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Attn: Docket PHMSA–2008–0255
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INGAA Comments to
Pipeline Safety: Workshop on Anomaly Assessment and Repair

INGAA would like to file the following information to docket PHMSA–2008–0255 in order to clarify the INGAA position discussed in the previously filed document.

There has been Corrective Action Orders (CAO) published recently (Columbia Gas 420071017H and Transco 120081004H) that addressed the evaluation, response, repair and mitigation of anomalies found during in-line inspection. In addition PHMSA has proposed and finalized criteria in the rulemaking titled "**Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines".**

INGAA is concerned that these positions by PHMSA vary from accepted consensus standards and practices of the natural gas transmission pipeline industry. Also, it appears that the PHMSA positions vary between the recently published CAOs (e.g. Remedial Work Plans) and even with the newly published rule even though they are addressing the same technical issues.

INGAA held a meeting with PHMSA representatives on June 12, 2008 to explain the technical, operational and regulatory basis for the consensus practices and the results of those practices. PowerPoint slides that document the INGAA presentations at the meeting have been previously filed in this docket.

Attached is a white paper that INGAA authored on the "**Evaluation, Response, Repair and Mitigation of Anomalies Found During In-Line Inspection**". This paper describes the position of INGAA on this subject and provides additional justification for the positions that were discussed on June 12, 2008. While some of the positions that INGAA supports in this paper have no apparent conflict with specific sections of the recently released rulemaking on increasing MAOP, it does address conflicts with recently issued CAOs.

Respectfully Submitted by,

Terry D Boss

INGAA Proposed Approach to the Evaluation, Response, Repair and Mitigation of Anomalies Found During In-Line Inspection

Introduction

Interstate Natural Gas Association of America (INGAA) members, representing approximately two-thirds of the gas transmission pipeline mileage in the United States, met recently with PHMSA to explore outstanding issues and work toward a common understanding and agreement regarding the evaluation, response timing, repair and mitigation requirements for time-dependent anomalies found by in-line inspection on natural gas transmission pipelines. In this paper, INGAA sets forth an approach to managing time-dependent anomalies identified using in-line inspection (ILI) with a technical rationale for each element of the proposal that has a foundation in a consensus standard, research and where possible the regulations.

INGAA members are committed to preventing failures on their pipeline systems. They believe that consistency of approach to addressing anomalies on pipelines enhances safety. In general, INGAA members have elected to manage anomalies and make repairs using American Society of Mechanical Engineers (ASME) B31.8S as the technical foundation, whether in an HCA, or a non-covered segment, i.e., outside of an HCA. INGAA believes this approach is also valid for pipelines operating under Maximum Allowable Operating Pressure (MAOP) or "class location" Special Permits, and ultimately under a regulation addressing design and operation using higher design factors [as set in the Final Rule for Increasing the MAOP in Gas Transmission Pipelines, October 17, 2008]. INGAA also believes this approach is applicable to the work completed to support extending of integrity management reassessment intervals longer than seven years.

Background

This proposal addresses two topical areas:

1. Time-Dependent Anomaly evaluation and response, and
2. Defect repair and mitigation.

Anomaly evaluation and response pertains to the activities that occur after receiving a report from an ILI vendor, including evaluation of anomalies and pipeline data to determine which anomalies require action "are actionable"), and responding in a prudent and diligent manner. **Defect repair and mitigation** refers to those activities related to examining the pipe and subsequent repair and mitigation; including long-term preventive and mitigative measures.

The time-dependent anomalies under consideration have been further subdivided into two groups, one of which is a relatively recent consideration for natural gas transmission pipeline integrity considerations. The two groups are,

1. Time-dependent anomalies that can result in rupture of a natural gas transmission pipeline and,
2. Time-dependent anomalies that can produce leaks in natural gas transmission pipelines.

Time-dependent anomalies resulting in ruptures.
Anomalies that can result in ruptures are the focus of the integrity management regulations, 49 CFR 192, Subpart O. The anomaly evaluation methods noted in the regulations, primarily B31G and RSTRENG, provide the operator with guidance on the calculation of predicted rupture pressure of a pipeline in the presence of a corrosion defect (time dependent). The standard relied upon frequently in the Subpart O regulations, referred to as ASME B31.8S, also provides guidance, in Figure 4 and accompanying material, on response timing to corrosion anomalies based on their calculated failure pressure ratio, again, using the calculated rupture pressure. This standard is based on research, empiracle data and is reasonable, understandable, and was thoroughly discussed and vetted during the development of the Subpart O regulations.

A pipeline rupture is the event the integrity management regulations are designed to prevent. It constitutes the highest rates of energy release from a pipeline, the potential highest consequences, and has been the event given the most attention by PHMSA. A rupture is much more likely to rise to the level of a reportable incident, as defined in the regulations. Incidents must be telephonically reported within a few hours of occurrence, and require at least one written report, which has become more and more detailed over the years. Incidents may also result in regulatory actions, in the form of Corrective Action Orders, which require both actions and periodic reporting by the operator.

There has been some misunderstanding regarding the applicability of these analytical methods, such as RSTRENG, to relatively short, deep corrosion pits. Such pits are much more likely to result in leaks rather than ruptures. Generally, RSTRENG and B31G are not used on features deeper than 80% of the wall thickness. This is not, however, because the calculations become invalid at that point. The calculated failure pressures (ruptures) are still valid. Rather, a decision was made to limit the application of these methods to no more than 80% penetration because it was believed that remaining pipe wall thickness was close enough to perforation that an operator would have to take some action regardless of the result. However, the actions a natural gas transmission pipeline operator may take could be very different from those a natural gas distribution operator would take, due to the safety implications. A single, prescriptive approach between these two applications is not appropriate or justified here.

