# Integrity Management of Gas Transmission Pipelines in High Consequence Areas


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National Transportation Safety Board

490 L'Enfant Plaza, SW
Washington, DC 20594

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**Abstract:** There are approximately 298,000 miles of onshore natural gas transmission pipelines in the United States. Although rare, failure of these pipelines poses a significant risk to the public, especially when pipelines traverse populated areas, known as high consequence areas (HCA). To ensure the physical integrity of their systems in HCAs, gas transmission pipeline operators have been required by the Pipeline and Hazardous Materials Safety Administration (PHMSA) to develop and implement integrity management programs since 2004.

The NTSB undertook this study because of concerns about deficiencies in the operators' integrity management programs and the oversight of these programs by PHMSA and state regulators—concerns that were also identified in three gas transmission pipeline accident investigations conducted by the NTSB in the last five years. These accidents resulted in 8 fatalities and over 50 injuries, and they also destroyed 41 homes. This study used both quantitative and qualitative approaches. Data analysis was combined with insights on industry practices and inspectors' experiences obtained through interviews and discussions with pipeline operators, state and federal inspectors, industry associations, and other stakeholders.

This study found that while the PHMSA's gas integrity management requirements have kept the rate of corrosion failures and material failures of pipe or welds low, there is no evidence that the overall occurrence of gas transmission pipeline incidents in HCA pipelines has declined. This study identified areas where improvements can be made to further enhance the safety of gas transmission pipelines in HCAs. Areas identified for safety improvements include (1) expanding and improving PHMSA guidance to both operators and inspectors for the development, implementation, and inspection of operators' integrity management programs; (2) expanding the use of in-line inspection, especially for intrastate pipelines; (3) eliminating the use of direct assessment as the sole integrity assessment method; (4) evaluating the effectiveness of the approved risk assessment approaches; (5) strengthening aspects of inspector training; (6) developing minimum professional qualification criteria for all personnel involved in integrity management programs; and (7) improving data collection and reporting, including geospatial data.

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# Acronyms and Abbreviations

| | |
|---|---|
| AGA | American Gas Association |
| APDM | ArcGIS Pipeline Data Model |
| ASME | American Society of Mechanical Engineers |
| CFR | Code of Federal Regulations |
| CIS | close interval survey |
| DOT | Department of Transportation |
| ECDA | external corrosion direct assessment |
| FAQ | frequently asked question |
| FGDC | Federal Geographic Data Committee |
| GIS | geographic information system |
| HCA | high consequence area |
| IA | Inspection Assistant |
| ILI | in-line inspection |
| IM | integrity management |
| INGAA | Interstate Natural Gas Association of America |
| ISAT | Integrated Spatial Analysis Techniques |
| MAOP | maximum allowable operating pressure |
| NACo | National Association of Counties |
| NAPSR | National Association of Pipeline Safety Representatives |
| NPMS | National Pipeline Mapping System |
| NSDI | National Spatial Data Infrastructure |

| | |
|---|---|
| NSGIC | National States Geographic Information Council |
| NTSB | National Transportation Safety Board |
| P&M | preventive and mitigative |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PIC | potential impact circle |
| PIPA | Pipelines and Informed Planning Alliance |
| PODS | Pipeline Open Data Standard |
| SME | subject matter expert |

# Executive Summary

There are approximately 298,000 miles of onshore natural gas transmission pipelines in the United States. Since 2004, the operators of these pipelines have been required by the Pipeline and Hazardous Materials Safety Administration (PHMSA) to develop and implement integrity management (IM) programs to ensure the integrity of their pipelines in populated areas (defined as high consequence areas [HCAs]) to reduce the risk of injuries and property damage from pipeline failures.

An operator's IM program is a management system designed and implemented by pipeline operators to ensure their pipeline system is safe and reliable. An IM program consists of multiple components, including procedures and processes for identifying HCAs, determining likely threats to the pipeline within the HCA, evaluating the physical integrity of the pipe within the HCA, and repairing or remediating any pipeline defects found. These procedures and processes are complex and interconnected. Effective implementation of an IM program relies on continual evaluation and data integration. The IM program is an ongoing program that is periodically inspected by PHMSA and/or state regulatory agencies to ensure compliance with regulatory requirements.

## Why the NTSB Did This Study

In the last six years, the National Transportation Safety Board (NTSB) investigated three major gas transmission pipeline accidents where deficiencies with the operators' IM programs and PHMSA oversight were identified as a concern.[1] These three accidents resulted in 8 fatalities, over 50 injuries, and 41 homes destroyed with many more damaged. As the IM requirements have now been in place for 10 years, with all HCA pipelines having had at least one integrity assessment, the NTSB believes that now is an appropriate time to evaluate the need for safety improvements to the IM program.

The focus of this study was to evaluate the need for safety improvements to IM programs and requirements for gas transmission pipelines in the United States by examining:

- Federal and state oversight of IM programs;
- Common practices associated with HCA identification and verification;
- Current threat identification and risk assessment techniques;
- The effectiveness of different pipeline integrity assessment methods; and
- Procedures for continual assessment and data integration within the IM framework.

The NTSB used a multifaceted approach to evaluate the effectiveness of IM program requirements and oversight. The quantitative analyses of PHMSA data were complemented by NTSB staff's qualitative analyses of information obtained from interviews and discussions with pipeline operators, state and federal inspectors, industry associations, researchers, and representatives of private companies that provide integrity assessments, risk analysis, and geospatial data services to gain insight into IM program practices and procedures.

[1] Palm City, Florida (5/4/2009); San Bruno, California (9/9/2010); and Sissonville, West Virginia (12/11/2012).

## What the NTSB Found

This study found that while PHMSA's gas IM requirements have kept the rate of corrosion failures and material failures of pipe or welds low, there is no evidence that the overall occurrence of gas transmission pipeline incidents in HCA pipelines has declined. This study identified areas where improvements can be made to further enhance the safety of gas transmission pipelines in HCAs. The study did find that IM programs are complex and require expert knowledge and integration of multiple technical disciplines including engineering, material science, geographic information systems (GIS), data management, probability and statistics, and risk management. This complexity requires pipeline operator personnel and pipeline inspectors to have a high level of knowledge to adequately perform their functions. This complexity can make IM program development, and the evaluation of operators' compliance with IM program requirements, difficult. The study found that PHMSA resources in guiding both operators and inspectors need to be expanded and improved.

The effectiveness of an IM program depends on many factors, including how well threats are identified and risks are estimated. This information guides the selection of integrity assessment methods that discover pipeline system defects that may need remediation. The study found that aspects of the operators' threat identification and risk assessment processes require improvement. Furthermore, the study found that of the four different integrity assessment methods (pressure test, direct assessment, in-line inspection [ILI], and other techniques), ILI yields the highest per-mile discovery of pipe anomalies and the use of direct assessment as the sole integrity assessment method has numerous limitations. Compared to their interstate counterparts, intrastate pipeline operators rely more on direct assessment and less on ILI.

## Recommendations

As a result of this safety study, the NTSB makes recommendations to PHMSA, the American Gas Association (AGA), the Interstate Natural Gas Association of America (INGAA), the Federal Geographic Data Committee (FGDC), and the National Association of Pipeline Safety Representatives (NAPSR). The recommendations include developing expanded and improved guidance for operators and inspectors for:

- The development of criteria for threat identification and elimination;
- Consideration of interactive threats; and
- Increased knowledge of the critical components associated with risk assessment approaches.

The NTSB also recommends evaluating and improving gas transmission pipeline integrity assessment methods, including increasing the use of ILI and eliminating the use of direct assessment as the sole integrity assessment method. Other recommendations include: evaluating the effectiveness of the approved risk assessment approaches for IM programs; developing minimum professional qualification criteria for all personnel involved in IM programs; and improving data collection and reporting, including geospatial data, to support the development of probabilistic risk assessment models and the evaluation of IM programs by state and federal regulators.

# 1 Introduction

There are 298,302 miles[2] (PHMSA 2014a) of onshore natural gas transmission pipelines in the United States. The safe operation of these pipelines is primarily regulated by the Department of Transportation (DOT)'s Pipeline and Hazardous Materials Safety Administration (PHMSA). Compared to ground transportation of hazardous materials, such as rail and highway, pipeline transportation is relatively safe (GAO 2013). However, the rupture of a natural gas pipeline in San Bruno, California (NTSB 2011) and other accidents (NTSB 2013, 2014)(called incidents in the pipeline community),[3] have shown that transmission pipeline incidents can be devastating in terms of fatalities, injuries, and property damage. Since 2004, all operators of gas transmission pipelines located in high consequence areas (HCA) have been subject to PHMSA's gas integrity management (IM) program requirements, commonly known as the gas IM rule.[4] An IM program is a management system comprised of a documented set of policies, processes, and procedures implemented to ensure the integrity of those portions of a pipeline that lie within an HCA (PHMSA 2011b).

Between 2010–2013, there were 375 onshore gas transmission pipeline incidents. The most common causes for onshore gas transmission pipeline incidents were corrosion, material failure of pipe or welds, and equipment failure. These are the types of problems that the IM programs are designed to detect through the required use of integrity assessment methods and other measures.[5] Incidents attributed to corrosion and material failure of pipe or weld alone resulted in 8 fatalities, 51 injuries, and more than $466 million of estimated total costs to operators.[6] Furthermore, within the past six years, the National Transportation Safety Board (NTSB) has investigated three gas transmission pipeline incidents in which issues related to operators' IM programs and PHMSA's oversight were of concern (NTSB 2011, 2013, 2014). Much of the industry's emphasis has been placed on the use of integrity assessment methods in detecting defects that may lead to failure causes such as corrosion and material failure. However, the general IM principle calls for the reduction of risk associated with all threats, including corrosion, manufacturing defects, equipment failures, third party damage, and incorrect operations.

[2] This includes interstate and intrastate onshore gas transmission pipelines.

[3] PHMSA uses "incident" instead of "accident" for gas transmission pipeline events that cause damage, injury, or other problems. Criteria for definition of an incident can be complex and can be found at http://primis.phmsa.dot.gov/comm/reports/safety/docs/IncidentReportingCriteriaHistory1990-2011.pdf.

[4] This rule became effective February 14, 2004. See http://primis.phmsa.dot.gov/gasimp/fact.htm.

[5] "2014-04-01 PHMSA Pipeline Safety – Flagged Incidents" was the data set used from http://www.phmsa.dot.gov/pipeline/library/datastatistics/pipelineincidenttrends.

[6] According to PHMSA's Form F7100.2, Incident Report Form, estimated total cost to operators includes public and non-operator private property damage paid/reimbursed by the operator, operator's property damage and repairs, operator's emergency response, commodities lost, emergency response, and other costs. http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/gtgg_f71002dec12.pdf

## 1.1 Study Goals

The goal of this study was to evaluate the need for safety improvements to IM programs and requirements for natural gas transmission pipelines in the United States by examining (1) federal and state oversight of IM programs; (2) common practices associated with HCA identification and verification; (3) current threat identification and risk assessment techniques; (4) the effectiveness of different pipeline integrity assessment methods; and (5) procedures for continual assessment and data integration within the IM framework.

## 1.2 Gas Transmission Pipelines in the United States

There are three types of pipeline systems through which gas is transported from the source to the end users: gathering, transmission, and distribution systems.[7] Gathering and distribution pipelines represent the beginning and end of the gas pipeline system. NTSB staff analyzed 10 years (2004–2013) of both annual report mileage and incident data for all pipelines. Although onshore gas transmission pipelines constitute only about 12 percent of all pipeline mileage in the United States,[8] they represent 15 percent of total incident numbers, 16 percent of combined fatalities and injuries (10 percent of fatalities and 18 percent of injuries), and 20 percent of reported property damage.[9] This indicates that although there were more fatalities and injuries associated with gas distribution incidents, injuries in gas transmission incidents (per mile) were overrepresented. Additionally, reported nominal property damages resulting from gas transmission pipeline incidents between 2004–2013 also far exceeded those caused by gas distribution incidents. Compared to gas distribution pipelines, transmission pipelines typically have larger diameters and operating pressures. Therefore, the potential impact of a transmission pipeline incident on its surroundings is high. This study focuses on onshore transmission pipelines.

From 1984–2013, onshore gas transmission pipeline mileage increased from approximately 280,000 to 300,000 miles, which represents approximately 750 miles of gas transmission pipelines added each year.[10] Transmission pipelines are classified as either interstate or intrastate. Interstate pipelines are subject to federal oversight, and most states assume oversight for intrastate pipelines. Figure 1 shows the onshore gas transmission pipeline

[7] 49 Code of Federal Regulations (CFR) §192.3 defines gathering, transmission, and distribution lines. 49 CFR §192.8, which incorporates API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," by reference, defines onshore gathering lines.

[8] In this study, gas transmission pipelines refer to onshore gas transmission pipelines unless otherwise noted. Onshore gas transmission mileage data and the corresponding total pipeline mileage data were obtained from PHMSA's Annual Report Mileage data at http://www.phmsa.dot.gov/pipeline/library/data-stats. The 12 percent value is based on 10-year average (2004–2013).

[9] These percentages were computed based on data obtained directly from PHMSA's all reported pipeline incidents data, at http://www.phmsa.dot.gov/pipeline/library/datastatistics/pipelineincidenttrends. The percentage values are based on 10-year totals (2004–2013).

[10] Onshore gas transmission mileage data and the corresponding total pipeline mileage data are obtained directly from PHMSA's Annual Report Mileage data at http://www.phmsa.dot.gov/pipeline/library/data-stats. An ordinary least squares regression model was developed to estimate the rate of increase throughout the 30-year period (1984–2013); the result shows a rate of 753 miles per year increase.

system for year-end 2012 by operation types.[11] A state must adopt the minimum Federal regulations and also provide for enforcement sanctions substantially the same as those authorized by the federal pipeline safety regulations. Based on mileage, 64 percent of all gas transmission pipelines are interstate pipelines, while 36 percent are intrastate pipelines.

The locations of these onshore gas transmission pipelines are not evenly distributed across the United States. Figure 2 shows that more than half of all transmission pipelines are located in 10 states,[12] with Texas and Louisiana having the most (15 percent and 9 percent, respectively). Texas has 71 operators with intrastate pipelines and Louisiana has 31. Seventy-five percent of all gas transmission pipelines are located in 20 states.

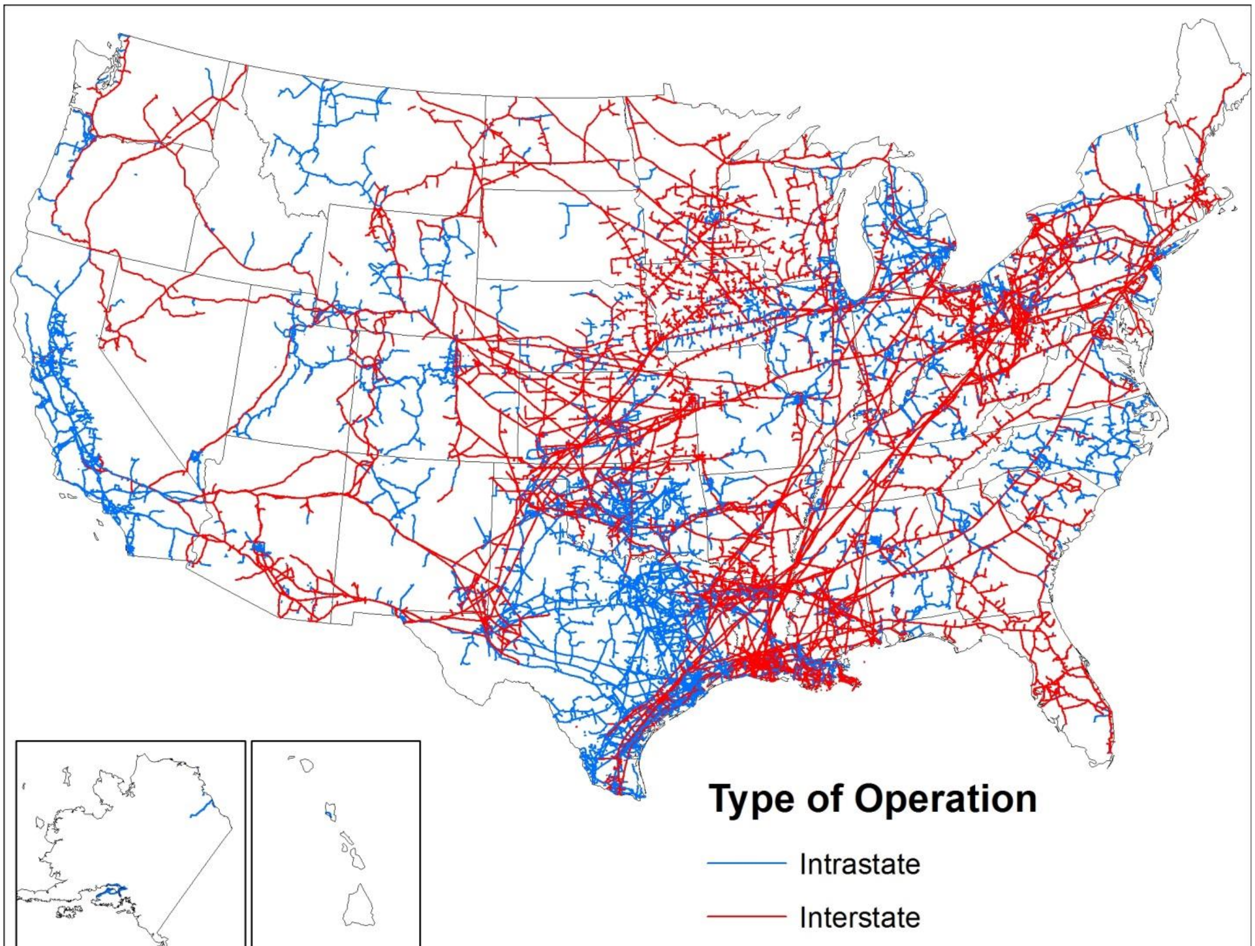


**Figure 1.** Map of the United States gas transmission pipeline systems by operation type (interstate and intrastate, year-end 2012)

[11] The data are based on the NPMS' 2013 (CY2012) gas pipelines only. This is the latest data available from PHMSA.

[12] Texas, Louisiana, Kansas, California, Mississippi, Oklahoma, Ohio, Pennsylvania, Illinois, and Michigan.

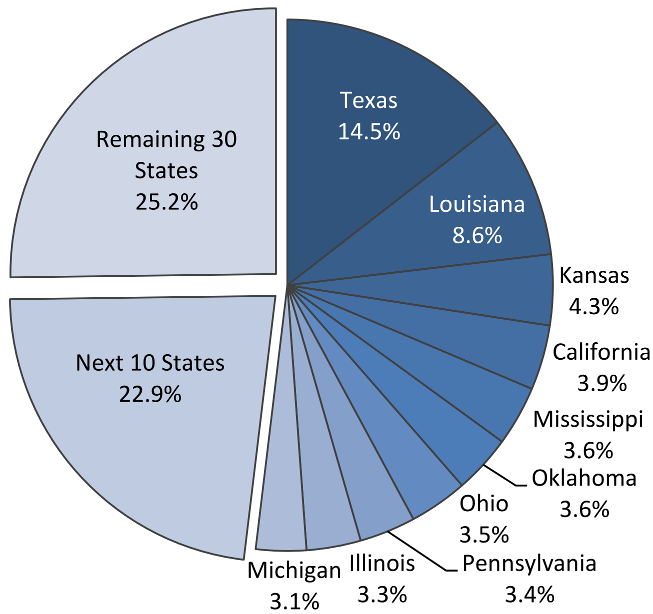


**Figure 2.** Distribution of onshore gas transmission pipeline by state (based on 2013 NPMS data, year-end 2012)

Many gas pipeline companies with large multi-state or nationwide systems operate both interstate pipelines (subject to federal regulation) and intrastate pipelines (usually subject to state regulation). For example, the 2013 PHMSA annual report[13] shows that 29 gas transmission pipeline operators operate both interstate and intrastate pipelines; 11 of these operators have intrastate pipelines in more than one state. There are 743 operators with intrastate pipelines only. Of these operators, 93 operate in more than one state, and one operator has intrastate pipelines in nine states. The remaining 121 operators only have interstate pipelines.[14] Thirty percent of all intrastate pipelines are located in Texas, followed by California (11 percent) and Oklahoma (6 percent).

## 1.3 PHMSA's IM Requirements for Gas Pipelines

### 1.3.1 Use of Class Locations Before 2004

In 1968, Congress passed the Natural Gas Pipeline Safety Act of 1968, which created the Office of Pipeline Safety within the DOT to implement and oversee pipeline safety regulations. These regulations were based, in large part, on an existing industry consensus standard belonging to the American Society of Mechanical Engineers (ASME), ASME B31.8, *Gas Transmission and Distribution Piping Systems*, which used class locations to differentiate risk along gas pipelines and provide an additional safety margin for more densely populated areas (ASME 2012a). Class locations, which are still used today (defined in 49 CFR §192.5) range from 1

[13] Using the PHMSA 2013 annual report, NTSB staff focused on onshore transmission pipelines used for natural gas (representing 99% of all onshore gas transmission pipelines). 893 operators had natural gas pipelines. See "Annual Report Data" and "Incident/Accident Data" at http://phmsa.dot.gov/pipeline/library/data-stats.

[14] Operator counts are based on the Operator ID captured in PHMSA's 2013 annual report.

(sparsely populated) to 4 (densely populated) and specify the maximum allowable operating pressure (MAOP) of the pipeline segment in each class location.[15]

### 1.3.2 PHMSA's 2004 Gas IM Rule

Several accidents involving both gas and hazardous liquid pipelines that occurred from 1991–2000 (NTSB 2003, 2002, 1998, 1996, 1995) illustrated the need for pipeline operators to better manage the safety of their systems. These accidents, when considered collectively, highlighted the importance of ensuring transmission pipeline safety and environmental protection in areas of high population density and in areas sensitive to environmental damage.[16] In response to growing concerns regarding the aging pipeline infrastructure, NTSB recommendations issued as a result of these accidents, and to satisfy Congressional mandates, including those in the Pipeline Safety Improvement Act of 2002, the DOT established IM regulations for hazardous liquid pipelines in 2001 and for gas transmission pipelines in 2003. These regulations came after several DOT pilot programs, including the Pipeline Risk Management Demonstration Program (*Federal Register* 1996, 58605) and the Systems Integrity Inspection Pilot Program (*Federal Register* 1998, 68819).

The gas transmission IM regulations, contained in 49 CFR Part 192**,** Subpart O, became effective in February 2004. An industry consensus standard, ASME B31.8S, is incorporated by reference into the PHSMA regulatory requirements and provides much of the detail for how an operator is to comply with the regulations. Additionally, PHMSA maintains a list of Frequently Asked Questions (FAQ) (PHMSA 2014c), as well as other guidance, which provides additional clarity to operators and inspectors.

The gas transmission IM regulations are designed to provide enhanced protection for HCAs, which are those geographic areas with population or structure densities at greatest risk if a gas transmission incident occurs. The regulations include a mix of performance-based and prescriptive requirements, with the intent of providing sufficient flexibility to reflect pipeline-specific conditions and risks without imposing unnecessary burdens on operators. The regulations require gas transmission pipeline operators to develop an IM program for their pipeline segments located within an HCA. The IM program must include 16 program elements.[17] However, for this study, only those program elements (listed below) that were associated with IM issues identified during recent NTSB gas transmission pipeline accidents were evaluated in detail.

- HCA identification: the process of determining those portions of a pipeline system for which a failure would have the highest impact (see section 1.4.1).

[15] Per 49 CFR §192.5, class location is determined by counting the number of dwellings within 660 feet of the pipeline for 1 mile (for Classes 1-3) or by determining that four-story buildings are prevalent along the pipeline (Class 4). Per 49 CFR §192.111, the maximum allowable operating stresses, as percentages of specified minimum yield strength (SMYS), are 72% for Class 1, 60% for Class 2, 50% for Class 3, and 40% for Class 4.

[16] IM regulations for hazardous liquid pipelines take into account environmental damage and environmentally sensitive areas; IM regulations for gas pipelines do not.

[17] For a list of the 16 program elements, see either 49 CFR §192.911 or PHMSA's Gas Transmission Integrity Management Fact Sheet (http://primis.phmsa.dot.gov/gasimp/fact.htm). Appendix A lists all 16 program elements.

- Threat identification, data integration, and risk assessment: the process of using all available information to determine which failure mechanisms each pipeline segment within an HCA is susceptible to and then estimating the risk of pipeline failure due to these mechanisms (see sections 1.4.2 and 1.4.3); pipeline segments are ranked according to their risks to create a prioritized schedule for integrity assessments, in which pipeline segments are inspected or tested to verify their integrity (see section 1.4.4).
- Baseline assessment plan: the first schedule for completing integrity assessments, including the selection of assessment method(s) appropriate to the threats identified; a baseline assessment plan must also be completed whenever new pipe is installed or a new HCA is identified.
- Direct assessment: one method of integrity assessment, used only for assessing corrosion threats (see section 1.4.4); a direct assessment plan is required only if an operator uses this assessment method. Other integrity assessment methods are allowed, such as pressure testing and in-line inspection (ILI). The requirements regarding the selection and use of these methods are included in the program elements of baseline assessment plan and continual evaluation and assessment.
- Confirmatory direct assessment: a direct assessment method used for integrity reassessments.
- Remediation: the process of repairing or replacing pipeline defects found during integrity assessments.
- Preventive and mitigative (P&M) measures: actions which lower the likelihood (preventive measures) or reduce the consequences (mitigative measures) of a pipeline failure. P&M measures are used to reduce the risk of some threats that cannot be assessed.
- Continual evaluation and assessment: the ongoing practice of repeating each of the processes described above, including the schedule and methods for integrity reassessments, to ensure the continued integrity of a pipeline (see section 1.4.5).

In addition to the eight program elements that are central to this study, each operator’s IM program must contain supporting plans and procedures covering performance measures, recordkeeping, management of change, quality assurance, communication, and documentation.

## 1.4 Key Program Elements of the Gas IM Rule

Figure 3 shows the major steps within a gas transmission IM program. All operators must complete the first step, which is to identify HCAs. If no pipeline segment contains HCAs, the operator is not required to develop the rest of the IM program. If an operator has pipeline segments in an HCA, the next steps are threat identification and risk assessment for these segments. Then an operator assesses the physical integrity of the pipeline segments and applies appropriate P&M measures; the choice of integrity assessment method(s) and P&M measures depends on the threats identified for each segment. After assessing pipeline integrity, an operator remediates defects and/or applies P&M measures, and the cycle continues as HCAs receive ongoing evaluation and periodic integrity reassessments to incorporate changes into the IM program.

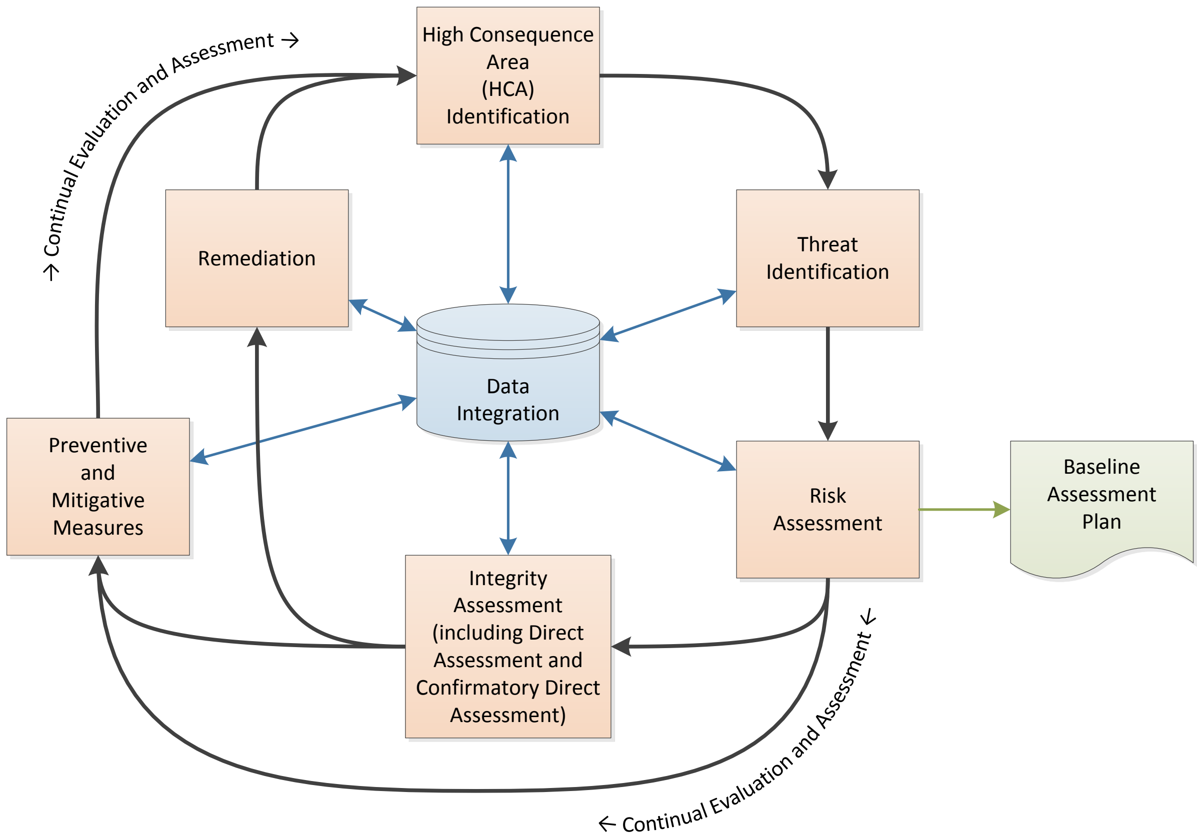


**Figure 3.** Gas transmission IM program flowchart

### 1.4.1 HCA Identification

The gas IM rule uses a more precise, data-driven approach to identify areas of higher risk along pipelines compared to the approach that relied on class locations only. As previously discussed, identifying an HCA is the first step in an IM program. This identification process should be repeated at least annually[18] by an operator to account for changes in population and structure densities. Two methods (Method 1 and Method 2) are permitted for determining HCAs (PHMSA 2006a). Both methods use the concept of a potential impact circle (PIC), which is an estimate of the area that would be thermally impacted by a pipeline rupture and gas ignition. For each point along a pipeline, the size of its PIC depends on the pipe's MAOP, the nominal pipe diameter at that point, and the energy content of the gas carried.

