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

Gas Transmission Integrity Management Progress Report

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EXECUTIVE SUMMARY

In 2003, the Office of Pipeline Safety (OPS) published new regulations requiring integrity management (IM) programs for gas transmission pipeline operators. This landmark set of regulations is broad-reaching and fundamentally different from the approaches used in the past for improving pipeline safety. These regulations supplement PHMSA's prescriptive safety requirements with new requirements which are very performance and process-oriented, setting expectations for operators, yet giving them the flexibility in how they choose to comply with several programmatic requirements. The primary objectives for the Gas Transmission IM Program are to:

- Accelerate and improve the quality of integrity assessments conducted on pipelines in areas with the highest potential for adverse consequences (High Consequence Areas – HCAs),
- Promote a more rigorous, integrated, and systematic management of pipeline integrity and risk by operators,
- Strengthen government's role in the oversight of pipeline operator integrity plans and programs, and
- Increase the public's confidence in the safe operation of the nation's pipeline network.

It has been seven years since the IM rule was published on December 15, 2003, and the baseline assessments of pipe that could potentially affect HCAs have mostly been completed. Thus, PHMSA is taking this opportunity to evaluate the progress and effectiveness of this major initiative. This report provides a discussion of PHMSA's progress in achieving the above program objectives as well as an examination of incident trends over this period.

Recent Accident History

The ultimate objective of the Gas Transmission pipeline IM regulations is to reduce pipeline risk through reducing the likelihood and consequences from releases that affect HCAs. PHMSA expects that actual improvements in accident frequency and consequences due to operator activities in response to the IM requirements will be observable over the long term. While some impacts may be observable in the short term (e.g., from operators making repairs to the most severe anomalies), other impacts from the IM programmatic requirements may not be apparent for several years. Operators also have an increased awareness of less severe conditions on their pipelines which are being monitored or scheduled for repair, providing an additional level of safety not in place before the IM rule.

Some measures developed using recent gas transmission pipeline incident history appears to indicate that the IM rule is having a positive impact on incident frequency and consequences.

The yearly number of reportable incidents[1] from all causes has fluctuated somewhat since 2005, but there is an overall decreasing trend over this period (see Figure 1). A similar decreasing trend is observed when considering only the subset of incident causes that are detectable by the rule's line pipe integrity assessment requirements (e.g., corrosion, dents, and material defects).[2]

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[1] Reportable Incidents for gas transmission operators are those incidents that satisfy any of the following conditions: 1) A death, or personal injury necessitating in-patient hospitalization; 2) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost; 3) Unintentional estimated gas loss of three million cubic feet or more; 4) An event that is significant in the judgment of the operator, even though it did not meet any of the above criteria.

[2] The results shown here are not normalized by the number of pipeline miles that gas transmission pipeline operators have reported in annual reports. Gas transmission operators have only been reporting IM metrics since 2004. Over 2004-2009, pipeline miles reported in annual reports have increased slightly, but the increase is not considered to have a significant effect on the trends shown here.

Additional examinations of pipeline incident frequency and consequence are provided later in this Progress Report.

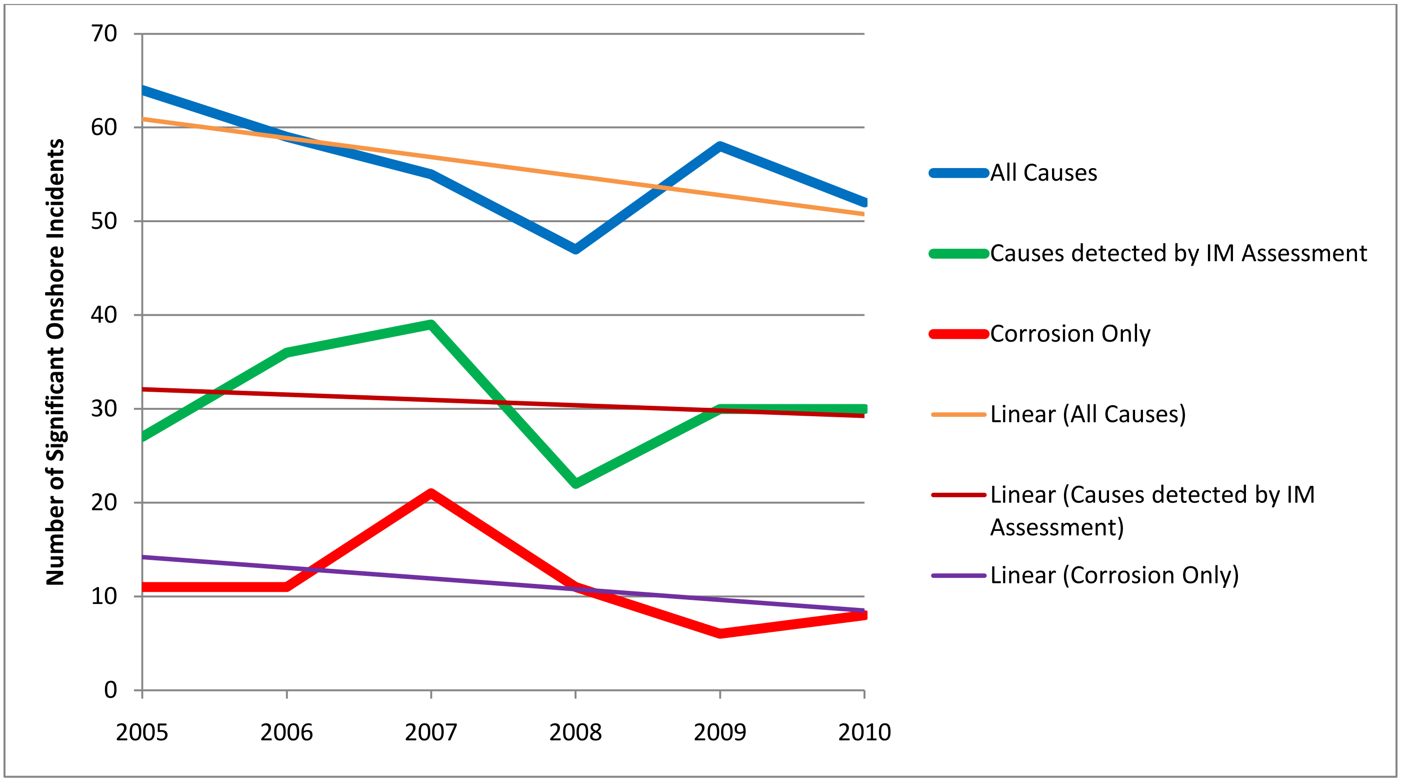


Figure 1 - Gas Transmission Pipeline Significant Accidents 2005 – 2010

Accelerate and Improve Integrity Assessments

The IM rule requires that operators conduct an initial baseline assessment of their HCA-affecting pipeline segments by December 2012 and then perform reassessments on a period not to exceed seven years thereafter. PHMSA inspections and the mandated annual reporting by operators (certified by company executives) have shown that operators are making adequate progress toward meeting these deadlines.

