT), the U.S. Government Accountability Office (GAO), the DOT Office of Inspector General (OIG), and the National Transportation Safety Board (NTSB) to enforce operational safety and legislative accountability.

The GAO serves as the primary non-partisan legislative oversight body, evaluating PHMSA's execution of pipeline safety regulations and congressional mandates driven by acts like the PIPES Acts of 2016 and 2020. Its oversight focuses on several core areas: auditing rule implementation and regulatory execution (such as gaps identified in the Gas Transmission "Mega Rule"), reviewing risk-based Integrity Management Programs in High Consequence Areas, tracking emerging priorities like methane emissions and leak-detection compliance, monitoring federal-state regulatory coordination and resource allocation, and investigating high-profile incidents or special permits like those for the Keystone Pipeline. Following audits, the GAO issues formal recommendations, maintains a public tracking database, and testifies before congressional committees.

Concurrently, **the DOT OIG acts as an independent body ensuring PHMSA operates efficiently and transparently.** The OIG conducts systematic audits and program evaluations targeting inspection and enforcement effectiveness, grant and funding administration, and rulemaking timeliness. Its Office of Investigations tackles criminal and administrative fraud, such as falsified inspection records, unpermitted hazardous material transport, and grant misuse. Finally, the OIG submits semiannual reports to Congress, tracks corrective action plans to completion, and prioritizes risk assessments for major infrastructure investments to prevent administrative waste.

The National Transportation Safety Board (NTSB) oversees the Pipeline and Hazardous Materials Safety Administration (PHMSA) through independent, post-incident investigations and formal safety recommendations, distinguishing itself as a non-regulatory investigative body created by Congress separate from PHMSA's executive regulatory role within the U.S. Department of Transportation.

Through independent accident investigations, the NTSB determines probable causes following major pipeline incidents or hazardous material spills, examining both operator actions and PHMSA's oversight to evaluate whether existing regulations or inspections were adequate. To address systemic gaps, the NTSB issues official safety recommendations—designated as "P" for pipeline or "R" for rail and hazardous materials—urging PHMSA to adopt new rules or update standards, which have historically driven major regulatory shifts like automatic shutoff valve mandates and Pipeline Safety Management Systems following 2010 incidents in San Bruno, California, and Marshall, Michigan.

To ensure accountability, federal law requires PHMSA to formally respond to every recommendation, with the NTSB tracking these responses via its public CAROL database and PHMSA submitting annual reports to Congress detailing closure actions.

Summary

The evolution of 49 CFR Part 192 reflects the important practice of incorporating standards by reference along with adoption of risk-based safety frameworks. Driven by statutory directives from the Natural Gas Pipeline Safety Act of 1968 through the PIPES Act of 2020, gas distribution regulations have continually adapted to address advances in materials and technology, third-party damage, human factors, and environmental impact. Today, the federal regulatory architecture combines baseline structural standards with integrity management and mandatory risk mitigation to protect public safety and system reliability. Broad oversight of PHMSA's work is conducted by bodies that represent the government's executive level and, ultimately, the public, including the Department of Transportation, the Office of the Inspector General (IG), the U.S. Government Accountability Office (GAO), and the National Transportation Safety Board (NTSB).

3. Repair, Rehabilitation and Replacement

Background

An important component of asset management and DIMP is determining the approach to mitigative actions to address identified system risk. This section describes approaches to be considered, including repair, rehabilitation, and replacement of distribution system pipes and components, and how these approaches have evolved and matured over time. When selecting an approach, it is critical to understand the nature of the risk, which actions can be taken given the specific nature and location of the risk, and whether each action will effectively reduce or eliminate the risk. This section describes the role of actions available to address leak-prone pipe.

The section begins by describing the evolution of materials used to construct gas distribution systems, including mains and services. The objective is to provide background on the variety of materials that operators have managed over time, using the regulatory construct described above within the specific unique regional and city/town characteristics, including the growth and density of population and businesses, the simultaneous growth of other underground infrastructure, and the native soils and weather conditions of those areas.

History of Gas Distribution Mains

The evolution of gas distribution mains reflects a shift from rigid, brittle metals prone to corrosion to modern, flexible, chemically inert synthetics.

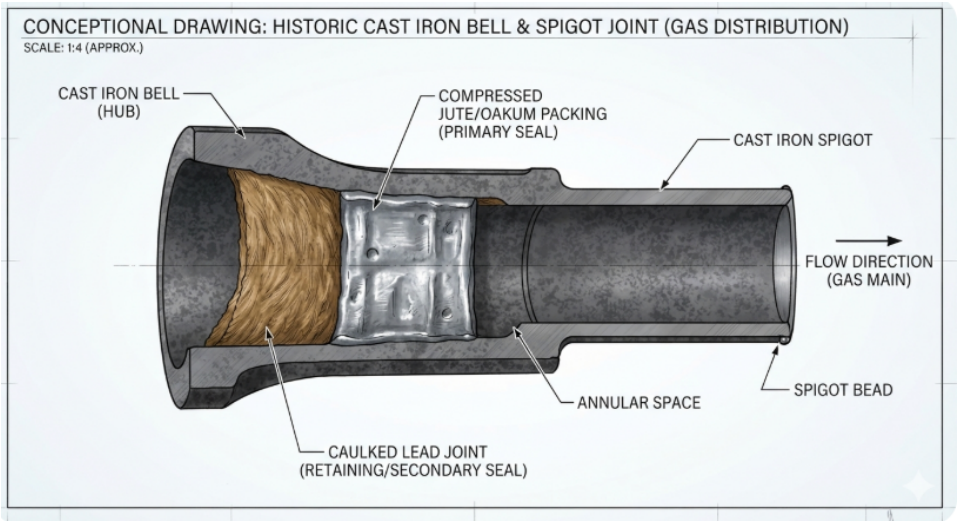
From the **early 1800s through the 1950s**, **Cast Iron** served as the foundational material for early gas networks distributing manufactured "town gas." While cast iron possessed excellent structural strength under compression, its extreme brittleness made it highly vulnerable to fractures caused by soil movement, traffic loads, and frost heave. It was also prone to graphitization—a form of corrosion that leaches iron, leaving a weak graphite structure that easily fails. Concurrently, from the **late 1800s to the 1960s**, **Wrought Iron** was frequently deployed for smaller-diameter mains. It offered slightly better ductility than cast iron but remained highly susceptible to environmental corrosion.

Additionally, cast iron pipe sections, generally twelve feet long, are joined by bell-and-spigot joints. A cast iron bell-and-spigot joint (historically referred to as a hub-and-spigot joint) was the standard engineering method for connecting low-pressure gas distribution mains from the 19th century through the mid-20th century.

The joint depicted in Figure 4 relies on interlocking geometry where the straight end of one pipe (spigot) is inserted into the flared end of the next pipe (bell or hub). The annular space between them is then packed with a sealing matrix. The packing used for bell-and-spigot joints was very effective during the early years of manufactured gas, a “wet gas” in which moisture interacted with the caulking/packing to keep gas from escaping through voids. As manufactured gas was replaced with pipeline gas, a much drier gas, some of the caulking materials began to dry out and eventually led to leakage from the joint. This transition became a maintenance and safety concern as bell joints became the leading cause of leakage in gas distribution mains.

Cast iron is a matrix of graphite (carbon) and iron. Over time, the iron can oxidize and yield corrosion products that are no longer structurally sound. The rate of degradation through corrosion of steel and

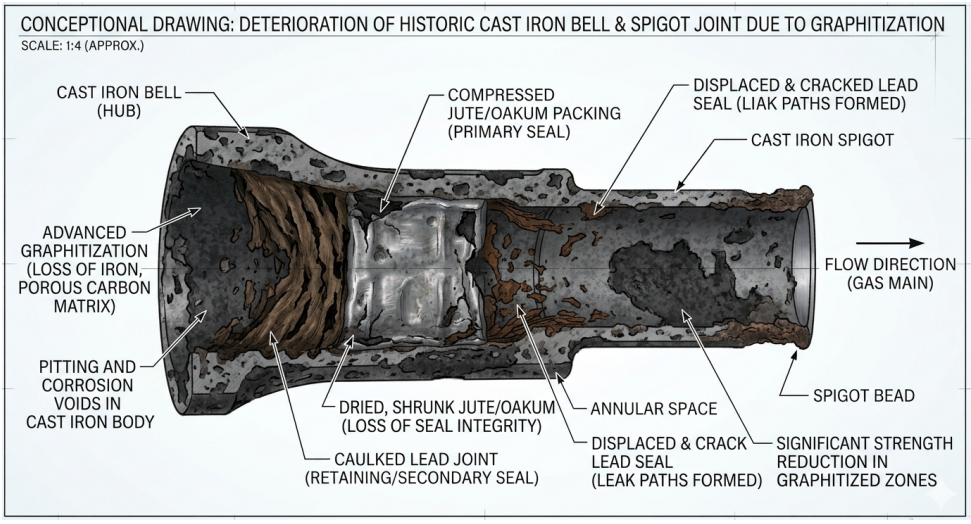
graphitization of cast iron depends on a variety of factors, such as soil types and corrosive constituents, which are not readily known.



Source: Depiction Courtesy of Google BN2

Figure 4 – Typical Cast Iron Bell and Spigot Joint

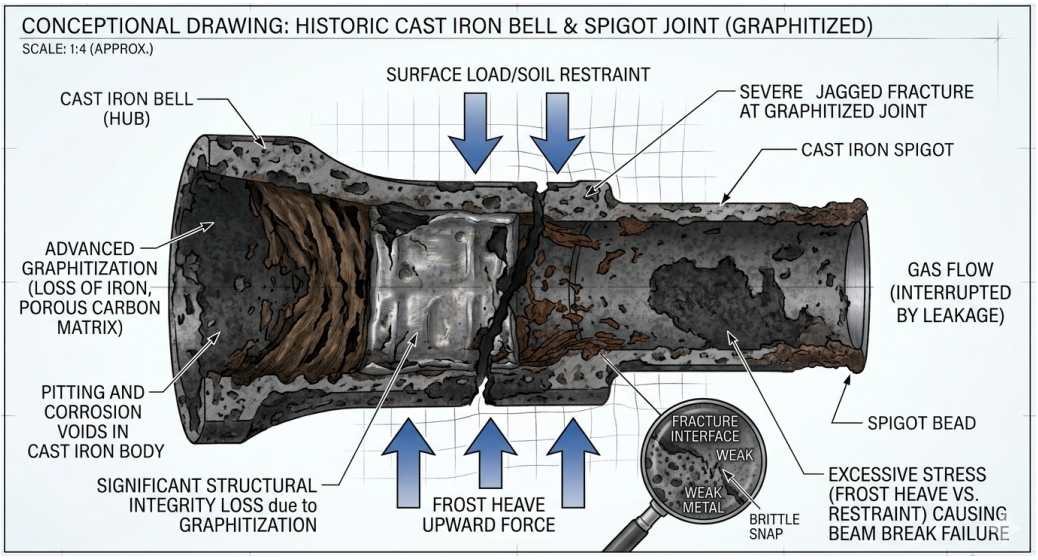
Graphitization is a process, shown in Figure 5, that can be quite rapid depending on the environment around the pipe.



Source: Depiction Courtesy of Google BN2

Figure 5 – Graphitization of Cast Iron

Over time, the pipe loses structural integrity, then becomes subject to threats beyond corrosion failure, including outside force - frost heave, ground movement, and wheel loading from vehicles, as well as failure due to other outside forces such as construction in proximity (encroachment), where nearby excavation destabilizes the supporting soil and the cast iron is subjected to stress and can fracture, either immediately or over time as latent “damage”, even though it was not struck by excavation equipment as shown in Figure 6. (Also refer to Figures 17 and 18, below).



Source: Depiction Courtesy of Google BN2

Figure 6 – Impact of Frost Heave and Surface Loading on Graphitized Cast Iron

Early steel was used bare, i.e., uncoated and unprotected from conditions that cause corrosion. Bare steel remains a significant part of distribution systems. It is difficult to cathodically protect, and leaks become more prevalent over time. It is prone to the same threats as cast iron, including frost heave and surface loading. It also has thinner wall thickness, so smaller-diameter steel is prone to bending and breakage.

By the **1920s**, **Steel** mains were introduced to accommodate the significantly higher operating pressures required as the industry transitioned to natural gas. Steel remains a premier choice for high-pressure systems because of its higher tensile strength. As described above, the 1970 regulations prohibited future use of bare and unprotected steel. In a brief transitional period between the **1950s and 1970s**, **Ductile Iron** was introduced as an upgrade to cast iron. The addition of magnesium gave the iron greater flexibility and impact resistance, drastically reducing catastrophic breaks.

However, ductile iron was quickly superseded by the modern industry standard: **Plastic (Polyethylene / PE)**. Emerging in the **1960s**, early PE formulations (such as **PE 2406 and PE 3408**) transformed gas utility engineering. Today, high-performance materials like **PE 4710** are used in gas distribution systems, including high-pressure networks. **Polyamides (PA11/PA12)** are not used broadly today but are an option for even higher-pressure applications provided for in standards incorporated by reference. Plastic is entirely immune to electrochemical corrosion, highly flexible, and joined using heat-fusion techniques that create homogeneous, leak-free joints stronger than the pipe itself.

History of Gas Service Lines

Because service lines are smaller, must navigate tight spaces, and connect the street main directly to a customer's meter, their material history favors ease of installation, pliability, and localized corrosion resistance.

During the **early to late 1800s**, the earliest manufactured gas services utilized **Lead and Wood**. Lead was favored for its extreme pliability, while bored-out logs were used out of pure availability. Both materials were quickly abandoned due to high leakage rates, structural decay, and shifting soil failures. From the **late 1800s through the mid-1900s**, threaded **Wrought Iron and Bare Steel** became the standard. While they easily contained system pressures, their direct contact with moisture and acidic soil resulted in external corrosion over time, and over time could lead to leaks.

From the **1930s to the 1980s**, **Copper** tubing became highly popular for service lines. Engineers favored copper because it was flexible, easy to bend around obstacles, use as an insert inside an older bare steel service line, and was resistant to standard soil corrosion. However, utilities later discovered that trace amounts of hydrogen sulfide in natural gas reacted with the copper, causing internal flaking. These flakes traveled down the line, clogging regulators and meters. As a result, copper use is now heavily restricted or outright banned.

From the **1950s through the 1970s**, plastics emerged, specifically **Cellulose Acetate Butyrate (CAB)** and **Polyvinyl Chloride (PVC)**. CAB proved chemically unstable over decades of burial, and PVC was brittle, often cracking under mechanical strain or in cold weather. Utilities have since systematically replaced most of these early plastics through replacement programs, as they have with other leak-prone pipe.

From the **1970s to the present**, utilities adopted **Polyethylene (PE)** for gas services. Modern PE service lines are resilient and cost-effective to install. Because they are flexible, utilities can use trenchless technologies like directional boring or simply "insert" a new, smaller plastic line directly through a failing legacy steel or copper service pipe, minimizing the need to excavate in both the public right-of-way and on customer property.

The History of Pressure Regulation and Control

Early gas systems distributed low-pressure town gas through local cast-iron mains, relying on crude, counterweighted bell-type gasometers to set system pressure. As systems were expanded, the industry transitioned from low-pressure local systems to pressurized networks. This transition required precise, dynamic control mechanisms that could safely reduce pressure from transmission systems to steady, lower delivery pressures for end-use appliances, measured in inches of water column, which correspond to fractions of a pound per square inch gage. Pressure regulators reduce and control pressure, so pipelines, meters, customer piping, and gas-burning equipment operate within their intended limits, a maximum allowable operating pressure (MAOP).

Regulator selection depends on factors such as operating pressure, flow capacity, temperature, accuracy, noise, materials, maintenance needs, and automation. Pressure-regulating equipment includes main-line, self-operated, pilot-operated, and service regulators; a typical residential service regulator reduces distribution pressure to about 7 inches of water column at the customer's meter.

Proper pressure regulation protects customers and infrastructure, supports accurate gas measurement and billing, and ensures appliances receive the consistent pressure needed for safe combustion. Pressure control safety features, potential failure modes, and maintenance requirements are important elements of the process. Relief mechanisms, vents, pressure-limiting devices, and slam-shut systems help prevent unsafe pressure conditions, but ruptured diaphragms, blocked vents, freezing, flooding, contamination, or mechanical wear can still cause problems. Proper vent placement, routine inspection, preventive maintenance, and timely replacement of worn components are therefore essential to maintaining reliable operation.

The Role of Repairs in Managing Mains and Services

In the early years of the gas system, when assets were new, repairs were the primary approach to manage leaks. Repairs remain a primary tool today to address gas leaks that are deemed hazardous and require immediate mitigation or repair or may become hazardous and require mitigation or repair within a year. For non-hazardous leaks, operators monitor their system through leak surveys and leak monitoring, in line with

regulatory requirements and the operating company's operations and maintenance procedures described in the prior section, until the leak requires repair or the gas pipe requires replacement. Thorough engineering evaluation of the asset materials and condition and operational evaluation of the location and performance history are considered prior to determining the best measure to address leak-prone pipe.

For repair to be considered as a viable option to address a leak, the material must be free of widespread graphitization or brittle crack growth. On cast iron pipe, if the issue is a localized joint leak (such as a single dry bell-and-spigot joint) and metallurgical testing confirms the pipe body is free of deep graphitization, an external joint repair kit can restore joint tightness. The repair is limited to that joint or a series of joints with little excavation or inspection of the existing twelve-foot pipe section between joints. If unknown graphitization is widespread across the segment, the pipe loses the beam strength needed to support a clamp, and subsequent soil settlement can trigger a break adjacent to the joint repair. Similarly, on plastic pipe, a spot repair via an electrofusion patch or squeeze-off and coupling replacement works well for mechanical gouges on modern polyethylene (PE). However, if vintage plastic such as Aldyl A shows evidence of cracking, localized patching may fail as adjacent micro-cracks continue to propagate.

If a pipe segment has a chronic history of recurring leaks, an operator will consider alternatives such as replacement or rehabilitation. A spot repair is a rational method on a segment of leak-prone pipe (LPP) when the defect is isolated and local rather than a symptom of systemic material degradation, such as individual bell and spigot joints, graphitization of cast iron, or corrosion of steel.

For repair to be viable, it must stem from an identifiable, localized event—such as a third-party excavation scrape, a single coating holiday, or a discrete area of stray current discharge—while the adjacent pipe wall retains its full pressure-containing capacity. Non-destructive examination (NDE) or ultrasonic testing (UT) thickness gauging confirms that the pipe wall around the defect has sufficient thickness and structural soundness to securely anchor a repair sleeve, clamp, or electrofusion fitting.

Concrete or asphalt cover impedes leaking gas from rising naturally to the surface. Gas follows the path of least resistance, often migrating horizontally along subsurface utility trenches, gravel bedding, pipe backfills, or soil void spaces. The point where gas disperses and rises to the surface (e.g., through a pavement crack, foundation wall, or utility vault) can be tens or hundreds of feet away from the actual leak source on the pipe. Gas entering nearby structures can create hazardous accumulation points inside buildings or distant utility manholes, obscuring the release origin.

If leaks increase and the operator determines gas can readily enter nearby secondary infrastructure such as electric ducts, telecommunications conduits, sewer lines, storm drains, or other abandoned underground structures, the operator may consider replacement and rehabilitation.

The Evolution of Main Replacement Programs

This section discusses the evolution of main replacement programs, which remain the most effective measure for permanently addressing gas system risk identified through DIMP, with the added benefits of eliminating existing leaks, preventing new leaks on existing leak-prone pipe, and reducing emissions. Only a small portion of the main inventory is replaced each year, focusing on the highest-risk gas main segments. The vast majority of gas systems are operating each and every day safely by deploying all of the tools in the DIMP toolbox, including leak surveys and leak repairs, extending the life of the majority of the gas system, including remaining leak-prone pipe until such time as it is determined that that pipe is no longer fit for service and needs to be replaced.