Method 1 is based upon pre-existing pipeline class location definitions. All Class 4 and Class 3 areas, and some Class 2 and Class 1 areas (depending on the PIC radius, the number of structures intended for human occupancy within the PIC, and any "identified sites"[19] within the

[18] See PHMSA Gas Transmission Integrity Management FAQ 19: "What are OPS expectations for operators to determine new or updated HCAs?"

[19] Per 49 CFR §192.903, identified sites include: (a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping

PIC) are identified as HCAs. Method 2 uses only the number of structures intended for human occupancy and identified sites within each PIC to identify HCAs. Figure 4 illustrates HCAs calculated via Method 2.

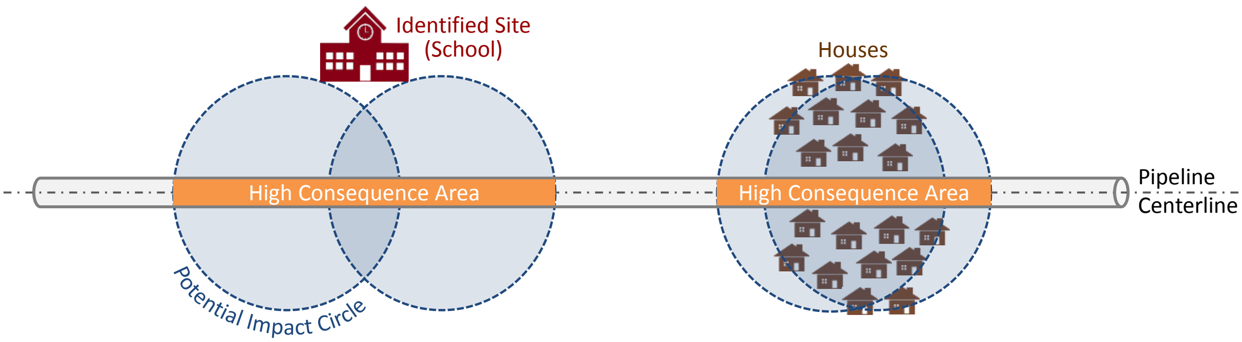


**Figure 4.** Method 2 for determining high consequence areas

A geographic understanding of the gas transmission pipeline location is fundamental to this first step of the IM process. In addition to physical verification, operators are increasingly relying on geographic information systems (GIS) and its related technologies, such as global positioning systems (GPS) and remote sensing (such as the use of aerial photography and satellite imageries) to accurately locate their pipeline. Operators must know precisely where their pipelines are buried and then assess what is around these pipelines. Because IM programs are primarily concerned with ensuring safety, this geospatial technology (including, but not limited to, GIS) is very useful in providing ongoing updates on development activities that could affect pipeline systems, including changes to HCAs. Furthermore, PHMSA requires operators to submit geospatial data for the National Pipeline Mapping System (NPMS), but the quality (such as positional accuracy) of such data varies substantially from operator to operator. The information gathered and disseminated through the NPMS is an important resource for both federal and state inspectors assessing pipeline operators' IM programs.[20]

### 1.4.2 Threat Identification

Once HCAs are identified, PHMSA requires pipeline operators to identify and evaluate all potential threats to each HCA. ASME B31.8S, one of the standards referenced in the PHMSA

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grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or (b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or (c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities, or assisted-living facilities.

[20] The NPMS is a dataset containing locations of and information about gas transmission and hazardous liquid pipelines and Liquefied Natural Gas (LNG) plants which are under the jurisdiction of PHMSA. The NPMS also contains voluntarily submitted breakout tank data. The data is used by PHMSA for emergency response, pipeline inspections, regulatory management and compliance, and analysis purposes. It is used by government officials, pipeline operators, and the general public for a variety of tasks including emergency response, smart growth planning, critical infrastructure protection, and environmental protection. See https://www.npms.phmsa.dot.gov/About.aspx.

requirements, describes three general threat types that must be considered. Each general threat type has three specific threat categories (ASME 2012b). Additionally, operators must consider interactions among these different threats, as well as the effects of metal fatigue,[21] if applicable. Table 1 provides a listing of these threat types and associated threat categories.

**Table 1.** Threat types, threat categories, and threat descriptions

| Threat Type | Threat Category | Description (ASME 2012c) |
|---|---|---|
| Time-Dependent | **External Corrosion** | Deterioration of the pipe due to an electrochemical reaction between the pipe material and the environment outside the pipe |
| | **Internal Corrosion** | Deterioration of the pipe due to an electrochemical reaction between the pipe material and the environment inside the pipe |
| | **Stress Corrosion Cracking** | Cracks in the pipe due to the interaction of tensile stresses in the pipe material with a corrosive environment |
| Stable[22] | **Manufacturing** | Defects introduced during pipe manufacturing, such as laminations, inclusions, hard spots; pipe manufactured using techniques now known to have weaknesses, such as low-frequency electric resistance welded pipe, lap welds, butt welds, and electric flash welds |
| | **Construction** | Defects and weaknesses introduced during pipeline construction, such as bad field welds, wrinkle bends, stripped threads, and broken pipe |
| | **Equipment** | Pipeline facilities other than pipe and pipe components, such as pressure control and relief equipment, gaskets, o-rings, and seals |
| Time-Independent | **Third Party/Mechanical** | Accidental or intentional excavation damage by a third party (that is, not the pipeline operator or contractor) that causes an immediate failure or introduces a weakness (such as a dent or gouge) into the pipe |
| | **Incorrect Operations** | Incorrect operation or maintenance procedures or a failure of pipeline operator personnel to correctly follow procedures |
| | **Weather-Related/ Outside Forces** | Earth movement, seismic events, heavy rains or floods, erosion, cold weather, lightning |

### 1.4.3 Risk Assessment

Once the threats to each HCA are identified, operators must assess the risk of these threats. Risk is often defined as the product of (1) the likelihood of a failure occurring, and (2) the consequences of that failure. Operators are required to use one or more of the following types of risk assessment approaches:

- <u>Subject Matter Expert (SME)</u>: In this approach, SMEs (either pipeline employees or contractors) use their collective expertise and knowledge of a particular pipeline system to determine the likelihood and consequence of failures, leading to estimates of the risk of failure of each pipeline segment in the system.

[21] Metal fatigue is cracking of the pipe material due to repeatedly applied stresses, such as pressure cycling, vibration, or thermal expansion and contraction.

[22] Another term that is commonly used is "resident" threat.

- Relative Assessment Models: In this approach, algorithms (using known or estimated pipeline characteristics, SME input, historical failure experience, and failure models) assign a risk score for each threat on a pipeline segment. These threat-specific risk scores are then weighted and summed to produce an overall relative risk value for each pipeline segment.
- Scenario-Based Models: In this approach, various risk-producing scenarios are described (for example, using event tree or fault tree analysis), including their likelihoods and consequences.
- Probabilistic Models: In this approach, probabilities (in contrast to the previous approaches, which used relative likelihoods) are calculated. This approach allows an absolute risk value to be calculated for each pipeline segment (for example, deaths per mile per year). If consequences are monetized, this approach also enables monetization of risk (for example, dollars per mile per year).

The results of the risk assessment approach(es) are threat-specific risk estimates for each pipeline segment within an HCA; these estimates can be considered on their own or with other threat risks. Using these results, operators can prioritize pipeline segments for integrity assessment, choose the appropriate assessment tool(s), and determine which P&M measures should be taken.

### 1.4.4 Integrity Assessment

By December 17, 2012,[23] all pipeline segments within HCAs were required by PHMSA to be inspected for their integrity. There are four types of integrity assessment methods allowed by the IM regulations. It is the operator's responsibility to choose which method(s) is most appropriate for each pipeline segment, depending upon the threats to and characteristics of the pipeline. These integrity assessment methods are primarily geared toward detecting defects tied to some threats (for example, corrosion and manufacturing defects), but not others (for example, equipment failure and incorrect operations), which are addressed by P&M measures. The four allowed assessment methods (ASME 2004) are:

- In-line Inspection (ILI): ILI is an internal pipeline inspection technique that uses magnetic flux leakage, ultrasound, eddy current, or other sensing technology to locate and characterize indications of defects, such as metal loss or deformation in the pipeline. The sensor is mounted on a device (known as a "smart pig"), which is inserted into the pipeline segment between a launching station and a receiving trap. The smart pig moves through the pipe scanning the pipe for specific types of defects. Pipeline segments that can accommodate ILI tools are considered "piggable." Different sensors are used for different defects.
- Pressure Testing: A pressure test can be used as a strength or leak test. A common type of pressure test is a hydrostatic test, which involves taking the pipeline out of service and pressurizing a section of pipe with water to a much higher percentage of the pipe material's maximum design strength than the pipe will ever operate at with

[23] 49 CFR §192.921(d) states that an operator "must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012."

natural gas. This verifies the capability of a pipeline to safely operate at the MAOP and can reveal weaknesses that could lead to defects and leaks in the pipe. Pressure testing of pipelines is designed to find critical seam defects (as well as other defects caused by corrosion, stress corrosion cracking, and fatigue) by causing the pipe to fail at these critical defect locations.

- Direct Assessment: Direct assessment relies on the examination of the pipeline at pre-selected locations to evaluate a pipeline for external corrosion, internal corrosion, or stress corrosion cracking threats. Most of the pipeline segment being inspected is usually not directly examined. Direct assessment uses multiple steps (four steps for external and internal corrosion, and two steps for stress corrosion cracking). For example, for external corrosion direct assessment (ECDA), the steps are (NACE 2008): pre-assessment (the operator determines the feasibility of ECDA, determines ECDA regions, and selects tools for indirect inspection), indirect inspection (the operator conducts above-ground inspections, such as a close interval survey (CIS),[24] to identify and classify indicators of corrosion and pipe coating defects), direct examination (the operator excavates the pipe at selected locations to measure actual corrosion damage), and post-assessment (the operator determines reassessment intervals and evaluates the effectiveness of the ECDA process). This method requires the identification of regions within the pipeline segments for excavation and direct examination. Therefore, even though a pipeline segment may be inspected with direct assessment, only a small sub-segment is directly examined.
- Other Technologies: These technologies include methods that are industry-recognized, approved, and published by an industry consensus standards organization or other methodologies that follow performance requirements with documentation. One example is guided wave ultrasonics (PHMSA 2014b).[25] Operators must inform PHMSA 180 days before an assessment if they are using these other methodologies and technologies.

The results of integrity assessment determine the next steps, which can include remediation and/or P&M measures. Remediation, such as repair or replacement, depends upon the severity of the defects and must be completed within a specific time frame. The P&M measures may include installing automatic shut-off valves or remote control valves, installing computerized monitoring and leak detection systems, or improving operator performance through training.[26] Once the baseline integrity assessment is performed, the integrity assessment results are among the factors used in the process of determining the appropriate reassessment interval; this interval cannot exceed more than seven years (PHMSA 2006b).

[24] CIS is one of several approved indirect assessment methods used in ECDA. CIS is also known as a pipe-to-soil or a potential gradient survey. It assesses the effectiveness of cathodic protection systems used on buried pipelines. See http://primis.phmsa.dot.gov/comm/FactSheets/FSCloseInternalSurvey.htm?nocache=1702 for more information.

[25] Guided wave ultrasonic testing is a tool for assessing cased pipeline segments.

[26] A list of P&M measures can be found in 49 CFR §192.935 and in ASME B31.8S.

### 1.4.5 Continual Assessment and Data Integration

A gas transmission pipeline operator must periodically monitor and evaluate the overall integrity performance of pipeline segments covered by IM programs. This process is known as "continual assessment." Continual assessment relies on information gained from past assessment results, analysis of relevant data, remediation decisions, and P&M measures that apply to a specific pipeline or segment. The outermost line in figure 3 illustrates how the actions and information from different IM program elements form a continual assessment process or loop. The goal of continual assessment is to ensure that operators provide an ongoing assessment of pipeline segments covered by IM programs.

A key ingredient in continual assessment is data integration, which is the process of assembling and evaluating all relevant information regarding the integrity of a pipeline or segment. This relevant information may include maintenance and operation histories, results from previous integrity assessments, damage prevention activities, design and construction records, and corrosion control program information, as well as inspection and incident data associated with non-HCA pipelines. Because continual assessment is data-driven, the various sources of data should be integrated within the same referencing system. Because pipeline infrastructure and its environment are readily captured and stored with location information, a GIS can be a significant aid in integrating this information to more easily facilitate continual assessment.

## 1.5 PHMSA Oversight and State Programs

Although PHMSA is primarily responsible for developing, issuing, and enforcing pipeline safety regulations for interstate pipelines, the Pipeline Safety Act allows state assumption of the intrastate regulatory, inspection, and enforcement responsibilities.[27] To qualify for this assumption of responsibilities, a state must adopt at least the minimum federal regulations and provide for enforcement sanctions that are substantially the same as those authorized by the federal pipeline safety statutes. For gas pipelines, almost all states participate.[28] Furthermore, PHMSA may authorize a state to act as its agent to inspect interstate pipelines, but retains responsibility for enforcement of the regulations. Eight states are currently authorized as interstate agents.[29]

Currently, there are 376 inspectors employed by state regulators and 99 PHMSA inspectors.[30] State inspectors sometimes participate alongside PHMSA personnel during IM inspections. State regulators and their inspectors play a critical role in safeguarding the integrity of US transmission pipelines through their gas transmission IM program inspections.

[27] State pipeline safety programs (commonly called "state programs") are codified in 49 United States Code (USC) Chapter 601.

[28] The exceptions are Alaska and Hawaii. Legislators of these two states have not established pipeline safety programs.

[29] Arizona, Connecticut, Iowa, Michigan, Minnesota, New York, Ohio, and Washington.

[30] These numbers were obtained from PHMSA's Inspector Training and Qualification Division (TQ) (September 5, 2014).

In some states, the agency responsible for pipeline safety regulation is also responsible for economic regulation of intrastate pipelines (that is, determining prices charged for gas transportation); in other states, these functions are performed by separate entities.[31] Although a dual mandate of safety and economic regulation could potentially cause conflicts of interest, this study does not address the safety implications of such an arrangement, as economic regulation is outside the immediate scope of IM.

## 1.6 Previous NTSB Investigations

Within the past six years, the NTSB investigated three major onshore gas transmission pipeline incidents in which elements of the operators' IM programs were of concern. The analyses and findings associated with these three investigations helped form the foci of this safety study.

### 1.6.1 Palm City, Florida: May 4, 2009

An 18-inch-diameter interstate natural gas transmission pipeline, operated and owned by Florida Gas Transmission Company (FGT), ruptured in a sparsely populated area approximately six miles south of Palm City, Florida (NTSB 2013). An estimated 36 million cubic feet of natural gas was released during the accident without ignition. Three minor injuries were attributed to the rupture. The NTSB determined that the probable cause was environmentally assisted cracking under a disbonded polyethylene coating that remained undetected by FGT's IM program. A contributing factor was FGT's failure to include the ruptured pipe in its IM program.

FGT determined that the ruptured section was in a Class 1 location with no HCA identified sites. Therefore, FGT did not include the pipe section that ruptured under their IM program. However, a post-accident review of the area by PHMSA determined that a neighboring high school qualified as an HCA identified site. Because the potential impact circle intersected three semi-open structures at the nearby high school, the ruptured section should have been included the FGT IM program. The misclassification of the ruptured section highlighted one of the core elements of IM program—HCA identification.

Although the ruptured section was not included in FGT's IM program, it was inspected with in-line tools during the IM baseline assessment of a 56.8-mile section of transmission pipeline that included other HCAs. ILIs were performed in 2004 using both a caliper tool to locate dents and a high-resolution second-generation axial magnetic flux leakage (MFL) tool to locate metal loss caused by corrosion. However, axial MFL tools are incapable of accurately detecting longitudinally oriented defects, including colonies of stress corrosion cracking (SCC). The rupture in this accident was determined to be the result of externally assisted cracks along the longitudinal seam weld. Therefore, the ILI tool used was unable to detect the defect that led to the pipe failure. The selection of this tool was driven by the risk analysis documented in FGT's IM program. Because pipeline segments along the Florida peninsula had no prior history of SCC-related failures, despite the fact that polyethylene-tape-coated pipe had the highest risk

[31] The Federal Energy Regulatory Commission (FERC), an independent agency separate from the DOT and PHMSA, is responsible for economic regulation of interstate gas transmission pipelines.

weighting for SCC, the pipeline segments upstream and downstream of the rupture location had very low risk scores for both the external corrosion and the SCC threats. Therefore, the use of axial MFL tools was deemed an appropriate integrity assessment tool. Had the ruptured section been identified as susceptible to SCC, a spike test[32] would have been appropriate and might have identified the defect. Therefore, this accident highlights the need for appropriate threat identification and risk analysis.

### 1.6.2 San Bruno, California: September 9, 2010

A 30-inch-diameter segment of an intrastate natural gas transmission pipeline, owned and operated by the Pacific Gas and Electric Company (PG&E), ruptured in a residential area in San Bruno, California (NTSB 2011). The released natural gas ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area. The NTSB determined that PG&E's inadequate pipeline IM program, which failed to detect and repair, or remove, the defective pipe section, was a critical component of the probable cause.

The ruptured pipeline was determined to be an HCA pipeline segment and was covered by PG&E's IM program. The pipeline segment was installed in 1956 during a relocation project. The post-accident investigation found that the segment was poorly welded with a visible seam weld flaw that grew to a critical size over time. The segment ultimately ruptured during a pressure increase during a poorly planned maintenance session to address electrical problems. The NTSB found that PG&E's pipeline IM program was deficient and ineffective because it (1) was based on incomplete and inaccurate pipeline information (that was contained in the operator's GIS), (2) did not consider the design and materials contribution to the risk of a pipeline failure, (3) failed to consider the presence of previously identified welded seam cracks as part of its risk assessment, (4) resulted in the selection of an examination method that could not detect weld seam defects, and (5) led to internal assessments of the program that were superficial and resulted in no improvement. Furthermore, the NTSB also determined that the California Public Utilities Commission, the pipeline safety regulator within the state of California, failed to detect the inadequacies in PG&E's IM program and that the IM program inspection tool used by state and federal inspectors, also known as the PHMSA IM inspection protocols, needed improvement.

### 1.6.3 Sissonville, West Virginia: December 11, 2012

A 20-inch-diameter interstate natural gas transmission pipeline, owned and operated by the Columbia Gas Transmission Corporation, ruptured near Interstate 77 (I-77) in a sparsely populated area near Sissonville, West Virginia (NTSB 2014). The escaping high-pressure natural gas ignited immediately. Three houses were destroyed by the fire and several other houses were damaged. There were no fatalities or serious injuries. The asphalt pavement of the northbound and southbound lanes of I-77 was heavily damaged by the intense fire and it took work crews 18 hours to repair and reopen all four lanes of the highway. The NTSB determined that the probable

[32] A spike test is a type of pressure test in which the pressure inside the pipe is raised to and held at a high value for a short period of time.

cause of the pipeline rupture was external corrosion of the pipe wall due to deteriorated coating and ineffective cathodic protection and the failure to detect the corrosion because the pipeline was not inspected or tested after 1988.

The ruptured pipeline was not an HCA pipeline segment and therefore not covered by the operator's IM program. However it was interconnected in a system that included two adjacent HCA pipelines. All three pipelines were protected against external corrosion threats using external coating and cathodic protection. The two adjacent pipelines were integrity assessed using ILI and results showed external corrosion that required repairs. The ruptured pipeline was not assessed by ILI, but was assessed in 1995 using a CIS. In the case of the ruptured pipeline, the CIS was the only method used in assessing the integrity of the pipeline. CIS measures the cathodic protection voltage every few feet along a specific length of the pipe; it does not cover 100 percent of the pipe and does not detect shielding caused by rocks or other material. No mitigation was done to the segment of the pipeline that eventually failed. Because the ruptured pipeline was not covered by the operator's IM program, no additional assessment method was required or used to detect any defect that might pose a high risk of failure. The information gathered from the two adjacent pipelines that were integrity assessed by ILI and showed defects that needed repairs was not incorporated into the corrosion mitigation approaches for the ruptured pipeline.

## 1.7 Current Rulemaking

As the result of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the 2011 Act), PHMSA has begun a series of rulemaking activities directly related to IM of gas transmission pipelines. Section 5 of the 2011 Act requires PHMSA to conduct an evaluation on (1) whether IM should be expanded beyond current HCAs, and (2) whether doing so would mitigate the need for class location requirements for gas transmission pipelines. One mandate of Section 6 of the Pipeline Safety Act requires that PHMSA maintain a map of all gas HCAs as part of the NPMS.[33] PHMSA has recently begun a request for comments on the intent to collect enhanced data for the NPMS.[34] The original standard for collection was drafted in 1998 (PHMSA 2014d). Although this study does not address these rulemaking activities directly, the NTSB has found safety issues related to HCA identification and the NPMS.

[33] Complete information about this rulemaking activity and its status can be found in http://www.phmsa.dot.gov/pipeline/regs/rulemaking. The two relevant notices are: (1) 76 FR 5308 Pipeline Safety: Safety of Gas Transmission Pipelines - Advanced Notice of Proposed Rulemaking (ANPRM) Aug 25, 2011; and (2) 76 FR 70953 Pipeline Safety: Safety of Gas Transmission Pipelines - Advance notice of proposed rulemaking; extension of comment period Nov 16, 2011.

[34] Complete information about this information collection activity can be found in https://www.federalregister.gov/articles/2014/09/30/2014-23174/pipeline-safety-request-for-revision-of-a-previously-approved-information-collection-national.

# 2 Methodology and Data Sources

This study employed a multifaceted approach using both quantitative and qualitative data and associated analytical methods. Information was obtained from PHMSA data systems, federal and state pipeline inspectors, gas transmission pipeline operators, industry associations, and pipeline safety and engineering contract support organizations.

## 2.1 PHMSA's Incident Data, Annual Report Data, and NPMS Data

This study analyzed PHMSA's incident data,[35] PHMSA's annual report data,[36] and NPMS data.[37] To evaluate the overall trend of gas transmission pipeline incidents, this study examined incident data from 1994–2013. PHMSA's incident data is used to assess safety trends and guide the development of new initiatives to enhance safety. Annual reports include general information such as total pipeline mileage, commodities transported, miles by material, and installation dates. These annual reports are widely used by safety researchers, government agencies, industry professionals, and by PHMSA personnel for inspection planning and risk assessment. Appendix A includes descriptions of data sources, including incident and annual report data, along with field names, specific questions, and descriptions used in this study. It also includes names of specific data files and how they were obtained. An emphasis was placed on detailed analyses of incident data from 2010–2013, since PHMSA made substantial changes to both the incident data reporting requirements and the annual report data in 2010, which increased the amount of information collected. The 2013 NPMS data, which provides a snapshot description of the geographic distribution of gas transmission pipelines in the United States, and PHMSA incident data were used to support descriptive GIS analyses.

## 2.2 Discussions with Industry Representatives

NTSB staff conducted structured interviews with pipeline operators, state and federal inspectors, industry associations, researchers, and representatives of private companies providing integrity assessments, risk analysis, and geospatial data and services. NTSB staff contacted the following groups and organizations:

- The National Association of Pipeline Safety Representatives (NAPSR). NAPSR is an organization of state pipeline safety personnel. NTSB staff contacted NAPSR to obtain perspectives from state inspectors regarding the IM inspection process. In response to these inquiries, NAPSR conducted a voluntary survey of its members and provided the aggregated results to NTSB. See Appendix B for a more detailed discussion of the questions developed by NAPSR and the responses from its membership.
- Gas Transmission Pipeline Operators. NTSB staff interviewed personnel responsible for IM program design and operation at seven pipeline operators, operating both interstate

[35] "2014-04-01 PHMSA Pipeline Safety – Flagged Incidents" was the data set used from http://www.phmsa.dot.gov/pipeline/library/datastatistics/pipelineincidenttrends; the actual data sources were tied to specific forms.

[36] PHMSA's annual report data is at http://www.phmsa.dot.gov/pipeline/library/data-stats.

[37] NPMS data was obtained via a confidential agreement with PHMSA and accessed through a secured FTP site.

and intrastate pipelines in various parts of the United States. These interviews focused on the development and application of each operator's IM program.

- Federal Regulators. NTSB staff interviewed personnel within PHMSA's Office of Pipeline Safety, including pipeline inspectors from all five PHMSA regions and personnel in the Program Development Division (which is responsible for the GIS, including the NPMS), the State Programs Division, and the Inspector Training and Qualifications Division.
- State Regulators. NTSB staff interviewed pipeline inspectors and supervisors from five states. In each state, the state was responsible for the inspection of intrastate gas pipeline operators. None of the five state regulators were interstate agents.
- IM Services Firms. NTSB staff interviewed several companies that provide IM services to the pipeline industry, including firms that provide ILI hardware and analysis, GIS services, and risk assessment software.
- Industry Organizations. NTSB staff met with several organizations representing the pipeline industry to better understand the history of and current industry initiatives relating to IM.

NTSB staff analyzed the results of these interviews to identify common themes and viewpoints that were shared among multiple organizations.

## 2.3 PHMSA's Gas Transmission IM Progress Reports

NTSB staff contacted PHMSA to determine if any systematic evaluation of the IM inspection process had been conducted to identify areas of potential improvement. PHMSA has conducted two separate studies (called progress reports) of the gas transmission IM program. The first one was internally distributed in 2011 and was based on PHMSA's federal IM inspections through December 2010. The second report, based on state inspections through February 2013, was completed in 2013 and shared with NAPSR. Neither report was publicly available. NTSB staff reviewed these progress reports to analyze IM program areas where issues were often found by federal and state inspectors.

## 2.4 PHMSA's Enforcement Actions

NTSB staff obtained summary information of PHMSA's enforcement actions involving gas transmission pipeline operations. The frequency of these enforcement actions was summarized (by IM program area) for both interstate and intrastate pipelines from the implementation of the 2004 gas IM rule through April 2014.

# 3 Analysis of PHMSA's Gas Transmission Pipeline Incident Data

## 3.1 Overall Counts and Rates of All Gas Transmission Pipeline Incidents

Although gas transmission pipeline incidents are uncommon, these incidents can result in fatalities, injuries, and property damage. Table 2 shows the number of incidents, fatalities, injured persons, and adjusted reported property damage of significant[38] incidents from 1994–2013. For reference, the number of all reported incidents is provided as well.[39] Between 1994–2013, an annual average of 47 significant gas transmission pipeline incidents occurred, resulting in an average of two fatalities and injuring nine persons each year.[40] These significant incidents caused an average of 65 million dollars of property damage each year; approximately 61 percent of all incidents in this period were considered significant. Only two years (2000 and 2010) had 10 or more fatalities.

[38] PHMSA defines significant incidents for gas transmission pipeline as those incidents reported by pipeline operators when any of the following consequences occur: (1) fatality or injury requiring inpatient hospitalization, or (2) $50,000 or more in total costs, measured in 1984 dollars. See http://primis.phmsa.dot.gov/comm/reports/safety/sigpsi.html

[39] Operators currently must report incidents to PHMSA that result in a fatality or injury necessitating inpatient hospitalization, estimated property damage (excluding the cost of lost gas) of $50,000 or more, or unintentional gas loss of 3,000,000 cubic feet or more. In addition, operators may report any incidents that do not meet these criteria but are considered significant in their judgment. These reporting requirements, listed in 49 CFR 192.3, were last changed in 2011, when the cost of lost gas was removed from the property damage criterion and the gas loss quantity criterion was added. See https://hip.phmsa.dot.gov/Hip_Help/pdmpublic_incident_page_allrpt.pdf for additional details.