In addition, the threat identification and risk analysis work leading up to operators' creation of their Baseline Assessment Plans has yielded benefits, as has PHMSA's efforts – working with numerous Federal and State agencies – to catalogue and locate those areas across the nation most susceptible to damage from pipeline failures (HCAs). Not only is there a vast increase in the awareness of these susceptibilities by operators (as well as responders), there is now for the first time a consistent understanding among operators, oversight agencies, and first responders of precisely where they are located and where additional protection is warranted. Operators now have a much better understanding of which particular portions of their pipelines, as well as other facilities, have the potential to impact these sensitive areas.

Not only are these most sensitive sections of pipelines now more secure, but the assessments required by the IM rule are providing additional protection beyond HCAs. While operators are only required to assess the pipeline segments that can affect HCAs (~6.5% of the pipeline mileage, nationwide), they have in fact smart pigged, pressure tested, or otherwise assessed more than 40% of the total gas transmission pipeline mileage, thus increasing safety in locations well beyond the originally designated HCAs. (Identified anomalies outside HCAs must be repaired in accordance with §192.485.)

These assessments have revealed a large number of potentially injurious conditions which pipeline operators have remediated in accordance with the IM rule (HCA). To date, more than 1,052 serious pipeline anomalies or defects have been repaired immediately after they were discovered. In addition, some 2,239 other, less serious anomalies have been repaired on a scheduled timeframe allowed in the rule – all of these occurring in sections of pipeline systems which could adversely impact the nation's HCAs.

Promote Rigorous Operator IM Programs

The IM rule goes beyond simply assessing pipeline segments and repairing defects. Improving operators' management of pipeline integrity, their associated analytical processes, and their across-the-board application of rigorous risk management is also a critical objective of PHMSA's IM rule. The ability to integrate and analyze threat and integrity related data from many sources is critical to proactive safety management. In creating a robust IM program, PHMSA's regulations identify sixteen essential program elements, which must be fully developed by operators in order to comply with the rule.

PHMSA inspections have shown that operators have made substantial progress in developing these program elements. However, there are areas that still require significant industry attention. These include the program elements that go beyond assessing and repairing line pipe to prevent and mitigate accidents (e.g., Threat Identification and Risk Analysis, and the Preventive and Mitigative Measures Program Element). PHMSA recognizes that each pipeline is unique with a pipeline-specific risk profile dependent on the pipeline location, operating environment, and numerous other factors. For this reason, PHMSA's IM rule requires operators to develop the processes and tools needed to identify and analyze these unique risks – risks which can vary considerably both from one pipeline to another, as well as from end-to-end of any given pipeline. The IM rule also requires operators to have systematic approaches to use this risk information to identify and implement additional preventive and mitigative measures to prevent releases and further reduce risk beyond the level achieved through repairing defects identified through integrity assessment. While operators have understandably devoted significant resources to completing their baseline assessments to meet the initial deadlines in the regulations, they still need to devote more effort and resources to those elements considered to be crucial for a mature IM Program - specifically risk analysis, the identification and implementation of additional preventive and mitigative measures, and the ongoing and continuing improvement of IM program processes.

Strengthen Government Oversight

Accompanying the new IM rule, PHMSA launched a new inspection program in 2005 to assure compliance with the new IM requirements and promote improved operator IM Programs. A comprehensive set of inspection protocols were developed that not only checked for compliance with the rule's prescriptive requirements, but also supported a detailed audit of an operator's management and analytical systems, processes, and practices to manage pipeline integrity. The insights from these inspections are summarized later in this report.

When operators fall short of meeting the rule's requirements for IM Program development, PHMSA takes enforcement action to accelerate program development and address program deficiencies. Through the first two rounds of IM inspections, PHMSA has issued enforcement letters for 76% of inspections. When violations of the rule's prescriptive requirements occur, PHMSA has not hesitated to exercise its civil penalty authority. For the initial set of operator IM inspections, the average civil penalty was approximately $125,000.

Increase Public Assurance in Pipeline Safety

Transparency to the public and the regulated community has been a hallmark of the IM Program since its inception. After the rule was issued, PHMSA developed the Implementing Integrity Management web site to provide information on the rule and PHMSA's oversight efforts. This publicly accessible web site includes more than 200 Frequently Asked Questions to explain the rule provisions and PHMSA's expectations. This resource also provides access to inspection protocols, an IM fact sheet, a glossary of IM terminology, a flow chart of the IM process, reference documents, and industry performance measures. With the 2007 launch of PHMSA's enforcement transparency web site, the public now has access to information on enforcement cases stemming from PHMSA's IM inspections as well. The recent addition of operator-specific reports to the Stakeholder Communications web site now makes it even easier for information on IM inspections and enforcement to be accessed for a given operator.

During the development of these web sites, as well as in several public meetings, PHMSA has engaged its public stakeholders as well as the operator community for input on how to improve communication and understanding of the IM Program.

GAS TRANSMISSION INTEGRITY MANAGEMENT PROGRESS REPORT

1. Recent Accident History

The ultimate objective of the gas transmission pipeline integrity management regulations is to reduce pipeline risk through reducing the likelihood and consequences of pipeline failures. It is expected that actual improvements in incident frequency and consequences due to operator activities in response to the IM requirements will be observable over the long term. Here we look at gas transmission pipeline reportable incident data over different periods related to the IM rule requirements to determine if any short term trends can be observed.

The periods that are considered are related to the following dates:

December 17, 2004 – Gas transmission pipeline operators were required to have a written integrity management program developed by this date.
December 17, 2007 – Gas transmission pipeline operators were required to complete baseline integrity assessments of 50% of their HCA mileage by this date.
December 17, 2012 – Operators are required to complete baseline assessments of all of their HCA mileage by this date.

