Docket No. PHMSA-2011-0127 -- Submission by Interstate Natural Gas Association of America to "The State of the National Pipeline Infrastructure – A Preliminary Report"

June 22, 2011

Overview

The Interstate Natural Gas Association of American (INGAA) is a trade association representing approximately two-thirds of the nation's transmission pipelines and 90 percent of interstate pipelines. The INGAA membership consists of 26 different pipeline companies. There are approximately 300,000 miles of natural gas transmission pipelines in America, delivering one quarter of the nation's energy.

In December 2010, INGAA's board of directors established a board-level task force to pursue further improvements in the industry's safety performance and expand public confidence in the natural gas pipeline infrastructure. INGAA's commitment aligns with DOT Secretary LaHood's call to action that produced the April 18, 2011 National Pipeline Safety Forum. INGAA's transmission company members will participate actively in responding to the secretary's challenge. One of the forums INGAA will use for this response and dialogue with pipeline safety stakeholders is the filings in this Docket.

In March 2011, the board of directors of INGAA adopted the following aspirational guiding principles, anchored by the goal of zero incidents.

Guiding Principles for Pipeline Safety

1. *Our goal is zero incidents - a perfect record of safety and reliability for the national pipeline system. We will work every day toward this goal.*
2. *We are committed to safety culture as a critical dimension to continuously improve our industry's performance.*
3. *We will be relentless in our pursuit of improving by learning from the past and anticipating the future.*
4. *We are committed to applying integrity management principles on a system-wide basis.*
5. *We will engage our stakeholders—from the local community to the national level—so they understand and can participate in reducing risk*

The INGAA Approach

INGAA members are focused on a comprehensive approach and are committed to the process established by the board task force. A nine-point action plan has been developed to identify lessons learned during the baseline period of the Transmission Integrity Management Program (TIMP) and further opportunities to improve pipeline safety by applying integrity management principles. TIMP has driven tremendous progress and consistency across the industry and has produced a step change in pipeline integrity management. But despite those improvements, there still have been significant pipeline accidents, indicating that further improvement is needed. TIMP clearly is the right foundation from which to grow, expand, and improve.

Many INGAA members have implemented practices beyond those required by laws or regulations to enhance pipeline safety. INGAA's goal is to expand the use of practices that produce positive results and to achieve greater alignment across the industry.

Much of the work in these action plans is highly technical and may require extensive data collection and analysis. To this end, INGAA and its technical teams are coordinating with Pipeline Research Council International (PRCI) and the INGAA Foundation to collaborate, leverage, and build on the work, projects and studies being conducted or planned by those organizations.

The following nine action plans have been identified by the INGAA Pipeline Safety Task Force:

1. *Stakeholder Engagement and Outreach*: Facilitate two-way communication between stakeholders using meaningful pipeline integrity performance measures. Actively promote the Pipeline and Informed Planning Alliance, a joint government-industry-stakeholder initiative.
2. *Risk Management*: Continue application and enhancement of risk-management concepts beyond current regulatory requirements, which focus on high-consequence areas, including a comprehensive threat analysis for all transmission pipelines.
3. *Integrity Management Tools*: Enhance pipeline anomaly detection, response and remediation criteria, methods and management protocols.
4. *Pipelines Built Prior to PHMSA Regulations*: Develop an inventory and enhance protocols to manage integrity.
5. *Technology Development and Deployment*: Improve crack-detection tool capability; develop protocols for material threat management; work with PHMSA to produce an R & D roadmap; and define assessment alternatives for non-piggable pipelines.
6. *Management Systems*: Develop and apply management systems that support a strong implementation and maintenance of integrity management principles. Safety culture principles are a fundamental component of management systems, not just for public and employee safety, but also in developing a strong operational culture.
7. *Emergency Preparedness and Response*: Update isolation valve evaluation; enhance public awareness of pipelines. Enhance emergency responder communication and education regarding pipeline locations and appropriate response to pipeline emergencies.
8. *New Construction*: Fully implement the 2010-2011 INGAA Foundation Pipe Quality and Construction Action Plans

9. *Gas Storage:* Review and evaluate integrity management and risk mitigation programs and practices to enhance the public safety, environmental stewardship and service reliability of natural gas storage facilities.

Action Plan Information

INGAA will provide materials in this docket to inform stakeholders about the status of action plan initiatives, solicit input to inform INGAA's evaluation of potential pipeline safety innovations and implementation of those innovations that result from this process. As action plans are further developed, INGAA will update docket materials to keep stakeholders informed and seek further public input.