[40] See http://www.phmsa.dot.gov/pipeline/library/datastatistics/pipelineincidenttrends for all reported incidents and significant incidents.

**Table 2.** Gas transmission incidents by injury type and significance, fatalities, and injuries by year (1994–2013)

| Year | Reported Incidents | Significant Incidents | | | |
|---|---|---|---|---|---|
| | | Significant Incident Count | Fatalities | Injured Persons | Reported Property Damage ($1,000,000)[41] |
| **1994** | 52 | 34 | 0 | 15 | 60 |
| **1995** | 41 | 22 | 0 | 7 | 9 |
| **1996** | 62 | 34 | 1 | 5 | 14 |
| **1997** | 58 | 26 | 1 | 5 | 12 |
| **1998** | 72 | 40 | 1 | 11 | 45 |
| **1999** | 42 | 34 | 2 | 8 | 22 |
| **2000** | 65 | 45 | 15 | 16 | 19 |
| **2001** | 67 | 45 | 2 | 5 | 15 |
| **2002** | 57 | 40 | 1 | 4 | 19 |
| **2003** | 81 | 61 | 1 | 8 | 50 |
| **2004** | 83 | 44 | 0 | 2 | 9 |
| **2005** | 106 | 63 | 0 | 5 | 214 |
| **2006** | 108 | 59 | 3 | 3 | 29 |
| **2007** | 87 | 56 | 2 | 7 | 37 |
| **2008** | 93 | 47 | 0 | 5 | 114 |
| **2009** | 92 | 60 | 0 | 11 | 44 |
| **2010** | 84 | 58 | 10 | 61 | 417 |
| **2011** | 106 | 71 | 0 | 1 | 89 |
| **2012** | 89 | 47 | 0 | 7 | 44 |
| **2013** | 96 | 60 | 0 | 2 | 42 |
| **Total** | **1,541** | **946** | **39** | **188** | **1,303** |
| **Average** | **77** | **47** | **2** | **9** | **65** |

[41] The reported property damage values are shown in 2013 dollars. The cost of gas lost is indexed via the Energy Information Administration, natural gas city gate prices. All other costs are adjusted via the Bureau of Economic Analysis, Government Printing Office inflation values.

From 1994–2013, total gas transmission pipeline mileage increased from 293,438 miles to 298,302 miles — an overall increase of only two percent. However, significant incidents increased considerably during this period. Figure 5 shows that the rates of significant gas transmission pipeline incidents exhibited a gradual increasing trend throughout the 20-year period. The average annual significant incident rate increased from 0.13 (pre-gas IM rule, 1994–2003) to 0.19 (post-gas IM rule, 2004–2013) incidents per 1,000 miles of pipeline. One potential factor is a price change over time that can impact the determination of whether an incident is considered significant.[42] Using data presented in Table 2, the average number of injured persons increased from 8 persons per year from 1994–2003 to 10 persons per year from 2004–2013, while average fatalities remained at two fatalities per year for both time periods. The NTSB concludes that there has been a gradual increasing trend in the gas transmission significant incident rate between 1994–2004 and this trend has leveled off since the implementation of the integrity management program in 2004.

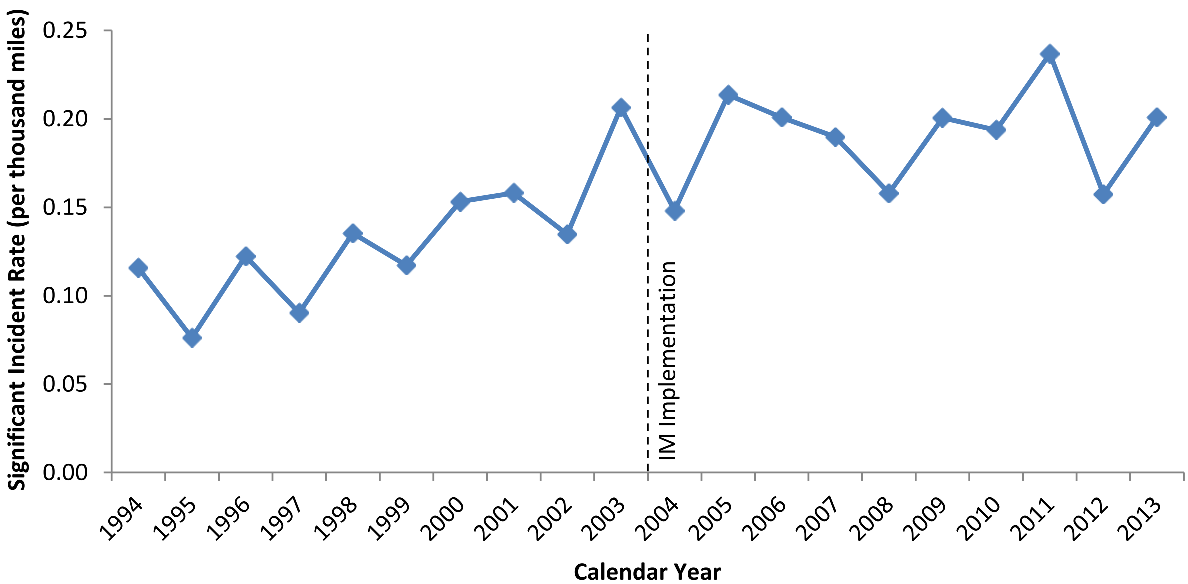


**Figure 5.** Significant incident rate per thousand miles (1994–2013)

## 3.2 HCA Incidents

PHMSA's annual report provides mileage data for all gas transmission pipelines but only began to report HCA mileage in 2010.[43] Therefore, HCA-related incident rates can only be calculated from 2010–2013. Table 3 shows incident counts and mileage by HCA classification from 2010–2013.[44] Due to the reporting criteria change in 2011 and the short time frame, it is

[42] Based on communication with PHMSA staff.

[43] HCA mileages for 2010-2013 were obtained from data from PHMSA's Annual Report, section L. Specifically, we used onshore gas transmission pipeline IM program mileage. Non-HCA mileage was computed by subtracting HCA mileage from the total onshore gas transmission pipeline mileage.

[44] The cost of lost gas was removed as an incident reporting criterion, and the quantity of lost gas was added as an incident reporting criterion. See http://primis.phmsa.dot.gov/comm/reports/safety/docs/IncidentReportingCriteriaHistory1990-2011.pdf.

difficult to discern trends in the data; rather, averages of incidents and mileages by HCA classification are presented for the four-year period. The percentage of HCA pipeline miles compared to all gas transmission pipeline miles remained constant. On average, seven percent of all onshore gas pipelines are HCA pipelines. However, 11 percent of all reported onshore gas transmission pipeline incidents occurred on HCA pipelines. Figure 6 shows that for all reported incidents as well as significant incidents, the average incident rates were higher for HCA pipelines when compared to non-HCA pipelines. While it may seem expected that incident rates would be higher in densely populated areas like HCAs due to the greater likelihood of property damage and casualties, gas IM requirements are specifically designed to reduce risk in HCAs. The NTSB concludes that from 2010–2013, gas transmission pipeline incidents were overrepresented on HCA pipelines compared to non-HCA pipelines.

**Table 3.** Total incidents and mileage by HCA classification (2010–2013)

| Year | Incidents | | | | Miles | | | |
|---|---|---|---|---|---|---|---|---|
| | Non-HCA | HCA | All | Percent HCA | Non-HCA | HCA | All | Percent HCA |
| **2010** | 78 | 6 | 84 | 7 | 279,320 | 20,223 | 299,343 | 7 |
| **2011** | 96 | 10 | 106 | 9 | 279,372 | 20,351 | 299,723 | 7 |
| **2012** | 75 | 14 | 89 | 16 | 278,742 | 19,820 | 298,562 | 7 |
| **2013** | 84 | 12 | 96 | 13 | 278,687 | 19,615 | 298,302 | 7 |
| **Average** | **83** | **11** | **94** | **11** | **279,030** | **19,030** | **298,983** | **7** |

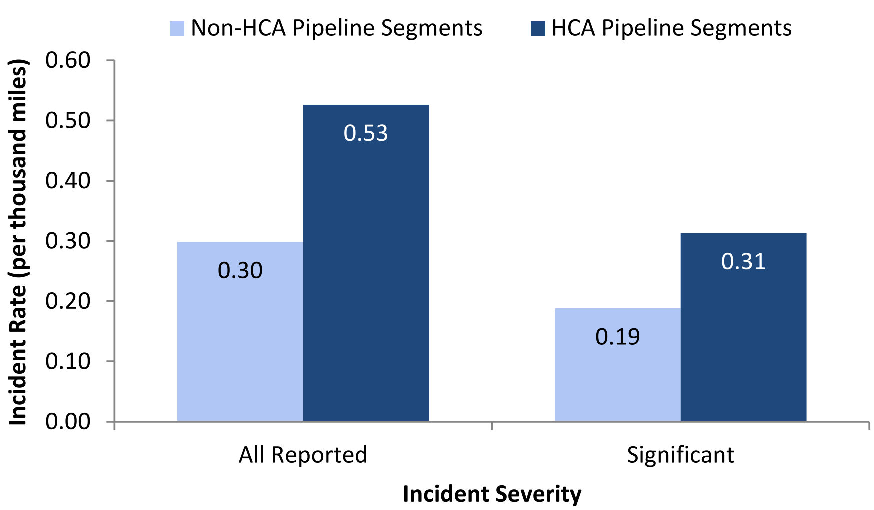


**Figure 6.** Average incident rates per 1,000 miles by HCA classification and incident severity level (2010–2013)

## 3.3 Incidents by Cause

IM programs require an evaluation of all potential threats that, if left unmitigated, may lead to pipeline incidents such as ruptures or leaks. As discussed in chapter 1, these threats must be identified, analyzed, and assessed. Once a threat is identified, strategies are implemented to reduce the risk associated with these identified threats. Time-dependent threats, such as internal and external corrosion and stress corrosion cracking, may introduce weaknesses in the pipelines that can grow over time. These threats, which may lead to material failure, are more readily assessed than other threats, such as incorrect operations and equipment failure. Stable threats, such as manufacturing and construction defects, may introduce defects and weaknesses that do not grow in time but may still lead to leaks or ruptures. Integrity assessment methods are developed to detect defects within the pipeline systems that may lead to such incidents. However, other threat categories, such as equipment failure and incorrect operation, cannot be readily detected by integrity assessment methods and must be prevented or mitigated by other measures. In the PHMSA incident database, one apparent cause must be attributed to each reported incident.[45] These causes and the corresponding threats described in section 1.4.2 and table 1 are:

- Corrosion failure (external and internal corrosion threat)
- Natural force damage (weather-related/outside forces threat)
- Excavation damage (third party/ mechanical threat)
- Other outside force damage (weather-related/outside forces threat)
- Material failure of pipe or weld (manufacturing, construction, or stress corrosion cracking threat)
- Equipment failure (equipment threat)
- Incorrect operation (incorrect operations threat)
- Other incident cause

Table 4 shows the numbers and percentages of incidents between 2010–2013 by the above listed failure causes and incident severity levels. Corrosion failure and material failure of pipe or weld were attributed to 13.6 and 13.1 percent of all incidents, respectively. Combined, these two causes represent 27 percent of all incidents. When focusing on only significant incidents, the combined percentage for these two causes is even higher at 34 percent. Integrity assessment methods are used to primarily detect defects that may lead to corrosion failure or material failure. The former is directly linked to internal and external corrosion, whereas the latter is associated with defects introduced during manufacturing, construction, and installation. Furthermore, some integrity assessment methods may also detect defects introduced due to previous excavation damage, natural forces, and other outside forces. It is, however, important to emphasize that a comprehensive IM program should assess risk associated with all threat categories, including equipment failure and incorrect operations, thereby reducing all pipeline failures due to all causes. Currently, while all threats are required to be identified by the gas IM rule in 49 CFR subpart O, additional requirements on how an operator implements the program with respect to equipment failure, incorrect operations, and excavation damage are contained in 49 CFR subpart L.[46]

[45] PHMSA's Form F7100.2, Incident Report Form, part G specifically deals with these eight apparent causes.

[46] For example, requirements outside of the gas IM rule include 49 CFR §192.617, Investigation of failures, for equipment failure; and 49 CFR §192.616, Public awareness, for excavation damage.

**Table 4.** Number and percentage of incidents by causes and severity levels (2010-2013)

| Apparent Cause | Number of Incidents | | | Percent of Incidents | | |
|---|---|---|---|---|---|---|
| | Significant | Non-Significant | All | Significant | Non-Significant | All |
| **Corrosion** | 40 | 11 | 51 | 17.0 | 7.9 | 13.6 |
| **Material Failure** | 41 | 8 | 49 | 17.4 | 5.7 | 13.1 |
| **Equipment** | 49 | 55 | 104 | 20.9 | 39.3 | 27.7 |
| **Excavation** | 38 | 22 | 60 | 16.2 | 15.7 | 16.0 |
| **Incorrect Operations** | 13 | 11 | 24 | 5.5 | 7.9 | 6.4 |
| **Natural Forces** | 21 | 14 | 35 | 8.9 | 10.0 | 9.3 |
| **Other Outside Forces** | 14 | 12 | 26 | 6.0 | 8.6 | 6.9 |
| **Other** | 19 | 7 | 26 | 8.1 | 5.0 | 6.9 |
| **Total** | **235** | **140** | **375** | **100.0** | **100.0** | **100.0** |

Figure 7 shows the breakdown by HCA classification of the 375 incidents that occurred from 2010–2013. Eighty-nine percent of these incidents occurred in non-HCA pipelines and 11 percent in HCA pipelines (four percentage points higher than the percentages of HCA mileage during the same period). Of the 42 HCA incidents, 5 incidents (12%) were attributed to corrosion failure or material failure of pipe or weld. The most frequently found causes are equipment failure (12 incidents, 29%), followed by excavation damage (8 incidents, 19%). In contrast, corrosion failure and material failure of pipe or weld make up a much higher percentage of incidents in non-HCA pipelines, comprising a total of 28% of all causes. Because the gas IM rule required that all HCA pipelines be baseline assessed by December 2012, and these integrity assessments are primarily intended to detect defects that may lead to corrosion failure and material failure, it is not surprising that these incident causes are less prevalent among HCA pipelines. These observations suggest that strategies for reducing potential incidents due to corrosion and material failure appear to be effective and should be expanded to non-HCA pipelines and that strategies should be developed to reduce other failure causes, such as equipment failure and excavation damage, in all pipelines.

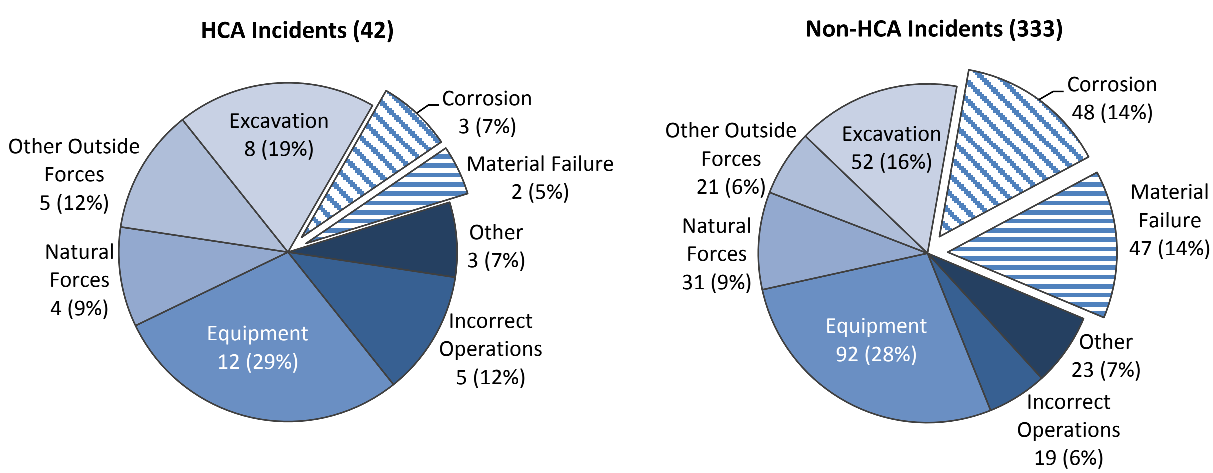


**Figure 7.** Incidents by failure cause and HCA classification (2010–2013)

The need to focus on other causes is highlighted in Figure 8, which shows incident counts (significant and non-significant) for HCA pipelines from 2002–2013. Incident causes are grouped into corrosion, material failure of pipe or weld, and all other causes.[47] The first two causes are associated with threats that can be potentially detected by integrity assessment methods. With the exceptions of 2009 and 2013, there has been at least one incident annually, caused by either corrosion or material failure of pipe or weld. Combining the three failure causes, there has been an increase in HCA-related incidents since 2009. This increase is driven by the increase in other failure causes. As discussed earlier, within the "others" category, excavation damage and equipment failure make up the majority of incidents.

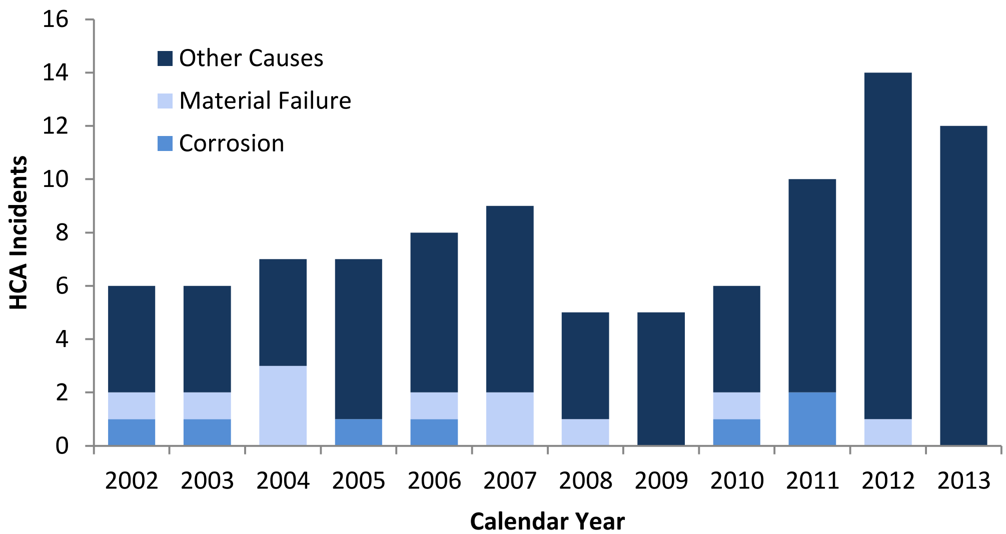


**Figure 8.** Incident counts of HCA pipelines by cause and year (2002–2013)

The NTSB concludes that while PHMSA's gas IM requirements have kept the rate of corrosion failures and material failures of pipe or welds low, there is no evidence that the overall occurrence of gas transmission pipeline incidents in high consequence area pipelines has declined. The NTSB further concludes that despite the intention of the gas IM regulations to reduce the risk of all identified threats, HCA incidents attributed to causes other than corrosion and material defects in pipe or weld increased from 2010–2013.

## 3.4 Pipeline Age and Apparent Failure Causes

The catalyst for the implementation of IM program requirements originated partially from the growing concerns regarding the aging pipeline infrastructure in the United States. Figure 9 shows the installation year for all gas transmission pipelines based on PHMSA's 2013 annual report data. Nearly half of all pipelines were installed between 1950 and 1969, and 57 percent of all pipelines were installed before 1970. The age of the pipeline, in and of itself, is not a failure cause. However, manufacturing and construction practices improve over time; therefore, older pipelines are more susceptible to failure due to those threats. Additionally, older

[47] All other causes include natural forces, excavation, other outside forces, equipment failure, and incorrect operations.

pipelines were buried in the ground and have interacted with their environment for longer. Therefore, they are also susceptible to threats, such as external corrosion and stress corrosion cracking, that are time-dependent.

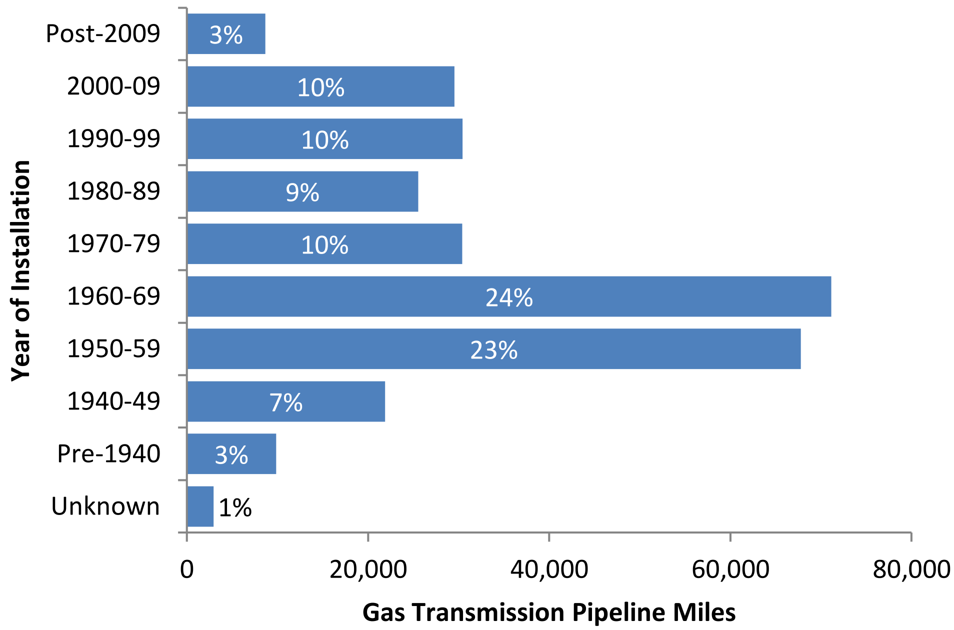


**Figure 9.** Year of installation of all gas transmission pipelines (based on 2013 annual report data)

Figure 10 presents the percentage of gas transmission incidents from 2010–2013 for pipelines installed before 1970.[48] There were 330 incidents in all locations, at all levels of severity, and with known years of pipe installation; 179 of these incidents (54 percent) occurred in pipelines installed before 1970.[49] However, for corrosion failure and material failure of pipe or weld, 73 percent of the incidents occurred on pipelines installed before 1970. These two failure causes are of interest when considering the age of the pipelines. Although manufacturing and construction defects are considered stable threats, there is still a time element associated with them. Safety procedures and processes, as well as materials, improve over time, and pipelines installed before 1970 would not have been subject to the same manufacturing and construction standards. Therefore, it is not unexpected that a considerably higher percentage of pipeline incidents attributed to material failure occurred in pipelines installed before 1970. Corrosion threats are time-dependent. Three pipeline incidents that were caused by corrosion failure occurred in HCAs; all of these pipelines were installed before 1970. Therefore, the NTSB concludes that despite the emphasis of IM programs on time-dependent threats, such as corrosion, gas transmission pipeline incidents associated with corrosion failure continue to disproportionately occur on pipelines installed before 1970.

[48] The year 1970 was used in this analysis because of the “grandfather clause” in 49 CFR §192.619(a) that allows the MAOP to be based on “the highest actual operating pressure to which the segment was subjected during the 5 years preceding … July 1, 1970.”

[49] The differences in the two datasets (pre- and post-1970) precluded direct comparisons.

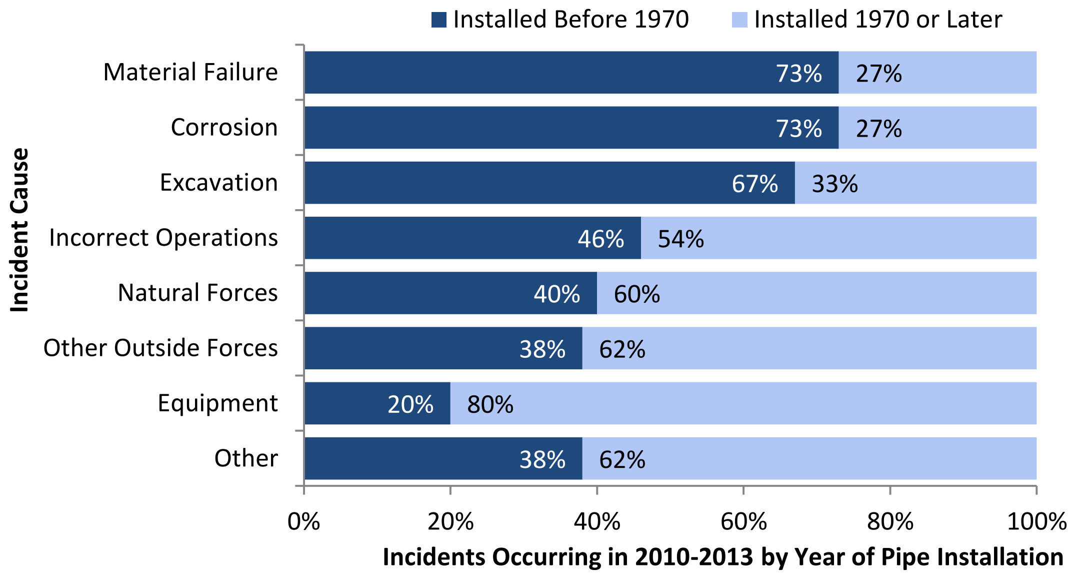


**Figure 10.** Percent of all pipeline incidents occurring on pipelines installed before 1970 vs. after 1970 by failure cause (2010–2013)

## 3.5 Interstate and Intrastate Incidents

Pipeline systems are categorized as either interstate or intrastate; interstate pipelines cross state borders, while intrastate pipelines begin and end in the same state. Table 5 shows that 27 of the 42 HCA incidents occurred during 2010-2013 occurred on intrastate HCA pipelines, representing 64 percent of all HCA incidents. In comparison, only 59 percent of all HCA pipelines are intrastate. Table 4 also shows that the 4-year HCA incident rate was 1.82 incidents per 1,000 miles for interstate pipelines, while the incident rate was 2.31 for intrastate pipelines. The rate ratio between the two incident rates is 1.27. Therefore, the NTSB concludes that from 2010–2013, the intrastate gas transmission pipeline HCA incident rate was 27 percent higher than that of the interstate gas transmission pipeline HCA incident rate.

**Table 5.** HCA incidents, HCA mileage, incident rate, and rate ratio by operation type, 2010–2013

| Operation Type | HCA Incidents | | HCA Pipeline Miles | | 4-Year Incident Rate (per 1,000 miles) | Rate Ratio* |
|---|---|---|---|---|---|---|
| | Number | Percent of Total | Number | Percent of Total | | |
| **Interstate** | 15 | 36 | 8,262 | 41 | 1.82 | 1.27 |
| **Intrastate** | 27 | 64 | 11,690 | 59 | 2.31 | |
| **Total** | **42** | **100** | **19,952** | **100** | **2.11** | **n/a** |

* Rate ratio is the incident rate for intrastate HCA incidents divided by the incident rate for interstate HCA incidents.

## 3.6 Incidents by Integrity Assessment Method

### 3.6.1 Lessons Learned from Five Significant HCA Pipeline Incidents

For some incidents, data on previous integrity assessments can be analyzed. According to PHMSA's Form F7100.2, Incident Report Form, operators are required to complete integrity assessment information if the item involved in the incident was a pipe or weld, and one of the following apparent causes is selected: corrosion (internal or external), material failure of pipe or weld, previous damage due to excavation activity, or previous mechanical damage not related to excavation. From 2010–2013, there were 17 incidents involving the pipe or welds[50] of HCA gas transmission pipelines. Of the 17 HCA incidents, five incidents (29 percent) involved the listed causes; therefore, information about their integrity assessments was required. All five incidents were identified as significant incidents, one of which involved fatalities and injuries. Two incidents were attributed to corrosion failure, two to material failure of pipe or weld, and one to previous excavation damage.

Table 6 gives information about the five HCA incidents discussed above. Although there were five HCA incidents, a total of six integrity assessments were conducted: four direct assessments and two pressure tests. None of these pipeline segments were integrity assessed by ILI. Based on PHMSA's incident data, the pipeline segment associated with the Houston, Texas (12/13/2011) incident was configured to accommodate internal inspection tools, and there was no operational factor complicating its execution.[51] In this incident, the operator did not use ILI, but did conduct a hydrostatic test in 2007. Pressure tests (such as hydrostatic testing) are appropriate for use when addressing corrosion threats, which are considered time-dependent, as well as the pipe seam aspect of the manufacturing threat.