The reactive, "find-it-and-fix-it" approach of making repairs, focused on immediate stabilization rather than long-term asset management, worked for many years when the assets were relatively new, as reflected in improved safety performance and fewer incidents from the 1980s into the 1990s. However, as assets aged, relying predominantly on repairs to manage pipeline integrity became less effective.

During the post-World War II economic boom of the **1950s and 1960s**, driven by an unprecedented surge in consumer demand for natural gas, utilities rapidly expanded their infrastructure. As they upgraded system capacity to handle higher pressures, operators began replacing low-pressure cast-iron segments with significant leak history with modern steel and early-vintage plastics.

Historical NTSB investigations highlight the catastrophic risks of aging cast iron infrastructure, notably a 1986 restaurant explosion in Derby, Connecticut, that killed six and injured 12, followed by a 1990 Allentown, Pennsylvania, incident where a water main leak eroded support beneath a graphitized, 4-inch cast iron gas main, causing a circumferential crack, gas migration, and a fatal house explosion.

Following these investigations, in 1991 NTSB recommended that the RSPA mandate cast iron identification and replacement programs; the agency issued two advisory notices: **RSPA Alert Notice 91-02**, which encouraged operators to identify segment replacements, replace graphitized pipe, and protect excavated mains; and **RSPA Alert Notice 92-02**, which reminded operators to maintain continuous surveillance procedures to monitor leaks, failures, and graphitization-related risks.

A key milestone described in Section 2 was the promulgation of the **DIMP** rule. As described in Section 2, while life-cycle based, prescriptive regulations were designed to anticipate and prevent leaks and incidents, one of the lessons from the evaluation and early adoption of risk assessment was that it is not always possible to foresee every possible circumstance that may arise in operations and the busy environment around distribution systems. Operators and trade associations, such as the American Gas Association (AGA), Northeast Gas Association (NGA), and SGA Natural Gas Association, recognized the value of risk-based approaches. Under DIMP, utilities broadened the use of more comprehensive threat analyses and forward-looking risk assessment programs. This required operators to actively identify threats to their specific systems, quantify the risks using risk models, and aid in planning main replacement programs.

Early Mains and Service Replacement Methods

In the early years of systematic main replacement, spanning the **1950s through the 1970s**, the industry relied almost entirely on traditional, invasive construction practices. The definitive method of this era was open-cut trenching with direct burial. To replace a failing cast-iron main, utility crews had to excavate a continuous, open trench along the entire street, fully exposing the old pipe. The crews then broke up the old main and hauled it away or left it in place while laying a new steel or early plastic line alongside it.

For smaller service lines or smaller-diameter mains, utilities also relied on **pneumatic pipe pushing or pulling**. This involved using heavy hydraulic rams to force a new steel pipe through the soil from one small pit to another, or using the machinery's strength to pull a new line directly through the old one’s path. However, this early method was severely limited by soil conditions and could easily damage adjacent underground utilities, such as water and sewer lines.

The Evolution of Replacement Methods

As the gas distribution industry matured, operators faced a critical operational challenge: proactively and efficiently replacing or rehabilitating aging infrastructure. This reality catalyzed the development of multiple

construction methods. These methods developed in distinct phases, with each generation of technology seeking to minimize customer disruption while maximizing installation efficiency.

The first major breakthrough emerged during the **1970s and 1980s** with the widespread adoption of **pipeline insertion**. Operators recognized that vintage cast iron and steel mains, despite undergoing structural degradation, still functioned as viable underground conduits. Instead of excavating a continuous trench, utility crews began digging small access pits at either end of a street segment. They then physically slid a new, flexible, and smaller-diameter polyethylene pipe directly through the interior of the existing main. While insertion drastically reduced excavation and pavement restoration costs and neighborhood disruption, it carried a distinct engineering trade-off: because the new pipe had to fit inside the old one, the gas line's overall volumetric capacity was inevitably reduced. Insertions were difficult if not impossible in mains with turns and offsets, or at connections at tees and elbows.

To overcome the capacity limitations of standard insertion, the industry developed and adopted **pipe bursting** during the **1990s**. This trenchless method allowed utilities to replace an existing main with a new one of the exact same size, or even a larger diameter, without digging a continuous trench. The process relied on a heavy, cone-shaped steel bursting head that was pulled through the legacy cast iron main by a high-capacity hydraulic winch or cable system. As the expansion head advanced, it shattered the brittle cast iron from the inside out, forcing the fragments directly into the surrounding soil. At the same time, the bursting tool towed a continuous string of brand-new Polyethylene pipe immediately behind it, replacing the fractured line in a single, efficient pass. It required access holes every several hundred feet to load the bursting head in the main and feed the cable behind it, so traffic was disrupted, but only locally. This method proved difficult because it required temporarily disconnecting customers for multiple days while the old gas main was abandoned, burst, and the new main installed.

By the **2000s and into the present day**, **Horizontal Directional Drilling (HDD)** became another alternative for main replacement projects. Unlike insertion or pipe bursting, which are tethered to the path of the existing pipeline, HDD decouples the replacement process from the existing main or service entirely. Using a surface-launched, track-mounted drilling rig, operators bore a highly precise, steerable pilot hole horizontally beneath roads, sidewalks, rivers, and heavily manicured landscapes. Once the drill path is complete and verified, operators attach a reaming tool and the new pipeline string—whether flexible plastic or high-strength coated steel—to the drill string and pull it back through the borehole. This method lets utilities install thousands of feet of new gas main with virtually no impact on surface infrastructure. Similarly, the industry has adopted pneumatic soil-piercing tools for trenchless installation of service lines. This method is often best suited for new installations or replacement projects in suburban or rural communities, where underground utility congestion is less severe than in densely populated urban areas.

The Emergence and Evolution of Main Rehabilitation Methods

While pipeline replacement involves installing a brand-new pipe, **main rehabilitation** emerged as a distinct engineering discipline focused on repairing, sealing, or structurally reinforcing existing, vintage mains without abandoning them. The evolution of rehabilitation technologies was driven by the need to address the primary failure point of legacy cast iron and unprotected steel systems—leaking bell joints and corrosion—and evolved into internal lining life-extension systems that fully restored the pipe's structural integrity. While main rehabilitation is an important and useful tool, as discussed below, technical requirements and practical application often limit its use to a small percent of the leak-prone pipe inventory.

The earliest forms of systematic main rehabilitation emerged in the **1950s and 1960s** as direct responses to the prior and ongoing shift to natural gas. When utilities switched from manufactured town gas to natural gas, the gas's dry nature sometimes caused the moisture-retentive jute packings in vintage cast iron bell-and-spigot joints to dry out, shrink, and leak. To combat joint leaks without digging up every joint, the industry developed **liquid sealant conditioning**. Utilities sprayed or fogged liquid chemical compounds, such as diethylene glycol or ethylene glycol, directly into the gas stream. The flowing gas carried these vapors through the network, where they were absorbed by the dried-out jute joints, forcing the fibers to swell up again and temporarily seal the leaks. While innovative, this chemical conditioning required continuous maintenance and offered only a short-term fix. As this method proved too cumbersome, operators continued the arduous task of pinpointing leaking joints and excavating and installing a metallic clamp on the exterior of the joint face to stop the leak.

By the **1970s and 1980s**, as joint failures persisted and environmental regulations tightened, the industry transitioned to localized mechanical and chemical remediation. For larger-diameter mains that could be isolated, utilities pioneered **encapsulation molds**. On the exterior, if a joint was exposed, crews used polyurethane or epoxy encapsulation molds to completely encase the joint in a solid, leak-proof block of plastic. This era marked the first successful deployment of durable, engineered polymers to extend the working life of cast iron and steel networks by targeting their weakest points.

Technology continued to advance in the **1990s and 2000s** with the commercialization of **internal joint sealing robots.** Technicians passed remote-controlled mechanical seals, or internal sealing boots, through the pipe, positioned them precisely over a leaking joint, and expanded them to form a tight, long-lasting rubber seal. The decade also introduced **Cured-in-Place Lining (CIPL) and internal lining systems**, often referred to as trenchless structural lining. Instead of sealing individual joints one by one, engineers adapted wastewater-industry technology to rehabilitate entire lengths of a main simultaneously. In this process, a flexible, fabric-reinforced tube saturated with liquid epoxy or polyurethane resin was inserted into an isolated, cleaned gas main using fluid or air pressure to turn the liner inside out against the pipe wall. Once in place, ambient air is used to cure the resin, transforming the soft fabric into a slick, high-strength, independent structural pipe inside the old main. This method allowed utilities to completely eliminate joint leaks and internal corrosion across hundreds of feet of main with only minimal access pits at either end of a block. CIPL is used in other industries where preventing leaks and ruptures is critical, including chemical manufacturing, paper mills, and petroleum refineries, to rehabilitate process piping, cooling water loops, and pipelines carrying corrosive fluids.

Selection of Replacement Versus Rehabilitation

When deciding whether to replace a gas distribution main and its associated services or structurally rehabilitate it, operators consider each method's estimated cost based on historical data but must first evaluate the pipe's fitness-for-service for the application and the practical limitations of each method. The operator’s primary objective is to maintain a safe system, ensure operational reliability, and match the chosen construction methodology to the project area's specific subterranean conditions.

Operators must balance several objectives and constraints when making decisions about strategy and approach to repairing, replacing, and/or rehabilitating aging infrastructure. The choice between replacement and rehabilitation is not formulaic. Factors and practical limitations typically considered include those listed below for each type in Table 2:

Table 2 – Considerations in Replacement versus Rehabilitation

Replacement when:	Rehabilitation when:
• Main diameter is small (12 inches or less), and capacity cannot tolerate cross-sectional loss. • Service density is high, requiring an excavation at every residence or business. • The route contains multiple sharp 90°bends, mitered fittings, or heavy internal obstructions. • The host pipe has suffered complete structural collapse or severe displacement. • Pipes located in unstable soils. • Some jurisdictions require cast iron replacement if it is encroached. • In advance or in coordination with other planned municipal work such as road reconstruction and water and sewer replacement projects to reduce or eliminate the risks of cast iron encroachment • Long-term system modernization plans, such as eliminating LP networks and upgrading to medium pressures for increased safety and reliability.	• Main diameter is large (larger than 12 inches) where trenching and pavement restoration costs dominate the budget. • Service density is low or moderate, maximizing long continuous liner pulls (300–1,000+ feet) while minimizing customer interruption • Pavement cut moratoriums, heavy urban traffic, or subsurface utility congestion make open trench excavation unviable or extremely difficult. • Main crosses over/under critical infrastructure such as bridges, highways, or rail tracks. • Hydraulic modeling confirms that reduced interior diameter still satisfies peak winter gas demand.

Additional Safety Benefits from Pipeline Replacement and Rehabilitation Programs

Replacement and rehabilitation programs provide significant safety enhancements that go beyond incident and leak reduction. They harden or fortify the system from an integrity standpoint and increase system resiliency and reliability, which provide multiple safety benefits, including:

- Gas service and meters/regulators moved outside
    - Local fire departments/Operator personnel can more safely manage actual emergencies requiring gas shutdown without needing access to the customer's premises
    - Ability to perform required meter replacement work without entering premises or interrupting gas service (use of bypass meter bars)
    - Reduced risk of tampering/theft of service
    - Improved access for safety/compliance inspections
- Customer piping and equipment/appliances checked for safety during the relight process.
- Excess flow valves installed
    - Immediate shutdown of gas service for unplanned high gas flow (damage, large leak); enhances customer, public, and pipeline safety.
- Additional emergency sectionalizing valves installed, increasing the ability to isolate discrete sections of pipe and enhancing emergency response.

- Improved gas facility records significantly reduce facility damage. Vintage infrastructure may have records that are not as accurate as records created today, including use of GPS/GIS and barcoding of materials.
    - Improved ability to locate via installation of tracer wire and pipeline marker balls.
- Reduced customer outages due to water intrusion in leak-prone low-pressure gas systems enhance reliability
    - Water main breaks, water leaks
    - Storm flooding (ocean, rivers, streams, high water table areas)
- Reduced responses and repairs of hazardous leaks by operator personnel and local fire departments enhance public and personal safety, allowing for redeployment of leak response resources towards other proactive safety work, e.g., damage prevention.
- Reduced leak investigations/repairs reduce operator/contractor personnel exposure to vehicular or other hazards associated with working in the public right-of-way, enhancing personal safety.
- Elimination of vintage, sometimes unmapped appurtenances that are at high risk for excavation damage.
- Customer benefit of upgrading to higher pressure supporting installation of back-up generation during electrical outages.

Each item above has a tangible impact on the safety of the gas distribution system as well as the safety of employees, contractors, and the public.

The Importance of Cast Iron Replacement and Rehabilitation

To further highlight the serious consequences of incidents caused by cast iron breaks and bell joint leaks, PHMSA published the following facts and examples, highlighting the fact that **when cast/wrought iron was involved, fatalities or injuries were twice as likely to occur.** From 2005 – 2025:

38% of cast/wrought iron incidents caused a fatality or injury,
compared to 19% of the incidents on other types of mains

33% of all fatalities and 15% of all injuries in incidents
caused by gas distribution mains involved cast/wrought iron.

PHMSA also published a series of examples of the consequences of incidents involving cast/wrought iron, which further reinforce that although rare, they can be catastrophic. Recent examples include:

Incidents Involving Cast Iron Pipelines

- **November 22, 2022** – A natural gas explosion occurred at a residential building, injuring 3 people in Baltimore City, MD. Baltimore Gas & Electric Co determined after the incident that a 4" cast iron low-pressure gas main installed in 1904 experienced a full circumferential break, which allowed natural gas to migrate underground into a residence where it was ignited, causing an explosion.
- **January 27, 2022** – Gas from a leaking cast iron joint ignited, causing a manhole cover to lift and strike a City of Baltimore welding contractor, resulting in an injury that required inpatient

hospitalization. Baltimore Gas & Electric Co determined the cause as leaks at joints of a 12" cast iron main, installed in 1920.

- **December 19, 2019** – Philadelphia Gas Works (PGW) crews responded to three properties on fire on South 8th Street in Philadelphia, PA. A 6" cast iron gas main had suffered a circumferential break where a large underground cavity caused ground movement and resulted in the rupture of the main installed in 1928. There were 2 fatalities. PGW evacuated approximately 60 people during the event.
- **June 16, 2018** – A Baltimore Gas and Electric (BGE) contractor paving crew was injured while installing thermoplastic marker traffic lines using a heat torch in Baltimore, MD, and required an overnight hospital stay. A gas main leak was identified, and a 1903 installed cast iron joint was found leaking and was repaired.
- **January 20, 2018** – A gas fire at a two-story residential building in Brooklyn, NY injured four, with one person requiring overnight inpatient hospitalization. The building suffered moderate structural damage. The 6-inch cast iron main was installed in approximately 1927 and was operating at 0.3 psig. The apparent cause of the incident was reported as a cast iron break due to frost heave.

It is important to reiterate that, unlike other leakage mechanisms, cast iron breaks are not time-dependent and generally fail quickly, with a large, immediate release of gas underground. Although proactive leak surveys target cast iron breaks in winter, their effectiveness is limited, as the break must have already occurred to be discovered through survey. The largest remaining inventories of cast iron are located predominantly in the Northeastern and Midwest U.S., where the realities of winter weather must be considered in addressing cast/wrought iron inventories. Coupled with the inventory's location in densely populated urban environments, repairing or maintaining cast iron is not in the long-term interest of pipeline and public safety.

The Transition to Distribution Integrity Management: Addressing the Plateau in Safety Performance

In the late 2000s, even though the Conventional Life-Cycle Based Regulations had created a strong safety net, safety performance, as measured by PHMSA-reportable incidents, had plateaued.

High-Level View of Safety Performance Over Six Decades

As described in Section 1, at the highest level, safety performance is viewed in terms of incidents, as reducing incidents is critical to protecting people, property, and the environment. Figure 1 shows a graph of U.S. incidents by year and a five-year rolling average. A rolling average accounts for fluctuations and helps reveal trends in data. As the graph shows, incidents trended downward into the early 1990s. Life-cycle-based, prescriptive, standards-based regulations drove improvement from the 1970s to 1990s; however, the improvement trend began to plateau in the early 1990s and into the early 2000s.

Recognition of a Plateau in Safety Performance and the Advent of Risk Assessment

This report highlights the recognition of this plateau in incident reduction within PHMSA and among operators, including the American Gas Association and the Northeast Gas Association, and the actions taken to address it.

A negative trend in safety performance, shown in Figure 1 in the early 2000s, accelerated the focus on risk-based methods. Broader use of risk in replacement and rehabilitation programs and learnings from gas and liquid transmission led the distribution industry and PHMSA, in concert with NAPSR, to commission the Gas Piping Technology Committee (GPTC) in 2005 to develop a framework for DIMP.

The prescriptive inspection and maintenance intervals, with repairs as needed, were based on experience (e.g., maintenance histories/asset), but adverse events continued to occur**.** The industry, working with Federal and State regulators, decided additional focus was needed:

- How could operators better identify the most significant risks on the system?
- How could operators better identify the most important work on the system?
- How could operators demonstrate that they were properly prioritizing work and that it was having an impact?
- How could operators improve the focus on managing compliance with regulation by applying risk-based methods?

The section above provided background on replacement, rehabilitation, and repair and their use over the last century, through the first decade of the 2000s. The section that follows discusses the advent of DIMP and its impact, in concert with replacement and rehabilitation programs, on pipeline safety performance.

4. Distribution Integrity Management

As shown below, DIMP has driven significant safety improvements in gas systems since its implementation and continues to be a critical tool in identifying and eliminating gas system risk. This section describes distribution integrity management and how an operator builds its program. This section also describes the connection between DIMP and repair, rehabilitation, and replacement programs, and how they interrelate. Additionally, it shows how repairs provide data used to manage the program.

As noted in Section1, with legislative support from Congress, PHMSA used the framework to create a performance-based regulation in 2009 known as distribution integrity management, under which operators adopt risk-based DIMPs. In 2011, shortly after the DIMP regulations took effect, the Secretary of Transportation issued a Call to Action, placing additional emphasis on safety improvements. Although the Call to Action addressed all modes of pipeline transportation, the Secretary said gas distribution replacement and rehabilitation programs needed to accelerate. Later that year, the National Association of Regulatory Utility Commissioners (NARUC) sent a written response and action plan to Secretary Raymond H. LaHood detailing the commitments and resolutions passed by state utility commissioners to support accelerated replacement of vintage and leak-prone natural gas infrastructure.

Asset Management

Operators utilize overarching asset management for capital and expense planning. The advent of DIMP brings greater structure and transparency to the asset management process of managing the diverse assets that comprise distribution systems. Utilities have strategic plans for managing assets, including multi-year plans for asset replacement and rehabilitation. Some utilities use asset families and develop plans for them and, as discussed below, use risk assessment to prioritize risk among asset types, considering different types of data.

Annual plans are developed for each asset type, considering the longer-term plans and risk assessment results, as described below. The annual plans are used to develop specific projects to be undertaken in the year ahead. While risk drives priorities, specific project planning can change a segment's priority. For example, a project plan that entails replacement of mains and services in the section of a neighborhood for replacing a higher-risk segment may also be bundled as a larger project to include a lower-risk segment because of the efficiency realized in getting work done before planned repaving in the community, thereby minimizing mobilization and demobilization inefficiencies. Another example is replacing and upgrading a higher-risk district regulator station; it may be most efficient to also replace lower-risk, low-pressure (utilization pressure) mains, services, and meters at the same time.

The DIMP Seven Step Process

A Distribution Integrity Management Program (DIMP), mandated under 49 CFR Part 192, Subpart P (§ 192.1001–192.1015), establishes a systematic framework for gas distribution operators to identify, assess, and mitigate pipeline safety risks. DIMP is structured around seven core element steps shown below.