Four of the nine action plans are set forth below along with specific requests for stakeholder input. INGAA will continue to post developments in connection with these four action items. In addition, INGAA also will post information on additional action items over the coming weeks.

Action Plan 2 –Expand Risk Management Beyond HCAs

Current Situation

The regulations implementing the Integrity Management Program (TIMP) for gas transmission pipelines, 49 CFR § 192, Subpart O (*Gas Transmission Pipeline Integrity Management), were* promulgated in 2003. TIMP stands as one of the most important regulatory initiatives to improve pipeline safety since Part 192 was issued in 1970.

A fundamental part of TIMP was the development and application of an ASME consensus standard, B31.8S – *Managing System Integrity of Gas Pipelines*, which was based upon risk management concepts championed by DOT and consensus standard organizations. Several interstate gas transmission companies applied these concepts in pilot demonstration projects in the late 1990s and early 2000. These activities verified the value of applying risk management processes to assess and mitigate threats so that resources could be applied most effectively.

Risk management (*probability X consequence*) is the cornerstone of the Subpart O regulation. B31.8S served as the basis of the threat assessment and the mitigation component of Subpart O. This consensus standard established threat assessment and mitigation measures to prevent the failure of a pipeline or reduce the *probability* of such an occurrence.

The concept of High Consequence Areas (HCAs) was codified in the Subpart O regulation to address the *consequence* component of risk management. The definition of an HCA is based upon the structure density inside a circle known as the Potential Impact Radius (PIR). The size of the PIR around a pipeline is determined by pipeline diameter and operating pressure, which represent a measure of the energy that could be released by a pipeline rupture. Consequently, the higher the potential release of energy from a rupture, the greater the PIR. The HCA definition also incorporates the concept of an "identified site" in recognition of the fact that periodic gatherings of people at such a place would increase the possible *consequence* of a pipeline failure.

TIMP requires all gas transmission operators to assess and mitigate threats, utilizing Subpart O requirements, to their pipelines located in HCA by December 2012, 10 years after the regulation was effective. While only 4.5% of INGAA member pipeline miles are classified as being located within HCAs subject to IMP, a full 53% of INGAA-operated transmission miles have been assessed and mitigated using the standard integrity management process prescribed in B31.8S. Due to the configuration of pipeline systems, this extra assessment and mitigation was anticipated when Subpart O was promulgated.

INGAA's Objectives for Improvement

Data show that serious pipeline incidents involving the public have been declining over the past four decades. This is attributable in large part to new technologies and processes. Today, the U.S. pipeline infrastructure is increasingly safe as a direct result of implementing the DOT TIMP regulations over the last nine years and the application of ASME B31.8S integrity management programs by operating companies. These recent efforts also have resulted in a significantly reduced number of pipeline leaks caused by the leading threats.

While these results are encouraging, we believe that significant incidents still are occurring at an unacceptable level.

An important contributor to achieving INGAA's goal of zero incidents will be expanding improved standardized risk management practices beyond HCAs. INGAA's objectives in this regard are as follows:

- Apply integrity management principles on pipelines beyond the 53% already assessed and mitigated – the goal is to apply the principles to 100% of the interstate pipeline system.
- Commit to phasing the completion of this additional assessment, beyond existing HCAs, in future years based upon a consequence-based gradient
- Apply risk management principles to reduce the probability of an incident by implementing ASME B31.8S to assess and mitigate threats.
- Recommend enhancements to B31.8S to improve threat analysis by integrating data better. Also, evaluate the interaction of individual threats that increase the probability and severity of incidents.
- Recommend enhancements to future editions of ASME B31.8S to confirm the basis for concluding that resident material and construction threats remain stable and clarify the circumstances requiring an engineering review and possible assessment
- Assess the potential impact to interstate natural gas transmission operators and natural gas suppliers and consumers of various proposals to expand risk management beyond HCAs.