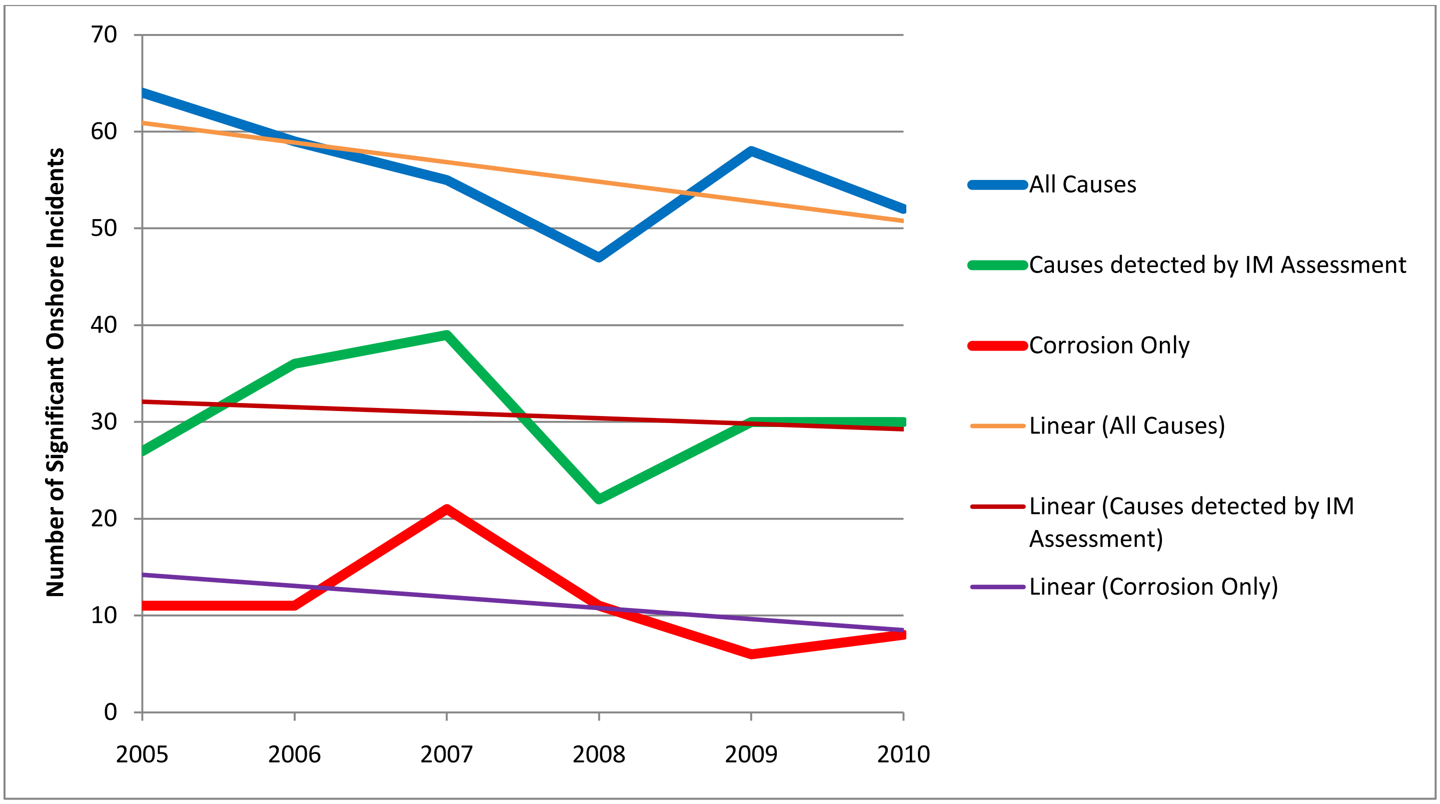


Figure 1: Gas Transmission Significant Incidents 2005-2010

Figure 1 shows that over the years since gas transmission operators were required to develop an integrity management program, there has been a slight downward trend in the annual number of significant incidents[3].

[3] The results shown here are not normalized by the number of pipeline miles that gas transmission pipeline operators have reported in annual reports. Over 2005-2009, total onshore gas transmission pipeline miles reported

Integrity Management regulations include some requirements that address pipeline risks from all causes. However, requirements for integrity assessment and repair primarily address risks from a subset of possible incident causes that may be detected during integrity assessments, such as corrosion and certain materials defects. The requirements for integrity assessments do not affect most incidents caused by mechanical damage (i.e., excavation damage, natural forces damage, other outside force damage), incorrect operation, or equipment failures. If we wish to focus on the possible effects of the IM requirements for integrity assessment, then incidents caused by the subset of causes that are detectable during integrity assessments should be considered. Figure 1 also shows a slight downward trend for incidents due to this subset of "detectable" causes. A downward trend is also shown if only significant incidents due to external or internal corrosion are counted.

The IM regulations required gas transmission operators to develop an IM program by December 17, 2004 and to complete baseline assessments of at least 50% of covered segment mileage by December 17, 2007. Comparing incident history for 2005-2007 vs. 2008-2010 shows a lower average yearly number of significant incidents for the later period:

Table 1: Incident History 2005-2010

Period	Yearly Average Number of Significant Accidents - All Causes	Yearly Average Number of Significant Accidents – "Detectable Causes"	Yearly Average Number of Significant Accidents - Caused by Corrosion
2005-2007	59	34	14
2008-2010	52	27	8

The average number of incidents per year is 13% lower in the later period for all causes, 24% lower for incidents with causes that may be detected by integrity assessments, and 72% lower for incidents caused by corrosion.

Although much of the Integrity Management requirements address risks for all parts of a pipeline system, the IM requirements for integrity assessment and repair primarily affect risks from line pipe and do not directly apply to other pipeline facilities such as compressor stations and regulator/metering stations[4]. If only line pipe incidents are included, and incident causes are limited to corrosion and other causes that could be detected by integrity assessments, then the incident trend over 2005-2010 is as follows:

in annual reports have increased slightly, but the increase (around 1%) is not considered to have a significant effect on the trends shown here.

Only onshore gas transmission pipelines are included in this analysis.

[4] Risks from these facilities are addressed by other IM requirements, such as requirements to implement other preventive and mitigative measures.