Direct assessments were performed in pipeline segments in four of the five HCA incidents. However, only one of these four incidents (Novato, California, 9/19/2011) was attributed to the apparent cause of corrosion. Direct assessment is an approved integrity assessment method used to identify only corrosion defects. This incident demonstrates that direct assessment, though appropriate, was not able to discover the defect in the pipe that ultimately led to the incident. In the other three incidents (San Bruno, California, 9/9/2010; Houston, Texas, 8/2/2012; and Stockton, California, 12/1/2012), direct assessment was the only integrity assessment method used in the associated HCA pipeline segments. However, the apparent causes attributed to these three incidents were material failure of pipe or weld (two incidents) and previous excavation damage (one incident). Direct assessment is not meant to detect weld seam anomalies or material failure of pipe. However, these defects could have been potentially detected by ILI or pressure testing. These incidents illustrate that choosing the appropriate integrity assessment method for the identified threat is critical in an IM program. The operator must properly identify threats to choose the appropriate integrity assessment method as the San

[50] PHMSA's Form F7100.2, Incident Report Form, part C, question 3 identifies item involved in incidents. The HCA incidents involving pipe or weld as items involved are included in these 17 incidents. All 17 HCA incidents involve the pipes.

[51] PHMSA's Form F7100.2, Incident Report Form, part E questions 5.d and 5.e addresses the issue of whether the pipeline is configured to accommodate internal inspection tools and whether operational factors significantly complicate its execution.

Bruno, California, incident (9/9/2010) demonstrates. Operators used direct assessment to integrity assess the pipeline segment because the threat of external corrosion had been identified for the segment involved in the incident. Because the threat of manufacturing defects was not identified as a threat due to poor pipeline data in the operator's database, an appropriate assessment tool for this threat (such as ILI or hydrostatic testing) was not scheduled (NTSB 2011).

**Table 6.** HCA pipeline incidents in which integrity assessment methods were previously used

| Incident Date and Location | Year Installed | Apparent Cause (Release Type) | Previous Integrity Assessments | Test Year | Configured for ILI? | Operational Factors Complicating ILI? |
|---|---|---|---|---|---|---|
| **9/9/2010 San Bruno, CA** | 1956 | Material Failure (Rupture) | Direct Assessment (not dig site) | 2009 | No | Unknown |
| **9/19/2011 Novato, CA** | 1961 | Corrosion (Leak) | Pressure Test<br>Direct assessment (dig site) | 1972<br>2011 | No | No |
| **12/13/2011 Houston, TX** | 1957 | Corrosion (Leak) | Pressure Test | 2007 | Yes | No |
| **8/2/2012 Nashville, TN** | 1982 | Material Failure (Rupture) | Direct assessment (not dig site) | 2005 | No | No |
| **12/1/2012 Stockton, CA** | 1985 | Excavation (Rupture) | Direct Assessment (not dig site) | 1985 | Unknown | Unknown |

Table 6 also illustrates the prevalence of the use of direct assessment for intrastate HCA pipelines, as all five incidents occurred on intrastate HCA pipelines. For the Novato, California (9/19/2011) incident, a pressure test was conducted in 1972, almost 40 years before the incident occurred and 30 years before the gas IM rule became effective. That was the only incident out of the five in which the pipeline segments were integrity assessed by both direct assessment and another approved method. Because three of the four incidents which were integrity assessed by direct assessment had apparent causes other than corrosion, the use of only direct assessment should be called into question. These five significant intrastate HCA incidents illustrate that (1) operators primarily use only one integrity assessment method to assess the physical integrity of their HCA pipelines, (2) the corrosion threat was highly prioritized by the operators in their relative risk calculation to justify the use of direct assessment, and (3) ILI was either not applicable due to configuration or not selected as an integrity assessment tool.

### 3.6.2 Difference in Usage of ILI Between Interstate and Intrastate Significant Incident Pipelines

Among the 375 onshore gas transmission incidents contained in PHMSA's incident database (2010–2013), 163 significant incidents provide information about whether internal inspection tools can be accommodated by the pipeline configuration, and whether operational factors significantly complicate its execution. Using these 163 significant incidents as convenient samples, Figure 11 compares the feasibility and usage of internal inspection tools between interstate and intrastate pipelines. Of the 100 significant incidents occurring on interstate gas transmission pipelines, 53 incident segments (53 percent) were configured for the use of internal inspection tools with no significant complication. Of these, 32 incident segments were integrity assessed by internal inspection tools, representing 60 percent of all locations where internal inspection tools could have been accommodated. In comparison, 26 intrastate pipeline segments (42 percent) were configured for internal inspection tools with no significant complication. Internal inspection tools were only used in three incidents, which is only 12 percent of all locations that could have accommodated internal inspection tools. Although this comparison is based on convenient samples of significant incident locations, the large discrepancy (12 percent for intrastate versus 60 percent for interstate significant incident pipeline segments) suggests lower utilization of internal inspection tools by intrastate operators.

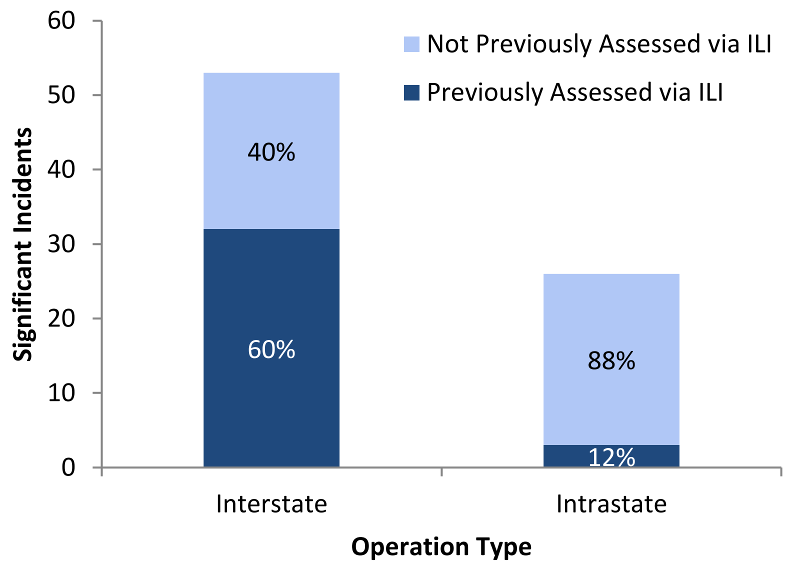


**Figure 11.** Significant incidents associated with pipeline segments that could accommodate internal inspection tools and in which internal inspection tools were used, by operation type (2010–2013)

# 4 Safety Issues

The goal of gas transmission pipeline IM programs is to protect the public from the safety risks associated with pipeline leaks or failures. The effectiveness of how this is achieved relies upon many factors, including the contribution and coordination of many stakeholders, such as the regulators, operators, and pipeline inspectors who use a variety of different approaches and methods. Some of the key elements of this multifaceted safety oversight and inspection process are discussed in this chapter.

The NTSB identified six issue areas for safety improvements based on the results of this study: (1) coordination between federal and state safety programs, (2) HCA identification and verification, (3) threat identification, (4) risk assessment, (5) integrity assessment, and (6) continual assessment and data integration.

## 4.1 Federal and State Safety Programs

### 4.1.1 Protocol-based vs Integrated Inspections

As discussed in section 1.3.2, the IM requirements involve 16 program elements and an operator's IM program must include a set of documented plans and procedures, known as an IM plan, to address these program elements. Federal inspectors and interstate agents for interstate pipelines[52] or state inspectors for intrastate pipelines conduct IM inspections. PHMSA has recently implemented a new integrated inspection approach using a software application called Inspection Assistant (IA) that helps streamline the inspection process for federal inspectors. This integrated inspection approach using IA is more focused on certain program elements that present a higher risk among all IM program elements for a specific operator compared to the approach used by state inspectors.

State inspectors generally use the Gas Integrity Management Inspection Protocol (inspection protocol), a 132-page manual organized by protocol areas tied to the IM program elements (PHMSA 2013a). The inspection protocol includes a series of questions that are designed to help inspectors examine and determine the level of compliance of an operator's IM program. PHMSA also makes available an internal guidance document published in 2008 (PHMSA 2008) that provides guidance to all questions in the inspection protocol. The information in this document is often directly linked to the Frequently Asked Questions (FAQ) published on the PHMSA website (PHMSA 2014c). Before PHMSA implemented the integrated inspection approach, both federal and state inspectors used the same protocol-based IM inspection approach.

The IM program elements are structured differently in an interstate integrated inspection compared to a protocol-based intrastate inspection. For example, determination of whether a certain element of the IM program of an interstate operator warrants a higher level of scrutiny is driven by the risk profile prepared by federal inspectors in the pre-inspection phase of the

[52] See Section 1.5.

integrated inspection using the IA software tool. In contrast, because the guidance presented in the inspection protocol is very structured, it is far likelier that state inspectors will follow the entire protocol without weighing different program elements. State inspectors revealed somewhat diverging opinions about the effectiveness of the 132-page inspection protocol. One inspector stated that it “was very good and comprehensive,” and he “only had to go through the inspection protocol” as if it were a checklist. On the other hand, one inspector pointed out that the inspection protocol “is basically a paper audit, and it lacks field observations and validation.” Some other inspectors suggested that although the inspection protocol is very long, it did not go into enough detail to actually assess the effectiveness of the operator’s IM program. One state inspector noted that they created additional forms to augment the protocol. On numerous occasions, state inspectors expressed their desire to have additional guidance, as well as other resources to improve their efficiency in conducting IM inspections.

The use of drill-down questions, which go beyond the initial inspection protocol question, is an area that needs improvement. A drill-down question should lead an operator to conduct a hands-on examination of data and analysis of such data. For example, the inspector may ask the operator to pull up a sample of pipeline segments within the operator’s entire system in the in-house GIS or online mapping application (such as Google Maps or Google Earth) to ensure that the operator is making accurate determinations of the location and boundaries of HCAs (PHMSA 2014c). PHMSA recommended in its 2013 progress report that state inspectors use data drill-down questions as they conduct the IM inspections (PHMSA 2013c). Currently, there is no official repository of a comprehensive set of drill-down questions. Of 22 state inspectors responding to NAPSR’s voluntary survey (NAPSR 2014), only 3 (14 percent) indicated that their state inspection program uses a standard set of drill-down questions to supplement questions currently included in the inspection protocol. Many state inspectors indicated that they had heard about integrated inspections and the IA software, and most expressed optimism that integrated inspections using the IA software would be incorporated at the state level. In conversations with PHMSA personnel, they have indicated that there is currently no plan for this transition; however, the IA software is available for state inspectors upon request.

Integrated inspections using the IA software are usually team-based, whereas inspection protocol-based inspections involve either individual or team-based inspections. In one state, each inspector is assigned an operator and the inspectors interviewed often referred to the operator as “his operator.” In this case, the same inspectors inspected the same operators over time. In NAPSR’s voluntary survey, 27 percent of respondents indicated that the IM inspections they conducted were typically done by an individual inspector. Some state safety commission inspection program managers, and all interviewed inspectors, mentioned that it was not feasible to have team-based inspections due to a lack of staff. This is because state inspectors conduct not only gas transmission IM inspections, but other inspections, such as facility inspections and gas distribution IM inspections. The NTSB concludes that approaches used during IM inspections of gas transmission pipelines conducted in state inspections vary among states and whether this variability affects the effectiveness of IM inspections has not been evaluated.

### 4.1.2 Federal and State Coordination

There are many roles that PHMSA plays in state inspection programs. NAPSR provided some insight to state inspectors' perceptions of PHMSA. In the voluntary survey, NAPSR asked the responding inspectors to rate their perception of PHMSA's role in four areas: oversight of the state program, collection and dissemination of data, mentoring of state inspectors, and provision of reference materials. Figure 12 shows the responses. A high proportion of inspectors (59 percent) felt that PHMSA played a critical role in state inspection program oversight.

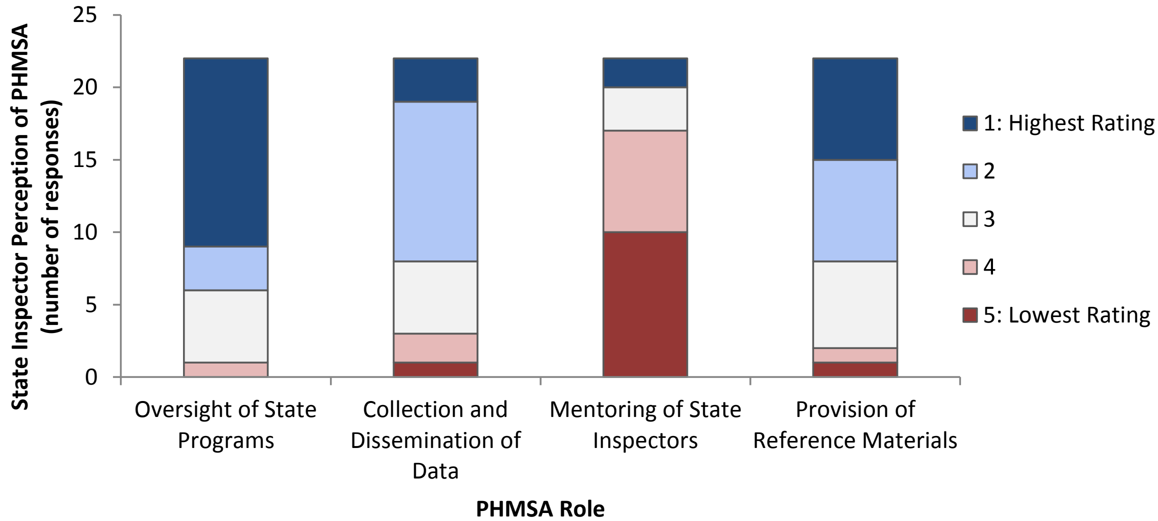


**Figure 12.** Perceptions of PHMSA roles in state inspection programs, as rated by state inspectors (NAPSR, 2014)

To lead IM inspections, state inspectors must complete a minimum of 14 training courses given by PHMSA.[53] However, after completing these training courses, the interaction between state inspectors and their PHMSA counterparts is minimal, informal, and largely reliant on personal relationships. There is no requirement for recurrent training of state inspectors. The state program manager determines if recurrent training is necessary for their inspectors. There is no formal PHMSA program for mentoring state pipeline inspectors. Additionally, there is no formal procedure for PHMSA to provide guidance during state-conducted IM inspections beyond those included in the guidance document. Many state inspectors expressed their desire to be able to participate in federal IM inspections as a way of gaining additional on-the-job experience by observing federal inspectors.

In discussions with state pipeline inspectors, it became clear that state inspectors generally view PHMSA inspectors as being very knowledgeable about IM and a good resource for clarifying issues that arise during inspections. However, 45 percent of all respondents to the

[53] The 14 training courses include eight required of all gas pipeline inspectors (an introductory class and courses covering pressure regulation, plastic and composite materials, welding, failure investigation, corrosion control, compliance procedures, and hazardous waste) plus six specific to gas IM (an introductory class and courses covering the gas IM protocols, supervisory control, ILI, ECDA, and internal corrosion).

NAPSR voluntary survey poorly rated PHMSA's role in mentoring. Some inspectors felt that they did not have enough knowledge to adequately critique or dispute the operator's SMEs' opinions and perspectives. They felt that gaining adequate resources, having more opportunities to participate in interstate inspections with PHMSA inspectors, and having more access to PHMSA's SMEs would improve their ability to complete the IM inspection tasks. The NTSB concludes that PHMSA's resources on IM inspections for state inspectors, including existing inspection protocol guidance, mentorship opportunities, and the availability of PHMSA's inspection subject matter experts for consultation, are inadequate. The NTSB recommends that PHMSA assess (1) the need for additional inspection protocol guidance for state inspectors, (2) the adequacy of your existing mentorship program for these inspectors, and (3) the availability of your SMEs for consultation with them, and implement the necessary improvements.

It is a very time-consuming process to conduct an IM inspection. Results from the NAPSR survey indicate that, on average, state inspectors spend at least three days preparing for an inspection and eight days conducting the inspection. As discussed in section 1.2, many pipeline operators operate both interstate and intrastate pipelines, while many intrastate pipeline operators operate in more than one state. Therefore, coordinated inspections between PHMSA inspectors and state inspectors, as well as coordination between states may alleviate some of the time burden. One state inspection manager expressed this view and indicated that some degree of state-to-state coordination does occur. However, it is not a common practice across all regions in the United States. Currently, PHMSA regional offices may invite specific state inspectors to participate in their interstate IM inspections, but it is unclear how systematic and frequent such practices are. The state inspectors also indicated that such state-to-state coordination is completely voluntary and largely dependent on the personalities of state agency directors. Because financial and human resources are limited in most state safety agencies, improved coordination between PHMSA and state safety regulators, as well as among state safety regulators, should lead to a greater efficiency in how overlapping inspections are conducted, increase knowledge sharing and information exchange among states that have inspection responsibility for the same operators. The NTSB concludes that federal-to-state and state-to-state coordination between inspectors of gas transmission pipelines is limited. The NTSB recommends that PHMSA modify the overall state program evaluation, training, and qualification requirements for state inspectors to include federal-to-state coordination in IM inspections. The NTSB also recommends that PHMSA work with NAPSR to develop and implement a program to formalize, publicize, and facilitate increased state-to-state coordination in IM inspections.

### 4.1.3 National Pipeline Mapping System (NPMS) Data

According to the PHMSA guidance (PHMSA 2013b), federal inspectors are expected to use multiple databases to gather information and prepare an inspection profile as part of their pre-inspection preparation. One of the data sources is the NPMS, which is a GIS consisting of geospatial data on transmission pipelines.[54] During discussions with federal inspectors, some inspectors acknowledged that PHMSA should require more detailed pipeline data from operators in the NPMS and suggested that PHMSA should consider changing the yearly submission

[54] See https://www.npms.phmsa.dot.gov/FAQ.aspx for more information.

interval to a more frequent schedule. In the NAPSR voluntary survey of state inspectors, only 17 percent of respondents gave the NPMS the highest rating when asked about its importance in preparing or conducting IM inspections. One respondent of the NAPSR voluntary survey stated that they use the state agency's GIS instead of NPMS data. In interviews with inspectors, it was mentioned that state safety commissions also often have their own GIS because the quality (such as positional accuracy and attribute details) of the current NPMS data is not high enough for inspectors to properly conduct their pre-inspection preparation.

The NPMS pipeline attribute data is limited. The original standards for the NPMS data collection were drafted in 1998 and its role has evolved over time. It was originally created to help PHMSA manage its regulatory assets and to help inspectors in the field. Now its role has been expanded in disaster response to help ensure that emergency response agencies and communities are better prepared during incidents. The NPMS is also the primary tool for PHMSA's pipeline risk ranking calculation to prioritize inspections. It contains information about the operators (operator ID and name) and pipeline attributes (system/subsystem name, diameter, and commodity transported, and interstate/intrastate operation type). Specific data reporting requirements for operators can be found in the NPMS Operator Standards Manual (NPMS 2014). The NPMS data currently contains no attribute associated with HCA identification, which limits the inspectors' ability to conduct pre-inspection assessments of the adequacy of an operator's HCA identification process. The NTSB concludes that the lack of HCA identification in the NPMS limits the effectiveness of pre-inspection preparations for both federal and state inspectors of gas transmission pipelines.

The NPMS data has a target accuracy of only +/- 500 feet, but operators often provide more accurate data.[55] Therefore, the 500 feet accuracy means that the true centerline of the pipeline segment can be 500 feet on either side of what is contained in the NPMS data. This uncertainty is on the order of typical PIC radii used for calculating HCAs. For example, a pipe with a 24-inch outside diameter with an MAOP of 911 pounds per square inch gauge (psig) or a pipe with 30 inch outside diameter with MAOP of 583 psig will both produce a potential impact radius of 500 feet. [56] The NPMS attribute data captures the operator's estimate of the positional accuracy of the submitted pipeline data. In the NPMS, the estimate is broken into classes: within 50 feet (excellent), 50-300 feet (very good), 301-500 feet (good), and 501-1000 feet (poor). Figure 13 shows the percentage of pipeline mileage by the operator's estimate of positional accuracy in the NPMS 2013 dataset. Less than 22 percent of all gas transmission pipeline mileage has a positional accuracy of within 50 feet. Interstate pipelines have better positional accuracy, as shown by the total of 88 percent within 300 feet, compared to only 64 percent for intrastate pipelines. Although state and federal inspectors do not rely on NPMS data during the actual IM inspections, the NPMS is one of the PHMSA databases used during the information

[55] NPMS data sets are for the purpose of tracking all gas transmission pipelines, hazardous liquid transmission pipelines, and LNG plants in the United States, as well as some breakout tanks. The data is used to support the assessment risk associated with the United States' liquid and gas pipeline infrastructure. NPMS data cannot be used as a substitute for contacting the appropriate local on-call center before digging.

[56] See page 7 of ASME B31.8S-2004. The equation is (1), $r = 0.69 \cdot d\sqrt{p}$, where r = radius of the impact circle (ft), d = outside diameter of the pipeline (in), and p = pipeline segment's maximum allowable operating pressure (MAOP) (psig).

gathering and inspection preparation phase of the IM inspections. The NTSB concludes that there is a considerable difference in positional accuracy between interstate and intrastate gas transmission pipelines in the NPMS, and this discrepancy, combined with the lack of detailed attributes, may reduce state and federal inspectors' ability to properly prepare for IM inspections. Therefore, the NTSB recommends that PHMSA increase the positional accuracy of pipeline centerlines and pipeline attribute details relevant to safety in the NPMS.

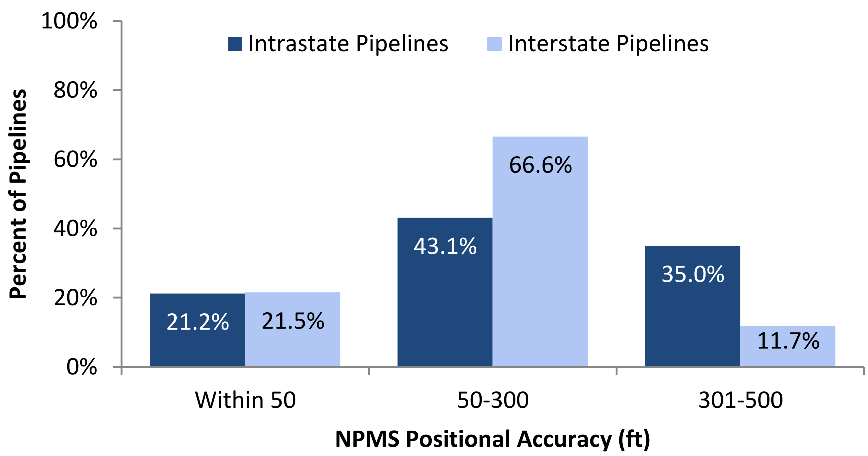


**Figure 13.** Pipeline mileage by operation type and NPMS positional accuracy (NPMS, 2013)

Currently, there is limited information included in the NPMS data. To obtain additional information about the operator, it is necessary to link the NPMS data to other PHMSA data sources. The ability to properly link geospatial data of pipelines in the NPMS to annual report and incident data is beneficial to inspectors for their pre-inspection preparation. The operator ID is a potential link between the NPMS, and the annual report and incident databases. We compared the operator IDs in NPMS and the annual reports. In general, the operator IDs that do not match between the two datasets have fairly short gas pipelines, with only two operators having more than 100 miles of gas transmission pipelines. We also used GIS and the spatial-join process[57] to link gas transmission incidents to the closest pipeline segments included in the NPMS data, compared the operator IDs, and found mismatched operator IDs. One reason for the mismatch may be due to the transaction of business.[58] The NTSB concludes that the discrepancies between PHMSA's NPMS, annual report database, and incident database may result in state and federal inspectors' use of inaccurate information during pre-inspection preparations.

[57] "Spatial-join" is a commonly used GIS process that joins attributes (such as operator ID and name) from one GIS data layer (for example, gas transmission pipelines) to another GIS data layer (for example, incident locations) based on the spatial relationship (for example, straight line distance).

[58] The operator may change after the incident due to contractual relationships or sale of the pipeline.

### 4.1.4 DOT IG Report Findings

In 2011, as a result of the San Bruno, California, incident investigation (NTSB 2011), the NTSB concluded that oversight of state public utility commissions needed improvement and recommended[59] that USDOT conduct an audit of PHMSA's state pipeline safety program certification program. The DOT Inspector General (DOT IG) completed this audit in May 2014, analyzing all aspects of the state pipeline safety program (not only IM) and finding deficiencies in the following areas: PHMSA's formula for calculating staffing levels, qualifications for leading inspections, guidelines for scheduling and conducting inspections, reviews of grant expenditures, evaluation of states' compliance with program requirements, and the use of grant funds for fiscally challenged states (USDOT 2014). The NTSB also issued a companion safety recommendation,[60] which recommended that USDOT make certain that the state pipeline safety program certification program is modified to incorporate the results of this audit. The NTSB reiterates Safety Recommendation P-11-7 to USDOT to ensure that PHMSA amends the certification program, as appropriate, to comply with the findings of the audit recommended in Safety Recommendation P-11-6.

## 4.2 HCA Identification and Verification

Although an IM program is continuous and ongoing, HCA identification can be considered the first task and must be repeated periodically to examine population density changes along the pipeline. Figure 14 shows the steps within the HCA identification process in which pipeline attributes, location data (which may be updated based on previous remediation activities or P&M measures), and information about the surrounding environment are used to identify HCAs.

[59] NTSB Safety Recommendation P-11-006 to USDOT. http://www.ntsb.gov/doclib/recletters/2011/P-11-004-007.pdf

[60] NTSB Safety Recommendation P-11-007 to USDOT. http://www.ntsb.gov/doclib/recletters/2011/P-11-004-007.pdf. This recommendation is currently classified "Open—Acceptable Response."

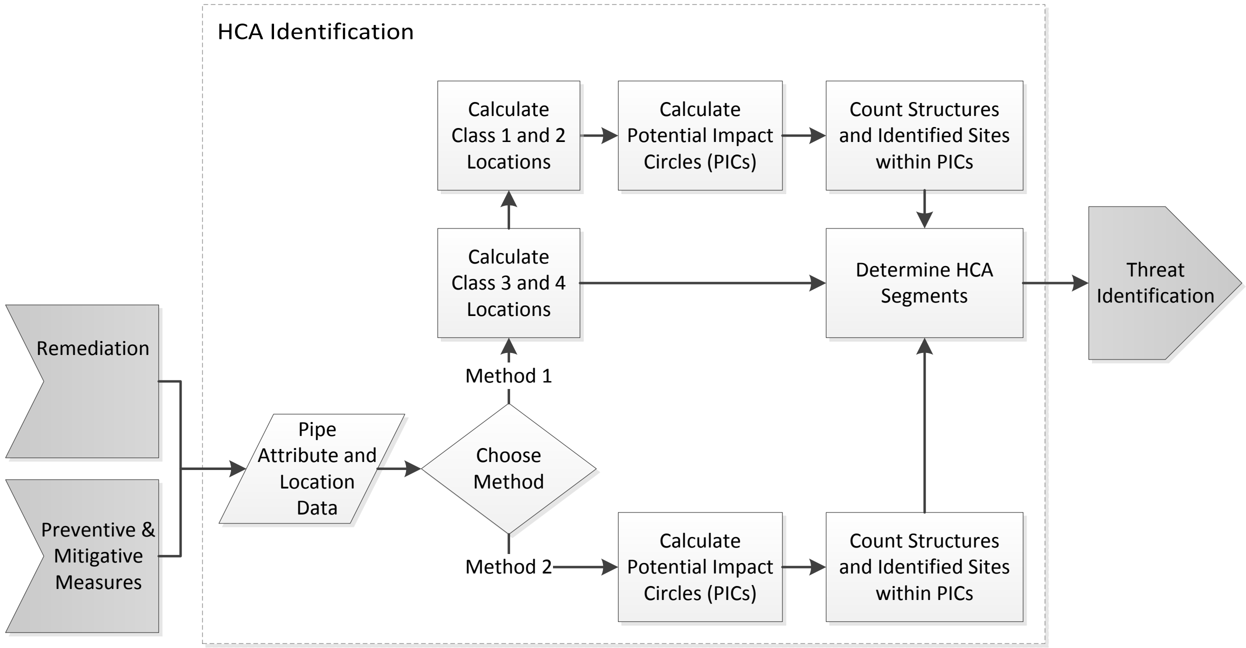


**Figure 14.** HCA identification flowchart

### 4.2.1 HCA Issues and Enforcement Actions

As noted in section 2.4, PHMSA completed two progress reports on gas transmission IM; one on federal inspections in 2011 and the other on state inspections in 2013. Figure 15 is based on these progress reports and shows the total counts of compliance issues found in these inspections by IM program element and type of inspection (that is, federal versus state). A total of 532 compliance issues (11 percent of all compliance issues found) were in the IM program element for HCA identification.