INGAA is focusing on these tasks using a team of industry and technical experts and will post updates as the work progresses. To inform this analysis further, INGAA encourages dialogue on the following questions:

1. *What integrity management principles should be applied to pipelines outside of HCAs – B31.8S or other alternatives?*
2. *How can the concept of stable threats be validated and properly understood?*
3. *How should the interaction of threats be evaluated to consider this phenomenon properly in the application of integrity management?*
4. *Should the application of integrity management principles expand based on ranking consequences or other criteria?*
    - *What would a surrogate model look like for population density near the pipeline (such as structure density)?*

    - *How could this model be used to establish the gradient for consequences to guide future assessments?*
    - *What other consequence factors could be considered (e.g., locations with historical, recreational or economic significance)?*
5. *What new assessment technologies and processes could be useful in expanded areas?*
6. *What additional data reporting requirements, if any, should be applied to all pipelines including those outside of HCAs?*

Action Plan 3 – Pipeline Anomaly Management

Current Situation

The management (categorization, prioritizing, mitigation) of metal loss anomalies identified in pipeline systems is addressed by two different regulatory requirements, depending upon whether the pipeline is within an HCA. For anomalies inside an HCA, a regulatory standard was developed using technically-based criteria of ANSI/ASME Standard B31.8S – *Managing System Integrity of Gas Pipelines*. In addition, the Subpart O regulations, applicable only within HCAs, require periodic reassessment of pipelines (every seven years).

For pipelines outside HCAs, the regulations (49 CFR §192.485) address corrosion mitigation, but provide no prescriptive requirements that relate to anomaly response criteria for in-line-inspection (ILI) or timing of responses. This provision was added in 1971 as part of an early amendment to the pipeline safety regulations. It was to address the mitigation of corrosion found during planned and unplanned excavations of a pipeline and subsequent visual inspection. The regulation was amended in 1996 and again in 1999, to include specific corrosion evaluation methods, ASME B31.8 (B31G), and a method developed by the PRCI (RSTRENG) for visual inspection.

In this regard, §192.485 provides guidance on analytical methods to be used in the visual inspection, but otherwise is structured as a performance-based standard rather than as a prescriptive requirement. When directly inspecting exposed pipe, an operator is expected to perform the analyses and take appropriate actions as required by these regulations. These responses must occur immediately.

With the advent of reliable, high resolution, and highly accurate in-line inspection tools for locating and characterizing metal loss anomalies in a pipeline, operators no longer must excavate a pipeline to evaluate accurately the significance of an anomaly. This development is the basis for the anomaly evaluation criteria in ASME B31.8S, which has proven to be an effective methodology.

In surveying how INGAA members manage anomalies identified using ILI on piping outside of HCAs, it was found that pipeline operators generally used the criteria in ASME B31.8S. While not required by regulation, operators do this because of the proven success in applying ASME B31.8S to mitigate the risk of failures due to corrosion anomalies. In other words, it is a generally recognized sound technical practice.

INGAA's Objectives for Improvement

Going forward, INGAA members recognize that learning from experience will be essential to improving safety further. Anomaly management represents a significant opportunity to apply lessons learned.

This portion of the INGAA action plan includes addressing the detection, analysis, response criteria and timing, and remediation guidance for three categories of anomaly:

- Corrosion – general, pitting, selective[1]
- Expanded or low strength pipe
- Dents – plain, with corrosion metal loss, with mechanical damage metal loss

INGAA's goal is to establish standardized guidance for mitigation for all the above anomaly categories. While INGAA is focusing on all categories, the first group to be addressed is pitting or metal loss anomalies. INGAA believes that metal loss anomalies that occur outside an HCA should be managed on the same basis, using ASME B31.8S, as anomalies occurring within an HCA. INGAA members acknowledge that current practices outside of HCAs vary somewhat among operators. INGAA is committed to standardizing practices based upon experience and sound technical criteria for reassessments. Also, some anomaly categories, such as general corrosion or selective seam corrosion, may require advances in technology or more conservative analysis to improve effective management.

INGAA is focusing on these tasks using a team of industry and technical experts and will post updates as the work progresses. To inform this analysis further, INGAA is encouraging dialogue on the following questions:

1. *What metal loss anomaly management criteria should be used outside of HCAs?*
2. *What uncertainties exist in connection with the inspection tools and analytic methods applied to detect metal loss anomalies and how should these uncertainties be adequately accounted for?*
3. *What technical criteria should be used for reassessment requirements outside of HCAs?*
4. *What, if any, technology or analytical gaps must be overcome to address matters within the scope of this action plan?*
5. *What information is needed to measure the performance of the assessment tools used to detect and characterize critical anomalies?*

[1] Time dependent anomalies, essentially selective seam corrosion of vintage seams such as early ERW and EFW, are included within this scope.