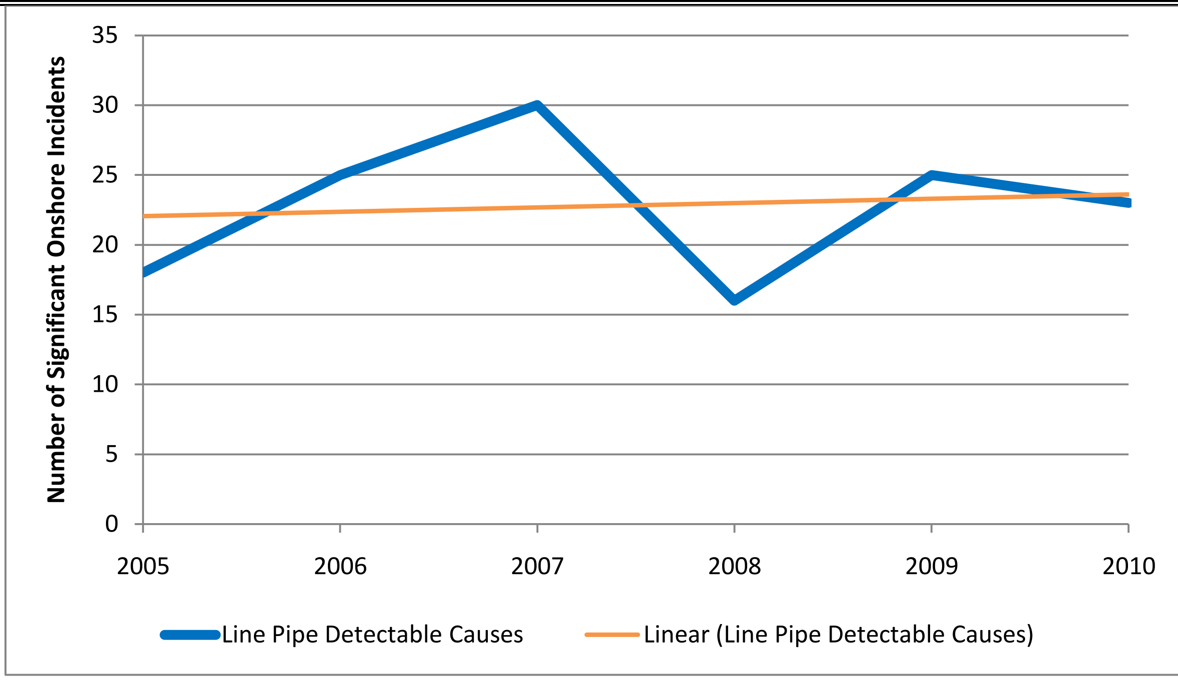


Figure 2: Significant Onshore Gas Transmission Pipeline Incidents - Line Pipe, "Detectable" Causes Only

For line pipe only, the number of significant incidents fluctuates over 2005-2009, with a flat to slightly increasing trend.

The requirements of the integrity management regulations directly apply to pipeline segments identified by operators as high consequence areas (HCAs), which is a small portion (around 7% nationwide) of gas transmission pipelines. Gas transmission incident reports have not identified which incidents occur in HCAs, but HCAs are primarily located in the areas around pipelines with the highest population density and highest density of occupied buildings.

2. Accelerate and Improve Integrity Assessments

The IM rule requires that operators conduct baseline assessments on covered segments of their pipeline. Assessments can be performed using in-line inspection tools (aka “smart pigs”), hydrostatic pressure testing, and direct assessment (for selected threats). Operators were provided more than seven years in which to complete all of their baseline assessments and then are required to periodically reassess their pipelines at a frequency not to exceed seven years. Gas transmission operators are required to complete the initial baseline assessments by December 17, 2012.

As part of each IM inspection prior to that deadline, PHMSA inspectors carefully reviewed the operator’s Baseline Assessment Plan and the progress toward meeting the compliance deadline. These inspections demonstrate that operators are on pace to complete their baseline assessments in advance of the deadline. Furthermore, each year operators provide PHMSA with a performance metrics that include information on their integrity assessments and repairs, including mileage inspected and repairs performed. These annual reports, signed by the company’s senior executive, likewise showed operators are making adequate progress toward completing baseline assessments on time.

Some highlights from the performance metrics include:

- PHMSA regulates approximately 292,000 miles of gas transmission pipelines in the United States.
- The approximately 19,100 miles of gas transmission in covered segments, to which the IM rules apply, represents approximately 6.5% of the total gas transmission pipeline mileage in the U.S.
- From 2004-2009[5], approximately 140,000 miles of Gas Transmission pipelines[2] have been inspected using one or more of the assessment methods specified in the IM rules. These assessments were performed on covered segments, as well as many other miles of pipelines. See Figure 3.
- Since the IM Program’s inception, there have been over 1,052 conditions repaired that required immediate attention, over 2,239 other conditions repaired on a scheduled basis.
- In 2007 alone, 258 conditions were repaired that were deemed by the rule to be serious enough to warrant immediate attention in covered segments. In 2008, 146 immediate conditions were repaired and in 2009, 124 immediate conditions were repaired.
- The number of these immediate conditions repaired has declined in 2008 and 2009, suggesting that the rule has achieved one of its associated, primary benefits. That is, operators were required to identify their highest risk segments and concentrate their initial assessments in the early program years on segments that were likely to have more anomalies.

[5] 2010 Annual Report submissions are not required until June 2011.

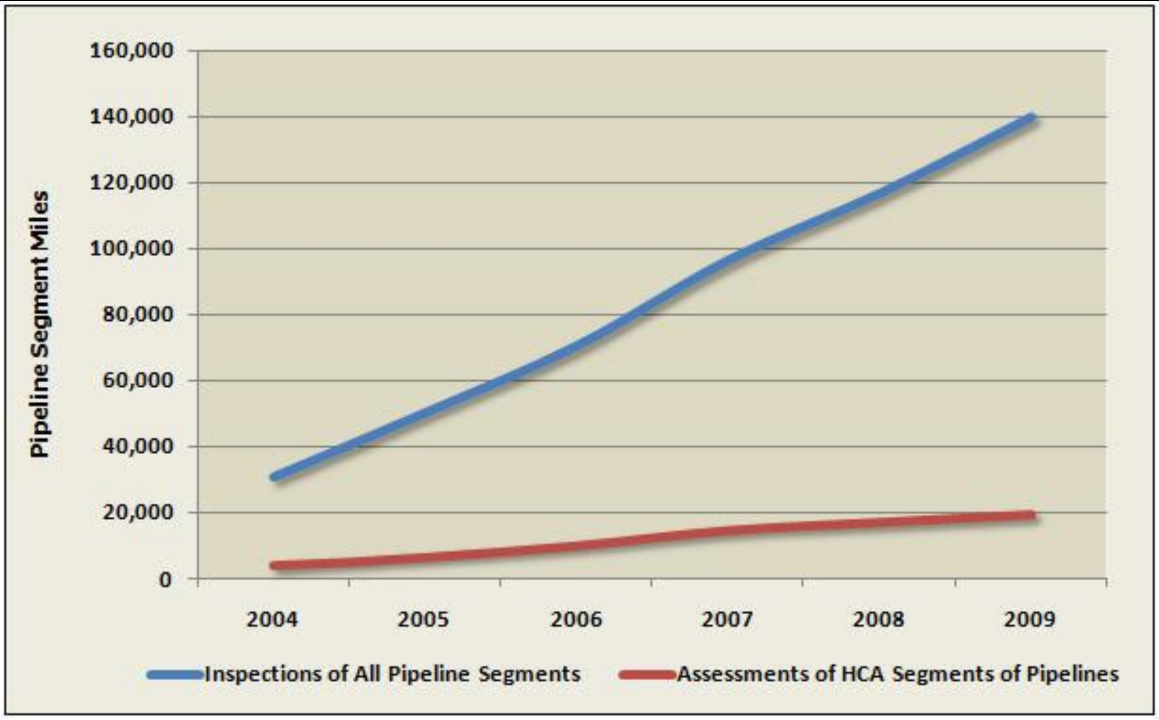


Figure 3 – Miles of Gas Transmission Pipeline Inspected Under the IM Rule 2004-2009