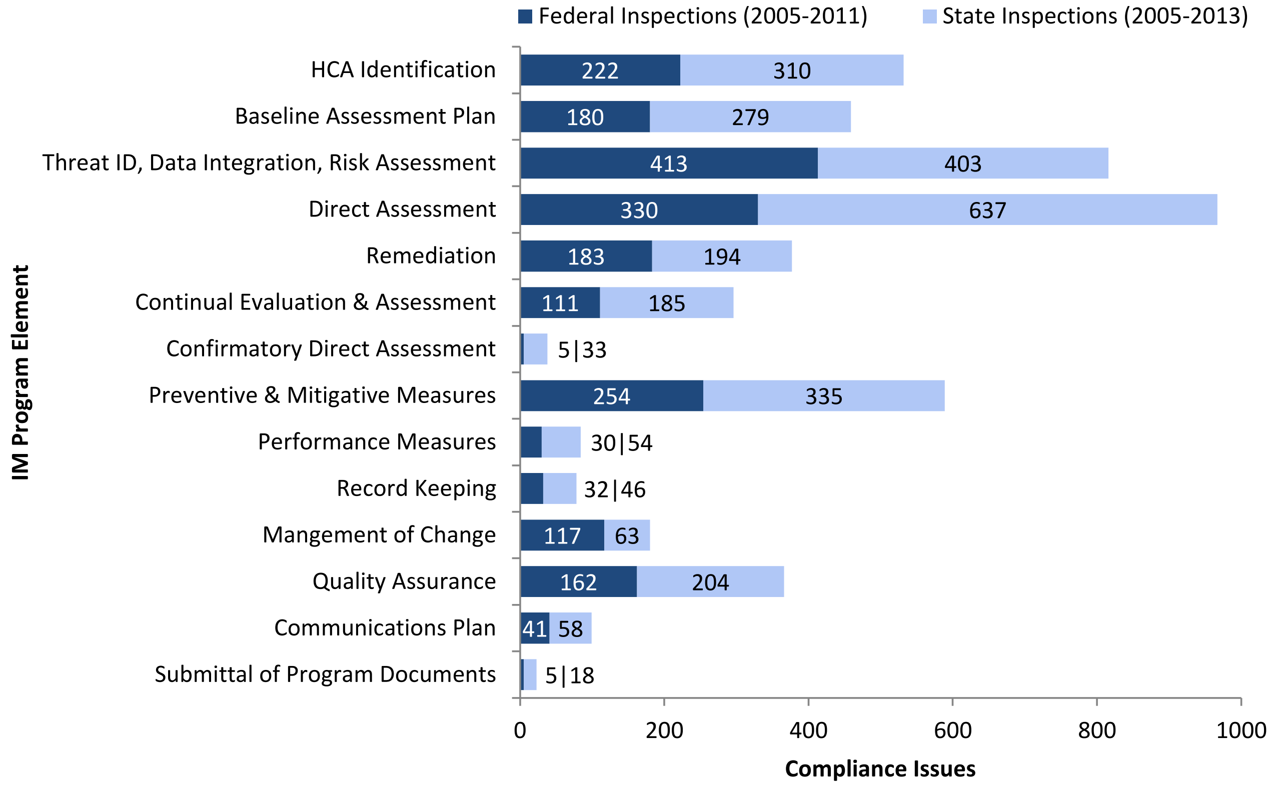


**Figure 15.** Compliance issues identified by federal and state inspectors

Although HCA identification is the first step in the IM program, it also includes the processes and procedures implemented by the operators to continually monitor any change in the HCA classification of their pipelines. For example, a change in the operation and characteristics of a pipeline such as change in diameter or relocation during a replacement, or developmental encroachments may change the classification of the pipeline, and require it to be designated as an HCA, or cause a section of pipeline to be removed from an HCA, which is less likely. In both the federal and state progress reports, the HCA compliance issues cited most often are related to the process of updating the HCA analysis (which was found in 34 percent of 78 federal IM inspections) and identifying and evaluating newly identified HCAs (which was found in 12 percent of 434 state IM inspections). Both federal and state inspectors also found another specific HCA compliance issue related to identified sites. This compliance issue involves the procedure used to determine identified sites (29 percent of 78 federal IM inspections) and the sources of information used to identify HCAs (10 percent of 434 state IM inspections).

NTSB staff also obtained PHMSA enforcement action data from 2006–2013 for a set of program elements that are relevant to the IM process for all gas transmission pipelines (both HCA and non-HCA).[61] These enforcement data may indicate where operators are having problems meeting the intent of IM program elements. Figure 16 shows the distribution of

[61] Enforcement action data were obtained from PHMSA via direct communication. The enforcement actions were linked to particular regulations within 49 CFR 192. This information was then reorganized by the NTSB into IM program elements and presented in Figure 16. See Appendix A for more information.

enforcement action counts by program element and type of action. HCA identification ranked fifth among 11 program elements. Among all the program elements, HCA-related enforcement represents the highest percentage (27 percent) of all collected civil penalties during 2006–2013. The IM program area of HCA identification, particularly the sub-areas of periodic verification and identified sites, is frequently cited as a compliance issue in both federal and state IM inspections.

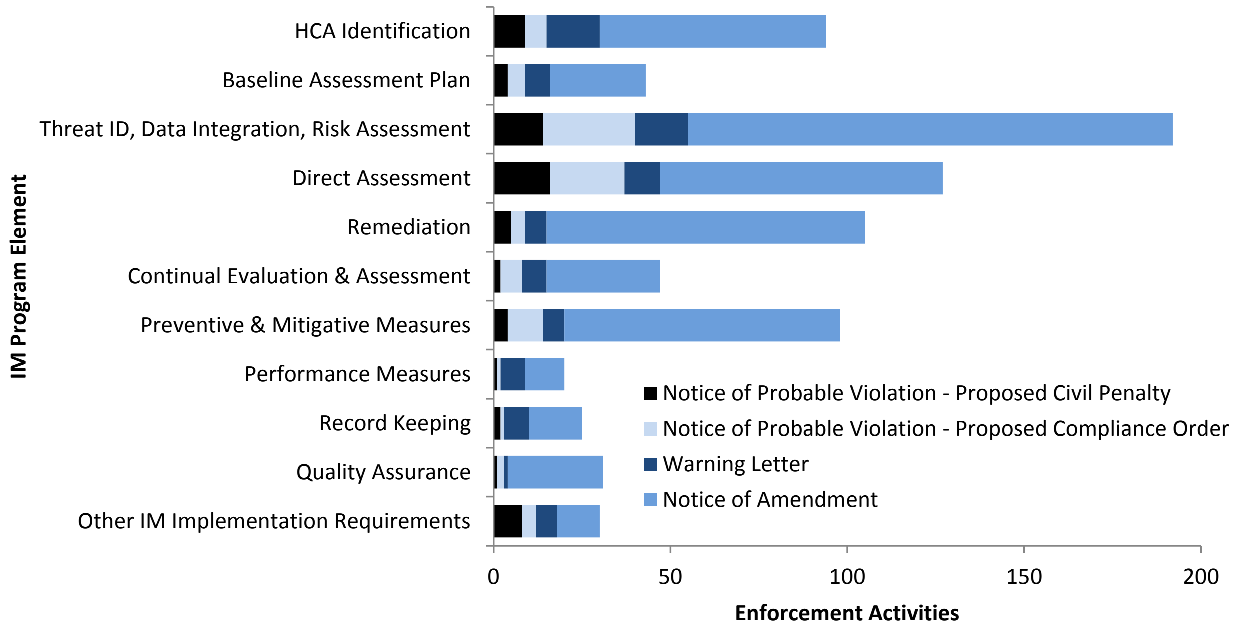


**Figure 16.** Enforcement counts by program element and enforcement activity (2006–2013)

### 4.2.2 Reporting Requirements

From 2010–2013, operators reported a total of 375 incidents, 42 (11 percent) of which occurred in HCAs. On PHMSA's Form F7100.2, Incident Report Form,[62] operators are asked if the incident occurred in an HCA, and if so, operators are asked to specify the method used to identify the HCA (class locations [Method 1] or PICs [Method 2]). Of the 42 HCA incidents, 12 were identified as HCAs using class locations, while 29 were identified as HCAs using PICs.[63] Currently, PHMSA's incident database does not indicate the method by which the operator determines if the pipeline is non-HCA, nor does it include a data element to verify if the non-HCA pipeline was correctly identified. As the NTSB's Palm City accident investigation shows, it is possible to incorrectly exclude pipeline segments from IM requirements if an HCA is not correctly identified. In the case of Palm City, an identified site was misclassified. To truly understand the magnitude of the problem, it is necessary to collect the relevant information, such as the method used to determine if the pipeline segment is a non-HCA. As discussed in 4.1.4, there is currently no submission requirement for HCA identification in NPMS. This lack of HCA

[62] See part D, questions 2 and 2a in PHMSA's Form F7100.2, Incident Report Form.
[63] One of the HCA incidents does not have method determination listed.

identification information hinders the effectiveness of pre-inspection preparations for both federal and state inspectors. Adding this information to NPMS will allow federal and state inspectors to improve their pre-inspection preparation, and also allow for a thorough evaluation of the current HCA identification processes. Therefore, the NTSB recommends that PHMSA revise the submission requirement to include HCA identification as an attribute data element to the NPMS. The NTSB further recommends that PHMSA assess the limitations associated with the current process for identifying HCAs, and disseminate the results of this assessment to the pipeline industry, inspectors, and the public.

### 4.2.3 Reliance on Geospatial Data and Technology

Operators are responsible for knowing the environment surrounding their pipelines to maintain an awareness of developments that may change HCA classifications. There are two primary approaches to do this, and all operators interviewed indicated that they used a combination of both approaches. The first approach involves the use of geospatial data and technology. Operators typically use a variety of information sources, including digital aerial photographs, satellite images, and GIS data (such as buildings). These geospatial data are typically of a very high resolution (often sub-meter resolution for satellite images) and are expensive. The digital images are then orthorectified[64] and geo-referenced with the operators' pipeline centerline data, typically in their in-house GIS. Often, these images are obtained on an annual basis to support the periodic evaluation of the pipeline environment to comply with the IM requirements.

The second approach for identification and periodic verification of HCAs relies on local surveillance.[65] This is particularly important for identified sites[66] because while geospatial technology can identify the structure, it may not be able to identify the function of the structure. Routine operations and maintenance activities and input from public officials with safety or emergency response or planning responsibilities are usually the main sources of information for identified sites.[67] All operators interviewed noted that this information is eventually incorporated into their in-house GIS.

### 4.2.4 Positional Accuracy and Buffering Standard

The proper identification of an HCA and periodic verification relies on two key types of information: (1) pipeline-specific information that includes the accurate location of the centerline of the pipeline, the nominal diameter of the pipeline, and the pipeline segment's MAOP; and (2) all the structures and their usage (including occupancy) located along the pipeline. From a geographic perspective, both the location of the pipeline centerlines and surrounding structures have limitations due to the positional precision of the acquiring technology (such as the global positioning tool) and the geospatial data (such as digital aerial photography and satellite

[64] Orthorectified images refer to those satellite or aerial photographic images that have been corrected for distortion due to terrain.

[65] One activity cited by multiple operators is foot patrolling their pipelines.

[66] See section 1.4.1.

[67] See PHMSA's *Gas Integrity Management Inspection Manual: Inspection Protocols with Results Forms*, A.03.b: "Identified sites must be identified using the following sources of information: [§192.905(b)]."

imagery). This positional uncertainty is the fundamental reason why pipeline operators add a buffer to the calculated PIC. PHMSA's gas IM FAQ 174 discusses this limitation and offers the following advice:[68]

> PHMSA recognizes that mapping and measuring technologies involve some level of inaccuracy/tolerance. Operators must take these into account and consider the uncertainties in the distances they measure or infer when evaluating potential impact circles (PICs). Each operator's approach must be technically sound, must account for the uncertainties as they exist in the mapping/measurement methods used by the operator, and must be documented in its IM plan or related procedures.

It is clear that PHMSA expects operators to apply a technically sound approach for HCA identification and account for positional inaccuracies. All but one operator interviewed adds buffers to their PICs, up to 100 feet. That operator claimed that distances calculated from positions measured by the same tool (for example, GPS or aerial photography) have no uncertainty and did not need a buffer area. Federal and state IM inspectors are expected to understand the possibility of some positional inaccuracy when using geospatial technology. Inspectors must determine if the approaches used by operators to account for the potential positional inaccuracy are technically sound.

As discussed earlier, many operators are relying on the use of geospatial data such as aerial or satellite based imagery for HCA identification. However, there is no standard or guidance from PHMSA regarding the use of geospatial data for this purpose. The positional errors inherent in these geospatial data can be additive and can considerably diminish the accuracy of HCA identification. Therefore, it is important for PHMSA to establish guidelines for geospatial data standards for operators to use. To accomplish this, PHMSA should leverage existing established federal resources. For example, at the federal level, the Federal Geographic Data Committee (FGDC)[69] is well-suited to work with PHMSA to develop guidelines for operators and inspectors regarding digital spatial data standards and specifications relevant to commonly used geospatial data. The NTSB concludes that the lack of published standards for geospatial data commonly used by pipeline operators limits operators' ability to determine technically sound buffers to provide a sufficient safety margin for HCA identification and also hinders IM inspectors from evaluating the buffer's technical validity. The NTSB recommends that PHMSA work with the FGDC to identify and publish standards and specifications for geospatial data commonly used by gas transmission pipeline operators, and disseminate the standards and specifications to these operators and inspectors.

[68] See PHMSA Gas Transmission Integrity Management FAQ 174: "The centerline of a pipeline may not be accurately determined via GIS or other method. The locations of structures (for example, from aerial photography) may also involve inaccuracies. What provisions must be taken to address for inaccuracies in these measurements, in order to accurately determine the relative location of structures with respect to the pipeline?"

[69] The Federal Geographic Data Committee (FGDC) is an interagency committee that promotes the coordinated development, use, sharing, and dissemination of geospatial data on a national basis. This nationwide data publishing effort is known as the National Spatial Data Infrastructure (NSDI). The NSDI is a physical, organizational, and virtual network designed to enable the development and sharing of this nation's digital geographic information resources. FGDC activities are administered through the FGDC Secretariat, hosted by the US Geological Survey.

### 4.2.5 Repository of Geospatial Data Resources

As shown in both state and federal progress reports, identified sites[70] (such as recreational facilities and churches) are a compliance issue often discovered during IM inspections. The Palm City incident also highlighted the role inaccurate HCA identification played. Currently, there is no national repository of geospatial data resources for the HCA identification process, especially with respect to identified sites. All the operators interviewed for this study indicated that they rely heavily on contact with local officials to identify sites, and the information is then incorporated into their in-house GIS. The National Association of Counties (NACo), the only national organization that represents county governments in the United States, has worked closely with PHMSA[71] as part of the Pipelines and Informed Planning Alliance (PIPA). PIPA's goal is to improve safety for the communities that surround high-pressure transmission pipelines by developing recommended practices that are intended to complement existing regulations or laws. PIPA helps communities make risk-informed decisions for land-use planning and development adjacent to high pressure gas pipelines. In 2010, PIPA issued a report that included 46 recommendations to local organizations and governments to develop (PIPA 2010) a plan addressing mapping, land records management, communications, and design and development considerations with respect to pipeline safety. This activity shows that a working relationship exists between local governments, PHMSA, and transmission pipeline operators, and a working relationship also exists at the local level because local governments are responsible for planning, emergency response, and safety of identified sites.

At the state level, the National State Geographic Information Council (NSGIC) works to promote statewide geospatial coordination activities in all states and to be an advocate for states in national geospatial policy and initiatives, thereby enabling and supporting the National Spatial Data Infrastructure (NSDI).[72] The NSGIC has two ongoing initiatives that may be beneficial to pipeline safety. The first is the "Address for the Nation" initiative and the other is the "Imagery for the Nation" initiative. The first initiative presents an opportunity to improve locational information of structures, potentially benefiting the HCA identification process. The second initiative aims at building a sustainable and flexible digital imagery program that meets the needs of local, state, regional, tribal, and federal agencies, and it may lead to cost savings in the development of a national repository of high resolution imagery that benefits both pipeline operators and state and federal inspectors.

Some other federal agencies play a role in the improvement of the HCA identification process, such as the US Census Bureau. PHMSA has published population-based geospatial data

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[70] See footnote 19 for a detail description of identified sites.

[71] One recent example is in the article "NACo plans tight focus on pipeline safety for counties", published on March 24, 2014. See http://www.naco.org/newsroom/countynews/Current%20Issue/3-24-2014/Pages/NACo-plans-tight-focus-on-pipeline-safety-for-counties.aspx.

[72] The NSDI was established by Executive Order 12906 (April 11, 1994). The goal of the NSDI is to reduce duplication of effort among agencies, to improve quality and reduce costs related to geographic information, to make geographic data more accessible to the public, to increase the benefits of using available data, and to establish key partnerships with states, counties, cities, tribal nations, academia, and the private sector to increase data availability.

produced by the US Census Bureau for HCA identification of hazardous liquid transmission pipelines, but has not done so for gas transmission pipelines. There are other federal agencies that develop, update, and distribute geospatial data that may be used as the foundational data layers for identified sites. Although it is unreasonable to build a static list of identified sites in the United States for the purpose of HCA identification and verification, it is important to explore the possibility of developing a repository of authoritative sources of geospatial data of these sites. The NTSB concludes that the lack of a repository of authoritative sources of geospatial data for identified sites may contribute to operators' inaccurate HCA identification. Therefore, the NTSB recommends that PHMSA work with the appropriate federal, state, and local agencies to develop a national repository of geospatial data resources for the process for HCA identification, and publicize the availability of the repository.

## 4.3 Threat Identification

Once HCAs are identified, threat identification is the next task in an IM program. Figure 17 shows the steps within the threat identification process. First, all possible threats that could act on the pipeline system must be identified, along with any possible threat interactions. Then, for each HCA segment, the specific threats and threat interactions applicable to the segment are identified, using pipe attribute and location data, along with data on the environment surrounding the pipe.

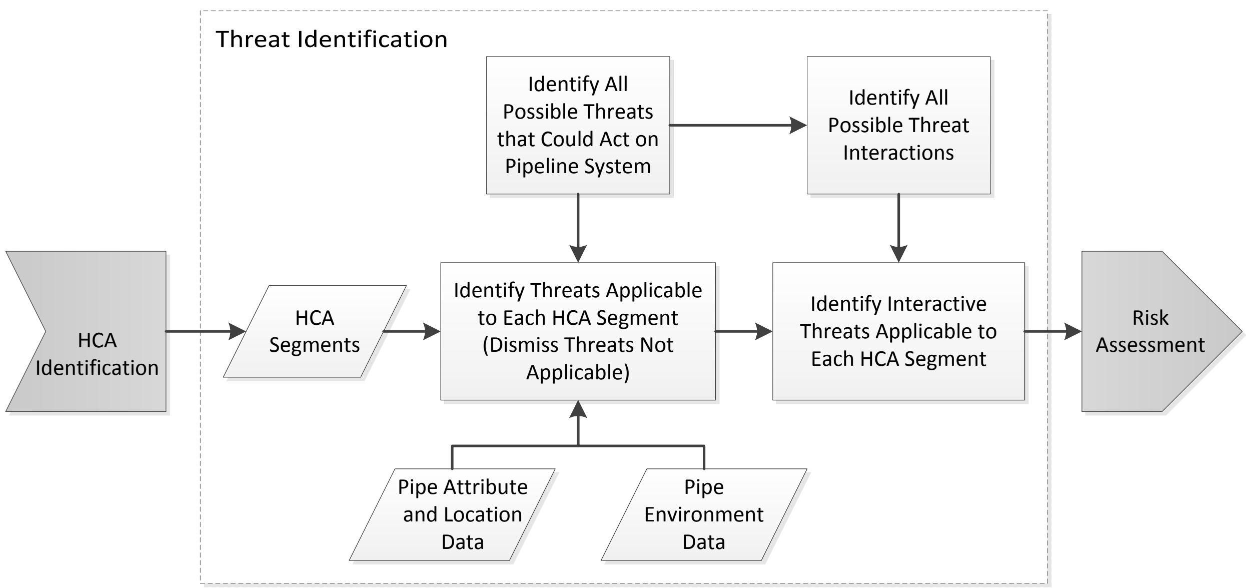


**Figure 17.** Threat identification flowchart

### 4.3.1 Current Practices

All operators interviewed for this study identify threats according to the nine threat categories listed in ASME B31.8S. In general, the operators interviewed for this study use two methods to determine which of these threats a pipeline segment is susceptible to (or, conversely, which threats can be eliminated from consideration). Some operators use SME-driven flowcharts or decision trees for each threat category. Other operators move directly to and use their risk assessment models, and consider a pipeline segment susceptible to a threat if:

1) the likelihood of failure exceeds a specified threshold value;
2) the threat likelihood, consequence, or total risk satisfies a statistical test within the population of HCA segments[73]; or
3) a segment has a high threat risk ranking among all HCA segments.

Lastly, for some threats, it is common for operators to always assume that the threat is present. For example, all but one of the interviewed operators considers external corrosion to be a threat for all steel pipelines.

### 4.3.2 Elimination of Threats

Because the identified threats determine the selection of appropriate integrity assessment methods and P&M measures, pipeline operators must take care not to erroneously assume that a threat is not present for a particular pipeline segment. Doing so could lead to the threat never being assessed via an appropriate integrity assessment method. For example, the San Bruno incident was caused by a manufacturing defect that was not identified as an unstable threat, and therefore not assessed, and in the Palm City incident the final stages of crack propagation in the pipe wall was caused by stress corrosion cracking that was not identified as a threat.

When state inspectors were asked to rate the difficulty of inspecting elements of operators' IM programs, threat identification received the highest number of responses as the most difficult element to inspect (see figure 18). This is not surprising, especially for those operators that use risk thresholds (based on a complex underlying risk model, described in section 4.4.1) or statistical tests to determine threat susceptibility, because considerable expertise is required to understand these methods. Of the interviewed operators that use their risk models directly to eliminate[74] threats, only one operator listed and provided justification for the threshold values in its IM plan.

[73] An example of a statistical test used by an interviewed operator is that an HCA would be considered susceptible to a threat if the length-averaged maximum likelihood of the threat in the HCA is at least one standard deviation above the mean value for all HCAs.

[74] Although PHMSA uses the term "elimination", a more appropriate word might be "dismissal." When an operator eliminates a threat for a particular pipeline segment, the operator is assuming that the pipeline segment is not susceptible to that threat.

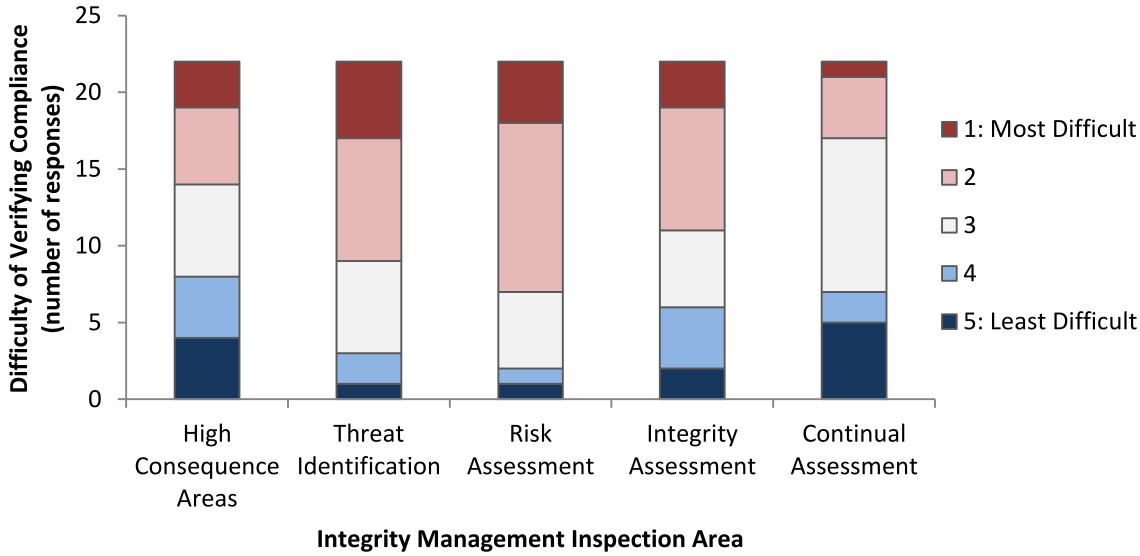


**Figure 18.** Difficulty of verifying compliance with IM regulations, by area, as rated by state inspectors (NAPSR, 2014)

Despite the need to correctly identify threats, ASME B31.8S provides little guidance on what criteria operators should use. It provides explicit threat identification criteria for only one threat type (stress corrosion cracking). For the other eight threat types, either no criteria are given, or the guidance is often vague. For example, for the equipment threat, ASME B31.8S notes that "certain gasket types are prone to premature degradation," but neither a listing of gasket types is provided, nor are resources suggested where operators could find this information. Likewise, for the weather-related/outside force threat, ASME B31.8S notes that the "pipe may be susceptible to extreme loading" where the pipeline "traverses steep slopes," but does not define what slopes would be considered "steep."

Several pipeline inspectors interviewed for this study stated that they thought it was too easy for operators to eliminate threats from pipeline segments. This opinion is supported by PHMSA inspection data. Through December 2010, in the first round of federal IM program inspections conducted after the IM regulations went into effect, "specific threats for a particular pipeline segment were eliminated from consideration without adequate justification" was cited as an issue in 30 percent of inspections (PHMSA 2011a). For state-conducted IM inspections, threat elimination[75] was tied for the seventh most frequently noted issue of 188 issue areas (PHMSA 2011a). The NTSB concludes that inappropriate elimination of threats by pipeline operators can result in undetected pipeline defects. The NTSB recommends that PHMSA establish minimum criteria for eliminating threats, and provide guidance to gas transmission pipeline operators for documenting their rationale for all eliminated threats.

[75] See PHMSA's *Gas Integrity Management Inspection Manual: Inspection Protocols with Results Forms*, C.01.d: "Verify that the approach incorporates appropriate criteria for eliminating a specific threat for a particular pipeline segment."

Although the problem of inappropriate threat elimination has surfaced in NTSB-investigated accidents, PHMSA inspections, and discussions with federal and state pipeline inspectors, a lack of data makes it difficult to quantitatively evaluate the prevalence of this problem across all pipeline incidents. PHMSA requires pipeline operators to identify the cause of an incident on PHMSA Form F7100.2, Incident Report Form, and include information on previous integrity assessment actions (such as the use of ILI or pressure testing). However, PHMSA does not require operators to state the results of these previous assessments (such as the discovery of external corrosion defects that need repair), nor does PHMSA require operators to indicate if the incident cause was previously identified as a threat for the pipeline segment involved in the incident. Additionally, the causes available for pipeline operators to choose from do not map directly to the 9 threat categories or 21 root causes specified in ASME B31.8S. The NTSB concludes that the prevalence of inappropriate threat elimination as a factor in gas transmission pipeline incidents cannot be determined because PHMSA does not collect threat identification data in pipeline incident reports.

### 4.3.3 Interactive Threats

Pipeline operators are required to consider interactive threats (which are defined as two or more threats that, when acting together on a pipeline segment, result in a greater risk than the sum of their individual risk contributions). However, ASME B31.8S provides very little guidance to operators on how to identify or evaluate interactive threats and simply states, "The interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) shall also be considered. An example of such an interaction is corrosion at a location that also has third-party damage."

The approaches to handling interactive threats varied considerably among the pipeline operators interviewed for this study. Although most operators included a matrix or list of threat interactions they considered in their IM plans, the interactions considered were not consistent among these operators, and no operators considered the simultaneous interaction of more than two threats. Additionally, several operators' IM plans stated that, by simply summing the risks of individual threats into an overall risk score (as illustrated in section 4.4.1), threat interactions were accounted for. However, calculating interactive threat risks in this way may result in an overall risk score that is equal to, not greater than, the sum of each threat's individual contribution to risk.

Federal and state regulators often cite inadequate consideration of interactive threats as a concern in their inspections of IM programs. Through December 2010, in the first round of federal IM program inspections conducted after the IM regulations went into effect, "interactive threats from different threat categories [that] were not adequately evaluated" was the issue cited with the most frequency, being noted in 56 percent of inspections (PHMSA 2011a). For state-conducted IM inspections, interactive threats[76] was the fourth most frequently noted issue

[76] See PHMSA's *Gas Integrity Management Inspection Manual: Inspection Protocols with Results Forms*, C.01.c: "Verify that the operator's threat identification has considered interactive threats from different categories (for example, manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage)."

of 188 issue areas (and the most frequently noted issue within the threat identification, data integration, and risk assessment area)(PHMSA 2013c). Additionally, the pipeline industry has acknowledged that interactive threat modeling needs improvement. The Interstate Natural Gas Association of America (INGAA) notes that "the ASME document does not provide specific guidance on models and methodologies" for consideration of interactive threats and that current methodologies used by industry "have inherent limitations" (INGAA 2013). The NTSB concludes that the inadequate evaluation of interactive threats is a frequently cited shortcoming of IM programs, which may lead to underestimating the true magnitude of risks to a pipeline. The NTSB recommends that PHMSA update guidance for gas transmission pipeline operators and inspectors on the evaluation of interactive threats. This guidance should list all threat interactions that must be evaluated and acceptable methods to be used.