Action Plan 4 – Establishing MAOP and Valid Records for Pre-Regulation Pipelines

Current Situation

Pipeline safety regulations (49 CFR §192.619) provide both a design basis relying on records and a testing basis relying on pressure testing for establishing the maximum allowable operating pressure (MAOP) for a natural gas pipeline. These requirements were established in 1970 after extensive public comment[2]. While PHMSA has re-examined this issue on several occasions,[3] the requirements established in 1970 have essentially remained intact.

NTSB issued an investigative update on the San Bruno incident on December 14, 2010. The Board's investigators found that although some records of the pipeline operator, Pacific Gas and Electric Company (PG&E), indicated that the short pipe segments in the area of the rupture were constructed of seamless API specification pipe, the segments in fact were constructed of material with longitudinally-welded seams. Some of the materials and longitudinal welds did not meet the API specifications for pipe with longitudinally welded seams at the time of manufacture.

The NTSB was concerned that the seam-welded sections perhaps were not as strong as the seamless pipe that was indicated in PG&E's records. Because it is critical to consider the characteristics of a pipeline in order to establish a safe maximum allowable operating pressure (MAOP), the NTSB asserted that these inaccurate records may have led to a potentially unsafe MAOP.

To address this issue, the NTSB issued three safety recommendations to PG&E, two of which were classified as urgent, and directed the operator to do the following:

1. Conduct an intensive records search to identify all gas transmission lines that had not previously undergone a pressure testing regimen[4] designed to validate a safe operating pressure (urgent recommendation);
2. Determine the maximum operating pressure by engineering calculations based on the weakest section of pipeline or component identified in the records search referenced above (urgent recommendation); and
3. If unable to validate a safe operating pressure through the methods described above, determine a safe operating pressure by a specified testing regimen[5].

INGAA agrees with the NTSB recommendations recognizing that a valid MAOP can be established with a valid pressure test. In addition, where population has grown around older pipelines, regulations already require that MAOP be re-validated and re-established through validation of pressure testing, replacement or pressure

[2] PHMSA Docket OPS-3

[3] Amdt. 195–51, 59 FR 29384, June 7, 1994, as amended by Amdt. 195–53, 59 FR 35471, July 12, 1994; Amdt. 195–51B, 61 FR 43027, Aug. 20, 1996; Amdt. 195–58, 62 FR 54592, Oct. 21, 1997; Amdt. 195–63, 63 FR 37506, July 13, 1998; Amdt. 195–65, 63 FR 59479, Nov. 4, 1998

[4] Subject the installed pipe section to an internal pressure higher than the MAOP.

[5] Pressure testing or utilizing inspection technology to achieve equivalent results

reduction. Finally, interstate transmission pipelines in high consequence areas are assessed through techniques designed to verify the safety of pipeline operations at MAOP, most commonly through in-line inspection, direct assessment or pressure testing.

INGAA's Objectives For Improvement

The Following is the scope of this portion of INGAA's present action plan addressing standards for establishing MAOP and records verification for pipelines installed prior to regulations includes the following deliverables:

- Guidance for verifying the MAOP of pipelines installed prior to federal pipeline safety regulations (within and outside an HCA).
- Guidance for what constitutes a traceable, verifiable and complete record in determining MAOP.
- Guidance for when compensating measures such as pressure testing, in-line inspection or a pressure reduction shall be implemented where adequate records cannot be produced, drawing upon the approach developed by PHMSA for hazardous liquid pipelines in section 195.303.
- Guidelines for what constitutes a sufficient pressure test for verifying the MAOP of a pipeline installed prior to federal pipeline safety regulations
- Assess the potential impact to interstate natural gas transmission operators and natural gas suppliers and consumers of various proposals to re-verify MAOP of pipelines installed prior to federal pipeline safety regulations

INGAA is focusing on these tasks using a team of industry and technical experts and will post updates as the work progresses. To inform this analysis further, INGAA encourages dialogue on the following questions:

1. *What criteria must be considered to determine if a pipeline is fit for an intended service?*
2. *How should record requirements vary based upon the vintage of the pipeline?*
3. *In what cases should a pipeline not continue to operate at its current MAOP without a documented pressure test?*
4. *What is an acceptable pressure testing method, level, and duration for a baseline test of a pipeline installed prior to regulations?*
5. *Under what conditions should a pipeline segment be retired or replaced?*

Action Plan 7 – Pipeline Isolation Valves

Current Situation

Pipeline isolation valves are important for pipeline control management. Valve installations are designed and constructed at locations along the pipeline as prescribed by PHMSA regulations, ASME consensus standards, or as deemed by the operator to be critical for operation of the pipeline segment. Valve spacing requirements are primarily determined by structure density (class location) along and adjacent to the pipeline. The primary purpose for pipeline valves is isolation of a particular segment and stopping the continuous flow of gas within the pipeline. It may be necessary to stop flow within a pipeline during maintenance activities, anomaly assessments and repairs, leak assessment and repair and during the unlikely event of a gas release.