The seven core elements include:

1. Build System Knowledge: Operators gather and evaluate physical, operational, environmental, and historical data across their entire system. This includes capturing attributes such as pipe materials, sizes, manufacturing vintages, operating pressures, joining methods, and installation methods. Operators build the system knowledge through the life-cycle compliance activities (e.g., leak surveys, valve inspections, cathodic protection monitoring) and opportunistic field inspections whenever buried assets are exposed during excavations. Where historical records are missing, operators establish procedures to capture key attributes during future field interventions.

Repairs made on the system provide essential data regarding the condition of the system, whether it is for mains, services or valving and pressure regulation and control equipment. Repair documentation provides data to confirm information on materials and their condition. Accurate information about system materials and their condition supports planning for replacement and repair programs.

2. Identify Threats: Operators systematically evaluate existing threats affecting their distribution system. Operators analyze both utility-specific operational data and industry-wide alerts across eight mandatory threat categories:

1. Corrosion (external, internal, atmospheric)
2. Natural Forces (earth movement, frost heave, washouts)
3. Excavation Damage (third-party hit, operator/contractor damage)
4. Other Outside Force Damage (vehicle impact, excessive surface loads, vandalism)
5. Material, Weld, or Joint Failure (vintage materials like Aldyl A, bare steel, cast iron)
6. Equipment Failure (malfunctioning pressure regulators, relief valves, seals)
7. Incorrect Operation (procedural non-compliance, qualification gaps, purging errors)
8. Other Concerns (legacy construction practices, stray AC interference).

Operators also consider emerging threats by observing the system during ongoing compliance work, including continuing surveillance. Additional detail in identifying threats is provided in Table 3, below.

3. Evaluate and Rank Risk: Once threats are identified, operators evaluate the likelihood of occurrence and the potential consequences of failure for each segment or sub-group of pipe. The scope of risk assessment includes each asset type within a system, including:

- Mains
- Services
- Meters and meter assemblies
- District Regulator Stations
- Industrial and commercial meter stations
- Gate Stations
- Some systems include LNG or, alternatively, propane/air peak shaving
- Some organizations consider “data” to be an asset type

It is important to recognize that mains and services, often the focus of rehabilitation and replacement, are just two of the asset types in managing the risk of distribution systems.

Operators use risk assessment models (ranging from qualitative matrices to relative risk scoring or quantitative probabilistic models) to prioritize system risks. The evaluation considers factors such as population density, proximity to key receptors, operating pressure, system redundancy, and interacting threats (e.g., cast iron subject to frost heave and heavy surface loading).

Table 3 – Threats to Gas Distribution System

Threat Category	Threat Sub-type	Primary Drivers & Risk Factors
Corrosion	External Corrosion	Pitting, coating disbondment, or metal loss on buried steel, ductile iron, or cast iron due to soil aggressiveness, inadequate cathodic protection (CP), or stray DC/AC currents.
	Internal Corrosion	Degradation driven by wet gas, free water, carbon dioxide (CO2), hydrogen sulfide (H2S), or Microbiologically Influenced Corrosion (MIC) inside the pipeline.
	Atmospheric Corrosion	Deterioration of exposed piping and components (meter sets, regulator stations, span crossings) subjected to moisture, industrial pollutants, or marine environments.
Natural Forces	Earth Movement	Landslides, soil subsidence, seismic faults, soil liquefaction, and slope instability that strain or displace pipe.
	Frost Heave & Thermal Contraction	Deep frost penetration causing ground movement or severe contraction stresses, particularly critical on rigid cast iron or vintage mechanical joints.
	Heavy Rains / Washouts / Flooding	Soil erosion around buried mains, river/creek bank erosion exposing pipe, and buoyancy forces on submerged assets.
Excavation Damage	Third-Party Excavation	Unintentional impacts by external contractors, municipalities, or homeowners, influenced by ticket volume, locate accuracy, depth of cover, and 811 One-Call compliance.
	Operator / Contractor Damage	First-party hits occurring during the utility's own construction, repair, or maintenance operations.
Other Outside Force Damage	Vehicle & Equipment Impact	Aboveground facilities (farm taps, district regulator stations, residential meter sets) struck by motor vehicles or heavy machinery.
	Vandalism & Sabotage	Intentional physical damage, tampering with valves/regulators, or unauthorized access.
	Excessive Surface Loads	Heavy traffic or construction equipment operating over shallow buried pipe or inadequate casing configurations.
Material or Weld Failure	Vintage Pipe & Fitting Vulnerabilities	Susceptible legacy materials, such as early-generation plastic pipe (e.g., pre-1981 Aldyl A), brittle cast iron mains, or pre-1970 DC-ERW steel pipe.
	Joinery & Fitting Defects	Failures occurring at heat fusion joints, mechanical couplings, threaded connections, or historical bell-and-spigot lead/yarn joints.
	Manufacturing Defects	Laminations, seam flaws, or material inclusions introduced during factory production.
Equipment Failure	Pressure Control & Relief Failure	Malfunctioning regulators, relief valves, or shut-off valves leading to overpressure or underpressure events.
	Seal & Gasket Degradation	O-ring failures, packing leaks, or gasket degradation in valves, meters, and pressure-regulating equipment.
	Instrument & Telemetry Malfunction	Sensor drift, SCADA communication outages, or incorrect transducer readings affecting operational control.
Incorrect Operation	Procedural Errors	Inappropriate valve sequencing, improper squeeze-off procedures, or incorrect pressure settings during maintenance.
	Qualification & Construction Defects	Improperly performed pipe joining (e.g., poor heat fusion or field welding) due to lack of Operator Qualification (OQ) adherence.
	Purging & Commissioning Mistakes	Inadequate air removal or improper gas introduction during system commissioning/decommissioning.
Other Concerns	Sub-standard Legacy Construction	Historical installation practices, such as improper backfill (rock impingement) or missing tracer wire on plastic pipe.
	Interference Hazards	Stray AC current from adjacent high-voltage transmission corridors causing accelerated corrosion or coating degradation.

4. Identify and Implement Measures to Address Risks: For high-risk segments identified during risk ranking, operators implement targeted preventive and mitigative (P&M) measures including and beyond standard compliance requirements. Examples include accelerated pipe replacement programs, installing excess flow valves (EFVs), manual block valves or service line shut-off valves, enhancing public awareness and one-call enforcement in high-excavation density areas, increasing leak survey or atmospheric corrosion inspection frequencies in defined areas.

5. Measure Performance, Monitor Results, and Evaluate Effectiveness: Operators track specific metrics known as key performance indicators (KPIs) to evaluate whether implemented risk-reduction measures are succeeding. Mandatory regulatory performance metrics reported annually to PHMSA include:

1. Number of hazardous leaks repaired or eliminated, categorized by material and cause
2. Number of third-party excavation damages and damage rates per 1,000 One-Call tickets
3. Total miles of main and number of service lines replaced by material type
4. Operational metrics specific to custom P&M measures

Operators can establish additional performance metrics, such as:

- Corrosion and graphitization leak and incident trends
- Emergency response times
- Completion of mitigation projects

These metrics show whether risk-reduction efforts are working.

6. Periodic Evaluation and Improvement: A DIMP is a dynamic program that requires regular re-evaluation at intervals not to exceed five years (or more frequently if driven by major system changes, significant incidents, or newly identified threats). During periodic reviews, operators update risk models with newly acquired system knowledge, reassess threat rankings, refine P&M strategies based on historical performance trends and incorporate lessons learned from incidents, near misses, and industry trends.

7. Reporting, Documentation and Recordkeeping: Operators maintain comprehensive written DIMP plans, procedures, risk models, and supporting records, reporting metrics annually to PHMSA. Operators must retain records demonstrating program implementation, risk evaluations, P&M decisions, performance metrics, and periodic reviews for at least ten years to verify compliance during state regulatory audits. Operators must maintain:

- A written DIMP plan
- All data used for threat identification
- Risk evaluation methodology
- Mitigation decisions and records
- Performance metrics
- Annual program reviews

Records must be available for the state pipeline safety regulator to inspect.

The Positive Impacts of the Layers of Protection Approach

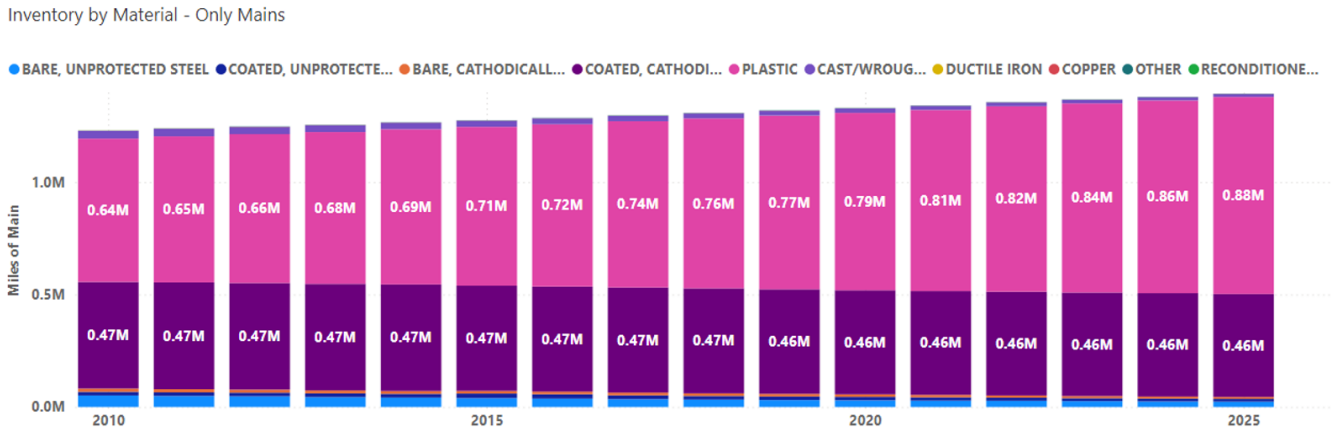
This section presents the impact of DIMP in concert with repair, replacement, and rehabilitation programs and describes progress made from 2010 to 2025, from the onset of DIMP, and the challenges remaining to be addressed. This section begins with an overview of material types in the U.S. and Northeastern U.S. It then evaluates leak activity, followed by total, as well as significant and serious incidents for the U.S. and the Northeastern U.S.

When you evaluate incidents and put them into their different causal categories, the results are often single digits. Evaluating each incident and learning from it has value; however, small numbers reduce their predictive value for trending. This is why examining leaks and other safety metrics matters.

- Total material inventory
- Leak-prone pipe inventory
- Hazardous leaks
- Total leaks
- Comparison of material inventory with leak repairs
- Leak backlog
- Reduction in bell joint inventories
- Experience Showing Heating Degree Days Relationship to Leak Activity

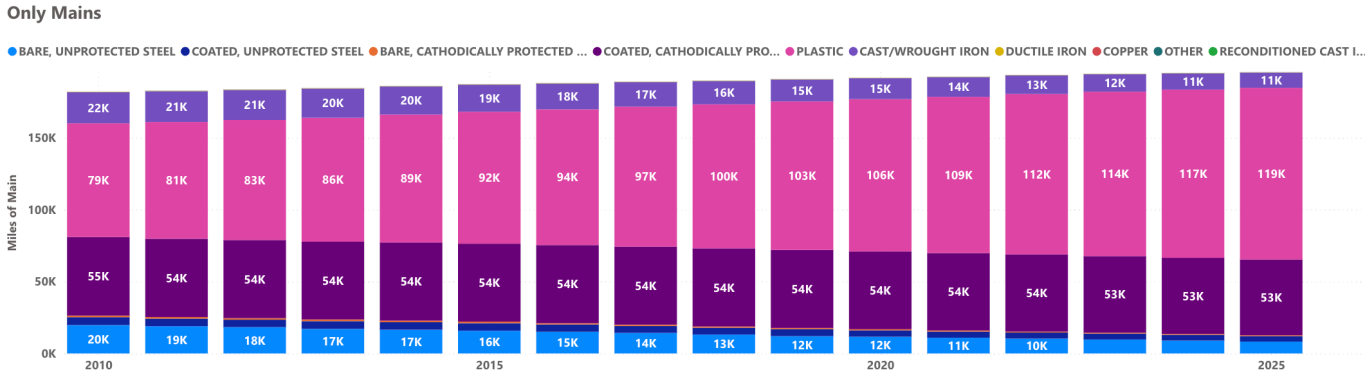
Total Inventory of Mains (Miles) and Services (Number)

Figures 7 and 8 below show the miles of mains and the number of services each year from 2010 through 2025 for both the U.S. and the Northeastern U.S.



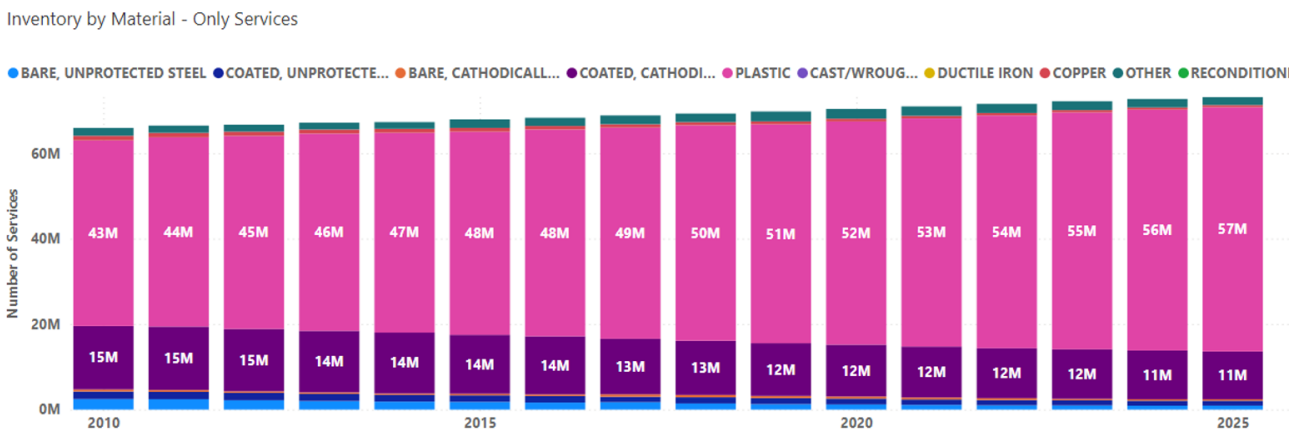
Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 7 – Inventory of Mains Mileage from 2010 to 2025 – U.S.



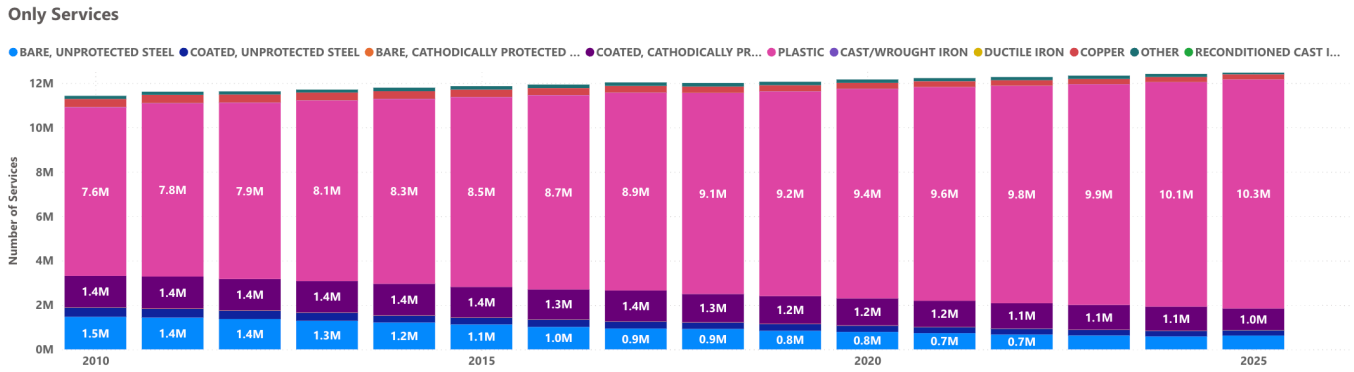
Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 8 – Inventory of Mains Mileage from 2010 to 2025 – Northeastern U.S.



Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 9 – Inventory of Services (Number) from 2010 to 2025 – U.S.



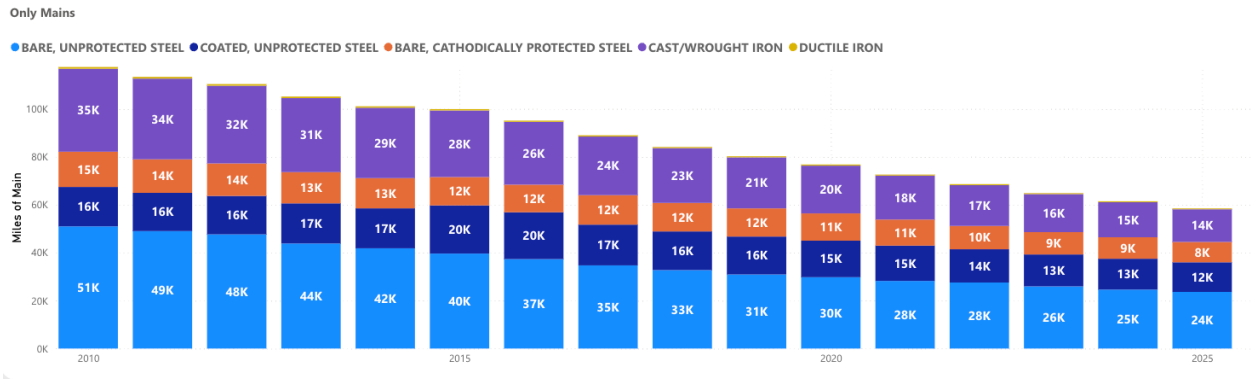
Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 10 – Inventory of Services (Number) from 2010 to 2025 – Northeastern U.S.

The four figures above show the increase in the use of plastic and the reduction in leak-prone materials. The leak-prone materials represent a small portion of the inventory but pose some of the greatest challenges in managing integrity. The magnitude of the leak-prone materials is depicted in Figures 11 through 14.

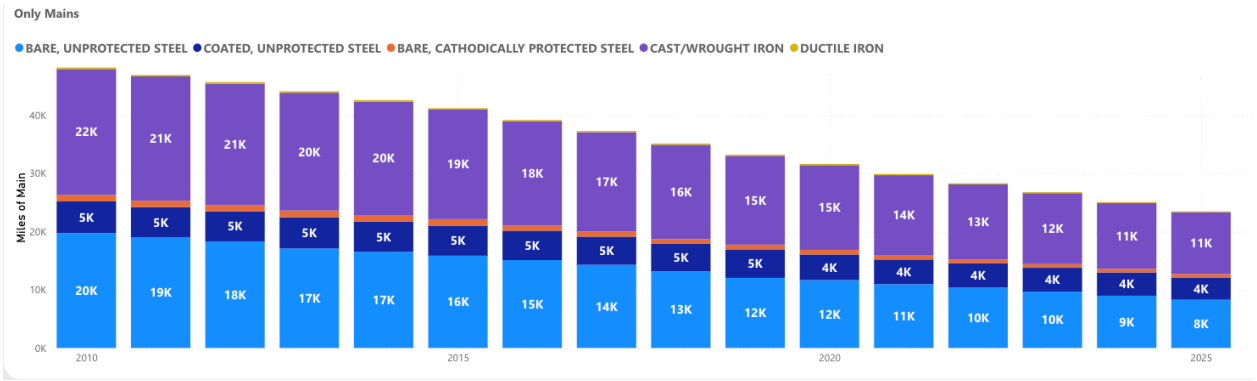
Total Leak-Prone Pipe Inventory

Figures 11 and 12 show the inventory of leak-prone mains mileage for the U.S. and the Northeastern U.S.



Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 11 – Leak-Prone Pipe by Material – Mains – U.S.



Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

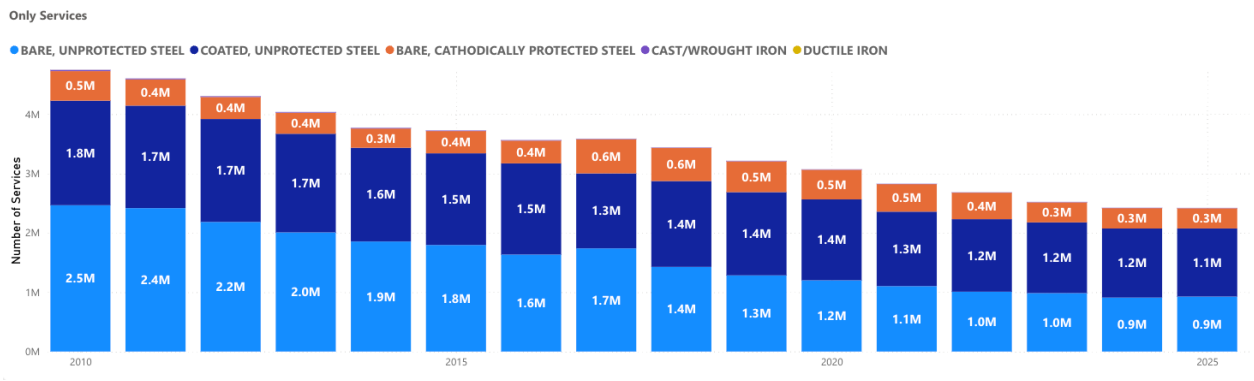
Figure 12 – Leak-Prone Pipe by Material – Mains – Northeastern U.S.

Across the U.S., from 2010 to 2025, leak-prone main inventory has been reduced from 117K miles to 58K miles – a reduction of just over 50%. Bare unprotected steel was reduced from approximately 51K miles to 24K miles, or 53%. Additionally, cast iron/wrought iron was reduced from 35K miles to 14K miles, or 60%. To put this into perspective, in 1983, gas distribution pipeline operators reported 61K miles of cast iron and 4.4K miles of wrought iron pipe[19].

Across the Northeastern U.S., from 2010 to 2025, the leak-prone main inventory has been reduced from approximately 49K miles to 24K miles – a reduction of 51%. Bare unprotected steel was reduced from 20K miles to 8K miles, or 60%. Cast iron/wrought iron was reduced from 22K miles to 11K miles, or 50%.

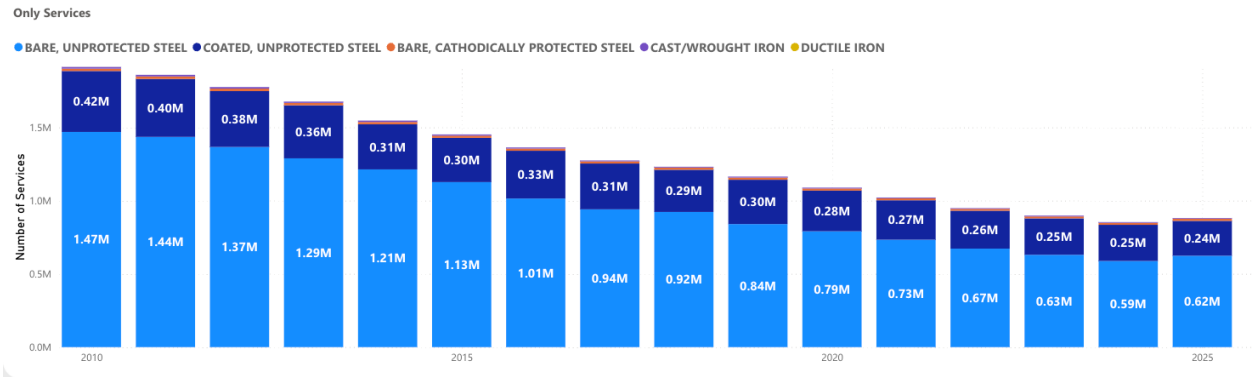
Leak-prone main replacement in the Northeastern U.S. over the past 15 years has followed a similar trajectory to the nationwide trajectory, although the Northeastern U.S. has outpaced the U.S. for bare and unprotected steel replacement.

Figures 13 and 14 below show the inventory (number) of leak-prone services for the U.S. and the Northeastern U.S.



Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 13 – Leak-Prone Pipe by Material – Services – U.S.



Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 14 – Leak-Prone Pipe by Material – Services – Northeastern U.S.

[19] PHMSA, Cast Iron and Wrought Iron Inventory, PHMSA website, https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/cast-and-wrought-iron-inventory, 2025.

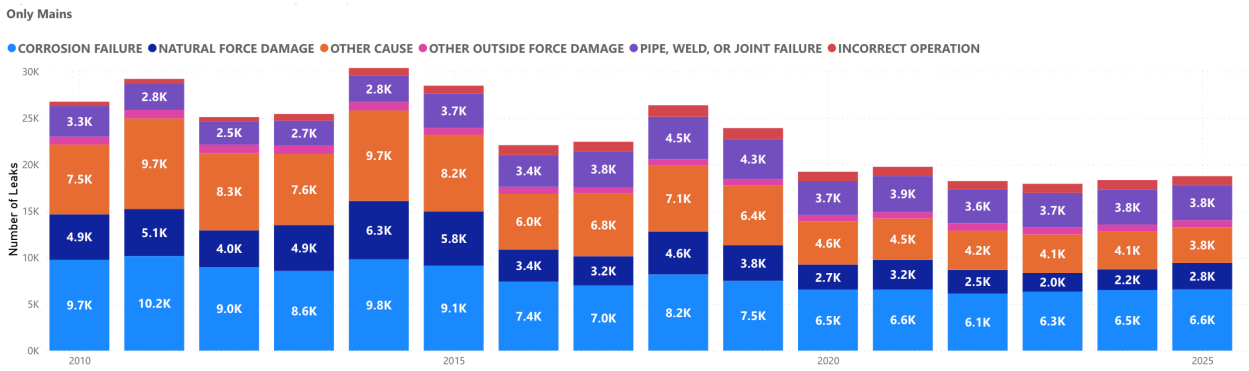
Across the U.S., from 2010 to 2025, leak-prone service inventory has been reduced from 4.8M services to 2.3M – a reduction of 52%. Bare unprotected steel services were reduced from 2.5M to 0.9M, or 64%.

Across the Northeastern U.S., from 2010 to 2025, leak-prone service inventory has been reduced from 1.89M services to 0.86M – a reduction of 54%. Bare unprotected steel services were reduced from 1.47M to 0.62M, or 58%.

Total leak-prone service replacement in the Northeastern U.S. over the past 15 years has followed a similar trajectory to the nationwide trajectory, slightly outpacing the nationwide numbers by 2 percentage points, although the Northeastern U.S. has been outpaced slightly by nationwide operators for bare and unprotected steel replacement by 6 percentage points. The Northeastern U.S.'s share of the nation's bare steel services rose from approximately 59% in 2010 to 69% in 2025, another clear illustration of the concentration of remaining bare steel service inventory in the Northeastern U.S.

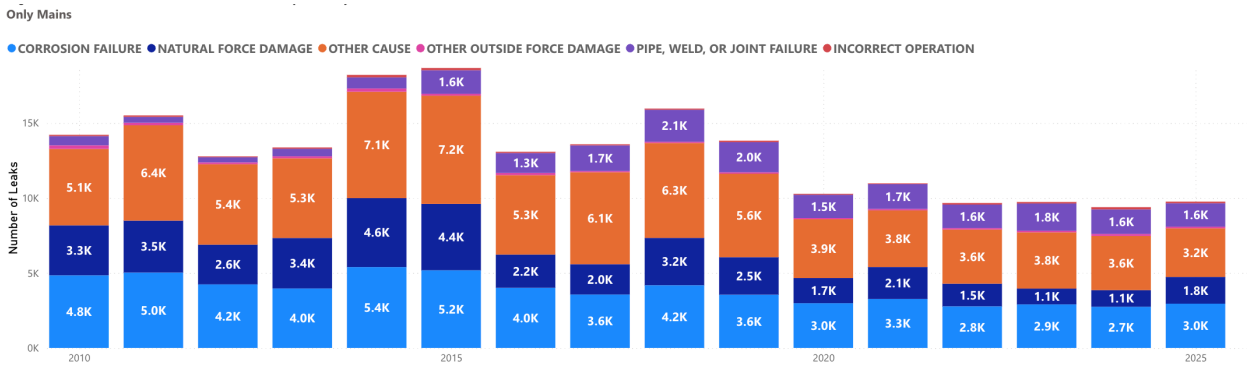
Hazardous Leaks

Figures 15 and 16 detail the trends in the U.S. and Northeastern U.S. for Hazardous Leak activity by Cause from 2010 to 2025, excluding excavation damage and equipment failure[20].



Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 15 – Hazardous Leaks Eliminated or Repaired by Cause – Excavation Damage and Equipment Failure Removed – U.S.



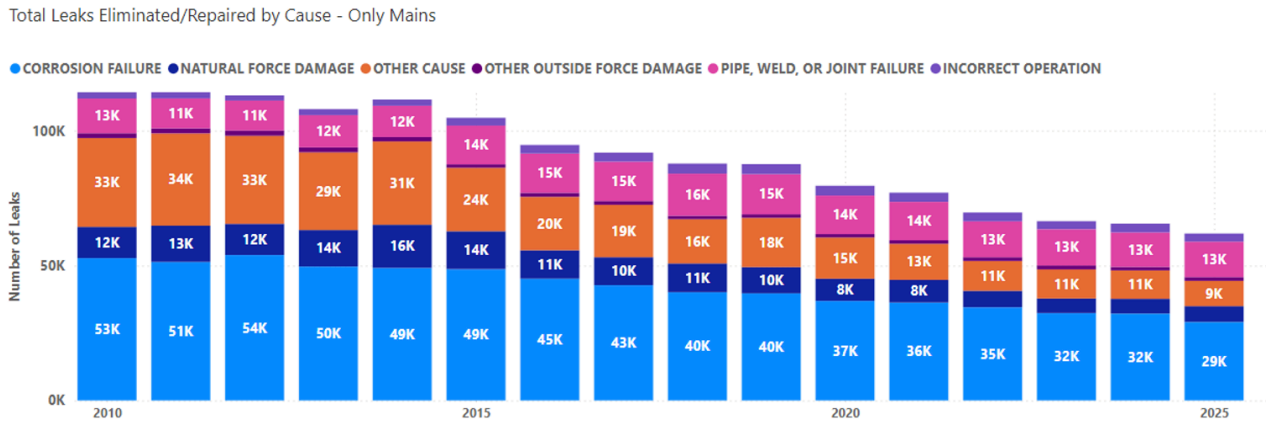
Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 16 – Hazardous Leaks Eliminated or Repaired – Excavation Damage and Equipment Failure Removed – Northeastern U.S.

[20] The analysis excludes excavation damage and equipment failure because these leaks are not material type dependent.

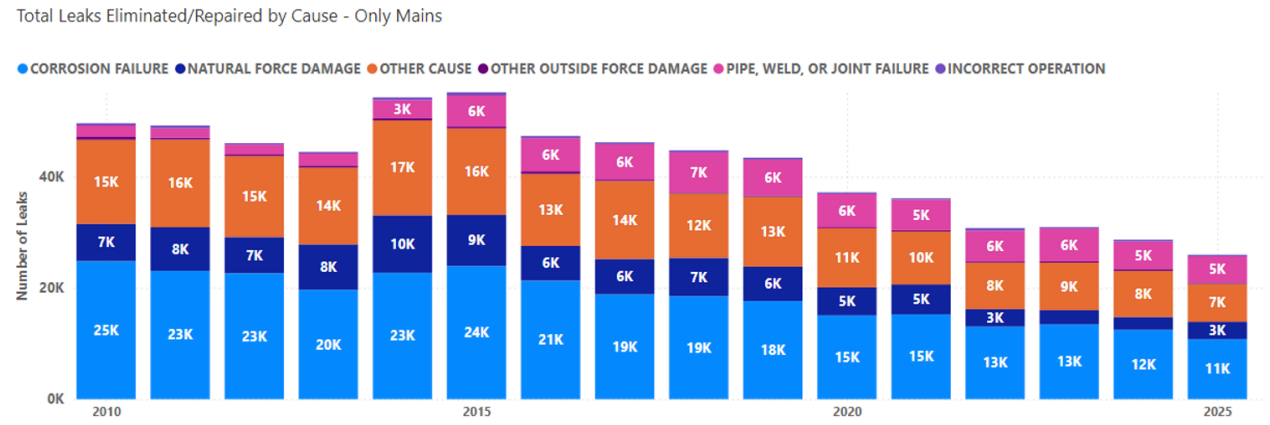
The data reveals that progress has been made in reducing the number of hazardous leaks over time. When excluding excavation damage and equipment failure, it is clear that the leading causes of hazardous leaks, especially in the Northeastern U.S., are "Other" (Bell Joint leaks) and Corrosion, followed closely by Natural Force Damage (CI main breaks). These data support the need to continue removing leak-prone inventory from the distribution system in these areas.

Figures 17 and 18 detail the trends in the U.S. and Northeastern U.S. for Total Leak activity by Cause from 2010 to 2025, excluding excavation damage and equipment failure.



Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 17 – Total Leaks Eliminated or Repaired by Cause – Excavation Damage and Equipment Failure Removed – U.S.



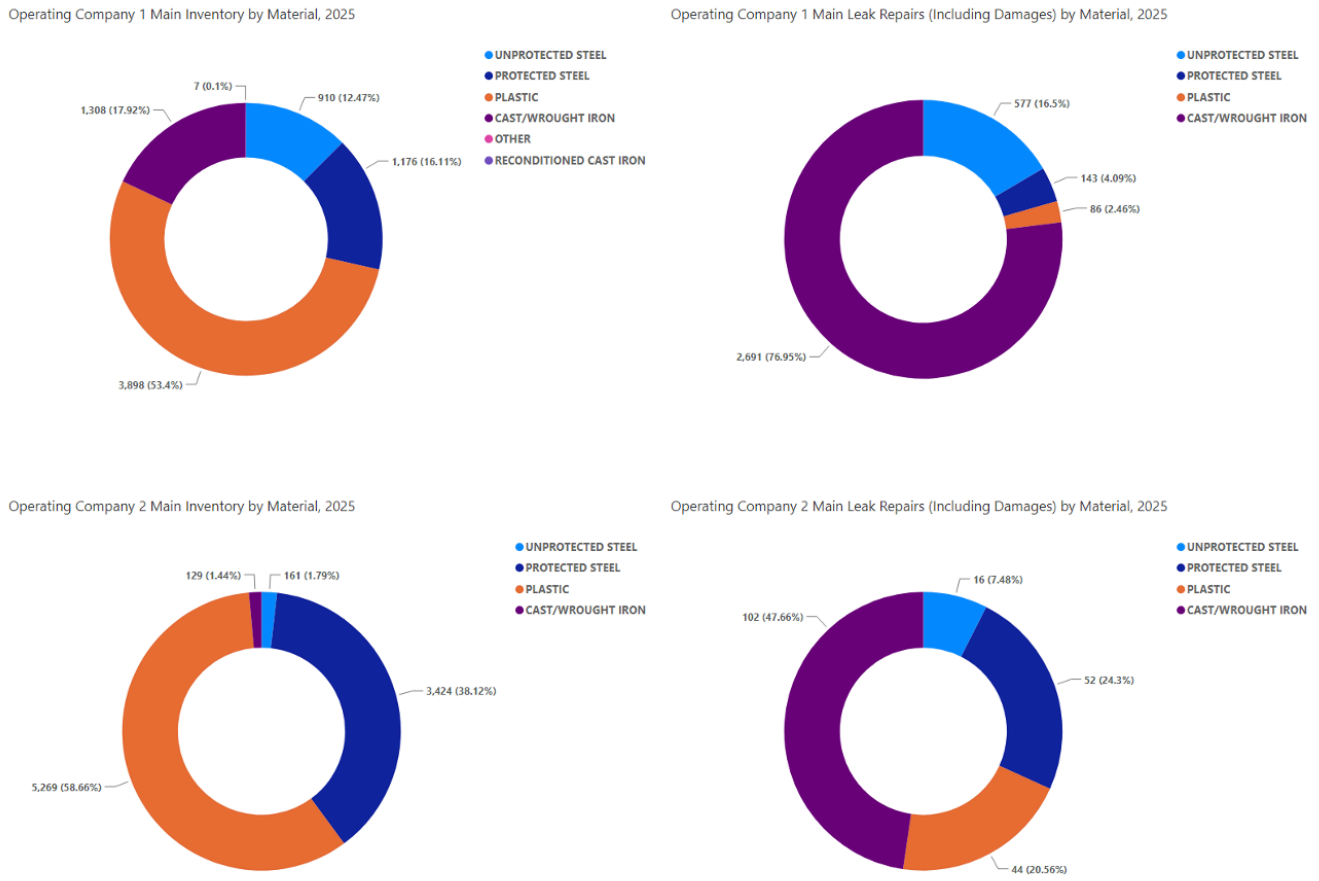
Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 18 – Total Leaks Eliminated or Repaired by Cause – Excavation Damage and Equipment Failure Removed – Northeastern U.S.

The total number of leaks repaired or eliminated from 2010 through 2025 for the U.S. and the Northeastern U.S., both have decreased approximately 48%. Year-to-year variability exists, but the declining trend shows operators are getting ahead of total leaks; however, more progress is still needed. The leaks shown as Other Cause are predominantly bell-and-spigot joint leaks, and these numbers are also declining.

Comparison of Material Inventory to Leak Repairs

In developing this report, two members of the Northeast Gas Association shared an analysis they use to illustrate how replacement and rehabilitation of leak-prone inventory affect the leak-repair contributions by material type for a year (2025), after considerable rehabilitation and replacement. Figure 19 shows a simple illustration that makes a very important point.

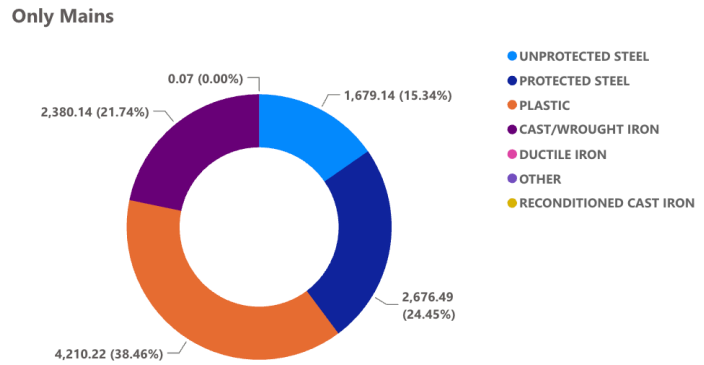


Source: NGA Member (Data for 2025)

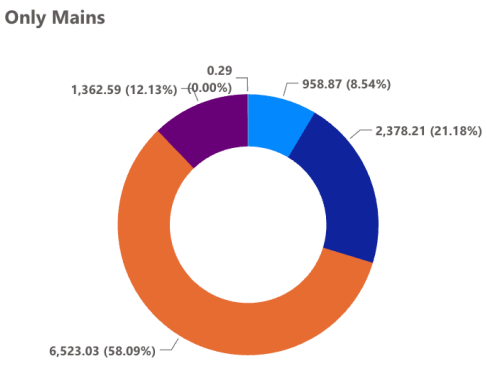
Figure 19 – Materials Proportion on Mains Inventory Versus Proportions of Leak Repairs

The top part of Figure 19 shows that for one operating company, cast iron represents 18% of the mains inventory but 77% of leak repairs, illustrating cast iron's disproportionately poor safety performance and the importance of removing it from the system. In contrast, plastic comprises 53% of the mains inventory but only 2% of leak repairs. It shows the value of replacement. Operating Company 2 has replaced nearly all of its cast iron, and yet 48% of its leak repairs result from the remaining cast iron. In the latter company, unprotected steel inventory has been reduced to 2%, yet it still accounts for 7% of repairs. These two examples show the importance of continuing to remove these leak-prone materials.