- Also in 2009, approximately 251 other conditions were repaired or mitigated on a scheduled basis as required by the IM Rule. The total number of repairs in the “scheduled” category has not decreased as noticeably. While the reasons for this continued rate of discovery are not entirely clear, continued operator vigilance in detecting mitigating, and ultimately preventing the anomalies remains a critical element of industry IM implementation.
- In addition to repairs in segments that can potentially affect HCAs, PHMSA believes operators are addressing a number of defects that are outside covered segments. However, operators are not required to report this data, so the extent to which pipelines outside of covered segments are being repaired is not known.

While the use of assessment tools is invaluable in identifying pipeline conditions that warrant repair, they are not technically capable of solely discovering all potential conditions that can lead to a loss of pipeline integrity. Therefore, it is important that all required elements of operator IM Programs – not just those portions specifically related to assessments – be fully developed and implemented to effectively manage pipeline integrity. The next section addresses the broader development of operator IM Programs.

3. Promote Rigorous Operator IM Programs

The IM rule identifies 16 program elements that must be part of an operator's IM program. These required program elements are:

- Identifying high consequence areas (Covered Segment Identification)-includes identifying new HCAs
- Developing and implementing a Baseline Assessment Plan to conduct integrity assessments on these HCA affecting pipeline segments (Baseline Assessment Plan) - includes a process to minimize safety and environmental risk when performing assessments
- Identifying the threats to pipeline integrity for each covered segment
- Developing and implementing a Direct Assessment Plan (if applicable)
- Remediating potentially injurious pipeline anomalies identified through assessments (Remediation)
- Continually evaluate pipeline risks and conduct re-assessments of pipeline segments that could affect HCAs on an on-going basis (Continual Assessment)
- Developing and implementing a Confirmatory Direct Assessment Plan (if applicable)
- Identifying and implementing additional preventive and mitigative measures to address the highest risks identified through risk analysis (Preventive and Mitigative Measures)
- Measure IM Program performance and make improvements as necessary (Performance Evaluation)
- Recordkeeping
- Management of Change
- Quality Assurance
- Communications Plan
- Procedures to provide risk analysis or IMP to regulators

PHMSA's federal IM inspections are structured to examine both the development and implementation of each program element. A comprehensive set of inspection protocols is used by inspectors to assure operators comply with the prescriptive requirements in the IM rule, and are developing IM programs consistent with the process-based requirements in the rule. Figure 4 shows the number of issues identified during the 78 federal inspections conducted as of December 2010 for each of the program elements.

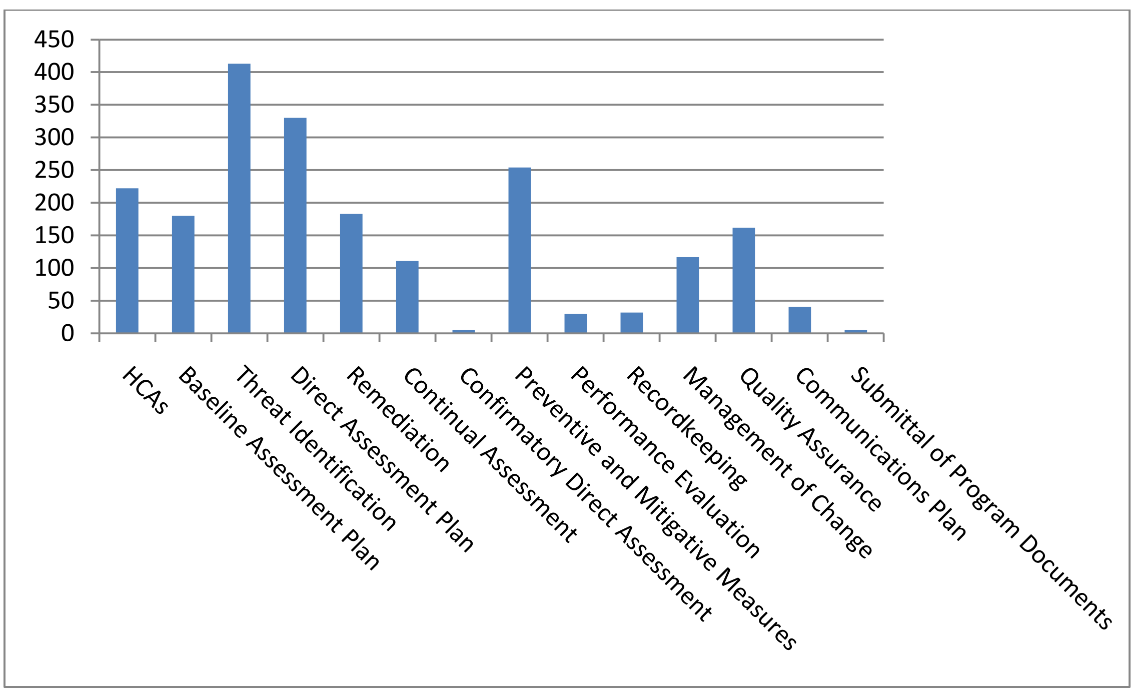


Figure 4 - Number of Issues Identified per Completed Inspection for each Program Element

Operators have generally identified their pipeline segments that can affect HCAs and have processes in place to identify when conditions around the line change (e.g., a new housing development adjacent to the pipeline right-of-way). Operators are making acceptable progress toward completing their baseline assessments. Finally, operator risk analysis methods are improving, though as noted later there is still work to do for these methods to be more useful in supporting broader risk management decisions.

Table 2 lists the most frequently identified problems from the first round of gas transmission IM inspections. Most of these concerns relate to integrating data and using risk analysis to improve the evaluation of integrity assessment results; identifying and implementing additional preventive and mitigative measures; and determining the appropriate frequency and methods for re-assessment.

In addition to simply counting the issues observed during inspections, PHMSA has also established the relative risk or severity of each inspection issue. Figure 5 shows the relative risk of inspection findings for operators discovered in their first PHMSA inspection.