PHMSA regulations and ASME consensus standards prescribe the construction spacing of valves along a pipeline depending upon the density of structures along the pipeline corridor (class location). Valves are at closer intervals when a pipeline is constructed in more densely populated areas.

Valves fall into three primary categories:

- Manual Valves: Opened and closed by personnel on site.
- Remote Valves: Opened and closed remotely from a gas pipeline control center. These valves can also be opened and closed by personnel on site.
- Automatic Shut-off Valves: Valves close based on a sensor that detects if pipeline pressure drops or if gas flow direction changes. These valves can also be opened and closed by personnel on site.

Pipeline control centers are staffed continuously and designed to monitor gas pressure and flow along the pipeline remotely. Qualified professional controllers are trained to react to information indicating a potential pipeline emergency. This is transmitted to a control center by sensors and instrumentation on the pipeline system, by the public or by first responders. Realistic drills are performed to maintain readiness.

Several studies have analyzed the benefits of installing remote or automatic shut-off capability on pipeline valves, including a PHMSA study in 1999. Those studies stopped short of recommending deployment of these technologies. As a result, PHMSA regulations have not prescribed the type of valve operation or the pipeline operator's response to an incident. The exception is the category of new higher technology pipelines that are permitted to operate at higher stress levels. The regulations and special permits for these pipelines require that automated valves (remote or automatic) be installed if the personnel response time to close the valves would exceed one hour from notification of an incident.

Even without a prescriptive PHMSA requirement, INGAA members have selectively installed valves with remote or automatic shut-off valve technology. This has provided a wealth of experience that can be used to guide future practices.

INGAA Objectives for Improvement

Today, INGAA members are acting to enhance the protection of both people and property adjacent to a pipeline. INGAA's initiatives are intended to align members on a standard practice that reduces the consequences of a pipeline rupture. INGAA's members are committed to the following objectives:

- Improve coordination with emergency responders to raise their awareness and preparedness[6] for response to an incident.
- Evaluate potential enhancements that would accelerate all stages of the response to a pipeline rupture – rupture detection, the decision to close valves, and the time needed to reach valves, close them and evacuate the gas from the pipeline.
- Evaluate potential improvements in valve operation by adding remote or automatic capability, particularly in areas of high consequence or other locations of strategic importance.
- Determine the relative benefits of quicker valve operation versus shorter valve spacing intervals on mitigation of consequences
- Recommend enhancements to operator's preparedness capability in order to improve valve-closing response during an incident. Weigh the reliability of automated valves (including the consequences of nuisance failures). Provide comprehensive and systematic guidance for INGAA operators that meet these objectives acknowledging the unique configuration of each pipeline system.

INGAA members and suppliers are actively evaluating potential criteria to guide the deployment of enhanced valve capability. INGAA is seeking input from emergency responders, public officials and the public by meeting with various stakeholder groups to guide this evaluation:

1. *What must pipeline operators do to improve understanding and coordination with emergency responders and local officials?*
2. *What is the acceptable response time to close a valve depending upon the location surrounding the pipeline?*
3. *How should the type of valve operator be determined?*
4. *Absent a regulatory requirement, how could INGAA provide guidance to implement these improvements by all member-operators?*
5. *How should valve spacing be adjusted, if at all, when a class location change occurs?*
6. *Is there a basis to prioritize valve installation within high consequence areas?*
7. *How should automation of valves be considered versus reducing valve spacing?*

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[6] *Preparedness is defined as readiness to take actions necessary to control the incident. Response is defined as actions taken from the occurrence of an incident to conclusion of emergency responder involvement.*

Conclusion

The purpose of this information is to provide input to the authors of the DOT report, "The State of the National Pipeline Infrastructure – A Preliminary Report". These materials also should inform and engage stakeholders in a dialogue about how INGAA members can improve pipeline safety. If you would like to discuss these matters with an INGAA representative, or if you are interested in learning more about initiatives described here, please contact tboss@ingaa.org. If you are personally familiar with an INGAA member company, you can also contact them directly for guidance on how best to engage INGAA.