NATIONAL TRANSPORTATION SAFETY BOARD
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(Information subject to editing)

Safety Study
Integrity Management of Gas Transmission Pipelines in High Consequence Areas
NTSB SS-15/01

This is a synopsis from the NTSB's Safety Study and does not include the Board's rationale for the conclusions and safety recommendations. NTSB staff is currently making final revisions to the report from which the attached conclusions and safety recommendations have been extracted. The final report and pertinent safety recommendation letters will be distributed to recommendation recipients as soon as possible. The attached information is subject to further review and editing.

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 are 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 to identify 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 five 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.

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

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 use of 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.

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's 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.

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.

RECOMMENDATIONS

<u>New Recommendations</u>

To the Pipeline and Hazardous Materials Safety Administration:

1. 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.

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

3. 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.

4. Increase the positional accuracy of pipeline centerlines and pipeline attribute details relevant to safety in the National Pipeline Mapping system.

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

6. 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.

7. 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.

8. 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.

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

10. 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.

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

12. 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.

13. 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.

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

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

16. 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.

17. Develop a program to use the data collected in response to Safety Recommendations [15] and [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.

18. 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 classified "Closed—Superseded.")

19. 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.

20. 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.

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

22. 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.

To the American Gas Association:

23. 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.

24. 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.

To the Interstate Natural Gas Association of America:

25. 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.

26. 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.

To the National Association of Pipeline Safety Representatives:

27. 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.

To the Federal Geographic Data Committee:

28. 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.

<u>Previously Issued Recommendations Reiterated in this Report</u>

As a result of this Safety Study, the National Transportation Safety Board reiterates the following previously issued recommendation:

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.

Previous Recommendation Reclassified in This Study

As a result of this Safety Study, the National Transportation Safety Board reclassifies the following previously issued recommendation:

To the Pipeline and Hazardous Materials Safety Administration

> 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) Reclassified *Closed – Superseded*