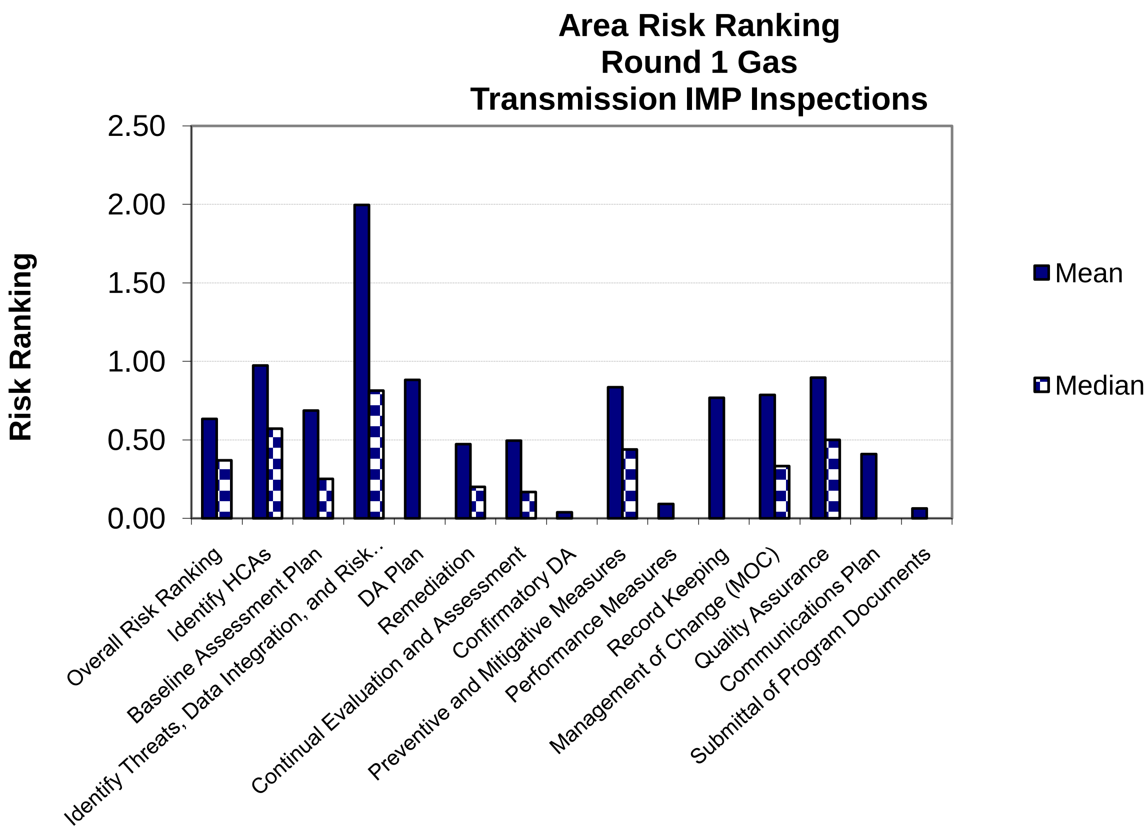


Figure 5 – Severity of Inspection Findings by Program Element

Table 2 - Most Frequently Observed Issues – 1st Round of Operator Gas IM Inspections

No. of Issues found	% of inspections that noted this issue	Issue Category
44	56%	Interactive threats from different threat categories were not adequately evaluated
32	41%	A documented decision-making process to determine which measures should be implemented was not adequately developed and/or implemented
28	35%	Non-mandatory requirements from industry standards or other documents that are invoked by Subpart O were not adequately addressed
27	34%	Procedures did not adequately describe the requirements to update the HCA analysis
27	34%	Procedures did not adequately document requirements to gather and/or integrate data.
26	33%	All of the threats required by the rule and standard for a prescriptive program were not adequately considered and/or evaluated
25	32%	An adequate process to decide if automatic shut-off valves or remote-control valves are an efficient means of adding protection was not developed and/or implemented
25	32%	When using outside resources to conduct processes that affect the quality of the integrity management process adequate quality was not ensured
24	30%	Procedures did not adequately describe how to identify HCAs using Method 1 and/or Method 2
24	30%	Specific threats for a particular pipeline segment were eliminated from consideration without adequate justification
24	30%	The plan for collecting, reviewing, and analyzing data was not adequate
24	30%	Process/procedures to identify and implement additional measures to prevent and mitigate a pipeline failure were inadequate
23	29%	Procedures to determine identified sites were inadequate
22	28%	Procedures did not adequately document requirements for discovery, evaluation and/or remediation scheduling
20	25%	System maps or other suitable means of documenting the pipeline HCA segment locations were not appropriately utilized
20	25%	Procedures for conducting periodic evaluations were inadequate
20	25%	Changes to pipeline systems were not adequately considered in the integrity management program
19	24%	The decision-making process did not adequately consider both likelihood and consequences of pipeline failures
19	24%	Adequate reviews of the integrity management program were not required and/or adequately implemented
18	23%	The data sources specified in Table 2 of B31.8S were not adequately utilized during data gathering
18	23%	Individual data elements were not adequately brought together and analyzed (i.e., inadequate data integration)
18	23%	Procedures did not adequately document all requirements to develop, implement, document, and/or continually improve the risk assessment
18	23%	Adequate requirements were not specified to record and monitor anomalies that are classified as "monitored conditions"
17	21%	Data as specified in Table 1 of B31.8S was not adequately gathered and/or evaluated
17	21%	The criteria for discovery were not adequately documented
16	20%	The method or combination of methods used to identify HCAs was not adequately documented for each covered segment
16	20%	Enhancement to the Damage Prevention Program to require the collection in a central database location-specific information on excavation damage that occurs in covered and non-covered segments and the root cause analysis were
15	19%	New information was not adequately incorporated in a timely and/or effective manner

The preceding charts suggest that industry is not meeting PHMSA expectations to identify threats and analyze risks to its pipelines. Addressing the broad set of threats requires that operators develop the processes and tools to identify and analyze the risks unique to each pipeline. These risks are dependent on the pipeline location, operating environment, commodity transported, and many other factors. The IM rule also requires operators to have systematic approaches to use this risk information to identify and implement additional preventive and mitigative measures. If operators are to successfully and significantly reduce their operational risk, it is critical that the measures taken are based on a sound understanding of what is actually driving that risk and how those drivers can practically be impacted. As a specific example of the difference between a mature IM Program and one in the early stages of development, the risk analysis approach to support evaluation of potential preventive and mitigative measures needs to be more detailed than a simple approach used to prioritize pipeline segments for the baseline assessments.

The preceding charts also indicate the continued need for PHMSA vigilance with respect to industry remediation of anomalies identified during assessments (e.g., completing repairs within required timeframes, implementation of required pressure reductions), quality assurance, direct assessment, and identification of HCA segments (covered segments).