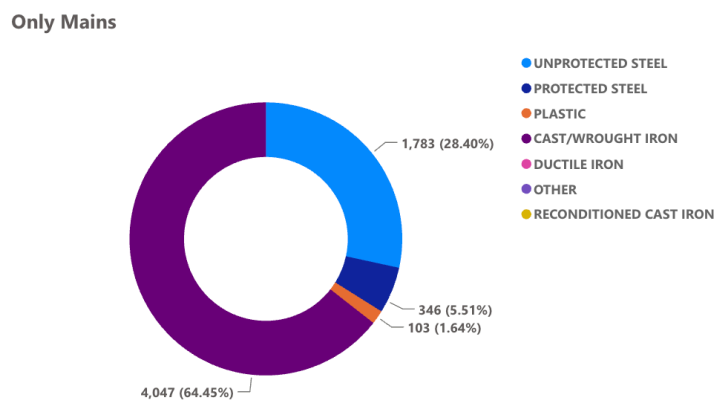
Another member of the Northeast Gas Association shared an analysis they use to illustrate how material degradation drives leak activity, contrasting 2010 and 2025 to show the change. Figure 20 shows a simple illustration.



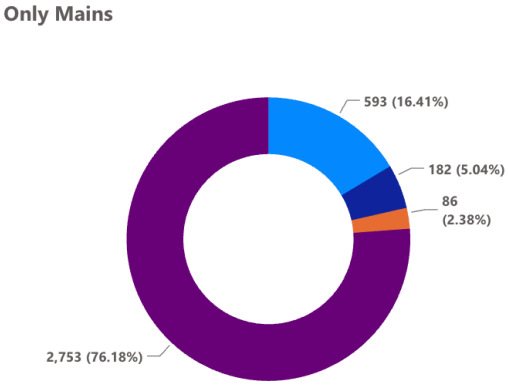
Main Inventory – 2010



Main Inventory – 2025



Total Leaks Eliminated/Repaired by Material, 2010



Total Leaks Eliminated/Repaired by Material, 2025

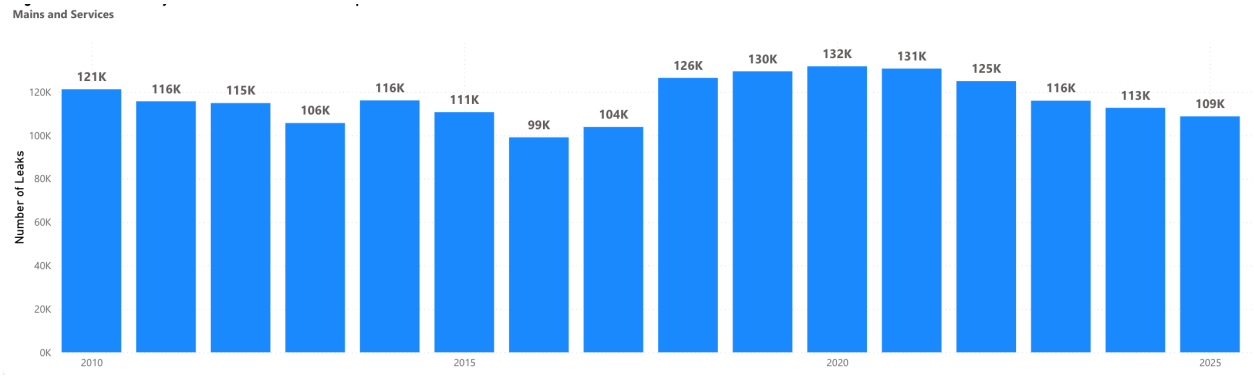
Figure 20 – Comparison of Changes in Material Inventory and Leaks Eliminated/ Repaired – 2010 to 2025

The top inventory donuts show the change in main inventory from 2010 to 2025. Unprotected steel started at 15.3% of total inventory in 2010 and was reduced to 8.5% in 2025 (a 42.9% reduction based on mileage). Cast iron started at 21.7% of total inventory in 2010 and was reduced to 12.2% in 2025 (a 42.7% reduction based on mileage). Plastic mains started at 38.5% in 2010 and increased to 58% in 2025 (a 55% increase based on mileage).

The bottom donuts show the change in total leaks eliminated/repaired from 2010 to 2025. Unprotected steel accounted for 28% of total leaks eliminated/repaired in 2010 and was reduced to 16.4% in 2025 (a 66.7% reduction in the total leaks eliminated/ repaired). Cast iron started at 64.5% of total leaks eliminated/repaired in 2010 and increased to 76% in 2025; however, the number of leaks eliminated/repaired on cast/wrought iron decreased by 32% overall. Plastic main repairs started at 103 in 2010 and fell to 86 in 2025, a decrease of over 16 % in total leaks repaired/eliminated on plastic mains.

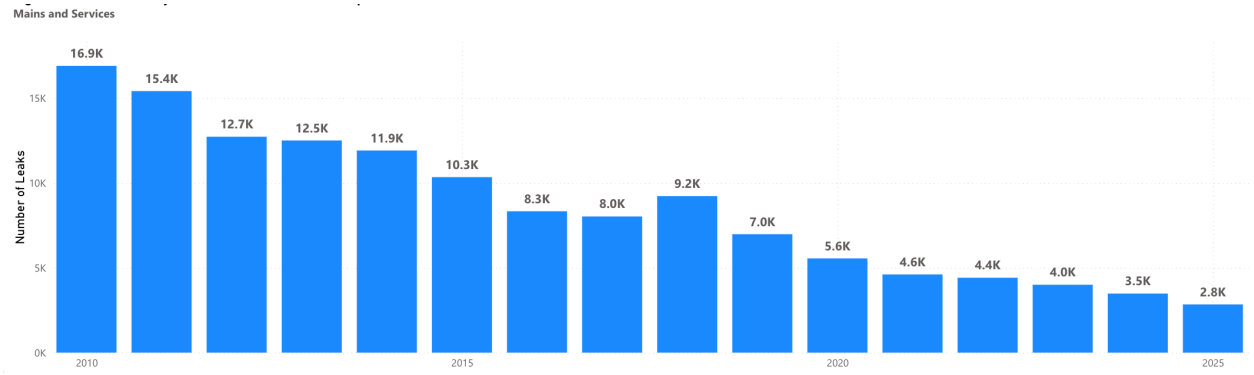
Leak Backlog

Figures 21 and 22 below show the trend in known system leaks scheduled for repair at the end of each year as reported by operators to PHMSA in their annual report. This is referred to as a leak backlog.



Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 21 – Known System Leaks Scheduled for Repair – U.S.



Source: PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 22 – Known System Leaks Scheduled for Repair – Northeastern U.S.

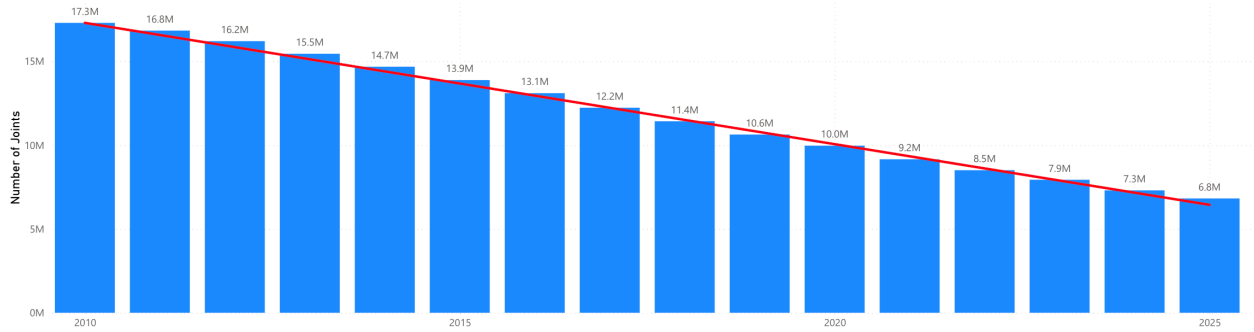
Figures 21 and 22 above detail the trend across the U.S. and the Northeastern U.S. in reducing the inventory of non-hazardous leaks at year-end as reported annually to PHMSA. This is a particularly important indicator of improved safety performance.

The nationwide leak backlog as reported to PHMSA for year-end has stayed relatively flat with some variability from 2010 to 2025, showing a decrease from 121K in 2010 to 109K in 2025, or approximately 10%, and from a high of 132K in 2020 to 109K in 2025, a reduction of approximately 17%.

The Northeastern U.S. leak backlog as reported to PHMSA for year-end has been reduced significantly from 2010 to 2025, dropping from 16.9K in 2010 to 2.8K in 2025, **a reduction of approximately 83%.**

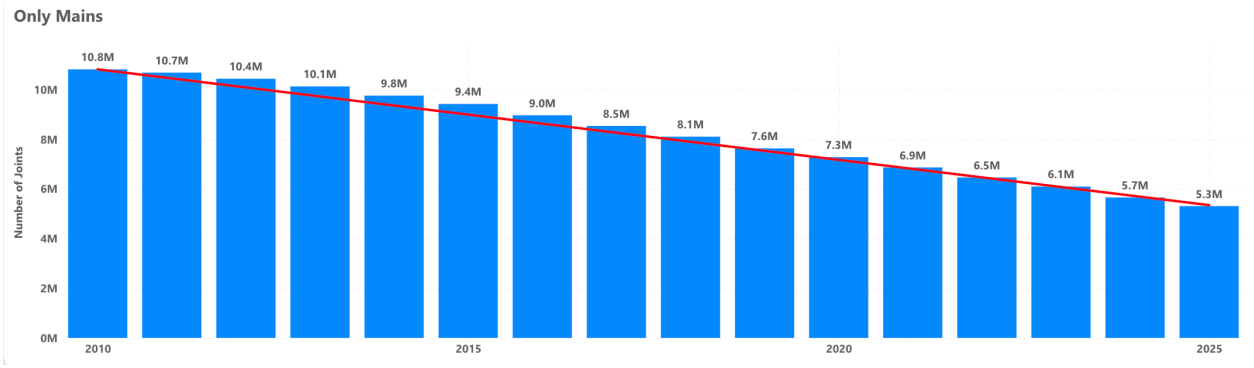
Year-end leak backlog is an important metric for operators in cold-weather climates during winter. The potential for existing non-hazardous leaks to become hazardous under cold-weather conditions (frost, ice, snow) is a potential safety risk. Reducing this backlog shows the value of reducing leaks by reducing the inventory of leak-prone infrastructure over time.

Figures 23 and 24 illustrate the trend in cast-iron bell-and-spigot joint numbers from 2010 to 2025.



Source: Estimate based on typical bell joint spacing of 12 feet, and multiple joints at street intersection tie-ins of 60/mile, with assumptions as described in text below and PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 23 – Cast/Wrought Iron Bell Joints at Year End From 2010 through 2025 – U.S.



Source: Estimate based on typical bell joint spacing of 12 feet, and multiple joints at street intersection tie-ins of 60/mile, with assumptions as described in text below and PHMSA Gas Distribution Annual Report Data, 2010 through 2025

Figure 24 – Cast/Wrought Iron Bell Joints at Year End From 2010 through 2025 – Northeastern U.S.

Figures 23 and 24 show a 61% reduction in bell joint numbers in the U.S. and 51% in the Northeastern U.S., respectively. Importantly, of the estimated 6.8M bell joints remaining in the U.S., 5.3M are in the Northeastern U.S. **Therefore, 78% of the bell joints remaining in the U.S. are located in the Northeastern U.S.** Bell and spigot joints are a leading source of leaks in cast iron systems due to ground movement, loss of joint packing, or weather-related soil subsidence. With extreme weather, particularly frost conditions, non-hazardous bell joint leaks can become hazardous by migrating into substructures, buildings, and residences because they cannot vent, and because underground air is drawn into buildings for combustion in heating systems.

Photo 1 illustrates the impact of repairing bell-and-spigot joints as they are found leaking.

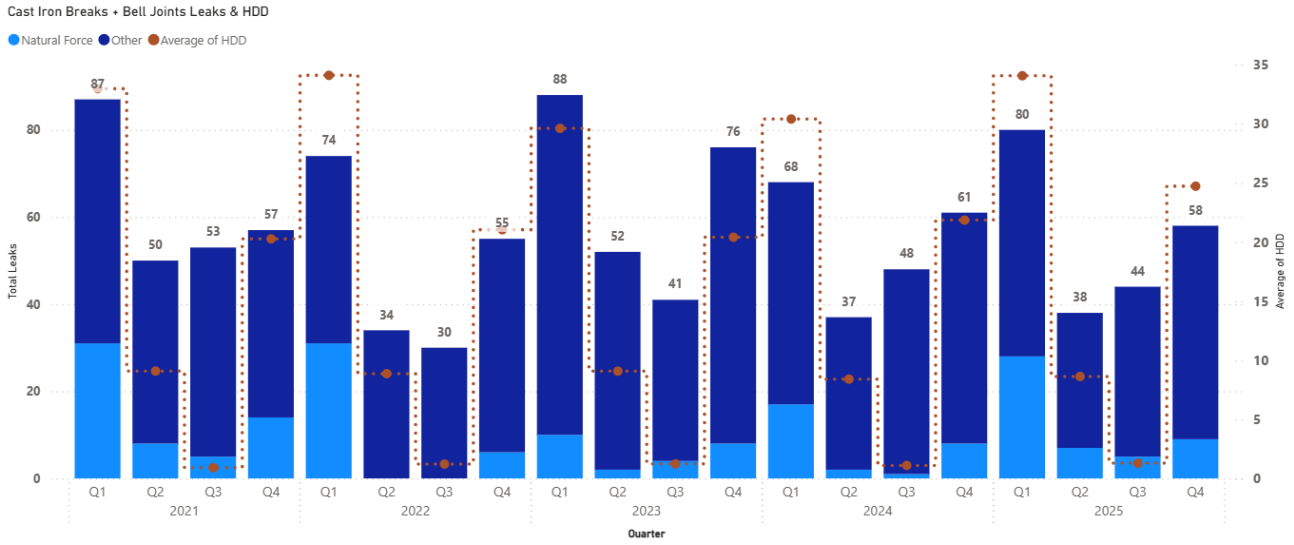


Photo 1 – Multiple Single Bell-and-Spigot Joint Repairs on a residential street in the Northeastern U.S.

As stated above, repairing leaking bell-and-spigot joints is not a durable strategy, as leak-prone pipe continues to leak. Continuing to address leaks as they occur results in multiple repeat repairs, including leak investigation, leak bar holing, and excavation to repair joints located every 12 feet. Photo 1 is a representative example of the long-term inefficiency of repair of cast iron. Additionally, after these repairs, the cast iron sections between joints remain in service and are still susceptible to failure from frost heave, nearby construction, etc.

Operator Experience Showing Heating Degree Days Relationship to Leak Activity

One operator also shared data for cast iron main breaks, a significant threat to pipeline and public safety, especially during winter operations and frost/snow/ice conditions. Cast iron main breaks are of particular concern because gas can escape in much larger volumes and in very short time frames, similar to an excavation damage. However, during winter or in fully paved areas, or both, the leaking gas can migrate below the surface unnoticed, potentially entering residences or businesses. Figure 25 shows cast iron breaks and bell joint leaks for 2021 through 2025 experienced by just one operator in the Northeastern U.S.

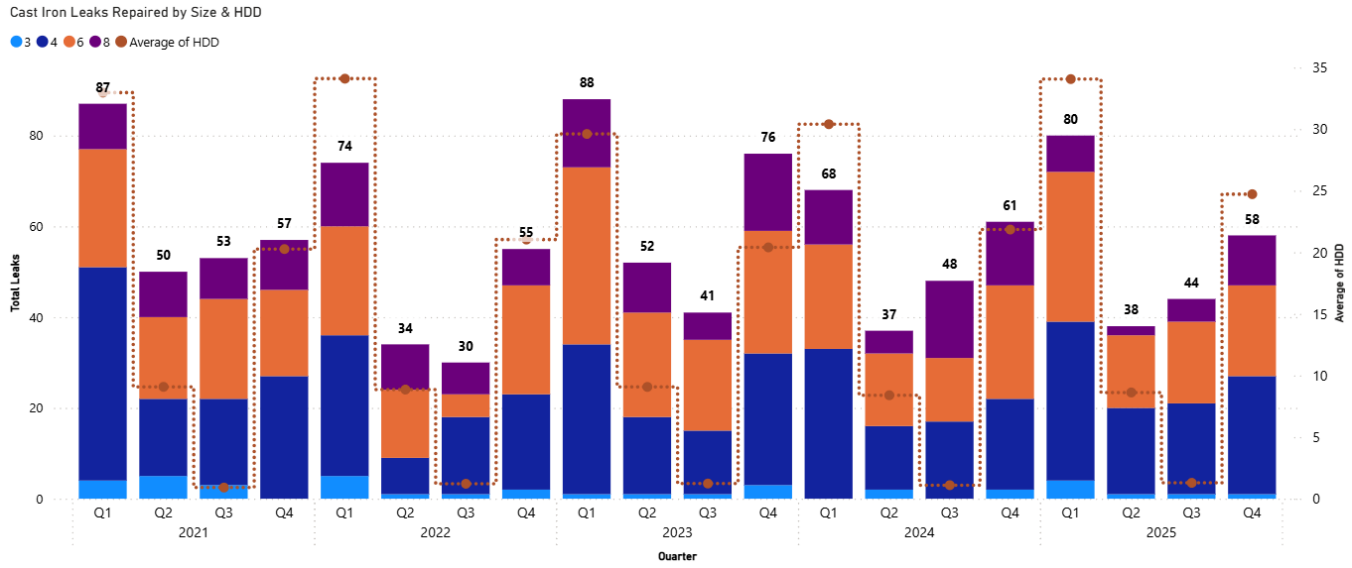


Source: NGA Operator

Figure 25 – Cast Iron Breaks and Bell Joint Leaks as a Function of Heating Degree Days Shown for Natural Force Damage and Other

While the inventory of leak-prone pipe has been reduced, Figure 25 shows that breaks and joint leaks are variable and, compared with Heating Degree Days (HDDs), the impact of cold temperatures, especially in Q4 and Q1, remains a determinant of leaks and breaks. HDDs measure the severity and duration of cold weather relative to a baseline temperature of 65˚F. HDDs strongly correlate with breaks and joint leaks. Notably, the number of breaks and joint leaks has not decreased as much as inventory, indicating that the remaining cast iron is getting worse. Figure 25 shows the importance of continuing to reduce leak-prone pipe inventory.

Figure 26 shows a similar depiction of the impact of HDDs, especially in Q4 and Q1, for cast iron leaks, examining the impact of various main diameters.



Source: Operator

Figure 26 – Cast Iron Leaks as a Function of Heating Degree Days Shown for Natural Force Damage and Other Outside Force

Slowing replacement or rehabilitation of cast iron risks more breaks and leaks in regions with the risk of winter weather conditions.

