Integrity Management for Pipeline and Infrastructure Safety

August 13, 2019

In the United States, 67% of natural gas transmission lines were installed before 1970[1] and 83% of gas pipelines (and 74% of liquid pipelines) were installed before 2000,[2] yet until the mid-2000s, there was no mandated process to assess their integrity. Previously, pipeline operators performed basic monitoring (e.g., cathodic protection) but rarely performed thorough integrity tests to ensure their pipelines were safe for continued use. In 2004, the Pipeline Hazardous Materials Safety Administration (PHMSA) supplemented maintenance requirements and began requiring natural gas transmission pipeline operators to perform periodic assessments to identify negative impacts from corrosion, construction damage, or other risks in areas where releases could have the most significant adverse consequences. This formalized system of assessing the integrity of pipelines and other infrastructure is called integrity management.

Fifteen years later, the integrity management process and the codes that regulate it continue to evolve. Ongoing discovery in the management of infrastructure assets is leading to new thinking about assessment methods, data interpretation, and the treatment of assessment trends. The availability of new technologies is also contributing to evolving industry best practices for effective integrity management and the associated regulatory codes.

Considerations for Effective Integrity Management

At a high level, when an operator is performing integrity management successfully, nothing happens. Pipeline corrosion and crack propagation are mitigated, third parties do not damage the pipeline with excavators, and so on. PHMSA requires utilities to track "reportable incidents" on an annual basis, which can serve as a metric for integrity management program success. For pipelines, this metric includes consequences for events that cause fatalities, property damage in excess of $50,000, and events that release gas in excess of an acceptable threshold.[3] Gas transmission operators, for example, report roughly 50–60 significant incidents per year.[4] The goal is to get that number as close to zero as possible.

All integrity management plans include three common components. Operators need to identify relevant threats to the asset, associate a risk to each threat, and assess the assets (pipelines) in a manner that will identify the presence of potential threats. Multiple assessment methods exist, many of which are continuing to improve over time. For example, operators can assess external pipe corrosion by pressurizing the pipeline with water to make sure it holds (strength testing), performing excavations at the most susceptible locations to evaluate the pipe condition (direct assessment), and/or in-line inspection (ILI), in which an instrumented piece of equipment travels inside a pipeline to identify abnormalities. ILI tools in

[1] Integrity Characteristics of Vintage Pipelines," Prepared by Battelle Memorial Institute for the INGAA Foundation, 2005.
[2] PHMSA Annual Gas Transmission and Gathering Data 2018; PHMSA Annual Hazardous Liquid Data 2017.
[3] PHMSA Incident Report Criteria History – Gas Distribution, Gas Gathering, Gas Transmission, and Liquefied Natural Gas (LNG) Incidents.
[4] https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends.

particular have advanced the assessment process by identifying smaller flaws with greater resolution. Not only has the clarity of assessment tools improved over time, but operators have also made strides in using these tools to address different threats. Stress corrosion cracking (SCC), for example, is often difficult to identify; however, recent developments in ILI technology have improved detection of SCC before leaks and ruptures can occur.

Continued Evolution of Regulatory Codes

Just as integrity management processes are evolving, so too are corresponding code requirements. In 2016, the U.S. Department of Transportation proposed a revision to gas pipeline code 49 CFR 192. While the revised codes have not yet been implemented, we expect they will edit details regarding what is and is not allowed in pipeline assessments.

Traditional integrity management has focused largely on high consequence areas (HCAs) along transmission pipelines but is currently expanding scope to additional transmission pipeline, beyond HCAs, as well as other assets. For example, the integrity management program was extended to lower-pressure distribution lines in 2009. Similarly, new regulations will require operators to better understand station and facility assets. As the industry collects more information and improves assessment processes, these learnings will be further implemented into operator practices and regulatory codes.

An Operator Case Study

Our team at Exponent recently partnered with an operator to overhaul their process for performing the direct assessment method of integrity management. We began by assessing the operator's existing standards and procedures and comparing them to code requirements, industry standards, and best practices. We then identified gaps in their program and developed end-to-end process improvements. This included new processes for identifying threats, timelines for reassessment, and metrics for measuring reassessment effectiveness. Once the new processes were developed, we worked with the operator to ensure correct implementation both moving forward and with retroactive application to past practices.

By rewriting this operator's integrity management standards and procedures, our team helped ensure their compliance with code requirements and best practices to optimize asset safety.

How Exponent Can Help

Exponent's multi-disciplinary team of metallurgists and materials, corrosion, mechanical, and thermal specialists are experts in the oil and gas industry and can partner with operators to understand integrity management assessment methods and limitations, assessment data, and the overall assessment process for optimizing asset safety.

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