Similar to inappropriate threat elimination, a lack of data also makes it difficult to quantitatively evaluate the degree to which interactive threats impact pipeline failures. PHMSA requires pipeline operators to select an apparent cause for each incident (for example, external corrosion) on PHMSA Form F7100.2, Incident Report Form. Although multiple sub-causes may be selected (for example, galvanic, atmospheric, stray current, microbiological, and selective seam corrosion within the category of external corrosion), only one primary cause may be selected. Secondary, contributing, and root cause information may only be included in the incident narrative. The NTSB concludes that the prevalence of interactive threats in gas transmission pipeline incidents cannot be determined because PHMSA does not allow operators to select multiple, interacting root causes when reporting pipeline incidents.

## 4.4 Risk Assessment

Once threats are identified for each pipeline segment within an HCA, the risk due to those threats must be evaluated. Figure 19 shows the steps within the risk assessment process. First, depending on the type of model used (SME, scenario-based, relative, or probabilistic), a likelihood or probability of failure is calculated for each threat applicable to each HCA segment. This is combined with the consequence of failure to determine the total risk for each HCA segment, which then allows segments to be ranked according to their risk.

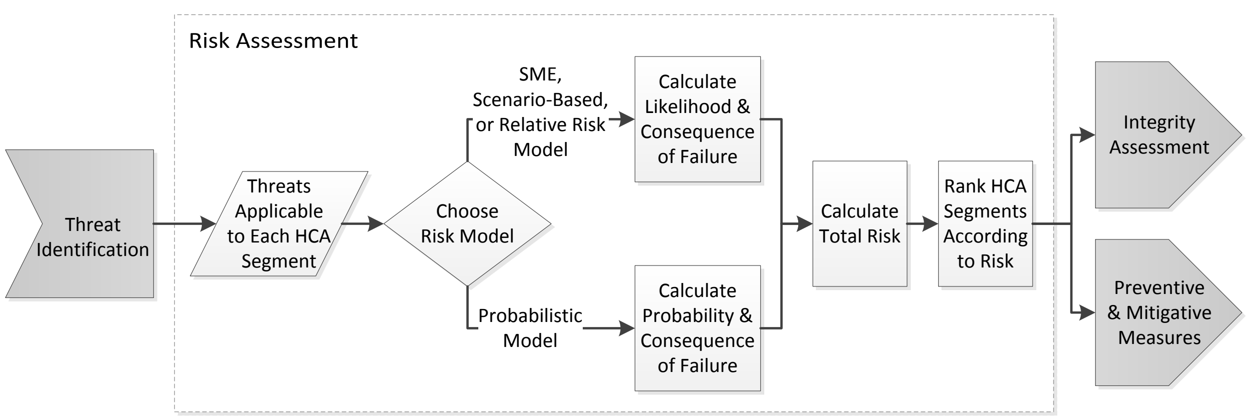


**Figure 19.** Risk assessment flowchart

### 4.4.1 Current Practices

Six of the seven operators interviewed for this study employed models that most closely fit the definition of a relative risk assessment model; the other operator characterized its risk assessment method as a SME approach. However, the distinction between these two approaches is small. The relative risk models all had a large SME component to their development, implementation, and validation, and the SME approach produced relative risk rankings. Most interviewed operators contracted with an outside consultant to help develop their risk model.

Although the relative risk models used by the operators interviewed for this study varied in their details, they shared a similar overall approach. This risk model structure is illustrated in figure 20. First, for each of the nine threat categories, factors are identified which impact the likelihood of failure due to that threat. These factors are combined (usually with weighting factors, which are estimated values indicating the relative importance or impact of each item in a group compared to the other items in the group) to produce an overall likelihood of failure for each threat on a pipeline segment. The nine threat likelihoods are then combined (usually with weighting factors) to produce a total likelihood of failure for each pipeline segment. Finally, this total likelihood of failure is multiplied by a consequence of failure value, resulting in the total risk for an individual pipeline segment. These risk values are then considered individually or aggregated over a longer section of pipeline and ranked for use in prioritizing pipeline assessments and P&M measures.

For example, the relative likelihood of external corrosion might be a function of the pipe material, pipe coating, corrosion protection system, surrounding soil characteristics, and other factors. Each of these factors is evaluated based on known or estimated data, engineering models, and SME input. A rating scale is often used to convert qualitative data (for example, pipe coating material or soil type) into quantitative data. The scores for pipe material, pipe coating, corrosion protection, soil, and other factors are then combined (usually with weightings) to calculate the likelihood of failure due to external corrosion. Likelihoods for the other eight threat categories are calculated in a similar manner, and an overall failure likelihood is determined by combining (usually with weightings) the nine individual threat likelihoods. For each segment, the overall likelihood is then multiplied by a consequence of failure value—itself a combination of consequence factors and weightings—to calculate the overall segment risk.

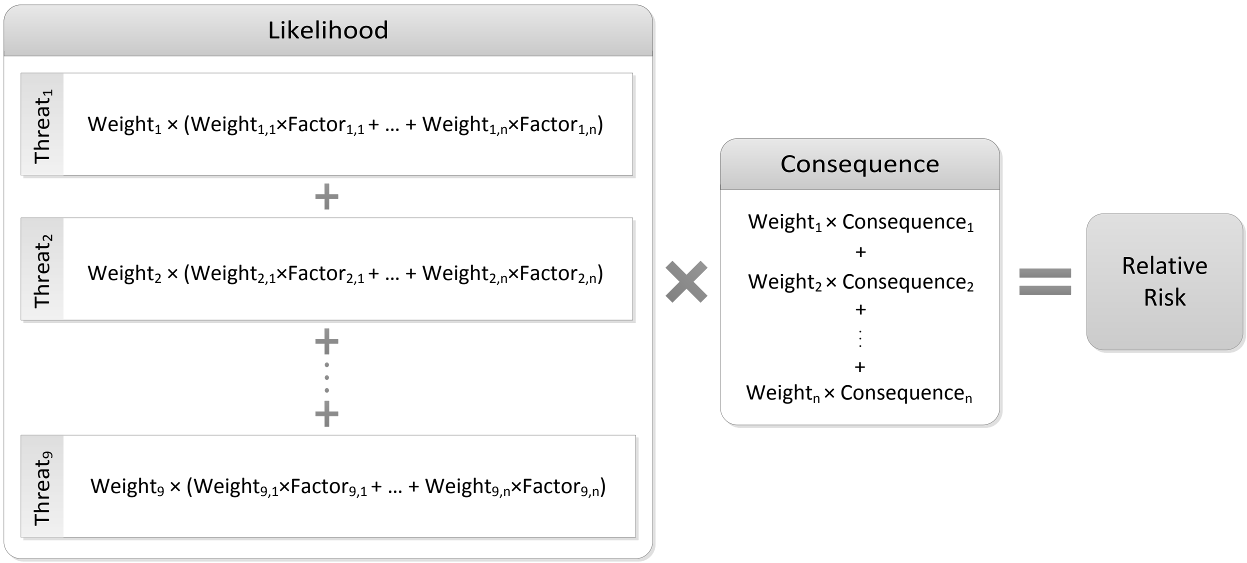


**Figure 20.** Notional schematic of relative risk assessment model

In total, it is not unusual for the risk models used today to contain hundreds of individual risk factors, each with their own rating scales and weightings. This makes it difficult for a single person, such as an inspector, to evaluate these models. Perhaps not surprisingly, when state inspectors were asked to rank the difficulty of inspecting elements of operator's IM programs, risk assessment was second only to threat identification in the number of inspectors ranking it as the most difficult element to inspect, as shown previously in figure 18. During interviews, several inspectors remarked that they felt they did not have the expertise or authority to challenge pipeline operator personnel about their risk models.

Because an operator's risk assessment results dictate their methods and schedules for conducting integrity assessments and applying P&M measures, it is critical that inspectors be able to evaluate the soundness of each operator's risk model. The PHMSA gas inspection protocol area C specifically deals with risk assessment. According to question C.03.C, the inspector is expected to "verify that the risk assessment explicitly accounts for factors that could affect the likelihood of a release and for factors that could affect the consequences of potential releases, and that these factors are combined in an appropriate manner to produce a risk value for each pipeline segment." The inspector is also asked to verify that the risk assessment approach "contains a defined logic and is structured to provide a complete, accurate, and objective analysis of risk." Question C.04.A further requires the inspector to "verify that the validation process includes a check that the risk results are logical and consistent with the operator's and other industry experience." However, the feedback from the NAPSR survey and NTSB interviews indicates that many inspectors feel they are not suitably equipped to perform these tasks. The NTSB concludes that inspectors lack training to effectively verify the validity of an operator's risk assessment. Therefore, the NTSB recommends that PHMSA develop and implement specific risk assessment training for inspectors in verifying the technical validity of risk assessments that operators use.

Validation of risk assessment results is typically a manual, qualitative process. An individual or team of engineers and SMEs from the pipeline operator will review pipeline segment risk rankings annually, often focusing on the highest-ranked and lowest-ranked segments. They will confirm that the risk model reflects operator-specific and industry-wide actual operating experience (such as leaks, incidents, and integrity assessment results) and confirm that the risk rankings match their mental model for pipeline risk. Risk model weighting factors will then be adjusted as necessary.

Finally, several of the interviewed pipeline operators were currently in the process of, or considering, moving toward a more probabilistic model. These operators cited the following advantages of using a probabilistic risk model:

- presentation of risk in units more easily interpreted by company decision-makers
- ability to set a target risk level
- ability to perform cost-benefit calculations for P&M measures, alternative assessment methods, and changes to the scope and schedule of assessments
- better justification to state regulators when proposing new gas service rates (for those gas transmission operators that also operate distribution systems)

However, many of these operators also stated that progress toward this goal is currently impeded by a lack of sufficient data. Specifically, operators expressed a desire for:

- the ability to select multiple root causes for an incident in PHMSA incident reports
- data describing incidents that do not meet the threshold for reporting to PHMSA, including their root cause(s)
- data to establish the prevalence of each failure mechanism and the frequency for which a failure mechanism leads to failure

While probabilistic risk models have many potential business advantages, the safety benefits of probabilistic risk models versus relative risk models, SME models, or scenario-based models has not been extensively studied. However, ASME B31.8S does note that probabilistic risk models are “the most complex and demanding with regard to data requirements.” The NTSB concludes that many pipeline operators do not have sufficient data to successfully implement probabilistic risk models. The NTSB recommends that the American Gas Association (AGA) and INGAA work together to collect data that will support the development of probabilistic risk assessment models, and share these data with gas transmission pipeline operators.

### 4.4.2 Weighting Factors

Weighting factors are used in relative risk models to allow the risk contributions of different threats—and of different risk factors within threats—to be summed into a total risk value without having a common unit of measure (for example, fatalities per mile per year, which might be used in a probabilistic risk model). For pipeline operators who purchase risk assessment software from an outside company, default values for these weighting factors are typically set by the software vendor. These default values are then adjusted by the operators’ IM engineers and SMEs to reflect both their intuition about the major drivers of risk for their pipelines as well as the operational history of their pipeline systems, including past failures. ASME B31.8S emphasizes the importance of weighting factors in risk models:

> All threats and consequences contained in a relative risk assessment process should not have the same level of influence on the risk estimate. Therefore, a structured set of weighting factors shall be included that indicate the value of each risk assessment component, including both failure probability and consequences. Such factors can be based on operational experience, the opinions of subject matter experts, or industry experience.

Based on previous failure experience, the risk models used by the operators interviewed for this study generally weighted the external corrosion and third-party damage threats very highly compared to the other seven threat categories. Although some operators with multiple pipeline systems used different weightings for different parts of their pipeline network (for example, to better model the risks of a recently-installed pipeline vs. an older pipeline), most operators used the same threat weightings for all of their transmission assets. By using system-wide weightings that emphasize only a few of the nine threat categories, high-risk segments susceptible to other threats (for example, an external forces threat where a pipeline crosses a fault line) may not be adequately accounted for in risk rankings. However, there has been little research to date on the appropriate use of risk model weighting factors.

### 4.4.3 Consequence of Failure Calculations

ASME B31.8S states that operators shall consider at least the following factors in their consequence of failure calculations: population density, proximity of the population to the pipeline, proximity of populations with limited or impaired mobility, property damage, environmental damage, effects of unignited gas releases, security of the gas supply, public convenience and necessity, and the potential for secondary failures.

Compared to likelihood of failure calculations, the consequence of failure models used by the pipeline operators interviewed for this study were relatively simple. All models used public safety (often using population density or class location as a proxy) as the primary factor affecting the consequence of failure. A few also included business considerations (such as the number of customers affected by a gas outage) and environmental considerations (such as water crossings and environmentally sensitive areas). However, none included emergency response factors, such as response time, emergency shutoff valve placement, or the presence of remotely-operated or automatic shutoff valves.

The safety benefits of quickly responding to pipeline incidents has been primarily analyzed in the context of valve placement (including remote control valves and automatic shutoff valves) and the effects of reducing the time to stop the flow of gas after a rupture (examples: RSPA 1999, Sulfredge 2007, ASME 2011, Qureshi 2012). Existing studies have determined that most casualties and property damage are incurred in the first few minutes following a pipeline rupture and that delays in stopping the gas flow after a rupture and fire have little effect on the size of the area thermally impacted. However, these studies also acknowledge that, while difficult to quantify, there may be additional risks in delaying gas shutoff following a fire, including additional property damage and reduced site access for first responders. The NTSB accident report for the San Bruno pipeline incident noted that the lack of nearby automatic shutoff or remote control valves prevented the operator from stopping the flow of gas sooner, which contributed to the severity and extent of property damage and increased risk to the residents and emergency responders. In an earlier gas transmission incident that occurred in Edison, New Jersey in 1994, the NTSB also found that a delay in stopping the flow of gas exacerbated damage to nearby property (NTSB 1995).

### 4.4.4 Risk Model Outputs and Aggregation of Risk Metrics

The operators interviewed for this study varied widely in the types of risk assessment metrics used for prioritizing assessments and P&M measures. Commonly-used metrics included:

- risk due to a single threat on a single segment
- total risk on a single segment
- length-weighted average risk aggregated over a longer section of pipeline spanning multiple segments (for example, an HCA, all pipe between two valves, or an entire pipeline system)
- maximum risk aggregated over a longer section of pipeline
- total risk aggregated over a longer section of pipeline

An advantage of aggregating risk over a longer distance is that assessments and P&M measures are often conducted over a larger distance rather than for a single pipeline segment. This allows company decision-makers to evaluate the merits of project alternatives to, for example, determine which option would "buy down" the most risk. However, a disadvantage of aggregate risk metrics is that they may obscure segments with high risks, especially if a length-weighted metric is used, and the high-risk segment is short relative to the total length of pipe under consideration. To illustrate this problem, Table 7 shows the mean and median length of HCAs, length of pipeline segments within an HCA, and number of segments within an HCA for a single operator interviewed in this study. This operator uses a length-weighted average risk value to rank HCAs for integrity assessment. However, each HCA is comprised of many shorter segments, each having its own risks. By aggregating risk to the HCA level, the risks of individual segments may be masked.

**Table 7.** HCA and segment length statistics for one gas transmission pipeline operator

| HCA Metric | Mean | Median |
|---|---|---|
| HCA Length (ft) | 3,551 | 2,165 |
| Length of segments in HCA (ft) | 47 | 20 |
| Number of segments in HCA | 27 | 12 |

Despite the importance of choosing an appropriate risk metric and risk aggregation method, there is little guidance available to operators concerning the safety implications of different risk metrics. Additionally, several of the pipeline operators interviewed for this study acknowledged that there was active debate within their IM organizations concerning the appropriate risk metrics to use.

In summary, the risk assessment approaches used by pipeline operators are very complex and diverse. The role of these risk assessments is paramount in an operator's IM program because the results and interpretations of the risk assessments are used by operators to guide their integrity assessment plans (such as prioritization and scheduling of assessments, as well as the determination of appropriate assessment tools and methods) and other P&M measures. However, how well these approaches perform, as well as their safety benefit, is unknown, due to the lack of data collected regarding these approaches. Currently, PHMSA does not require operators to indicate in incident reports which risk assessment approach they used for the pipeline segment involved in an incident. Therefore, the NTSB concludes that a lack of incident data regarding the risk assessment approach(es) used by pipeline operators limits the knowledge of the strengths and limitations of each risk assessment approach. The NTSB further concludes that whether the four approved risk assessment approaches produce a comparable safety benefit is unknown. Furthermore, because of the complex nature of these risk assessment approaches, it is a tremendous challenge for IM inspectors to evaluate their validity and performance. The NTSB concludes that sufficient guidance is not available to pipeline operators and inspectors regarding the safety performance of the four types of risk assessment approaches allowed by regulation, including the effects of weighting factors, calculation of consequences, and risk aggregation methods. The NTSB recommends that PHMSA evaluate the safety benefits of the four risk assessment approaches currently allowed by the gas IM regulations; determine whether they produce a comparable safety benefit; and disseminate the results of your evaluation to the pipeline industry, inspectors, and the public. The NTSB also recommends that PHMSA update guidance for gas transmission pipeline operators and inspectors on critical components of risk assessment approaches. Include (1) methods for setting weighting factors, (2) factors that should be included in consequence of failure calculations, and (3) appropriate risk metrics and methods for aggregating risk along a pipeline.

### 4.4.5 Qualifications of IM Personnel

Even for highly-structured and complex risk models, engineers and SMEs typically play a large role in their design, implementation, and validation. Although pipeline operators are required to include IM personnel qualifications in their IM plan, in practice, the qualifications listed for such personnel are quite vague. For example, Table 8 summarizes the qualifications required of the person responsible for risk assessment validation at each of the seven operators interviewed for this study. Only one operator listed any required training beyond a basic familiarity with the company’s IM program and the federal IM regulations. Additionally, despite the mathematical complexity of most risk models, only two operators listed mathematical or statistical knowledge as a requirement for this role. In the interviewed operators’ IM plans, qualifications for other threat identification and risk assessment roles were similarly inadequate. The NTSB concludes that professional qualification criteria for pipeline operator personnel performing IM functions are inadequate.

**Table 8.** Required qualifications for personnel responsible for risk assessment validation

| Operator | Title | Required Qualifications | | | |
|---|---|---|---|---|---|
| | | Education | Knowledge/Skills | Experience | Training |
| **A** | Risk SME | None listed | None listed | None listed | General training types described (such as seminars), but no specific requirements listed |
| **B** | Risk Management Engineer | Degreed engineer | None listed | IM in the pipeline industry | Yearly review of operator's IM plan; NACE CP1 and RSTRENG desired |
| **C** | Risk Engineer/Analyst | Bachelor's degree or higher in engineering, science, or related field | Statistics, structural reliability analysis, cost-benefit analysis, 49 CFR 192 Subpart O | Equivalent experience may be substituted for education requirement | Company IM program |
| **D** | Pipeline Integrity Engineer | Bachelor's degree in engineering | Physical sciences, engineering, mathematics sufficient to perform corrosion control and risk assessment | 5 years as an engineer, or equivalent | 49 CFR 192 Subpart O |
| **E** | Pipeline Integrity Engineer | None listed | None listed | None listed | None listed |
| **F** | Supervisor IM | High school degree or equivalent | Company policies and procedures, technical pipeline operations, company data sources, and 49 CFR Subpart O | 8 or more years in pipeline industry | Company IM program |
| **G** | None listed (validation is responsibility of committee) | None listed | None listed | None listed | None listed |

ASME B31.8S states that "the personnel involved in the IM program shall be competent, aware of the program and all of its activities, and be qualified to execute the activities within the program." However, 49 CFR §192.915 only requires qualifications for a subset of pipeline operator personnel. It states that an IM program must ensure that each supervisor "possesses and maintains a thorough knowledge of the integrity management program" and has "appropriate training or experience." This regulation also states that qualification criteria are required for persons involved in integrity assessments or who are responsible for P&M measures. Knowledge, training, and experience criteria are not explicitly required by 49 CFR §192 for those personnel involved in other facets of IM, including HCA identification, threat identification, and risk assessment. The NTSB recommends that PHMSA revise 49 CFR section 192.915 to require all personnel involved in IM programs to meet minimum professional qualification criteria.

## 4.5 Data Collection

To understand the prevalence of safety issues, relevant data must be collected. In this chapter, we identified some areas where data requirements are lacking and should be enhanced (see 4.1.4, 4.2,2, 4.3.2, and 4.3.3). These areas include:

1) HCA identification
2) HCA identification method
3) Information about risk assessment approaches
4) Information about elimination of threats
5) Information about interactive threats

HCA data is inherently geographic and should be addressed through the submission requirements of NPMS. The HCA identification method and risk assessment approach used by the operator are captured in the operator's IM plan. This information should be captured in PHMSA's annual reports. The NTSB recommends that PHMSA revise Form F7100.1, Annual Report Form, to collect information about which methods of HCA identification and risk assessment approaches were used. Because information about threat elimination and interactive threats is segment-specific, it is reasonable to capture this information in the incident report. The NTSB also recommends that PHMSA revise Form F7100.2, Incident Report Form, (1) to collect information about both the results of previous assessments and previously identified threats for each pipeline segment involved in an incident and (2) to allow for the inclusion of multiple root causes when multiple threats interacted. The NTSB further recommends that PHMSA develop a program to use the data collected in response to Safety Recommendations P-11-15 and P-11-16 to evaluate the relationship between incident occurrences and (1) inappropriate elimination of threats, (2) interactive threats, and (3) risk assessment approaches used by the gas transmission pipeline operators. Disseminate the results of this evaluation to the pipeline industry, inspectors, and the public annually.

## 4.6 Integrity Assessments

One of the core components of the IM program is integrity assessment, which is the inspection of the pipelines' integrity by the operators. Figure 21 shows the steps within the integrity assessment process. The method(s) used for an integrity assessment depend on the threats identified for each segment; each method can only assess particular threats, and some threats cannot be assessed at all (for these threats, P&M measures are used) (ASME 2004). If the pipeline segment is thought to be vulnerable to multiple threats, more than one integrity assessment method may be required. The schedule for integrity assessments depends on the HCA segment risk rankings developed during the risk assessment process.

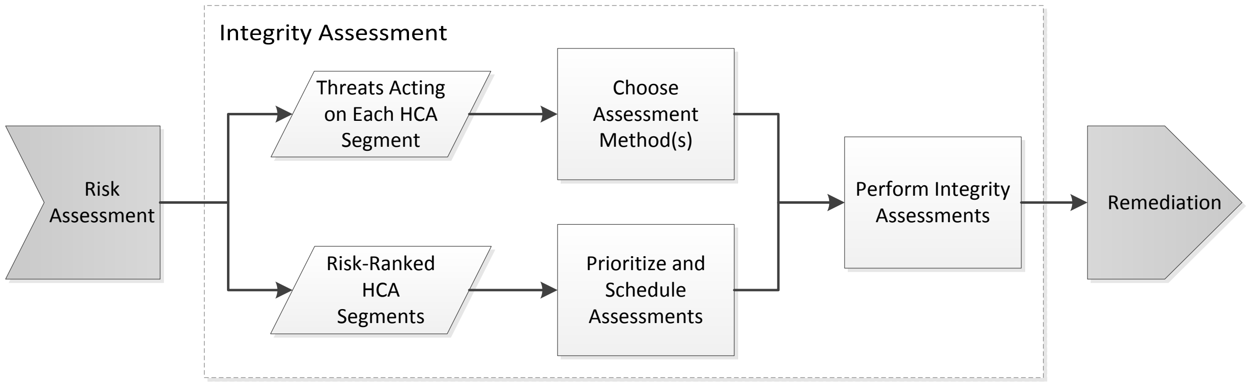


**Figure 21.** Integrity assessment flowchart

### 4.6.1 Integrity Assessment Methods

As discussed in chapter 1, there are four general sets of integrity assessment methods: ILI, pressure testing, direct assessment, and other inspection techniques. As noted before, all operators were required to have completed baseline assessments of all HCA pipelines by December 2012. Most operators are already performing the next round of required assessments. Because there are considerable differences in configurations and operational factors for interstate and intrastate pipelines, the assessment methods used are also different. Figure 22 shows the total miles of HCA pipelines assessed by all methods by operation type between 2010–2013, based on PHMSA's annual report data. For both interstate and intrastate pipelines, the total miles of integrity assessment peaked in 2012, the year by which 100 percent of all HCA pipelines were expected to be baseline assessed. In both cases, the proportion of HCA pipeline mileage being reassessed gradually increased from 2010–2013.

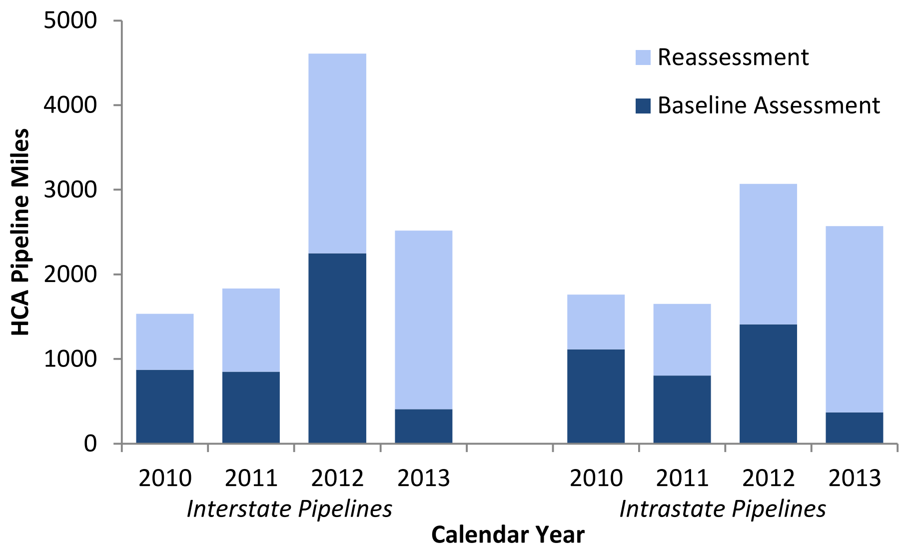


**Figure 22.** HCA pipelines baseline assessed or re-assessed by year and operation type (2010–2013)

From 2010–2013, 205,854 miles of interstate and intrastate pipelines were inspected by at least one integrity assessment method. Of these, 19,550 miles were HCA pipelines. Some pipelines might have been assessed more than once in this period or might have been assessed by more than one method.[77] Because PHMSA's annual report does not break down the inspected HCA pipeline mileage by integrity assessment methods, the comparison of the usage of integrity assessment methods and their efficiency is based on inspected mileage of all pipelines (not just HCA pipelines).

In general, there is a considerable difference between interstate and intrastate pipelines in terms of the assessment methods used. Figure 23 shows that 96 percent of assessed interstate pipeline mileages were inspected by ILI, while ILI was used for only 68 percent of assessed intrastate pipeline mileages, a 28 percentage point difference. Direct assessment methods represent 17 percent of all assessed intrastate pipeline miles, but only 2 percent of all assessed interstate pipelines.

Many factors influence the selection of the most appropriate integrity assessment method. Fundamentally, this should be driven by the threat identification and risk assessment processes. The appropriate integrity assessment method should be selected based on the risk rankings of specific threats along the pipeline segment. For example, a pipeline segment with high risk ranking of corrosion threat will have different options of integrity assessment methods compared to segment with high risk ranking of third party damage, Further, intrastate pipelines tend to be more urban, traverse more densely populated areas, and be closely tied to distribution systems. Therefore, there are operational factors that complicate the execution of ILI for these pipelines. In contrast, interstate pipeline segments are more rural and they tend to cover longer distances with configurations that are more feasible and economical to accommodate ILI. The NTSB concludes that the use of ILI as an integrity assessment method for intrastate pipelines is considerably lower than for interstate pipelines (68 percent compared to 96 percent) in part due to the operational and configuration differences. The NTSB also concludes that a much higher proportion of integrity assessments is conducted by direct assessment for intrastate pipelines than for interstate pipelines partly due to operational and configuration differences.

[77] Because a pipeline segment may be inspected by more than one integrity assessment method and it may have been inspected more than once during the 2010-2013 period, the mileage values do not represent unique pipeline mileage.