Incidents – PHMSA Reportable

PHMSA defines an incident at 49 CFR 190.5. Within PHMSA's definition, an incident means any of the following:

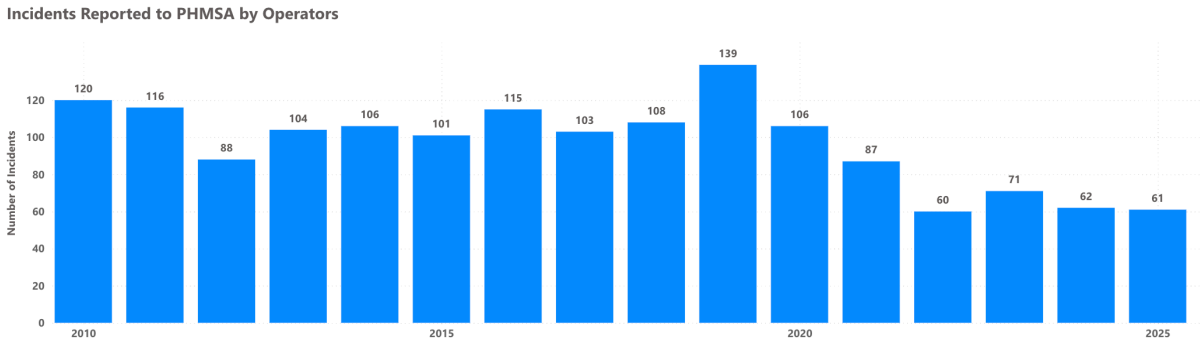
1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
    (i) A death, or personal injury necessitating in-patient hospitalization;
    (ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.
    (iii) Unintentional estimated gas loss of three million cubic feet or more.
2) An event that results in an emergency shutdown of an LNG facility or a UNGSF (Underground Natural Gas Storage Facility). Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.
3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

As noted in the Introduction, incident counts alone do not fully measure safety performance. Incidents should be evaluated with hazardous and total leaks, leak backlog, breaks, excavation damage, near misses, and asset-condition indicators that enable an operator to act to prevent an incident. This is especially important because annual counts in individual causal categories can be small and volatile, particularly when evaluating the data on a threat basis.

In addition, PHMSA's definitional changes complicate the use of incidents.[21] A 2010 change that added a 3 million cubic foot threshold starting in 2011 could have added incidents that would not otherwise have been reported. Downward trends following that timeframe are truly indicative of improvement. Likewise, a 2021 change in the property damage reporting threshold could have resulted in fewer incidents being reported when comparing 2021 and 2022, but downward trends after 2022 also indicate improvement. A clear downward trend from 2011 onward indicates improvement, as shown in Figures 28 and 30, among others.

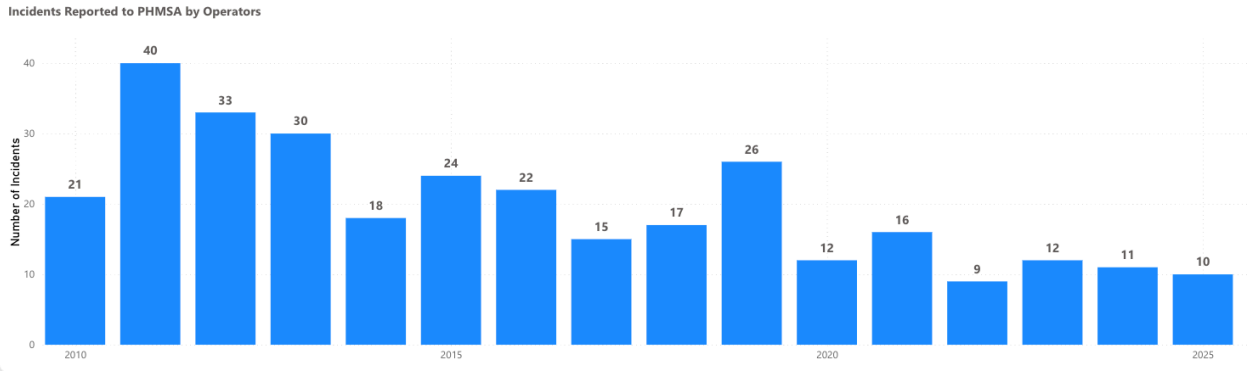
All Reportable Incidents

Figures 27 and 28 detail the trend for gas distribution incidents from 2010 to 2025 for both the U.S. and Northeastern U.S.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 27 – Reportable Incidents for All Causes – U.S.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 28 – Reportable Incidents for All Causes – Northeastern U.S.

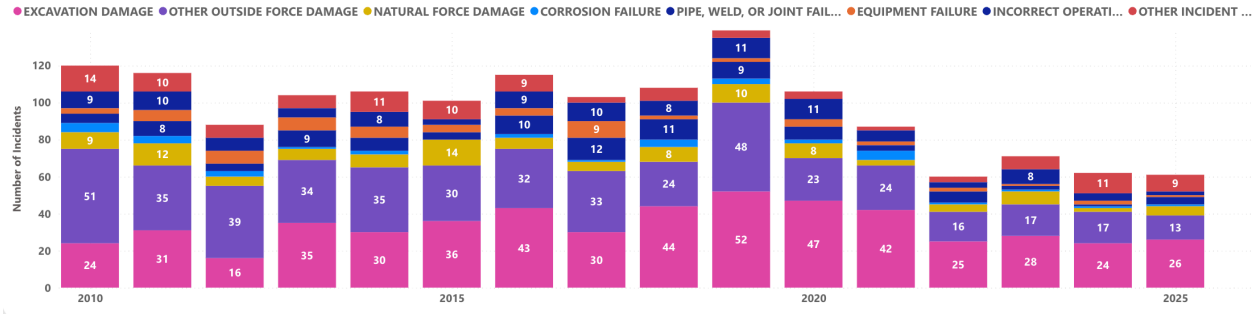
The figures show that incidents nationwide have been reduced from 120 to 61, or a reduction of 49%, and in the Northeastern U.S. from 21 in 2010 to 10 in 2025, a reduction of 52%, and a reduction from the 16-year high of 40 in 2011 down to 10 in 2025, a 75% reduction. Note: A spike occurred in 2019 for both the U.S. and Northeastern U.S., and an analysis of that spike indicates the leading causes were excavation damage and

[21] A rule published November 26, 2010 (75 FR 72905) added an unintentional gas loss criterion of three million cubic feet or more. A rule published January 11, 2021 (86 FR 2237) raised the property damage threshold from $50,000 to $122,000, with annual inflation adjustments thereafter. Some events reportable before 2021 were no longer reportable, which by itself can produce an apparent decline. The $50,000 threshold had been fixed in nominal dollars since 1984, so it also became progressively easier to meet in the years before 2021.

other outside force damage (motor vehicle damage, etc.). This anomaly interrupted an otherwise steady decline in incidents.

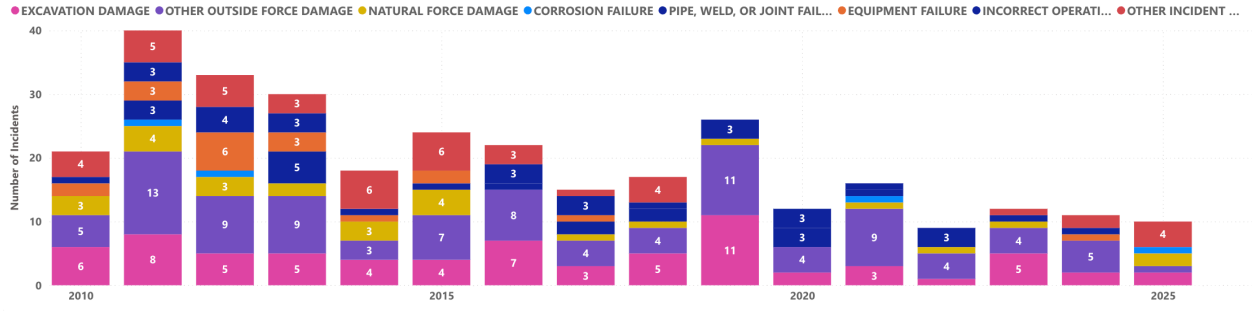
All Reportable Incidents by Cause

Figures 29 and 30 below detail the trends in incidents by cause from 2010 to 2025 in both the U.S. and the Northeastern U.S.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 29 – Incidents by Cause – U.S.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 30 – Incidents by Cause – Northeastern U.S.

Nationwide, incidents by cause data clearly indicate that the leading causes of incidents remain excavation damage and Other Outside Force damage. Excavation damage generally increased from 2010 through 2019 to a high of 52, then trended down from 2020 to 2025. The 2025 result of 26 incidents was up from the 24 incidents recorded in 2010. For other outside force damage nationwide, incidents were reduced from 51 to 13 or 74% but are still second only to excavation damage as a cause of incidents.

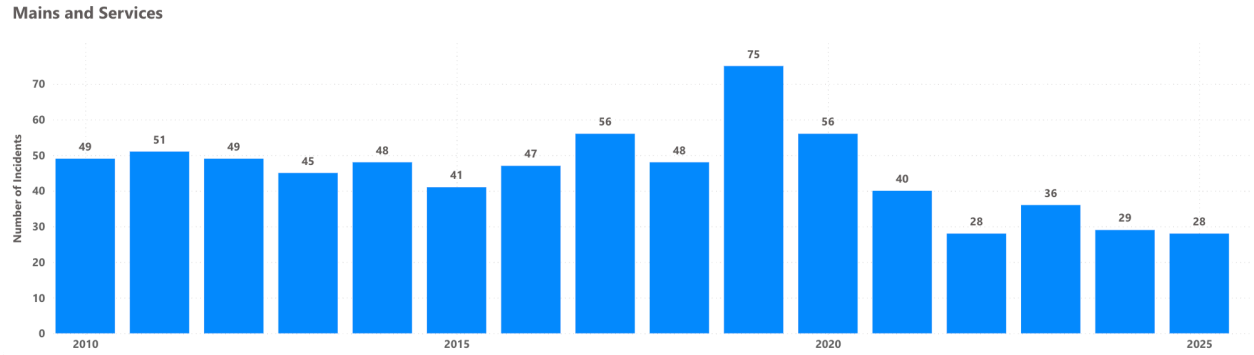
Note: Other outside force damage is defined by PHMSA as damage by vehicles not engaged in excavation, erosion of support due to other utilities, electrical arcing from another facility, damage by waterborne vessels, intentional damage, and nearby industrial man-made, or fire and explosion as the primary cause by others.

For the Northeastern U.S., incidents due to excavation damage were reduced from 6 to 2 from 2010 to 2025. Incidents due to excavation damage hit a period high of 11 in 2019 before falling to 2 in 2025. In the Northeastern U.S., incidents due to outside force damage fell from 5 in 2010 to 1 in 2025, and from a period high of 11 in 2019 to 1 in 2025, a reduction of an order of magnitude.

Although excavation damage and outside force damage are the leading causes of incidents, incidents alone are not the sole basis for decisions about repair, rehabilitation, or replacement. As described below, damage prevention programs are focused on reducing these causes. Decisions related to repair, rehabilitation, and replacement should be made with consideration of the measures described below, including leak trends, leak backlogs, etc. Excavation damage is the leading cause of incidents nationwide and indicates a risk that requires ongoing focus and continuous improvement. The FOHI suggestion to reallocate resources from leak-prone pipe replacement to damage prevention is not supportable. These risks are inherently different and require different mitigation strategies and resources.

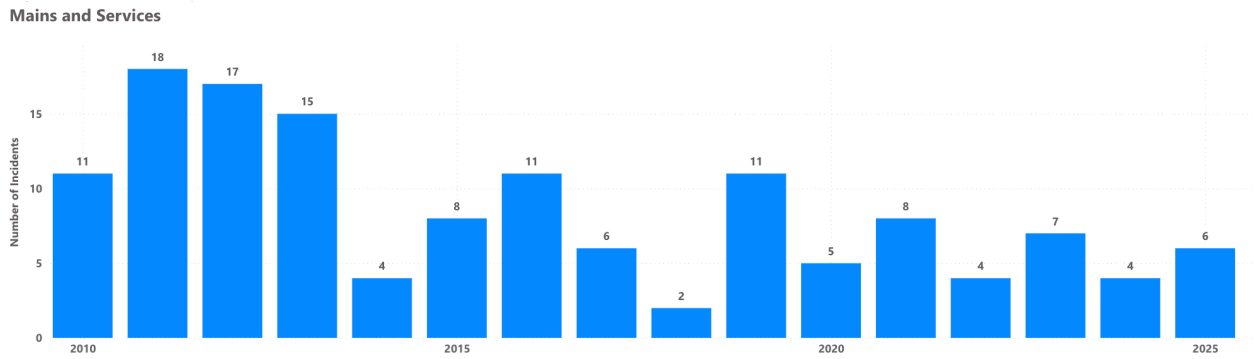
Reportable Incidents for Bare and Unprotected Mains and Services

Figures 31 and 32 below illustrate the trend for incidents involving bare and unprotected steel mains and services both in the U.S. and the Northeastern U.S.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 31 – Bare and Unprotected Steel Incidents – U.S.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

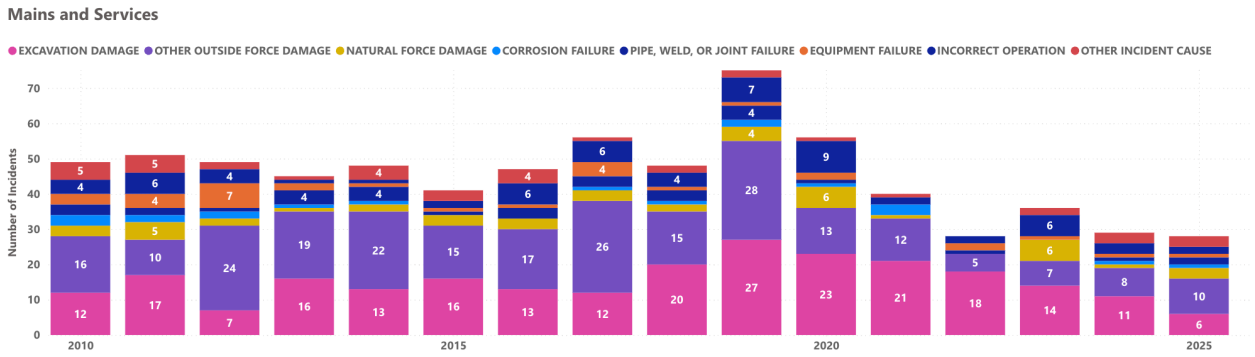
Figure 32 – Bare and Unprotected Steel Incidents – Northeastern U.S.

Nationwide, incidents involving bare and unprotected steel mains and services were reduced from 49 to 28 from 2010 to 2025, a 43% reduction. Incidents trended up generally from 2010 to a high of 75 in 2019 before declining to the 2025 low of 28.

In the Northeastern U.S., incidents involving bare and unprotected steel mains and services fell from 11 to 6 from 2010 to 2025, following a trend similar to the national performance. Incidents involving bare and unprotected steel peaked at 18 in the Northeastern U.S. in 2011 before falling to 6 in 2025.

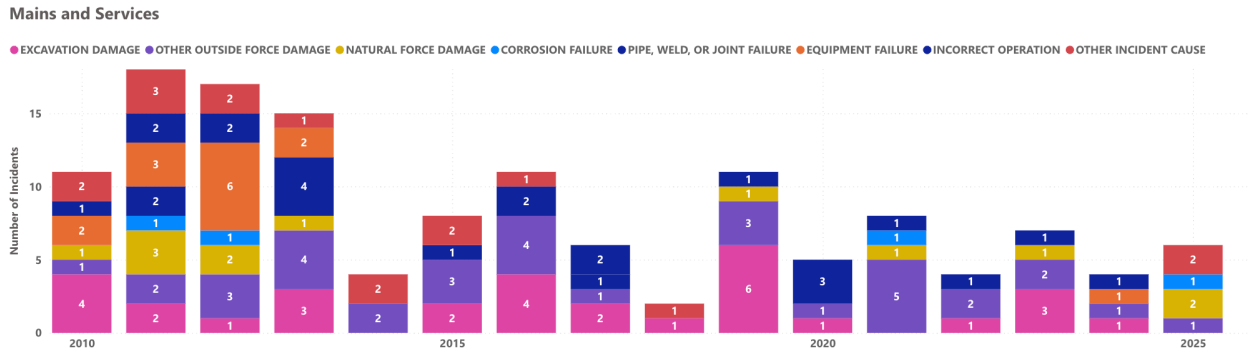
Reportable Incidents for Bare and Unprotected Mains and Services by Cause

Figures 33 and 34 below illustrate the incident trends for bare and unprotected steel mains and services by Cause from 2010 to 2025.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 33 – Bare and Unprotected Steel Incidents by Cause – U.S.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

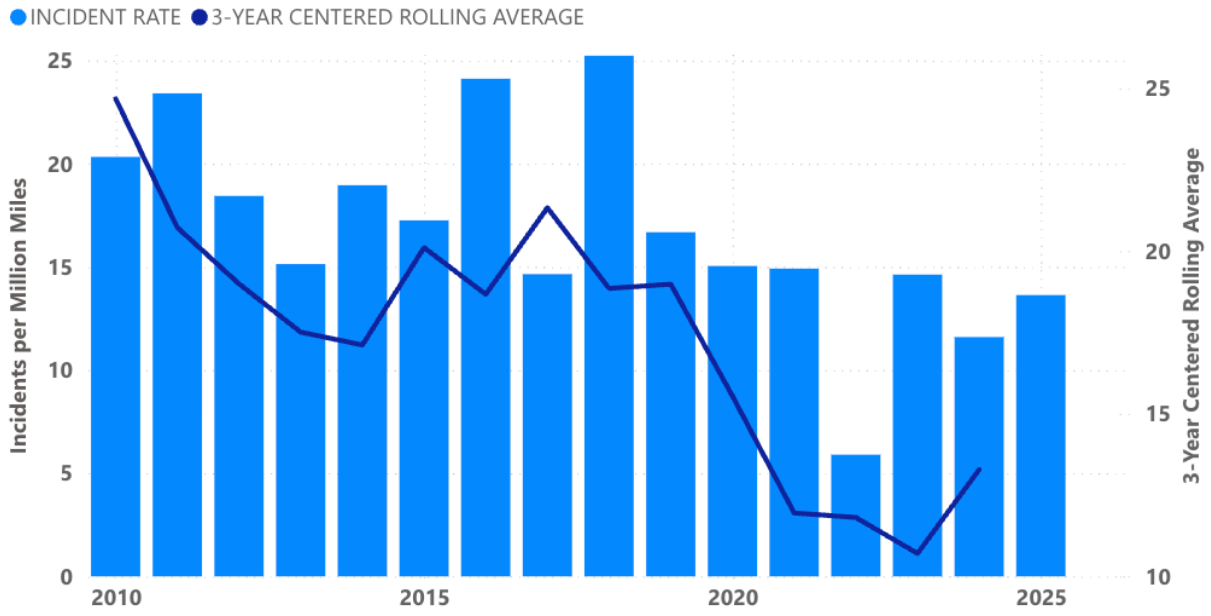
Figure 34 – Bare and Unprotected Steel Incidents by Cause – Northeastern U.S.

Nationwide, the leading cause of incidents involving bare and unprotected steel mains and services was other outside force damage; performance improved, with incidents falling from 16 in 2010 to 10 in 2025, a 37% reduction. Incidents caused by excavation damage involving bare and unprotected steel fell from 12 in 2010 to 6 in 2025.

In the Northeastern U.S., excavation damage and other outside force damage were also leading causes of incidents, with excavation damage on bare and unprotected steel mains and services falling from 6 in 2019 to 0 in 2025. For other outside damages, incidents were reduced from a high of 5 in 2021 to 1 in 2025.