While operators understandably devoted significant resources to completing their baseline assessments to meet the deadlines in the regulations, they now need to devote more effort and resources to those elements considered to be representative of a mature IM program, such as threat identification and risk analysis (including data integration), preventive and mitigative measures, continual evaluation and assessment, and their own internal program evaluation process.

4. Strengthen Government Oversight

In 2005, PHMSA launched a new inspection program to assure compliance with the new IM requirements and promote improved operator IM Programs. A comprehensive set of inspection protocols were developed that not only checked for compliance with the rule's prescriptive requirements, but also supported a detailed audit of an operator's management and analytical systems, processes, and practices to manage pipeline integrity. PHMSA inspects the IM Programs of interstate gas transmission operators that PHMSA's regulates as well as some intrastate pipeline operators.

When operators fall short of meeting the rule's requirements for IM program development, PHMSA takes enforcement action to address program deficiencies as well as to accelerate program development. PHMSA issues civil penalties as well as compliance directives which dictate the corrective actions which operators must take to address program deficiencies. PHMSA has issued enforcement letters for most of its IM inspections. When violations of the rule's prescriptive requirements occur, PHMSA has not hesitated to exercise its civil penalty authority. For PHMSA's first round of operator IM inspections, the average civil penalty was approximately $125,000. Further, when program deficiencies are identified, PHMSA likewise has not hesitated to exercise its directive authorities either. Approximately 28% of PHMSA's enforcement actions are in the form of a compliance directive known as a Proposed Compliance Order, which along with Notices of Amendment, are used to achieve needed programmatic improvements.

Table 3 – Integrity Management Enforcement Results

% of Inspections Resulting in Enforcement Action	% of Inspections Resulting in Proposed Compliance Order	% of Inspections Resulting in Proposed Civil Penalty	Average Proposed Civil Penalty[6]
76%	28%	16%	$125,183

Figure 6 shows how frequently each type of enforcement action has been applied.[7] As can be seen, the Notice of Amendment (NOA) action is the most frequently used compliance tool following IM inspections. NOAs are used to communicate needed program and process improvements to operators. Because the development and maturation of an IM Program takes significant operator time and resources, the NOA has been used frequently in the early stages of the IM oversight program to communicate PHMSA expectations for process-based requirements in the rule and facilitate the timely development of operator programs in the desired direction.

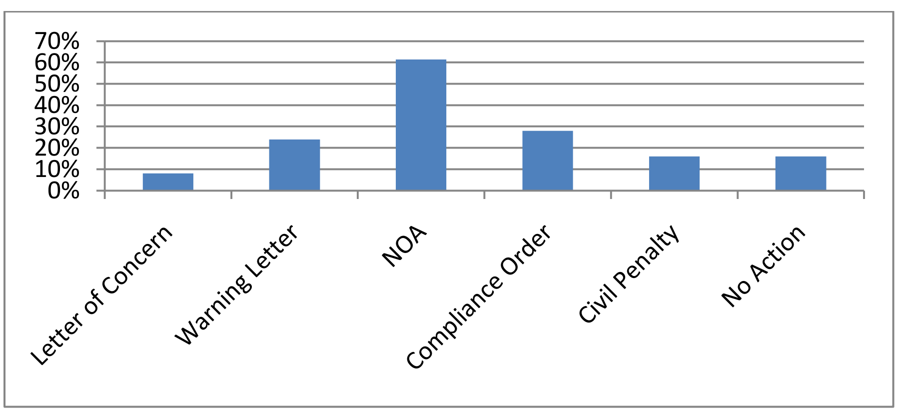


Figure 6 – Percentage of Inspections which Resulted in Each Type of Enforcement Action

[6] Average does not include cases with no civil penalty proposed.
[7] Some inspections result in more than one type of enforcement action

5. Increase Public Assurance in Pipeline Safety

The extensive performance and process-based requirements in the IM rule represent a significant departure from PHMSA's prior practice of issuing largely prescriptive regulations. PHMSA leadership recognized that a major outreach effort was required to both communicate to operators what was expected, and to foster the public's understanding of the rule and its safety improvement objectives.

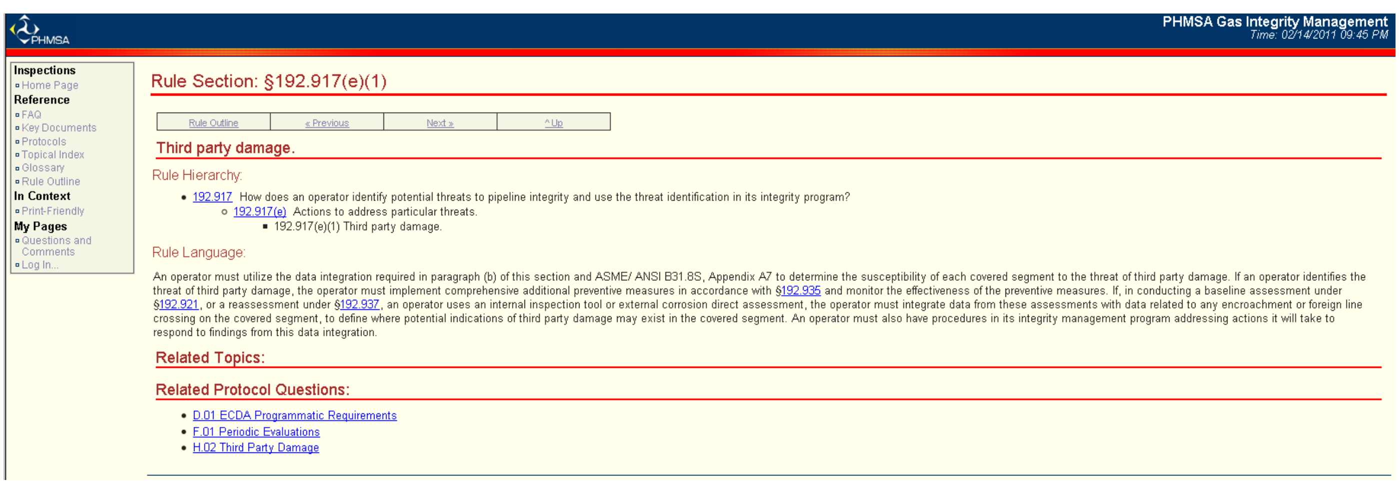
Since the initial publication of the IM rules, PHMSA has taken unprecedented steps to inform and involve the public and its regulated community. PHMSA conducted three public meetings since the rules were published to explain the rule and communicate PHMSA's expectations for compliance. The last of these workshops described some of the lessons learned from the early inspections providing the public with an opportunity to understand how the new rules were being enforced. The workshops also provided an opportunity for operators to share noteworthy integrity management practices and better understand PHMSA's oversight approach for this performance-based rule.