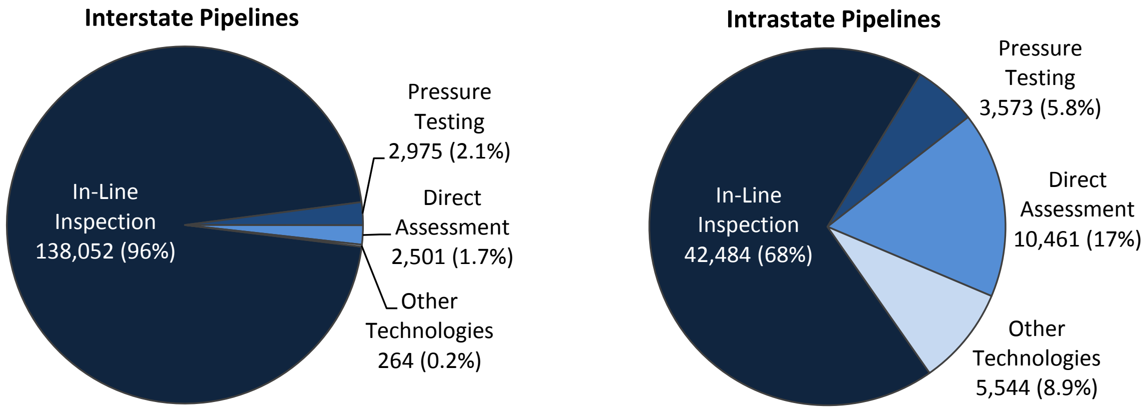


**Figure 23.** Total miles of interstate and intrastate pipelines by assessment tools (2010–2013)

### 4.6.2 Advantages of Using ILI

The IM requirement (49 CFR §192.921 for baseline assessments, 49 CFR §192.937 for reassessments) allows the operator to choose one of the four assessment methods when assessing the integrity of their pipelines. An operator's annual report includes information about the number of repaired anomalies that were identified by ILI, direct assessment, and other inspection techniques, along with pressure test failures (ruptures and leaks), both within an HCA segment and outside of an HCA segment.[78] Table 9 shows the anomaly count repaired per 1,000 miles assessed for all interstate and intrastate pipelines by the four assessment methods. It shows that ILI yields far more discoveries of anomalies that lead to repairs: 663 repairs per 1,000 miles assessed for ILI, compared to 264 for direct assessment, 35 for pressure tests, and 26 for other techniques. The NTSB concludes that, of the four integrity assessment methods, ILI yields the highest per-mile discovery of anomalies that have the potential to lead to failure if undetected.

**Table 9.** Anomalies repaired per 1,000 miles assessed for interstate and intrastate pipelines by assessment tool (2010–2013)

| Assessment Tool | Anomalies Repaired (per 1,000 miles) | | |
|---|---|---|---|
| | Assessed Interstate Pipelines | Assessed Intrastate Pipelines | Average for All Assessed Pipelines |
| **In-line Inspection** | 649 | 709 | 663 |
| **Pressure Test** | 21 | 46 | 35 |
| **Direct Assessment** | 86 | 307 | 264 |
| **Other Techniques** | 11 | 27 | 26 |
| **Average for All Assessment Tools** | **625** | **542** | **600** |

[78] PHMSA's Form 7100.1, Annual Report Form, part F questions 2b, 3b, 4b, and 5b provide information for these anomalies and pressure test failures whereas questions 1e, 3a, 4a, and 5a provide total mileage of pipe inspected by the four integrity assessment methods.

As discussed in ASME (2004), ILI is appropriate and effective in detecting defects on pipeline segments that are susceptible to internal and external corrosion, stress corrosion cracking, third party damage, and mechanical damage threats. Ongoing research in ILI technology and techniques continues to lead to new developments. For example, Westwood et al. (2014) describe the development of an ILI tool for the purpose of detecting defects attributed to geotechnical hazards, a natural force threat. This technology was not previously available. Therefore, the NTSB concludes that ILI is able to inspect the integrity of the pipeline segments susceptible to multiple threats.

49 CFR § 192.150 states that with some exceptions, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented ILI devices. Furthermore, justification of excluding the use of ILI as an integrity assessment tool must be provided by the operator. With the advancement of ILI tools and technology, such as the introduction of robotic devices, it is expected that more and more pipelines will become “piggable,” or able to accommodate ILI tools. INGAA and its members recognize that ILI is the most predictive and preferred tool, and have invested heavily in making their pipeline systems piggable by both making more of the pipeline system conducive to ILI and improving the capability of tools (INGAA 2012). The NTSB concludes that improvements in ILI tools allow for the inspection of gas transmission pipelines that were previously uninspectable by ILI. While it is up to the operators to choose the most appropriate method for their pipelines, it is clear that ILI is the best choice as an integrity assessment tool. The NTSB supersedes recommendation P-11-17 to PHMSA, which required that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines with the following recommendation: The NTSB recommends that PHMSA require that all natural gas transmission pipelines be capable of being in-line inspected by either reconfiguring the pipeline to accommodate ILI tools or by the use of new technology that permits the inspection of previously uninspectable pipelines; priority should be given to the highest risk transmission pipelines that considers age, internal pressure, pipe diameter, and class location. The NTSB recommends that AGA and INGAA work together to develop and implement a strategy for increasing the use of ILI tools as appropriate, with an emphasis on intrastate pipelines. The NTSB further recommends that PHMSA revise Form F7100.1, Annual Report Form, to collect information on the mileage of both HCA and non-HCA pipelines that can accommodate ILI tools.

Even if the pipeline segment is configured to accommodate ILI, the operators may still choose not to use such tools due to operational complications (such as low operating pressure, low flow, or absence of flow).[79] INGAA (2012) also states that many of the intrastate operators (AGA’s members) are single source lines (that is, the only source of natural gas to customers and communities), and single source pipelines cannot be shut down without disrupting customer supply. The NTSB concludes that operators may limit the use of ILI due to operational complications. The NTSB recommends that PHMSA identify all operational complications that

[79] In Form 7100.2, Incident Report, Part E question 5.e lists the following operational factors that may complicate the execution of an ILI tool run: excessive debris or scale, wax, or other wall build-up, low operating pressure(s), low flow or absence of flow, incompatible commodity, and other.

limit the use of ILI tools in piggable pipelines, develop methods to eliminate the operational complications, and require operators to use these methods to increase the use of ILI tools.

### 4.6.3 Limitations of Direct Assessment

Direct assessment is used to evaluate pipeline corrosion threats only. Operators typically identify sections of the pipeline that should be inspected using direct assessment by reviewing pipeline records, indirect inspection results, mathematical models, and environmental surveys. Likely locations of corrosion are then excavated and the exposed pipe is examined using visual, ultrasonic, or other non-destructive techniques. Unlike ILI and pressure tests, in which the integrity of the entire pipeline segment is examined, direct assessment methods (including external corrosion direct assessment, internal corrosion direct assessment, and stress corrosion cracking direct assessment), assess only the integrity of selected pipe areas where the operator suspects a problem. Therefore, direct assessment provides information only about threats that the operator is specifically looking for at locations where the threats are suspected.

Direct assessment is the element of an IM program that results in the most compliance issues found during federal and state IM inspections, comprising 20 percent of all issues found as reported in the two progress reports (see figure 15). In terms of enforcement actions, direct assessment ranks second behind threat identification (see figure 16). However, it has the highest count of citations that lead to proposed penalties. Direct assessment is also frequently an issue cited in state IM inspections. This is not unexpected since a much higher percentage of intrastate pipelines are assessed by direct assessment (see figure 22).

Between 2010 and 2013, five HCA incidents were caused by failure mechanisms that should have been discovered by one of the four integrity assessment methods. Four of five incidents involved HCA pipeline segments that were integrity assessed by direct assessment with only one actually excavated for examination (see Table 6). Because direct assessment methods were used in these four HCA pipeline segments, corrosion was identified as the threat to which these segments were most susceptible. However, as Table 6 shows, three out of these four incidents were attributed to apparent causes other than corrosion. Therefore, the integrity assessment method chosen for these pipeline segments were not suitable to detect the actual vulnerabilities.

As discussed in section 3.6.1, especially for intrastate pipelines (all five HCA significant incidents listed in Table 6 are intrastate pipeline incidents), operators chose to use direct assessment most often (three out of the five incidents involved the use of direct assessment alone). This could be the result of overemphasizing the corrosion threat in the operators' risk analysis approach, including threat identification and weighting methods, or this could be the result of pipeline configurations or operational complications preventing the use of ILI. Choosing to use direct assessment for a pipeline segment therefore requires justification for assigning a very high relative risk to corrosion threats. If the configuration of the pipeline segment is deemed unable to accommodate ILI tools or if there are operational factors limiting its execution, the operators can use direct assessment as the approved and appropriate integrity assessment method for the pipeline segment. Unlike pressure tests and ILI, direct assessment can only detect defects associated with corrosion and covers only specific locations selected by the operator. Even when direct assessment is the most appropriate integrity assessment method for the pipeline segment due to the threat of corrosion and other factors that prohibit the use of ILI, the effective execution of direct assessment relies on very specific decisions including the selection of the most appropriate location along the pipeline segments for excavation and direct examination (see section 1.4.4). Therefore, only a small sub-segment is directly examined. This suggests that more uncertainty about direct assessment is introduced due to the need to accurately select direct assessment examination locations.

The NTSB concludes that there are many limitations to direct assessment, including that (1) it is limited to the detection of defects attributed to corrosion threats, (2) it only covers very short sub-segments of the pipeline, (3) it relies on the operator's selection of specific locations for excavation and direct examination, and (4) it yields far fewer identifications of anomalies compared to ILI. In comparison, ILI and pressure testing assess the entire pipeline segment (not just a sub-segment) and are capable of detecting defects associated with multiple threats. These tools provide an added safeguard if a threat is misidentified or if other deficiencies exist in the risk analysis processes. The NTSB further concludes that the selection of direct assessment by the pipeline operator as the sole integrity assessment method must be subject to strict scrutiny by the inspectors due to its numerous limitations. Therefore, the NTSB recommends that PHMSA develop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines.

## 4.7 Continual Assessment and Data Integration

### 4.7.1 Use of Risk Assessment

Among the pipeline operators interviewed for this study, considerable variation existed regarding the frequency at which risk assessment was conducted, and the applications for which the risk assessment model was used. At some operators, risk assessment was only conducted once per year. This frequency satisfied federal regulations while not introducing unwanted disturbances into established business cycles (for example, yearly budgeting and selection of mitigation projects). One of the operators was skeptical of the usefulness of risk assessment, stating that because baseline assessment prioritization has been completed and regular assessment schedules have been established, there is little benefit to continually updating risk. Other operators used their risk models much more extensively and more frequently. For example, these operators were using their risk model as a "what-if" tool to evaluate alternative threat mitigation strategies to determine which were most cost effective.

### 4.7.2 Data Integration Guidance

Data integration is the process of assembling and evaluating all relevant information regarding the integrity of an operator's pipelines. It is a sub-element of the threat identification, risk assessment, and data integration IM program element. Figure 15 (in section 4.2.1) illustrates that both state and federal inspectors found a high frequency of compliance issues in this program element during the IM inspections. According to PHMSA's state IM progress report (PHMSA 2013c), specific compliance issues in the data gathering and integration areas included:

- Verifying that the operator has checked the data for accuracy
- Verifying that individual data elements are brought together and analyzed in their context such that the integrated data can provide improved confidence with respect to

determining the relevance of specific threats and can support an improved analysis of overall risk

- Verifying that the operator's program includes measures to ensure that new information is incorporated in a timely and effective manner
- Verifying that the operator has assembled data sets for threat identification and risk assessment according to the requirements
- Verifying that the operator has utilized the data sources

PHMSA's gas IM FAQ 240 states that "the analytical process considering the synergistic effect of multiple and/or independent facts or data constitutes data integration."[80] Section 4 of ASME B31.8S provides guidance on how to gather, review, and integrate data. The strength of an effective IM program lies in its ability to merge and utilize multiple data elements obtained from several sources to provide an improved confidence that a specific threat may or may not apply to a pipeline segment. The desired safety benefit of data integration is the improved analysis of overall risk.

Data quality is another critical component of an IM program. Section 4.2.4 discussed the issue of uncertainty and limitations associated with position precision and accuracy of geospatial data (such as pipeline centerline data and structure data). As demonstrated in the San Bruno incident, missing data and erroneous assumptions about data quality and uncertainties resulted in inadequate risk analysis. To account for uncertainties, PHMSA requires operators to assume conservative values for risk factors when data is unknown. However, in none of the risk models used by operators interviewed for this study were uncertainties explicitly included in risk model outputs. Therefore, although operators can categorize their pipeline segments by risk, it is impossible for operators to determine if the difference in risk between two pipeline segments is statistically significant. Additionally, this makes it difficult for inspectors to evaluate the accuracy of a risk model.

### 4.7.3 Use of GIS in Data Integration

As noted in section 4.2.3, all the operators interviewed use GIS extensively. Elliott and Anderson (2012), Adler and Beets (2012), and McCool (2014) illustrate some examples of GIS data integration. To integrate various types of data, including integrity assessment data, pipeline attributes (such as materials, diameter, and MAOP) must be referenced using a unified system. GIS is capable of linking multiple types of data with or without the geographic component. Most of the operators, researchers, and inspectors interviewed see GIS as the ideal data integration tool. Many geospatial and risk management companies provide both data and services that assist pipeline operators in that regard. In fact, most information extracted and analyzed by companies that provide ILI data distribute their products to their clients in a GIS data format that is compatible with the client's in-house GIS system. Section 4.5 of ASME B31.8S discusses how GIS can be used in integrating data.[81]

[80] See PHMSA Gas Transmission Integrity Management FAQ 240: "What must I do for 'data integration'?"

[81] Specifically, ASME B31.8S, section 4.5 states, "Graphical integration can be accomplished by loading risk-related data elements into an MIS/GIS system and graphically overlaying them to establish the location of a specific threat."

The data model is an important component of effective data integration for pipeline IM. Currently there are three very similar data models adopted by the pipeline industry: Integrated Spatial Analysis Techniques (ISAT), ArcGIS Pipeline Data Model (APDM), and the Pipeline Open Data Standard (PODS) pipeline data model. All operators interviewed use one of these three data models. These data models provide the database architecture pipeline operators use to store critical information and analyze data about their pipeline systems, and manage this data geospatially in a linear-referenced database, which can then be visualized in any GIS platform. Typical information stored in a PODS database includes: centerline location, pipeline materials and coatings, MAOP, cathodic protection, facilities and inspection results, pressure test results, ILI results, close-interval survey results, external records, risk analysis methods, and results (PODS 2014). There is an industry-wide synergetic effort to bring PODS and the APDM together.[82] Therefore, the pipeline operators are familiar with how GIS is enhancing their capability to improve data integration. However, PHMSA does not require the use of GIS, stating in IM FAQ 240, "GIS systems can be significant aids in performing data integration, but use of these systems is not required. The models used for risk analyses required by the rule can also be a valuable tool for performing data integration. In some cases, use of subject matter experts (SME) may be sufficient." The FAQ simultaneously stresses that GIS can be a "significant aid," while indicating that the use of SMEs is acceptable without explaining in what capacity SMEs can be used in data integration.

During our interviews with the pipeline operators as well as with geospatial companies, one common theme expressed was the desire of using GIS to provide operators with a single source of authoritative data accessible throughout all parts of a gas transmission company. Many operators expressed frustration with having multiple data systems relevant to IM across different divisions within the company. One operator showed that their GIS capabilities allow the IM division to maintain version control of the company's authoritative pipeline data and to share this information easily between safety, asset management, and local facility offices. This data was shared across the entire company, from the chief executive officer to the local engineer at the pipeline facilities. The dissemination of such data ensures all employees have a stake in the overall integrity and safety of the pipeline systems. Such a desire was common among the operators interviewed. The NTSB concludes that pipeline operators view GIS as the preferred tool for effective data integration, as it can be used as a system of records and a source of authoritative data. The NTSB recommends that PHMSA develop and implement a plan for all segments of the pipeline industry to improve data integration for IM through the use of GIS.

## 4.8 Overall IM Inspection Process

The overall goal of the gas transmission pipeline IM rule is to minimize the risk of gas transmission pipeline failures in HCAs. As discussed throughout this chapter, IM programs are complex and require expert knowledge and integration of multiple technical disciplines beyond engineering and material science knowledge specific to the pipeline industry. These disciplines

[82] The PODS ESRI Spatial Implementation is essentially identical in content to the PODS Relational Pipeline Data Model, but was specifically developed as a geodatabase for implementation on the ESRI platform. ESRI is the company that designed APDM.

include GIS, data management, remote sensing, probability and statistics, process safety, and risk management. To develop and operate an effective IM program, pipeline operators must employ professionals skilled in each of these disciplines, as well as people who can integrate the various elements of an IM program into a cohesive whole.

Oversight and evaluation of IM programs is accomplished by federal and state inspectors, who conduct inspections of a pipeline operator's IM program. To perform effective IM oversight, inspectors at PHMSA and state pipeline safety agencies must have knowledge of all of the associated disciplines involved in IM programs, be aware of the unique characteristics of the pipelines within their jurisdiction, and know the thresholds for regulatory compliance. Only then can inspectors question or challenge operators on the assumptions, processes, and models used in their IM programs. However, without extensive training, it is difficult for any one person to possess this knowledge. Moreover, the federal regulations specifying the required elements of IM programs are often vague, due to a desire to allow operators flexibility in how to satisfy these regulations. This regulatory flexibility puts an additional burden on the inspectors, because detailed guidance on IM program inspections, regulatory compliance, and noncompliance is insufficient. Furthermore, IM program inspections are labor-intensive and time-consuming, usually requiring significant preliminary preparation and several days to complete. While most IM inspections are conducted by a team, it is not uncommon for inspectors, especially at the state level, to work alone.

The inspection protocol is extensively used in ensuring compliance to the IM gas regulations by pipeline operators. Even though PHMSA inspectors have migrated to the integrated inspection approach with the Inspection Assistant software, the basic structure of the IM inspection process and the relevant inspection questions largely follow the inspection protocol. Additionally, the inspection protocol is the only method used by state inspectors. Although operator-specific knowledge and characteristics are the main drivers for the flexibility deliberately put in place in the gas IM regulations, there is tremendous commonality in IM plans and their implementations among operators, regardless of their operation types (whether they operate interstate and/or intrastate pipelines). Opportunities exist that may allow for a more centralized compliance auditing process to take place. For example, whether an operator has a compliance issue with including all relevant information about identified sites or whether the risk assessment approach used is properly calibrated may be better determined by centralized specialists whose expertise and training allow them to perform these evaluations consistently. In this report, the NTSB made numerous recommendations to PHMSA to strengthen resources, such as guidance documents and mentorship opportunities, to clarify the gas IM requirements. A larger question remains: Is the overall IM inspection process producing the safety benefit that the gas IM regulations intended to produce? To answer this question, an evaluation of the overall IM inspection process may be warranted. The elements of such an evaluation may include but should not be limited to: (1) the overall effectiveness of the inspection protocol and the integrated inspection approach; (2) the strength of each individual program element laid out in the inspection protocol and the integrated inspection approach; (3) the strengths and weaknesses of different IM inspection approaches used by the states; (4) the effectiveness of using FAQs for clarification and guidance; (5) the distribution of IM inspection workload and foci between federal and state inspectors.

# 5 Conclusions

## 5.1 Findings

1. There has been a gradual increasing trend in the gas transmission significant incident rate between 1994–2004 and this trend has leveled off since the implementation of the integrity management program in 2004.

2. From 2010–2013, gas transmission pipeline incidents were overrepresented on high consequence area pipelines compared to non-high consequence area pipelines.

3. While the Pipeline and Hazardous Materials Safety Administration's gas integrity management requirements have kept the rate of corrosion failures and material failures of pipe or welds low, there is no evidence that the overall occurrence of gas transmission pipeline incidents in high consequence area pipelines has declined.

4. Despite the intention of the gas integrity management regulations to reduce the risk of all identified threats, high consequence area incidents attributed to causes other than corrosion and material defects in pipe or weld increased from 2010–2013.

5. Despite the emphasis of integrity management programs on time-dependent threats, such as corrosion, gas transmission pipeline incidents associated with corrosion failure continue to disproportionately occur on pipelines installed before 1970.

6. From 2010–2013, the intrastate gas transmission pipeline high consequence area incident rate was 27 percent higher than that of the interstate gas transmission pipeline high consequence area incident rate.

7. Approaches used during integrity management inspections of gas transmission pipelines conducted in state inspections vary among states and whether this variability affects the effectiveness of integrity management inspections has not been evaluated.

8. The Pipeline and Hazardous Materials Safety Administration (PHMSA)'s resources on integrity management inspections for state inspectors, including existing inspection protocol guidance, mentorship opportunities, and the availability of PHMSA's inspection subject matter experts for consultation, are inadequate.

9. Federal-to-state and state-to-state coordination between inspectors of gas transmission pipelines is limited.

10. The lack of high consequence area identification in the National Pipeline Mapping System limits the effectiveness of pre-inspection preparations for both federal and state inspectors of gas transmission pipelines.

11. There is a considerable difference in positional accuracy between interstate and intrastate gas transmission pipelines in the National Pipeline Mapping System, and this discrepancy, combined with the lack of detailed attributes, may reduce state and federal inspectors' ability to properly prepare for integrity management inspections.

12. The discrepancies between the Pipeline and Hazardous Materials Safety Administration's National Pipeline Mapping System, annual report database, and incident database may result in state and federal inspectors' use of inaccurate information during pre-inspection preparations.

13. The lack of published standards for geospatial data commonly used by pipeline operators limits operators' ability to determine technically sound buffers to increase the safety margin and also hinders integrity management inspectors from evaluating the buffer's technical validity.

14. The lack of a repository of authoritative sources of geospatial data for identified sites may contribute to operators' inaccurate high consequence area identification.

15. Inappropriate elimination of threats by pipeline operators can result in undetected pipeline defects.

16. The prevalence of inappropriate threat elimination as a factor in gas transmission pipeline incidents cannot be determined because the Pipeline and Hazardous Materials Safety Administration does not collect threat identification data in pipeline incident reports.

17. The inadequate evaluation of interactive threats is a frequently cited shortcoming of integrity management programs, which may lead to underestimating the true magnitude of risks to a pipeline.

18. The prevalence of interactive threats in gas transmission pipeline incidents cannot be determined because the Pipeline and Hazardous Materials Safety Administration does not allow operators to select multiple, interacting root causes when reporting pipeline incidents.

19. Inspectors lack training to effectively verify the validity of an operator's risk assessment.

20. Many pipeline operators do not have sufficient data to successfully implement probabilistic risk models.

21. A lack of incident data regarding the risk assessment approach(es) used by pipeline operators limits the knowledge of the strengths and limitations of each risk assessment approach.

22. Whether the four approved risk assessment approaches produce a comparable safety benefit is unknown.

23. Sufficient guidance is not available to pipeline operators and inspectors regarding the safety performance of the four types of risk assessment approaches allowed by regulation, including the effects of weighting factors, calculation of consequences, and risk aggregation methods.

24. Professional qualification criteria for pipeline operator personnel performing integrity management functions are inadequate.

25. The use of in-line inspection as an integrity assessment method for intrastate pipelines is considerably lower than for interstate pipelines (68 percent compared to 96 percent) in part due to the operational and configuration differences.

26. A much higher proportion of integrity assessments is conducted by direct assessment for intrastate pipelines than for interstate pipelines partly due to operational and configuration differences.

27. Of the four integrity assessment methods, in-line inspection yields the highest per-mile discovery of anomalies that have the potential to lead to failure if undetected.

28. In-line inspection is able to inspect the integrity of the pipeline segments susceptible to multiple threats.

29. Improvements in in-line inspection tools allow for the inspection of gas transmission pipelines that were previously uninspectable by in-line inspection.

30. Operators may limit the use of in-line inspections due to operational complications.

31. There are many limitations to direct assessment, including that (1) it is limited to the detection of defects attributed to corrosion threats, (2) it only covers very short sub-segments of the pipeline, (3) it relies on the operator’s selection of specific locations for excavation and direct examination, and (4) it yields far fewer identifications of anomalies compared to in-line inspection.

32. The selection of direct assessment by the pipeline operator as the sole integrity assessment method must be subject to strict scrutiny by the inspectors due to its numerous limitations.

33. Pipeline operators view geographic information systems as the preferred tool for effective data integration, as it can be used as a system of records and a source of authoritative data.

# 6 Recommendations

## 6.1 New Recommendations

**To the Pipeline and Hazardous Materials Safety Administration**:

Assess (1) the need for additional inspection protocol guidance for state inspectors, (2) the adequacy of your existing mentorship program for these inspectors, and (3) the availability of your subject matter experts for consultation with them, and implement the necessary improvements. (P-15-1)

Modify the overall state program evaluation, training, and qualification requirements for state inspectors to include federal-to-state coordination in integrity management inspections. (P-15-2)

Work with the National Association of Pipeline Safety Representatives to develop and implement a program to formalize, publicize, and facilitate increased state-to-state coordination in integrity management inspections. (P-15-3)

Increase the positional accuracy of pipeline centerlines and pipeline attribute details relevant to safety in the National Pipeline Mapping System. (P-15-4)

Revise the submission requirement to include high consequence area identification as an attribute data element to the National Pipeline Mapping System. (P-15-5)

Assess the limitations associated with the current process for identifying high consequence areas, and disseminate the results of your assessment to the pipeline industry, inspectors, and the public. (P-15-6)

Work with the Federal Geographic Data Committee to identify and publish standards and specifications for geospatial data commonly used by gas transmission pipeline operators, and disseminate the standards and specifications to these operators and inspectors. (P-15-7)

Work with the appropriate federal, state, and local agencies to develop a national repository of geospatial data resources for the process for high consequence area identification, and publicize the availability of the repository. (P-15-8)

Establish minimum criteria for eliminating threats, and provide guidance to gas transmission pipeline operators for documenting their rationale for all eliminated threats. (P-15-9)

Update guidance for gas transmission pipeline operators and inspectors on the evaluation of interactive threats. This guidance should list all threat interactions that must be evaluated and acceptable methods to be used. (P-15-10)

Develop and implement specific risk assessment training for inspectors in verifying the technical validity of risk assessments that operators use. (P-15-11)

Evaluate the safety benefits of the four risk assessment approaches currently allowed by the gas integrity management regulations; determine whether they produce a comparable safety benefit; and disseminate the results of your evaluation to the pipeline industry, inspectors, and the public. (P-15-12)

Update guidance for gas transmission pipeline operators and inspectors on critical components of risk assessment approaches. Include (1) methods for setting weighting factors, (2) factors that should be included in consequence of failure calculations, and (3) appropriate risk metrics and methods for aggregating risk along a pipeline. (P-15-13)

Revise 49 *Code of Federal Regulations* section 192.915 to require all personnel involved in integrity management programs to meet minimum professional qualification criteria. (P-15-14)

Revise Form F7100.1, Annual Report Form, to collect information about which methods of high consequence area identification and risk assessment approaches were used. (P-15-15)

Revise Form F7100.2, Incident Report Form, (1) to collect information about both the results of previous assessments and previously identified threats for each pipeline segment involved in an incident and (2) to allow for the inclusion of multiple root causes when multiple threats interacted. (P-15-16)

Develop a program to use the data collected in response to Safety Recommendations P-15-15 and P-15-16 to evaluate the relationship between incident occurrences and (1) inappropriate elimination of threats, (2) interactive threats, and (3) risk assessment approaches used by the gas transmission pipeline operators. Disseminate the results of your evaluation to the pipeline industry, inspectors, and the public annually. (P-15-17)

Require that all natural gas transmission pipelines be capable of being in-line inspected by either reconfiguring the pipeline to accommodate in line inspection tools or by the use of new technology that permits the inspection of previously uninspectable pipelines; priority should be given to the highest risk transmission pipelines that considers age, internal pressure, pipe diameter, and class location. (Supersedes Safety Recommendation P-11-17, which is now classified "Closed—Superseded.") (P-15-18)

Revise Form F7100.1, Annual Report Form, to collect information on the mileage of both HCA and non-HCA pipeline that can accommodate in-line inspection tools. (P-15-19)

Identify all operational complications that limit the use of in-line inspection tools in piggable pipelines, develop methods to eliminate the operational complications, and require operators to use these methods to increase the use of in-line inspection tools. (P-15-20)

Develop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines. (P-15-21)

Develop and implement a plan for all segments of the pipeline industry to improve data integration for integrity management through the use of geographic information systems. (P-15-22)

**To the American Gas Association:**

Work with the Interstate Natural Gas Association of America to collect data that will support the development of probabilistic risk assessment models, and share these data with gas transmission pipeline operators. (P-15-23)

Work with the Interstate Natural Gas Association of America to develop and implement a strategy for increasing the use of in-line inspection tools as appropriate, with an emphasis on intrastate pipelines. (P-15-24)

**To the Interstate Natural Gas Association of America:**

Work with the American Gas Association to collect data that will support the development of probabilistic risk assessment models, and share these data with gas transmission pipeline operators. (P-15-25)

Work with the American Gas Association to develop and implement a strategy for increasing the use of in-line inspection tools as appropriate, with an emphasis on intrastate pipelines. (P-15-26)

**To the National Association of Pipeline Safety Representatives:**

Work with the Pipeline and Hazardous Materials Safety Administration to develop and implement a program to formalize, publicize, and facilitate increased state-to-state coordination in integrity management inspections. (P-15-27)

**To the Federal Geographic Data Committee:**

Work with the Pipeline and Hazardous Materials Safety Administration to identify and publish standards and specifications for geospatial data commonly used by gas transmission pipeline operators, and disseminate the standards and specifications to these operators and to inspectors. (P-15-28)

## 6.2 Reiterated Recommendations

**To the US Department of Transportation:**

> Ensure that PHMSA amends the certification program, as appropriate, to comply with the findings of the audit recommended in Safety Recommendation P-11-6. (P-11-7)

## 6.3 Previous Recommendations Reclassified in This Study

One recommendation to the Pipeline and Hazardous Materials Safety Administration is now classified “Closed—Superseded.”