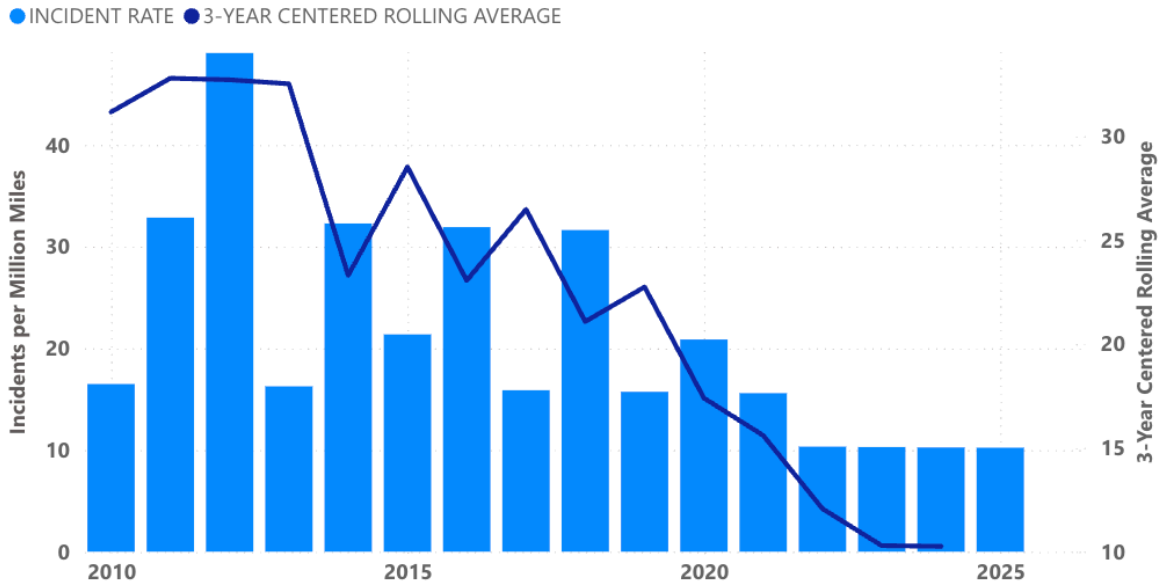
Serious Incidents

Figures 35 and 36 below illustrate the trend for serious incidents per million main miles from 2010 to 2025 for the U.S. and the Northeastern U.S.



Source: https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files

Figure 35 – Serious Incidents (Injuries and Fatalities) per Million Miles – U.S.



Source: https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files

Figure 36 – Serious Incidents (Injuries and Fatalities) per Million Miles – Northeastern U.S.

Nationwide, serious incidents per million miles fell from 20.3 incidents/million miles to 13.63 incidents/million miles from 2010 to 2025, a reduction of 33%. Incidents per million miles fell from a period high of 25.23/million miles in 2018 to a period low of 5.90/million miles in 2022, a reduction of 77%, before rising to 13.63/million miles in 2025, an increase of approximately 131% from the 2022 low.

For the Northeastern U.S., serious incidents per million miles vary significantly over the period, starting at 16.5 incidents/million miles and rising to 49.03 incidents/million miles, an increase of about 197%. Incidents then varied year by year until reaching the period low of 10.23 in 2025, a reduction from the period high of 49.03 in 2012, a reduction of approximately 79%.

Damage Prevention

In its report, using publicly available PHMSA data, the FOHI report identifies excavation damage as the leading cause of incidents in gas distribution in the U.S., and offers a depiction supposedly showing years of improvement followed by a nationwide plateau. Discussion of this critical pipeline safety topic deserves a closer examination of the complexity of damage prevention and the actual performance, using PHMSA data, over the past 16 years. The data are supplemented by data gathered and analyzed by The Common Ground Alliance (CGA) to provide a more complete understanding of how damage prevention works and the challenges that operators, as well as other underground infrastructure operators, face every day.

CGA has helped develop a solid foundation for damage prevention which is based on a documented operating model that meets federal requirements (49 CFR 192.614) and applicable state requirements. "Damage prevention is a shared responsibility among facility operators, excavators, one-call centers, locating organizations, regulators, designers, emergency responders, and other stakeholders" is a foundational principle in the CGA Best Practices.

A comprehensive program integrates eight mutually reinforcing disciplines: **planning and design; one-call ticket management; accurate locating and marking; safe excavation practices; reliable mapping and records; compliance and accountability; public education and stakeholder engagement; and reporting, evaluation, and continuous improvement.** It entails attention to timely and accurate positive response, qualified personnel, manageable ticket scope, tolerance-zone controls, current GIS records, quality assurance, consistent enforcement, and data-driven correction of root causes and near misses. Key program considerations are summarized in Table 4, below.

Table 4 – Key Damage Prevention Program Considerations at a Glance

Program dimension	Key controls and decisions	Evidence of effectiveness
Governance and compliance	Written program; state-specific requirements; defined roles; qualified personnel; proportionate enforcement.	Current procedures, assigned owners, completed training, audit results, and timely corrective-action closure.
Planning and design	Use available facility information, subsurface utility engineering where needed, separation criteria, pre-bid coordination, and provisions for complex or long-duration work.	Design reviews document conflicts, constructability risks, locate plans, and ticket-refresh requirements.
One-call and ticket management	Accurate work scope, reasonable ticket size, valid ticket duration, emergency criteria, timely transmission, and positive response.	On-time response rate, overdue tickets, emergency-ticket trends, and confirmation that all affected utilities responded.
Locating and marking	Use all available records, appropriate locating technology, uniform color codes, photographic documentation, trouble-locate escalation, and quality assurance.	Late- and mismark rates, quality-audit findings, repeat defects, and resource capacity during peak demand.
Excavation controls	White-line the work area, verify positive response, conduct a site review, protect markings, observe the tolerance zone, use soft-dig methods, and stop work when conditions differ.	Field observations, tolerance-zone compliance, valid-ticket checks, damage-notification timeliness, and contractor performance.

Mapping and records	Maintain accurate GIS and facility records, promptly incorporate field corrections, communicate newly installed facilities, and ensure assets are electronically locatable.	Record-update cycle time, mapping discrepancies, unlocatable assets, and closure of field-submitted corrections.
Education and engagement	Sustain 811 awareness, targeted and multilingual outreach where appropriate, role-based training, and regular coordination with all stakeholders.	Training completion, outreach reach and effectiveness, stakeholder participation, and reduction in no-call events.
Reporting and improvement	Use standardized event reporting, root-cause analysis, trend review, near-miss learning, and industry data repositories where appropriate.	Damage frequency and severity trends, causes by stakeholder, repeat-event rates, and measurable benefit from completed actions.

Source: Adapted from Common Ground Alliance Best Practices Guide, Version 21, February 2025.

The leading failure modes for excavation damage provide insights into the challenges in preventing damage to facilities **and harm to employees, contractors, and the public. The leading failure modes include excavating without notification, inaccurate or expired tickets, late or inaccurate locates, missing or outdated records, failure to preserve marks, and using mechanized equipment within the tolerance zone.** These leading causes vary by utility or infrastructure impacted. Operators require clear ownership of these risks and monitor a balanced set of indicators, including damages by root cause, damages per ticket or excavation volume, on-time locate performance, positive-response completion, mismark and late-mark rates, repeat violators, quality-audit findings, and timely closure of corrective actions.

Recent PHMSA actions serve to reinforce the importance of managing this threat. It issued an advisory bulletin addressing excavation damage prevention on **April 21, 2026** (91 FR 21368), with a follow-up administrative correction published on **June 22, 2026** (91 FR 37227) clarifying references to Common Ground Alliance (CGA) Best Practices Chapters 4 and 5. The advisory was entitled *Pipeline Safety: Advisory Bulletin on Preventing Excavation Damage During National Safe Digging Month and Beyond* (ADB-2026-05).

In 2025, based on data available from CGA, there were approximately 4.5M electronic and voice requests for locates across the U.S., an increase of just over 4%, or approximately 1.83M requests, in just one year. Transmissions of one-call tickets to facility owners based on those locate requests totaled just over 27M[22], meaning that for each locate request, an average of 6 utility owners were notified of the locate request. This illustrates not only the volume of locate requests, and therefore excavation activity, but also the complexity of locating all of the facilities with the potential for conflicts within the area to be excavated.

Total Damages and Near Misses U.S.

In 2025, based on reports submitted by operators and excavators to Common Ground Alliance DIRT, there were 213,985 damages in 2025, as well as 2,415 reported near misses. It is important to note that not all facility owners report, but this is the most comprehensive data available to all key industry stakeholders.

Figure 37 illustrates the Top Ten Known Damage Root Causes and highlights that the top root cause for damage nationwide for all underground infrastructure is excavator failure to notify One-Call centers or the 811 national number (22.3%), followed by the excavator failing to maintain proper clearance while excavating (14.8%), and facility not marked due to locator error (14.2%).

[22] Common Ground Alliance Annual Report – 2025.

2025 Top 10 Known Damage Root Causes				
Rank	**Root Cause**	**2025 Reports**	**% of Total**	**2024 Comparison**
1	No notification made to One Call Center/811	35,030	22.3%	↓ -2.2
2	Excavator failed to maintain clearance after verifying marks	23,240	14.8%	↓ -1.3
3	Facility not marked due to locator error	22,342	14.2%	↑ 2.3
4	Marked inaccurately due to locator error	14,392	9.2%	↑ 0.6
5	Excavator dug prior to verifying marks by potholing	11,340	7.2%	↑ 2.3
6	Improper excavation practice not listed elsewhere	9,698	6.2%	↓ -0.6
7	Facility not marked due to no response from operator/contract locator	6,607	4.2%	↓ -0.5
8	Excavator dug outside area described on ticket	4,753	3.0%	↑ 1.2
9	Excavator failed to shore excavation/support facilities	4,186	2.7%	↓ -0.6
10	Excavator dug after valid ticket expired	3,414	2.2%	↑ 0.1
	Top 10 Total	**135,002**	**86.0%**	
● Excavation Practices ● No Locate Request ● Locating Practices ● Invalid Use of Request				

Source: Common Ground Alliance DIRT Annual Trend Report 2025

Figure 37 – 2025 Top 10 Known Damage Root Causes

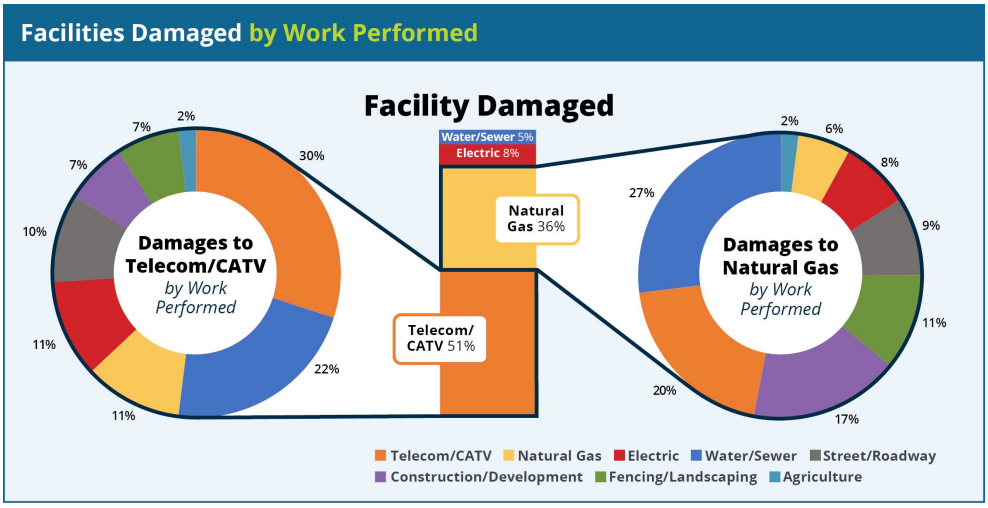
Figure 38 illustrates the top 5 known root causes for damage to natural gas facilities and highlights the fact that 4 of the top 5 root causes for damages, totaling just under 62%, are causes not directly under the operator's control. Importantly, damage to gas facilities due to No-Call, at just over 30%, are nearly 8 percentage points higher than the No-Call (Failure to Use One Call) root cause for all underground facilities.

Top Known Root Causes for Natural Gas Damages			
Rank	**Root Cause**	**2025 Reports**	**% of Total Known Data**
1	No notification made to One Call Center/811	21,685	30.1%
2	Excavator failed to maintain clearance after verifying marks	9,330	12.9%
3	Excavator dug prior to verifying marks by potholing	7,776	10.8%
4	Improper excavation practice not listed elsewhere	5,855	8.1%
5	Facility not marked due to locator error	5,111	7.1%
● Excavation Practices ● No Locate Request ● Locating Practices			

Source: Common Ground Alliance DIRT Annual Trend Report 2025

Figure 38 – 2025 Top Known Root Causes for Natural Gas Damages

Figure 39 illustrates the total damages to Telecom facilities (left donut) and natural gas facilities (right donut) by the work type being performed at the time of damage. For natural gas, the leading work type that caused damage was water/sewer work (27%), followed by telecom (20%).



Source: Common Ground Alliance DIRT Annual Trend Report 2025

Figure 39 – Facilities Damaged by Work Type Performed

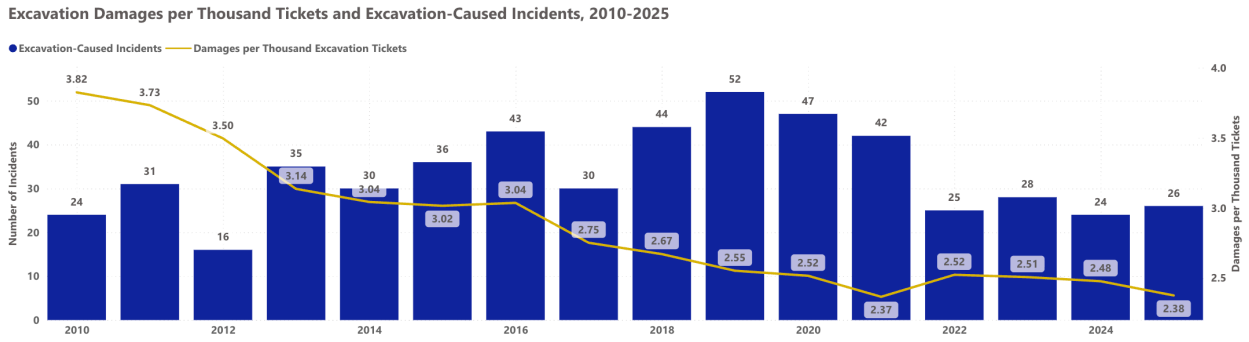
This indicates that ongoing and increasing water/sewer replacement work as well as telecom installations and upgrades are the key drivers of damage to gas facilities. Conversely, gas operators and their contractors are responsible for 6% of damages to gas facilities in the performance of their work on or near gas facilities. This includes all work performed on the distribution system and is not limited to leak-prone pipe replacement work. This should remain a focus for operators' oversight, quality control, and quality assurance programs.

Distribution Operators Performance 2010 through 2025

Through multiple processes and programs, along with stakeholder training and engagement, gas operators are focused on the issues that lead to excavation damage, and the results are clear. Excavation damage has continued to trend down, with some operators and the states they operate in showing significant reductions in damage per one thousand tickets, as well as significant reductions in reportable incidents, although excavation damage remains the leading cause of incidents nationwide. Operators have little authority to control the behaviors of outside parties, as evidenced by the high number of damages that are caused by excavators or property owners not using the one-call system to request a locate.

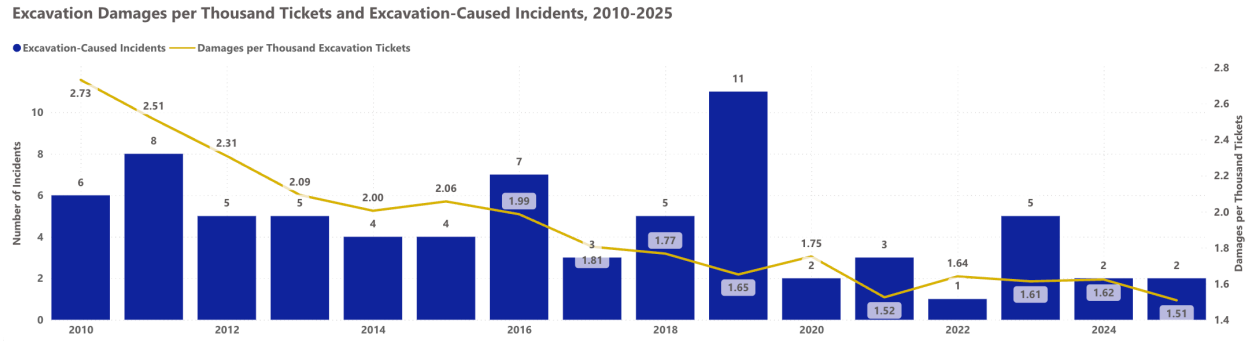
Operators inform and influence behaviors through Damage Prevention Programs and Stakeholder Engagement Programs; however, the challenge of driving compliance with these requirements is a shared responsibility for all stakeholders and remains a significant challenge.

Figures 40 and 41 below compare the trends in Excavation Damages per 1,000 Tickets and Excavation-Caused Incidents for the U.S. and Northeastern U.S. for 2010 through 2025.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 40 – Excavation Damages per 1,000 Tickets and Excavation-Caused Incidents – U.S.

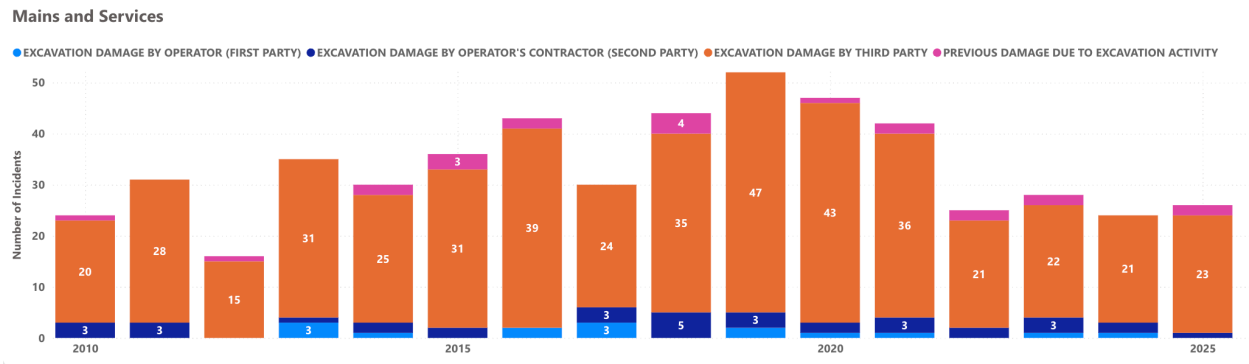


Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 41 – Excavation Damages per 1,000 Tickets and Excavation-Caused Incidents – Northeastern U.S.

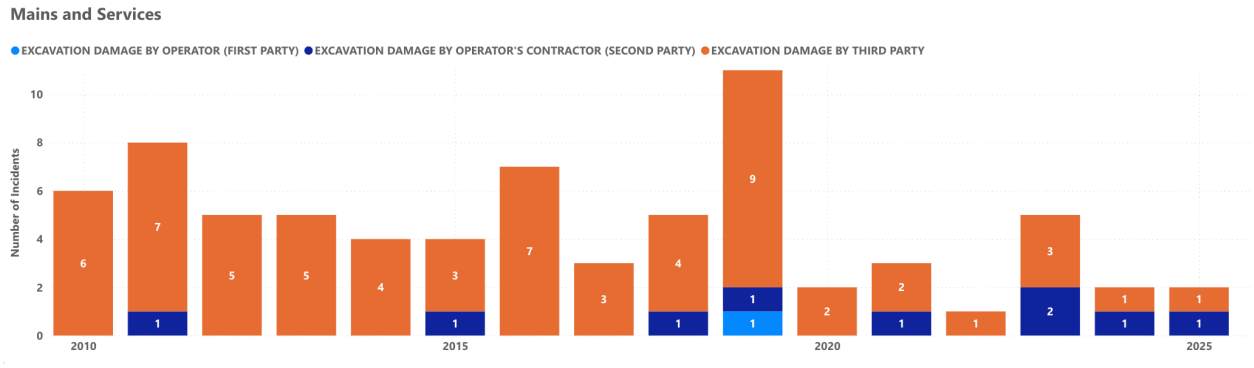
The damages-per-thousand-tickets trend for the U.S. and Northeastern U.S. shows clear improvement over the period, decreasing from 3.82 to 2.38 per thousand tickets nationwide and from 2.73 to 1.51 per thousand tickets in the Northeastern U.S., 38% and 45% improvement, respectively.