PHMSA has also held several workshops focused on a specific subjects and challenges operators face in managing safety and integrity. In particular, workshops on the Use of In-Line Inspection Devices and Anomaly Assessment and Repair were held in 2005 and 2008, respectively. The presentation material from these workshops was made available to a broader audience through PHMSA's web site.

Shortly after the rule was published, PHMSA launched the "Integrity Management" web site – a comprehensive resource of information related to the new IM rule .

The IIM web site provides copies of the rule language, a flow chart illustrating the IM process, a glossary of terms and other basic reference material related to IM (see menu from the web site to the right). The web site includes more than 200 Frequently Asked Questions (FAQs) to explain the rule provisions, PHMSA's compliance expectations, and PHMSA's oversight program. In the early development of the FAQs, the questions were collected through the previously mentioned public meetings, individual public and operator inquiries, and submissions from industry trade groups. The web site itself has a feature where users can send questions to PHMSA.

The IIM site is heavily interlinked. For example, clauses in the IM rule are linked to related inspection protocols so users can readily access additional information about PHMSA expectation for key rule requirements.



Since 2004, Gas Transmission operators have been required to file performance metrics that contain integrity management data on the number of pipeline miles inspected, the number of HCA segment miles that have been fully assessed, and the number of repairs that are made. The IIM site provides a summary of these statistics and graphs of historical trends, as well as links to PHMSA's data base where the public can view individual operator report submissions.

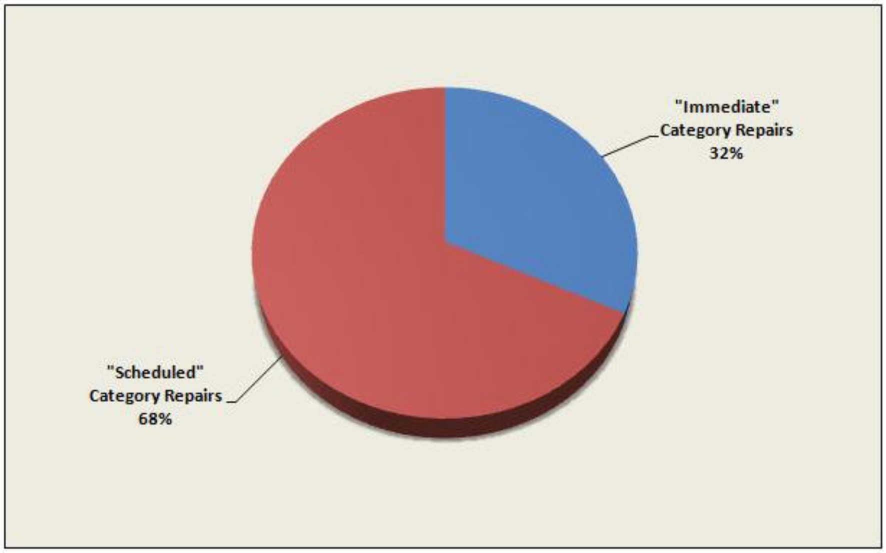


Figure 7: Types of Pipeline Repairs 2004-2009

The IM rule also includes several provisions where operators must notify PHMSA if they are unable to meet certain deadlines or intend to vary from specific rule requirements. Approximately 260 of these notifications have been submitted since the rule was published. These individual operator notifications are summarized on the IIM web site, as well as PHMSA's response to the Notification. PHMSA has objected to relatively few notifications (approximately 10%). The relatively low number of objections indicates that pipeline operators have adjusted to the demands that IM posed on their processes.

In the spring of 2007, PHMSA significantly enhanced the transparency of its enforcement program actions. A new section of the Stakeholder Communications web site was developed to portray industry wide and operator-specific enforcement information

Through this site, the public now has access to enforcement case information, PHMSA notice letters, operator responses to PHMSA's allegations, and final orders directing operator compliance. Thus, the public now has access to what actions PHMSA is taking for inspections, including IM.

Finally in the fall of 2010, PHMSA introduced a new series of operator-specific reports on the Stakeholder Communications web site. These reports allow the public to readily access information on specific pipeline operators. This information includes pipeline mileage, and incident, inspection, and enforcement history. Within the inspection history portion of these reports is a listing of specific inspections performed since 2005, including integrity management inspections. The listing of enforcement actions includes those that emanate from integrity management inspections.

In summary, PHMSA has taken unprecedented steps to inform the public and its stakeholders about the IM rule and its oversight for the new rule. The quantity and quality of information is far more than has been made available in the past. Informal communication and feedback from stakeholder groups indicates that this information is being used and found useful by stakeholder groups and the regulated community.

6. Summary

- PHMSA has made substantial progress in achieving its four primary IM Program objectives since the first rule was issued seven years ago.
- Operators have an improved understanding of the precise locations of their HCAs – those areas where integrity assessments and other protective measures spelled out in the IM rule must be taken to assure public safety and environmental protection. Some 6.5% of the nation's gas transmission pipelines can potentially affect HCAs and thus receive the enhanced level of integrity assessment and protection mandated by the IM rule.
- Operators are on track to complete baseline integrity assessments on pipelines that could affect HCAs by December 2012. Operators now have an improved understanding of the condition of pipelines in these safety-sensitive areas.
- As a result of these assessments, operators have made more than 1,052 repairs of anomalies that required immediate attention, and remediated over 2,200 other conditions on a scheduled basis, thus significantly improving the condition of the nation's pipelines.
- The programmatic and process-oriented requirements of the rule have fostered a more systematic, risk-based approach to managing integrity. Operators are generally making progress toward developing the mature, proactive IM programs which PHMSA expects.
- Improvement is still needed to identify and implement additional preventive and mitigative measures to reduce risk. This aspect of the rule is critical, as the integrity assessment provisions of the rule only address some of the causes of pipeline failures. The Preventive and Mitigative measures program element requirements are the means to achieve a comprehensive approach to reducing risk.
- PHMSA has a robust IM oversight program consisting of both comprehensive IM Program inspections and field validations. PHMSA has not hesitated to use its enforcement authority – nearly 80% of programmatic inspections result in enforcement action.
- PHMSA has taken unprecedented steps toward communicating its expectations and sharing program results with the public and the regulated community. A special web site was created solely to communicate information about Gas Transmission IM. More recently information on IM inspections and enforcement actions has been made available to the public.
- Finally, there has been a noticeable reduction in the frequency of significant incidents since the effective date of the gas transmission IM rule. These, and other metrics described in this Progress Report indicate an overall improvement in industry safety performance. Thus it appears that the IM rule and PHMSA's rigorous oversight of operator compliance with the rule is contributing to improved safety performance.