> Require that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines. (P-11-17)

## BY THE NATIONAL TRANSPORTATION SAFETY BOARD

**CHRISTOPHER A. HART**
Acting Chairman

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Member

**EARL F. WEENER**
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**Adopted: January 27, 2015**

# 7 Appendix A. PHMSA's Natural Gas Transmission and Gathering Incident Data File

## List of 16 Required Integrity Management Program Elements

The following list of 16 required integrity management program elements can also be found at PHMSA's Gas Transmission Integrity Management: Fact Sheet (https://primis.phmsa.dot.gov/gasimp/fact.htm). NTSB staff has added the corresponding areas in the Gas Integrity Management Inspection Protocol for clarification purposes.

| IM Program Element | Protocol Area |
|---|---|
| Identification of all high consequence areas | A. Identify HCAs |
| Baseline Assessment Plan | B. Baseline Assessment Plan |
| Identification of threats to each covered segment, including by the use of data integration and risk assessment | C. Identify Threats, Data Integration, and Risk Assessment |
| A direct assessment plan, if applicable | D. DA Plan |
| Provisions for remediating conditions found during integrity assessments | E. Remediation |
| A process for continual evaluation and assessment | F. Continual Evaluation and Assessment |
| A confirmatory direct assessment plan, if applicable | G. Confirmatory DA |
| A process to identify and implement additional preventive and mitigative measures | H. Preventive and Mitigative Measures |
| A performance plan including the use of specific performance measures | I. Performance Measures |
| Recordkeeping provisions | J. Record Keeping |
| Management of Change process | K. Management of Change (MOC) |
| Quality Assurance process | L. Quality Assurance |
| Communication Plan | M. Communications Plan |
| Procedures for providing to regulatory agencies copies of the risk analysis or integrity management program | N. Submittal of Program Documents |
| Procedures to ensure that integrity assessments are conducted to minimize environmental and safety risks | Specific questions relevant to this program element is incorporated into Protocol Area B |
| A process to identify and assess newly identified high consequence areas | Specific questions relevant to this program element is incorporated into Protocol Area A |

## PHMSA's Natural Gas Transmission and Gathering Incident Data File

The compressed data was obtained directly via online download from the PHMSA Portal. These are the "Flagged Incidents" data files. For this safety study, NTSB staff focused on incidents that occurred between January 1, 2010, and December 31, 2013. The data file name within the "Flagged Incidents" download is gt2010toPresent.csv. The following table includes fields used in the safety study.

| Field | Part, Question | Description |
|---|---|---|
| **SIGNIFICANT** | N/A | At least one fatality, or one injury, or property damage >= $50,000 (in 1984 dollars) |
| **OPERATOR_ID** | A, 1 | Operator's OPS-issued Operator Identification Number (OPID) |
| **LOCAL_DATETIME** | A, 4 | Local time (24-hr clock) and date of incident |
| **LOCATION_LATITUDE** | A, 5 | Location of incident (decimal degree latitude) |
| **LOCATION_LONGITUDE** | A, 5 | Location of incident (decimal degree longitude) |
| **COMMODITY_RELEASED_TYPE** | A, 9 | Gas released, include natural gas, propane gas, synthetic gas, hydrogen gas, and other gas |
| **FATAL** | A, 13 | Total fatalities |
| **INJURE** | A, 14 | Total injuries |
| **ON_OFF_SHORE** | B, 1 | Was the origin of the incident onshore? Y = Onshore |
| **PIPE_FACILITY_TYPE** | C, 1 | Interstate or Intrastate |
| **SYSTEM_PART_INVOLVED** | C, 2 | Part of system involved in incident |
| **ITME_INVOLVED** | C, 3 | Item involved in incident (e.g. Pipe, Weld) |
| **INSTALLATION_YEAR** | C, 4 | Year item involved in incident was installed |
| **RELEASE_TYPE** | C, 6 | Type of incident involved (e.g. Leak, Rupture) |
| **CLASS_LOCATION_TYPE** | D, 1 | Class location of incident (class 1 through 4) |
| **COULD_BE_HCA** | D, 2 | Did this incident occur in a High Consequence Area (HCA)? Y = HCA |
| **DETERMINATION_METHOD** | D, 2 | Specify the Method used to identify the HCA if COULD_BE_HCA = 1 |
| **PRPTY** | D, 7 | Estimated total costs |
| **INTERNAL_INSPECTION_IND** | E, 5 | Is the pipeline configured to accommodate internal inspection tools? |
| **OPERATION_COMPLICATIONS_IND** | E, 5 | For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run |
| **PIPELINE_FUNCTION** | E, 5 | Function of pipeline system (e.g. Transmission system, transmission line of distribution system, type A gathering, type B gathering, storage gathering) |
| **CAUSE** | G | Select one of the followings: corrosion failure, natural force damage, excavation damage, other outside force damage, material failure of pipe or weld, equipment failure, incorrect |

| | | |
|---|---|---|
| | | operation, other incident cause |
| **COR_INSPECT_TOOL_COLLECTED_IND** | G1, 14 | Has one or more internal inspection tool collected data at the point of the incident? |
| **COR_HYDROTEST** | G1, 15 | Has one or more hydrotest or other pressure test been conducted since original construction at the point of the incident? |
| **COR_DIRECT_INSPECTION_TYPE** | G1, 16 | Has one or more direct assessment been conducted on this segment? |
| **COR_DIRECT_YES_DIG_YEAR** | G1, 16 | An investigative dig conducted at the point of the incident |
| **COR_DIRECT_YES_NO_DIG_YEAR** | G1, 16 | The point of the incident was not identified as a dig site |
| **COR_NON_DESTRUCTIVE_IND** | G1, 17 | Has one or more non-destructive examination been conducted at the point of the incident since January 21, 2002? |
| **EX_INSPECT_TOOL_COLLECTED_IND** | G3, 1 | Has one or more internal inspection tool collected data at the point of the incident? |
| **EX_HYDROTEST** | G3, 3 | Has one or more hydrotest or other pressure test been conducted since original construction at the point of the incident? |
| **EX_DIRECT_INSPECTION_TYPE** | G3, 4 | Has one or more direct assessment been conducted on this segment? |
| **EX_DIRECT_YES_DIG_YEAR** | G3, 4 | An investigative dig conducted at the point of the incident |
| **EX_DIRECT_YES_NO_DIG_YEAR** | G3, 4 | The point of the incident was not identified as a dig site |
| **EX_NON_DESTRUCTIVE_IND** | G3, 5 | Has one or more non-destructive examination been conducted at the point of the incident since January 21, 2002? |
| **OSF_INSPECT_TOOL_COLLECTED_IND** | G4, 3 | Has one or more internal inspection tool collected data at the point of the incident? |
| **OSF_HYDROTEST** | G4, 5 | Has one or more hydrotest or other pressure test been conducted since original construction at the point of the incident? |
| **OSF_DIRECT_INSPECTION_TYPE** | G4, 6 | Has one or more direct assessment been conducted on this segment? |
| **OSF_DIRECT_YES_DIG_YEAR** | G4, 6 | An investigative dig conducted at the point of the incident |
| **OSF_DIRECT_YES_NO_DIG_YEAR** | G4, 6 | The point of the incident was not identified as a dig site |
| **OSF_NON_DESTRUCTIVE_IND** | G4, 7 | Has one or more non-destructive examination been conducted at the point of the incident since January 21, 2002? |
| **PWF_INSPECT_TOOL_COLLECTED_IND** | G5, 5 | Has one or more internal inspection tool collected data at the point of the incident? |
| **PWF_HYDROTEST** | G5, 6 | Has one or more hydrotest or other pressure test been conducted since original construction at the point of the incident? |
| **PWF_DIRECT_INSPECTION_TYPE** | G5, 7 | Has one or more direct assessment been |

| | | |
|---|---|---|
| | | conducted on this segment? |
| **PWF_DIRECT_YES_DIG_YEAR** | G5, 7 | An investigative dig conducted at the point of the incident |
| **PWF_DIRECT_YES_NO_DIG_YEAR** | G5, 7 | The point of the incident was not identified as a dig site |
| **PWF_NON_DESTRUCTIVE_IND** | G5, 8 | Has one or more non-destructive examination been conducted at the point of the incident since January 21, 2002? |

## PHMSA's Annual Report Data for Natural and Other Gas Transmission and Gathering Pipeline Systems

The data was obtained directly via online download from the PHMSA Portal. For this safety study, NTSB staff focused on annual reports for calendar years 2010 through 2013. For 2013, the data file name is annual_gas_transmission_gathering_2013.xlsx. The following table includes fields used in the safety study.

| Field | Part, Question | Description |
|---|---|---|
| **OPERATOR_ID** | A, 1 | Operator's 5 Digit Identification Number (OPID) |
| **PARTA5COMMONDITY** | A, 5 | This report pertains the following commodity group: natural gas, synthetic gas, hydrogen gas, propane gas, landfill gas, other gas |
| **PARTA7INTER** | A, 7 | List of all states and OCS portions in which Interstate pipelines and or/pipeline facilities included under the OPID exist |
| **PARTA7INTRA** | A, 7 | List of all states in which intrastate pipelines and/or pipeline facilities under the OPID exist |
| **PARTBHCAONSHORE** | B | Number of HCA Miles |
| **INTER_INTRA** | F and G | Interstate or intrastate pipelines/pipeline facilities |
| **PARTF1E** | F, 1e | Total tool mileage inspected in calendar year using in-line inspection tools |
| **PARTF2B** | F, 2b | Total number of anomalies repaired in calendar year that were identified by ILI based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment |
| **PARTF3A** | F, 3a | Total mileage inspected by pressure testing in calendar year |
| **PARTF3B** | F, 3b | Total number of pressure test failures (ruptures and leaks) repaired in calendar year, both within an HCA segment and outside of an HCA segment |
| **PARTF4A** | F, 4a | Total mileage inspected by each DA method in calendar year |
| **PARTF4B** | F, 4b | Total number of anomalies identified by each DA method and repaired in calendar year based on the operator's criteria, both within an HCA segment and outside of an HCA segment |
| **PART5A** | F, 5A | Total mileage inspected by inspection techniques other than those listed above in calendar year. Specify other inspection technique(s) |
| **PART5B** | F, 5B | Total number of anomalies identified by other inspection techniques and repaired in calendar year based on the operator's criteria, both within an HCA segment and outside of an HCA segment |
| **PARTGMBA** | G, a | Baseline assessment miles completed during the calendar year |

| Field | Part, Question | Description |
|---|---|---|
| **PARTGMRC** | G, b | Reassessment miles completed during the calendar year |
| **PARTGTOTMILES** | G, c | Total assessment and reassessment miles completed during the calendar year |
| **INTER_INTRA** | H, I, J, K, L, M, P, Q & R | Interstate or intrastate pipeline facilities |
| **PARTJTON (UNKNWON, PRE1940, 194049, 195059, 196069, 197079, 1978089, 199099, 200009, 201019, TOTAL)** | J | Online transmission pipeline mileage by installation decade |
| **PARTLTONTOT** | L | Total class location onshore transmission miles |
| **PARTLTONIMP** | L | HCA onshore transmission miles |

## PHMSA's National Pipeline Mapping System (NPMS) Data

The NPMS data for calendar year 2013 was obtained directly from PHMSA via secure FTP transfer process. The following table contains information of attribute fields used in the safety study.

| Field | Description | Data Element |
|---|---|---|
| **OPID** | Accounting number assigned by the PHMSA to the company that operates the pipeline | |
| **MILES** | Length in miles of the line segment | |
| **COMMODITY** | Abbreviation for the primary commodity carried by the pipeline | CRD=crude oil<br>PRD=non-HVL product<br>AA=anhydrous ammonia<br>LPG=liquefied petroleum gas<br>NGL=natural gas liquids<br>OHV=other HVLs<br>CO2=carbon dioxide<br>ETH=fuel grade ethanol<br>EPL=empty liquid<br>NG=natural gas<br>PG=propane gas<br>SG=synthetic gas<br>HG=hydrogen gas<br>OTG=other gas<br>EPG=empty gas |
| **INTERSTATE** | Designator to identify whether a pipeline is an interstate pipeline | Y = Interstate<br>N = Intrastate |
| **STATUS_CD** | Identifies the current status of the pipeline | I = in service<br>D = idle<br>B = abandoned<br>R = retired |
| **QUALITY_CD** | Operator's estimate of the positional accuracy of the submitted pipeline data | E = Excellent (within 50ft)<br>V = Very Good (50-300ft)<br>G = Good (301-500ft)<br>P = Poor (501-1000ft)<br>U = Unknown |
| **REVIS_CD** | Identifies pipeline as an addition or a modification of a previous submission | A=addition to the NPMS<br>C=addition due to construction<br>J=addition due to mileage which is new to PHMSA's jurisdiction<br>S=spatial modification of the existing NPMS feature<br>T=attribute modification of the existing NPMS feature<br>B=both a spatial and attribute modification of the existing NPMS feature<br>N=no change to the existing PMS feature |

## PHMSA's Enforcement Data (as of July 2014)

NTSB staff inquired with PHMSA staff regarding PHMSA's enforcement actions based on a select number of program areas within the 49 CFR 192 regulations. The following table includes section numbers (and subsections) that were provided to PHMSA.

| 49 CFR 192 Section | High Level Description | Subsections of Interest |
|---|---|---|
| **192.905** | IM High Consequence Areas - HCA Identification | 192.905(b)(1)<br>192.905(b)(2)<br>192.905(c) |
| **192.907** | Implementation of IM | 192.907(b) |
| **192.915** | IM Program Requirements for Supervisors | 192.915(a) |
| **192.917** | IM Threat Identification | 192.917(a)(1)<br>192.917(a)(2)<br>192.917(a)(3)<br>192.917(a)(4)<br>192.917(b)<br>192.917(c)<br>192.917(e)(1)<br>192.917(e)(2)<br>192.917(e)(3)<br>192.917(e)(4)<br>192.917(e)(5) |
| **192.921** | Conducting IM Baseline Assessment | 192.921(a)(1)<br>192.921(a)(2)<br>192.921(a)(3)<br>192.921(a)(4)<br>192.921(a)(5) |
| **192.923** | Direct Assessment | 192.923(b)(1)<br>192.923(b)(2)<br>192.923(b)(3) |
| **192.925** | Requirements for ECDA | 192.925(b)(1)<br>192.925(b)(2)<br>192.925(b)(3)<br>192.925(b)(4) |
| **192.927** | Requirements for ICDA | 192.927(b)(1)<br>192.927(b)(2)<br>192.927(b)(3)<br>192.927(b)(4)<br>192.927(b)(5) |
| **192.929** | Requirements for SCCDA | 192.929(b)(1)<br>192.929(b)(2) |
| **192.931** | Use of CDA | 192.931(b)(1)<br>192.931(b)(2) |
| **192.933** | Addressing Integrity Issues | 192.933(b)<br>192.933(c)<br>192.933(d)(1)<br>192.933(d)(2)<br>192.933(d)(3) |
| **192.935** | Preventative and Mitigative Measures | 192.935(c) |
| **192.937** | Continual Process of Evaluation and Assessment | 192.937(b)<br>192.937(c)(1) |

| 49 CFR 192 Section | High Level Description | Subsections of Interest |
|---|---|---|
| | | 192.937(c)(2)<br>192.937(c)(3)<br>192.937(c)(4)<br>192.937(c)(5) |
| **192.945** | Performance Measures | 192.945(a)<br>192.945(b) |
| **192.947** | Record Keeping | 192.947(d) |

The following descriptions of enforcement actions can also be found at PHMSA's Enforcement webpage (http://primis.phmsa.dot.gov/comm/reports/enforce/Enforcement.html?nocache=6308).

- Notices of Probable Violation: Notices of Probable Violations (NOPVs) are commonly used as an enforcement tool. After routine inspections, incident investigations, or other oversight activity by authorized Federal or Interstate Agent pipeline inspectors, the PHMSA Regional Director will determine if probable violations have occurred, and, if appropriate, issue an NOPV to the operator. The NOPV alleges specific regulatory violations and, where applicable, proposes appropriate corrective action in a Compliance Order and/or civil penalties. The operator has a right to respond to the NOPV and to request an administrative hearing. The administrative enforcement procedures and other regulations governing the enforcement program are described in 49 CFR 190 Subpart B "Enforcement."

- Warning Letters: For some probable violations (often lower risk), PHMSA has the option of issuing a Warning Letter notifying the operator of alleged violations and directing it to correct them or be subject to further enforcement action. PHMSA then follows up on these items during subsequent inspections or through other interactions with the operator. Warning Letters are described in 49 CFR §190.205.

- Notices of Amendment: PHMSA inspections, incident investigations, and other oversight activities routinely identify shortcomings in an operator's plans and procedures under PHMSA regulations. In these situations, PHMSA issues a Notice of Amendment (NOA) letter alleging that the operator's plans and procedures are inadequate and requiring that they be amended. The operator has a right to respond to the Notice and to request an administrative hearing. Notices of Amendment and the procedures for their issuance and enforcement are described in 49 CFR §190.237.

# 8 Appendix B. NAPSR Voluntary Survey of State Inspectors

In response to NTSB queries about the roles state inspectors play in gas transmission IM safety oversight and their opinions about the IM program inspection process, NAPSR leadership conducted a voluntary survey of their membership. In June 2014, NAPSR distributed the following 15-question survey to pipeline safety program managers in each state. A total of 23 responses were received, although not every respondent answered every question. These responses are summarized below.

### 1. Do you perform Integrity Management inspections as an Intrastate or Interstate agent for PHMSA?

**Table 1.** NAPSR Survey Question 1 Responses

| Intrastate/Interstate | Count |
|---|---|
| Intrastate | 16 |
| Interstate | 1 |
| Both | 4 |

### 2. Please provide the number 4.5.3 Use of IM program inspections (excluding Protocol A only) each inspector on your staff has led.

Each respondent was able to list the number of IM program inspections led for up to five inspectors. Twenty-one respondents answered this question.

**Table 2.** NAPSR Survey Question 2 Responses

| Inspections Led | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | >17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Count | 0 | 14 | 9 | 7 | 1 | 7 | 3 | 6 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 2 | 1 | 0 |

### 3. Please provide the number of IM program inspections (excluding Protocol A only) each inspector on your staff has participated in since January of 2012.

Each respondent was able to list the number of IM program inspections participated in for up to five inspectors. Twenty-two respondents answered this question.

**Table 3.** NAPSR Survey Question 3 Responses

| Inspections Participated In | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | >12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Count | 2 | 12 | 7 | 7 | 1 | 6 | 9 | 4 | 2 | 2 | 0 | 0 | 1 | 0 |

### 4. Are IM program inspections typically conducted by an individual inspector or a team of inspectors?

**Table 4.** NAPSR Survey Question 4 Responses

| Individual/Team Inspections | Count |
|---|---|
| Individual | 6 |
| Team | 12 |
| Both | 4 |

### 5. What is the average number of days or hours spent preparing for an IM program inspection (excluding protocol A only)?

Responses provided in hours were converted to days at 8 hours per day. Responses provided as a range (for example, 1 to 3 days) were converted to a single value, using the mean of the range.

**Table 5.** NAPSR Survey Question 5 Responses

| Days Preparing for Inspection | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | >11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Count | 0 | 6 | 7 | 2 | 3 | 0 | 2 | 0 | 0 | 0 | 1 | 1 | 0 |

### 6. What are the average number of days or hours spent actually conducting a single IM program inspection? (Excluding Protocol A only.)

Responses provided in hours were converted to days at 8 hours per day. Responses provided as a range (for example, 1 to 3 days) were converted to a single value, using the mean of the range.

**Table 6.** NAPSR Survey Question 6 Responses

| Days Conducting Inspection | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | >13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Count | 0 | 0 | 4 | 4 | 3 | 2 | 0 | 1 | 2 | 0 | 2 | 0 | 0 | 1 | 3* |

*One respondent reported an average of 23 days to conduct an inspection, and two respondents reported 30 days.

**7. On a scale of 1 to 5, with 1 representing the highest, please rank the importance of the following PHMSA data sources when preparing for or conducting IM program inspections.**

**Table 7.** NAPSR Survey Question 7 Responses

| PHMSA Data Source | Importance (Count) | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| Safety Monitoring and Reporting Tool (SMART) | 0 | 0 | 1 | 2 | 4 |
| Inspection Assistant (IA) | 1 | 4 | 2 | 1 | 4 |
| National Pipeline Mapping System (NPMS) | 3 | 2 | 3 | 4 | 6 |
| Pipeline Risk Management Information System (PRIMIS) | 3 | 4 | 1 | 3 | 3 |
| FedStar Data | 3 | 4 | 4 | 3 | 4 |
| Oracle Business Intelligence Tool Data | 1 | 0 | 1 | 1 | 3 |

**8. On a scale of 1 to 5, with 1 representing the highest, please rank the importance of the following when conducting IM program inspections.**

**Table 8.** NAPSR Survey Question 8 Responses

| Resource | Importance (Count) | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| PHMSA IMP Protocols | 12 | 3 | 2 | 0 | 4 |
| Geographic Information System (GIS) Data | 7 | 2 | 4 | 3 | 4 |
| Dig Data | 11 | 1 | 4 | 2 | 1 |
| Repair Data | 13 | 3 | 1 | 1 | 2 |
| Inspection Data | 14 | 1 | 2 | 1 | 2 |

**9. Does your IM program inspection program use a standard set of "drill down" questions (that are beyond the PHMSA protocols) when conducting IM program inspections?**

**Table 9.** NAPSR Survey Question 9 Responses

| Drill-Down Questions | Count |
|---|---|
| Yes | 3 |
| No | 19 |

**10. On a scale of 1 to 5, with 1 representing the highest, please rank each inspection category below in regards to the difficulty level in regards to verifying operator compliance.**

**Table 10.** NAPSR Survey Question 10 Responses

| Inspection Category | Difficulty (Count) | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| HCAs: Identification, updating, elimination | 3 | 5 | 6 | 4 | 4 |
| Threat Identification, including interactive threats | 5 | 8 | 6 | 2 | 1 |
| Risk Assessment Approaches | 4 | 11 | 5 | 1 | 1 |
| Integrity Assessment | 3 | 8 | 5 | 4 | 2 |
| Continual Assessment | 1 | 4 | 10 | 2 | 5 |

**11. On a scale of 1 to 5, with 1 representing the highest, please rank each area listed below regarding how your inspection staff generally perceives the role of PHMSA.**

**Table 11.** NAPSR Survey Question 11 Responses

| Area | Perception (Count) | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| Oversight of State Programs | 13 | 3 | 5 | 1 | 0 |
| Collection and Dissemination of Data | 3 | 11 | 5 | 2 | 1 |
| Mentoring of State Inspectors | 2 | 0 | 3 | 7 | 10 |
| Provision of Reference Materials | 7 | 7 | 6 | 1 | 1 |

**12. On a scale of 1 to 5, with 1 representing the highest, please rank the roles of the other stakeholders listed below in regards to your IM program inspection program.**

**Table 12.** NAPSR Survey Question 12 Responses

| Stakeholder | Role (Count) | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| Within state agencies/commissions | 1 | 5 | 3 | 3 | 6 |
| State-to-state coordination and communication | 3 | 6 | 3 | 3 | 6 |
| Professional associations (NAPSR, NARUC, etc.) | 3 | 3 | 7 | 4 | 4 |
| Trade organizations (AGA, APGA, INGAA, etc.) | 0 | 0 | 7 | 5 | 9 |
| Universities and research institutions | 0 | 1 | 1 | 0 | 13 |

**13. How many operators have you inspected since January 1, 2012?**

**Table 13.** NAPSR Survey Question 13 Responses

| Operators Inspected | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | >13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Count | 2 | 4 | 1 | 4 | 1 | 3 | 2 | 1 | 0 | 1 | 1 | 0 | 0 | 1 | 0 |

**14. What types of issues have you found during these IM program inspections?**

The following answers were provided for this free-response question:

- No jurisdictional Transmission in the state.
- Lack of outreach to other government agencies which have a role in Identifying HCAs; Elimination of Threats without proper justification; prioritization of defects
- Risk ranking scoring changed from region to region which made risk ranking not valid when looking at the operator's system as one
- Procedure Issues
- Operators seemed to have difficulty identifying HCA's, and record keeping, both following the written plan and the quality of the records.
- Inadequate number of ECDA digs. Reassessment not carried out. Not following sections of the IMP plan. Inadequate documentation. No RSRENG calculation done on corrosion pit found. Line with no HCA found to have HCA.
- Anomalies (due to corrosion) and repairs.
- Little ease of use of Operator manuals. Some are very difficult to find corresponding language with regs
- Various - failure to perform sufficient validation digs, hard to figure out risk models, failure to have procedures in place for performance metrics, no plan to acquire missing or incomplete data.
- Inadequate written procedures. Plans not completed in required time frame.
- Non compliance. Risks not identified

- No written procedure for operator establishment of baseline for performance measures. 2) No written procedure to collect data. 3) Operators plan does not include a list of additional information needed for future collection.4) Operators plan does not consider external research for threat identification. 5) Operators plan does not provide explicit guidelines to support use of SME's in risk analysis. 6) Results generated by the model should agree with the consensus of the validation group, SME's are reordering risk ranking.
- Inadequate historical information (record keeping). 2. Inadequate interpretation of assessment information
- Documentation of tool selection for reassessment. HCA identification using updated aerial photography. Interactive Threat Consideration
- No findings of violation.
- Operators did not effectively overlay previous inspection data. Operator tend to rely on the same evaluation methods for subsequent inspections. Operators appear to be satisfied with ECDA methods and have not implemented measures to make unpiggable pipelines piggable.
- Assessment tools inadequate for mechanically coupled pipelines, pressure test not possible. Additional P&M measures not performed. Procedural Issues.
- Inaccurate HCA maps have been identified. Identifying or discounting Interactive threats has been a challenge.
- PIR calculations 2- Lack of familiarity with their plan 3. Inability to comprehend requirements

**15. Please provide any Integrity Management-related thoughts, comments, or ideas in order to help improve pipeline safety.**

The following answers were provided for this free-response question:

- No jurisdictional Transmission in the state.
- I think this is a good program just need to make sure the operators are taking the responsibility of Managing and reducing the threats to their pipelines.
- IMP and now DIMP are viable programs however they are too comprehensive with too many elements involved to be reasonably regulated within the frame works of how PHMSA and state programs are set up to operate.
- This is a very complicated set of regulations to comply with for operators and inspect as regulators. The development of the regulations using some form of negotiated rulemaking and references to a few different industry standards contributes to the complication of the regulations. Consideration should be given to a simpler approach to regulating this activity that would also benefit pipeline safety. Allowing assessment intervals to increase for pipelines that have ILI assessments completed on them and/or changing validation dig requirements while requiring pipelines that are not currently capable of ILI assessments to be made to accommodate ILI tools. Some operators have taken this approach while still trying to comply with the existing requirements. They are reassessing at the minimum required interval and making more lines accommodate ILI tools. Requiring assessments of all transmission pipelines and eliminating many of the other requirements seems like a better long term approach.

- We can certainly use more inspectors. Having said that, moving toward SME's, for Integrity Management for example, seems prudent.
- Understandable protocols
- The validation of assessment data seems to be a weakness. Too often take ILI vendors conclusions at their word. Also, developing the fine longitudinal defect capabilities (cracks) would appear to be an important technology need. There is little practical guidance on evaluating some of the soft components required in the rule such as program adequacy, need to remote valve installation, and adequacy of QA/QC programs. Management oversight is the core of success and failure of these programs and we have not established a process to evaluate that.
- Seven years to evaluate a new HCA is a long period of time, specifically on pipelines with significant threats
- Expand definition of HCAs to include crossings or parallel encroachments on the right-of-way with other modes of transportation.
- The operators appear to have a check the box mentality when it comes to IMP compliance. Operators rarely identify or take measures to discover potential threats to the pipelines beyond the minimum requirements.

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