Figures 42 and 43 below illustrate the trends from 2010 to 2025 for incidents caused by excavation damage, sorted by responsible party.



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 42 – U.S. Incidents Caused by Excavation Damage by Responsible Party – 2010 to 2025



Source: PHMSA Gas Distribution Incident Report Data, 2010 through 2025

Figure 43 – Northeastern U.S. Incidents Caused by Excavation Damage by Responsible Party – 2010 to 2025

Excavation damage caused by 3rd parties continues to be the leading cause of incidents across the U.S.; however, there has been a significant reduction from the 15-year high of 47 in 2019 to 23 in 2025, a reduction of just over 50%. Excavation-related incidents are overwhelmingly caused by 3rd-party excavators, and this remains a challenge and a focus area across the industry. Incidents related to 3rd party excavation damage in the Northeastern U.S. have shown a steady decline from 2010 to 2025, dropping from 6 to 1 over that time period. The Northeastern U.S. has also seen a reduction from the 15-year high of 9 in 2019 to 1 in 2025.

In summary, excavation damage remains the leading cause of incidents on the gas distribution system; however, this fact alone does not support reducing leak-prone pipeline replacement.

Excavation damage and leak-prone infrastructure are separate risks that require sustained attention; redirecting replacement resources to damage prevention would be an ill-advised attempt to reduce one risk while increasing the other.

Available data show that excavation damage remains the leading cause of incidents across the U.S. However, national data can obscure continued state and regional progress; Northeastern operators, including those with robust leak-prone pipe replacement programs, have outpaced national performance. Excavation damage's status as a leading incident cause does not justify reducing main and service replacement or shifting those resources to damage prevention.

Analysis should also distinguish gas construction replacement-related excavation from unrelated non-gas construction. Work on the gas system by definition occurs on or near its facilities and therefore presents a higher level of exposure to gas facility damage than non-gas construction excavation. Although there is room for improvement, the facts show that gas-on-gas damage accounts for a much smaller percentage of damage than non-gas construction activities, even though workers are nearly 100% of the time working in proximity to gas infrastructure.

Because excavation laws, enforcement, ticket definitions, damage criteria, and reporting quality vary by jurisdiction, national comparisons are useful for general trends and high-level comparisons but less useful for detailed analysis of individual states or state groupings.

Continuous improvement in damage prevention has been, and must continue to be, a key focus for all industry stakeholders. Addressing the leading cause of damage, No-Call, would undoubtedly benefit pipeline and public safety.

Other Outside Force Damage

Although much attention, deservedly so, focuses on the leading cause of incidents, excavation damage, the next most prevalent cause is also damage-related. The category of "Other Outside Force Damage" is also a leading cause of incidents, including on newly installed materials.

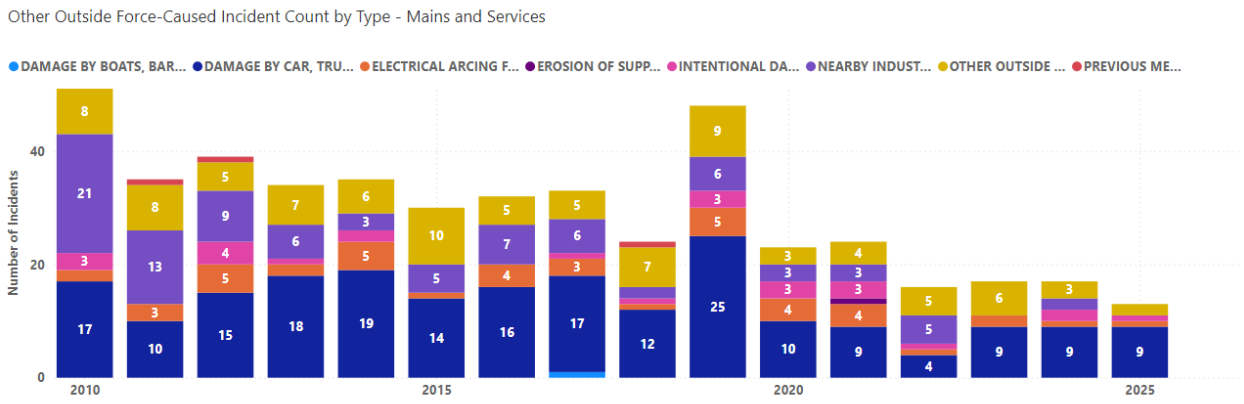
Other Outside Force Damage is defined by PHMSA as damage to a pipeline facility that includes activities caused by outside parties or forces other than through excavation or naturally occurring events and includes events like pipeline failures due to vehicle accidents and vandalism.

Sub-cause categories defined by PHMSA for this cause include:

- Nearby industrial, man-made, or other fire/explosion as primary cause
- Damage by car, truck, or other motorized vehicle/equipment not engaged in excavation
- Damage by boats, barges, drilling rigs, or other maritime equipment or vessels set adrift, or which have otherwise lost their mooring
- Routine fishing or other maritime activity not engaged in excavation
- Electrical arcing from other equipment or facility
- Previous mechanical damage not related to excavation
- Intentional damage
- Other outside force damage – not otherwise specified

Although, as noted in Figures 29 and 30 above, Excavation Damage continues to be the leading cause of incidents, Other Outside Force Damage is the second leading cause.

Figure 44 illustrates the other outside force incident counts by type, or sub-cause. Damage by motor vehicles (213 incidents) remains the leading cause of incidents attributed to other outside force damage, followed by fire first/nearby fire/heat events (96 incidents). As mentioned previously, the trend has been positive since the 2019 peak. Although not traditionally a focus in damage-prevention discussions, this data may warrant inclusion in a consolidated view of damage-prevention opportunities.



Source: PHMSA Annual Report 2010 through 2025

Figure 44 — Other Outside Force-Caused Incident Count by Type — Mains and Services, 2010–2025, U.S.

Incidents Related to New Facilities

Incidents at newly installed facilities were highlighted in the FOHI report Section 3.28 and used to suggest that replacement work may create more risk than it solves. This analysis and implication is flawed and misleading.

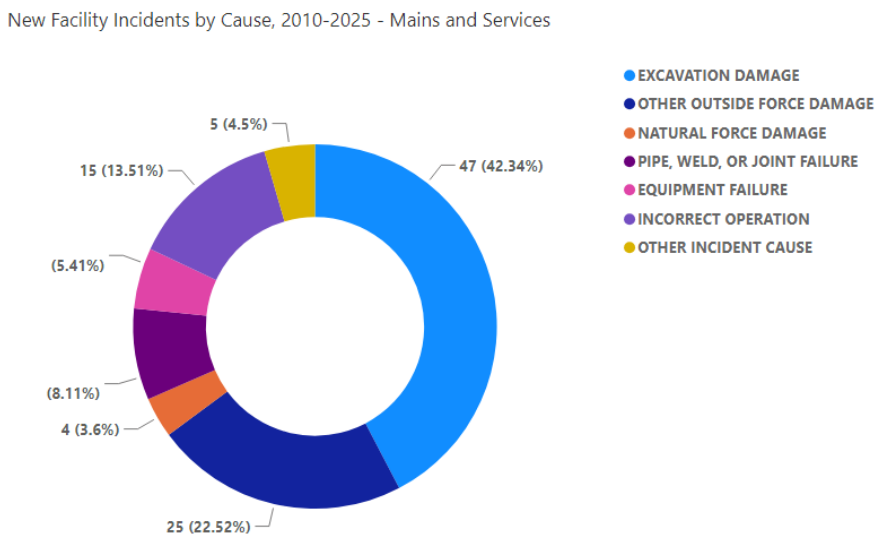
FOHI's report suggests that replacement work may create short-term risk through excavation damage, incorrect operation, installation defects, and documentation errors, citing incidents involving new facilities. Higher volumes of construction work may increase exposure to mistakes, but an incident involving recently installed pipe does not by itself establish that leak-prone pipe replacement work caused it. The record includes incidents on new facilities, yet it does not show that the incidents were tied to replacement programs. New facilities are installed for several reasons, including new customer installations, public works projects, system reliability upgrades, and asset replacement due to conditions such as corrosion. Excavation near gas facilities occurs for leak repairs and other maintenance work. Most incidents result from third-party excavation damage and other outside-force damage unrelated to the gas construction or maintenance work performed.

In analyzing the incidents from 2010 to 2025 related to new facilities summarized in Figure 45 (facilities less than 3 years old), approximately 42% were caused by excavation damage, and another 22% were caused by other outside force damage. Based on a review of the narratives in the PHMSA incidents, the leading sub-causes of other outside force damage were fire first/nearby fire/heat at 32%, followed by vehicle/equipment impacts at 28% and contractor/construction interaction at 20%. There were three fatalities recorded as a result of these incidents caused by other outside force damage.

These incidents highlight opportunities to strengthen processes and procedures, as well as construction oversight, quality control, and quality assurance, since the analysis indicates several causes that may relate to construction quality, such as incorrect operations and pipe, weld, or joint failures. These areas are key for operators implementing and maturing their pipeline safety management systems, including operational controls and safety assurance.

Additionally, FOHI cites 15 specific incidents involving newly installed facilities in its report. Our review found only two incidents were clearly tied to leak-prone pipe replacement. Most narratives did not identify the program that prompted the work, and several were clearly unrelated to replacement work, including a 30-inch transmission main weld failure. One 2024 incident involved facilities from a project completed in 2015. These findings support continued improvement across all construction-related work phases and types, but do not show that the issues are unique to leak-prone infrastructure replacement.

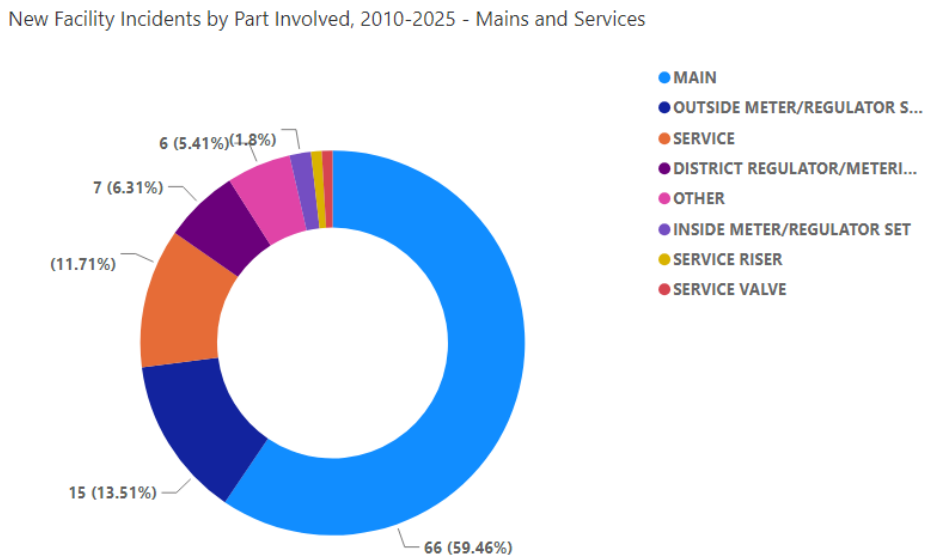
Additionally, FOHI's selective case studies may also overrepresent severe outcomes and underrepresent successful projects. Any increase in exposure from higher work volumes must be managed through strong construction oversight, quality control, and quality assurance across gas distribution operations, construction, and maintenance.



Source: PHMSA Annual Report – 2010 through 2025

Figure 45 — New Facility Incidents by Cause, 2010–2025 — Mains and Services – U.S. Wide

Figure 46 illustrates the newly installed distribution system components involved in incidents between 2010 and 2025. Although the majority of incidents involved new mains (59%), outside meter/regulator (13.5%) and service lines (11.7%) combined for 25.2%. District Regulator/Metering stations were the fourth most likely component to be damaged by outside force.



Source: PHMSA Annual Report – 2010 through 2025

Figure 46 — New Facility Incidents by Part Involved, 2010–2025 — Mains and Services, U.S.-Wide

Conclusions

The history and data evaluated in this report show that gas distribution safety has improved through successive layers of protection. The life-cycle-based federal standards established in 1970 created the essential foundation for materials, design, construction, testing, operations, maintenance, corrosion control, qualification, damage prevention, and public awareness. Those requirements remain indispensable. At the same time, the plateau in incident performance beginning in the 1990s showed that compliance with prescriptive requirements alone could not fully address vintage material degradation and diverse, locally variable distribution systems. Adopting risk assessment and Distribution Integrity Management Programs added complementary layers and the systemwide discipline needed to identify threats, rank risks, select mitigations, measure results, and continuously improve.

The available performance data indicate that this combined approach has produced substantial gains. Between 2010 and 2025, reportable distribution incidents declined by 49% nationwide and 52% in the Northeastern U.S. Hazardous main leaks declined by 13% nationally and 29% in the Northeastern U.S., while total main leaks repaired or eliminated for both declined by approximately 48%.

The 83% reduction in the Northeastern U.S.'s year-end leak backlog is especially important because it means fewer known leaks remain exposed to winter conditions, frost heave, paved urban environments, and the potential for subsurface gas migration into homes and businesses. These measures complement incident counts by capturing avoided exposure and near-miss potential before catastrophic consequences occur.

DIMP has been most effective when integrated with sustained repair, replacement, and rehabilitation programs. Replacement of cast iron, wrought iron, bare steel, and vulnerable vintage plastic removes materials with demonstrated leak and failure histories and can eliminate hundreds of potential joint leak points per mile of cast iron. The report also demonstrates that the benefits extend beyond the pipe itself: projects relocate meters and regulators for safer access with a technician checking the customer's piping and gas-burning equipment when restarting service, add excess flow and sectionalizing valves, strengthen emergency isolation, reduce water-intrusion outages, remove obsolete appurtenances, and improve mapping and records. Additionally, rebuilding the network reduces exposure of utility crews, contractors, first responders, customers, and the public to hazardous conditions and potentially hazardous consequences.

The report also supports a more precise conclusion than "replace rather than repair." Repair remains the correct response to immediate hazards and can be durable when a defect is localized, and the surrounding asset is structurally sound. Rehabilitation can extend service life and reduce community disruption where pipe condition, geometry, capacity, service configuration, approved technology, and cost-effectiveness make it feasible. Replacement is warranted where degradation is systemic, leaks recur, structural integrity or capacity is inadequate, interacting threats elevate consequences, or continued repair would leave unacceptable risk in place. DIMP provides the evidence and prioritization for that choice; material and service years are important risk indicators, but they should be considered with condition, leak history, operating environment, potential consequence, and project feasibility.

Continued progress cannot be assumed. The observed relationship between cold weather and cast-iron breaks indicates that risks associated with the condition of the remaining inventory may increase even as mileage declines. Slowing mitigation solely because total inventory is smaller could therefore increase risk

per remaining mile. Energy-transition planning does not remove the obligation to operate existing systems safely; it increases the importance of disciplined, transparent decisions that account for safety, remaining useful life, customer impacts, construction risk, cost, emissions, and the potential for future system use.

The next stage of improvement should preserve the strong regulatory baseline while deepening risk-informed asset management and the application of Pipeline Safety Management Systems. Operators, regulators, and communities should continue to:

- Use incident, hazardous-leak, and total-leak data, along with leading indicators, leak backlog, breaks, damages, and near-misses, together to assess safety performance rather than relying on a single outcome measure.
- Prioritize remaining leak-prone assets using verified condition, recurring leak history, interacting threats, and potential consequences.
- Coordinate projects with municipalities and other subsurface utilities to reduce construction risk, cost, pavement disruption, and avoidable rework.
- Maintain constant diligence in damage prevention, public awareness, operator qualification, pressure control, emergency response, records, and technology improvements alongside pipe programs.
- Strengthen the evidence base with normalized, multi-operator comparisons of safety outcomes, costs, construction risks, emissions, and useful-life benefits for repair, rehabilitation, and replacement.

The central conclusion is that sustained, data-driven asset management has materially improved gas distribution pipeline safety. Prescriptive standards, DIMP, and repair, rehabilitation, and replacement are complementary layers of protection. Maintaining progress will require applying each tool where it reduces risk most, documenting the basis for those choices, and continuing to act before known deterioration becomes an incident.

Every day, millions of Americans depend on natural gas to heat their homes, operate businesses, and power critical industrial processes. Customers may rarely think about the infrastructure that delivers this energy, but operators have a fundamental obligation to operate, maintain, and continually improve to provide safe, reliable natural gas service. For customers, the true measure of a natural gas distribution system's safety performance is confidence: confidence that energy will be there when needed, that safety remains the highest priority, and that infrastructure is being responsibly maintained, rehabilitated, or replaced for the future.

Epilogue

A regulator, a commissioner, or a member of the public can ask, "**How can operators sustain many of the observed trends and further improve the safety performance?**" They can, and they do so by adopting pipeline safety management systems (PSMS). NGA members pledged a commitment in 2019 and have worked ever since through a "PSMS Collaborative," sharing and learning together. AGA members have broadly adopted PSMS and committed to implementing it by the end of 2027, also continuing to share and learn together. The NGA and SGA Natural Gas Association have collaborated since 2021 to build tools that help leaders and employees understand, implement, and improve the impact of management systems in their respective work areas.

A PSMS is a structured, integrated framework for identifying and managing operational risk, promoting organizational learning, continuously improving pipeline safety, and strengthening safety culture. It builds on the DIMP framework to define elements that identify, manage, and reduce risk throughout a pipeline's life cycle and, at the earliest stage, help prevent or mitigate the likelihood and consequences of an unintended release or abnormal operations. **A PSMS uses an iterative process using the simple concepts of Plan, Do, Check, and Act.**

A PSMS also explicitly defines management's role in setting the vision, goals, and objectives, and in providing the resources to plan, do, check, and act. The management system's effectiveness is reviewed periodically through a defined management review process, one output of which is defining ways to continuously improve. The analyses presented in this report show many areas for improvement, as well as areas that need additional, ongoing attention, such as excavation damage. Implementing and maturing an operator's PSMS will help sustain improvements and drive improvement in other areas.

A management system requires engagement not just from management but from every employee and contractor in the work completed each day. For employees and contractors, it is:

Actively engaging in tailboard/tailgate meetings at your work center, control room, or worksite, including sharing of lessons learned.	Stopping and reporting any work you see performed outside of procedure, rather than letting it continue.
Actively engaging in safety briefs/job hazard analyses, including discussions of the work to be done and procedures we will use.	Identifying and raising potential AOCs and substandard conditions to your foreman, crew leader, or supervisor, as appropriate, and expecting them to act on it or tell you why not.
Actively engaging in all training activities and staying current on all training and qualification requirements.	Documenting your work accurately and completely.
Following your procedures, specifications, work methods, and technical guidance.	Owning your work - by ensuring high-quality workmanship.
Using materials, tools, and equipment as intended and specified in your procedures, work orders, and manufacturer's instructions.	Identifying and communicating improvements to procedures and work methods, rather than working around them.
Ensuring that you are qualified to perform the work assigned to you.	Taking ownership of quality control and quality assurance activities alongside your crew lead, supervisor, manager, or other personnel - not just assisting when asked.

Knowing that you have the responsibility and obligation to stop work if you identify an unsafe situation or if you are unsure of the work to be performed.	Ensuring that if you know a co-worker is impaired or unable to safely perform their duties, you stop the work until the issue is resolved.

When incidents and near misses occur, operators evaluate and learn from them, finding ways to improve data management, risk evaluation, and the selection of preventive and mitigative measures through annual management reviews using the iterative plan, do, check, and act cycle. Reducing risk and improving pipeline and public safety is a never-ending journey.