Time dependent anomalies resulting in leaks.
Historically, leaks on natural gas transmission pipelines have been regarded as not nearly the integrity threat nor the safety risk as ruptures. Recent INGAA analysis of the PHMSA reportable incident database confirms that belief. "Serious" and "Significant" incidents that are caused by these anomalies are reported to and cataloged by PHMSA and have been used as a data reference. This is not to say that they are disregarded or viewed as acceptable or not constituting any risk. There are many requirements in the regulations and in the underlying standards that provide guidance on surveying for and dealing with leaks. Examples are the leak surveys required as part of pipeline patrols and continuing surveillance, the instrumented leak detection surveys required in specific locations, the information on recognizing, reporting and responding to leaks that is required to be part of the public awareness programs, and the requirement that potentially hazardous leaks be repaired.

Natural gas transmission leaks are not ignored. However, historically, the management of potential leaks has been different than the management of potential ruptures. This is clear from the differential PHMSA reporting requirements and categorization. In contrast to the attention given ruptures that rise to the level of a reportable incident, a leak typically does not rise to that level and is reported on the PHMSA natural gas transmission pipeline annual report. Additionally, If a leak occurs in a high consequence area, it is also reported on the semiannual gas transmission integrity management program report. The differentiation is also clear from the PHMSA regulatory treatment of pipeline casings. PHMSA has noted that an operator, after unsuccessfully attempting to clear a cathodic protection electric short, may sniff the casing to detect leaks at a moderately increased frequency from normal rather than taking more drastic action. Also, during the development of the natural gas transmission integrity management regulations, leaks were not considered in the determination criteria of high consequence areas. Elevating leaks as an integrity and safety concern on natural gas transmission pipelines to the same level a ruptures is a bit problematic at this time, as guidance and criteria similar to those applied to ruptures have not been developed.

In comparison, leaks are a prime focus on distribution systems. Distribution systems are typically pipelines of a size and operating pressure that minimizes the probability of rupture. These pipelines are also much more likely to be in close proximity to occupied structures, other utilities and other concentrations of population. Further, the much lower operating pressures make a readily-identifiable blowing leak, such as may be experienced on a transmission line, much less likely, while more likely resulting in a difficult to detect underground migration of the escaping low pressure gas.

While it is technically correct and reasonable to have a different assessment of leaks depending on whether they are on a transmission or distribution line, there may be some commonalities. Distribution operators typically grade leaks depending on proximity to occupied structures. A similar approach may be valid for transmission lines, perhaps utilizing criteria such as those already developed for reporting a safety-related condition.

Anomaly Evaluation and Response

INGAA Proposal: Anomaly response and evaluation will be managed using Figure 4 and Table 3 of ASME B31.8S. Anomalies with a failure pressure ratio (FPR) of 1.1 or less will be managed as an immediate. In addition, anomalies greater than 80% in depth but with an FPR > 1.1 will be managed as a near-term potential leak and be evaluated per safety-related condition type criteria or managed as a scheduled response condition, whichever is more stringent.

Technical basis: Time dependent anomalies with an FPR < 1.1 require immediate examination as per ASME B31.8S. Time dependent anomalies greater than 80% in depth but with an FPR > 1.1 do not require immediate examination. The basis for establishing the 80% threshold is that the corrosion evaluation methods are not typically applied above a limit of 80% through wall, as stated in ASME B31G, Part 2[1], because the anomaly is believed to be near perforation and should be evaluated as a potential leak, if not overridden by a low FPR.

It is important to understand the basis for the use of 1.1xMAOP. The basis or the 1.1 relies on the requirements for over pressure protection at 192.201(a)(i). That is, the pipe will not ever see more than 1.1xMAOP, as the OPP will moderate the pressure. This provides time for the operator to schedule an examination.

INGAA Proposal: Anomalies with a FPR greater than 1.1 and less than the SMYS equivalent will be scheduled using Figure 4. In addition, when the operator has information that corrosion rates in a segment are greater than the basis used for Figure 4, the operator will develop a schedule for excavation of anomalies that applies the more conservative corrosion rate[2].

Technical basis: While Figure 4 was developed to be conservative in most instances and to provide a basis for a simple, prescriptive approach, there is a concern that there can be situations where Figure 4 is not sufficiently conservative. The developers of ASME B31.8S foresaw this possibility and in paragraph 7.2.4 required the operator to perform analyses to assure that the time-dependant defect will not grow to a critical size before the scheduled response.

Additional Discussion: INGAA members are sensitive to the concern raised by PHMSA personnel regarding the potential for short, deep anomalies to grow to a depth of 80% faster than they may grow in depth and length to 1.1xMAOP. However, knowing PHMSA's commitment to being data driven, INGAA is unaware of the specific data or experience driving PHMSA's concern in this regard. In submitting this, INGAA formally requests PHMSA to provide the data and analysis of the actual known events.

The remaining life methods are typically not applied above this limit of 80% of depth, not because the calculations no longer apply, but rather because such features are much more likely to result in leaks rather than ruptures. The behavior of short, deep anomalies was considered in the initial development of Figure 4 and its use with B31.8S. It was

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[1] - The limit of 80% is a limit of application from a practical standpoint rather that a limitation of accuracy (Kiefner).

[2] - Segment specific knowledge can be applied for rates that are known to be slower than the rate derived from Figure 4; however, operators will not apply this approach until there are at least two completed ILI runs on the segment.

acknowledged that given the nature of corrosion pits that an anomaly can grow to 80% depth sooner than it may grow in length and depth to reach the 1.1xMAOP threshold. It is important to note that when very short, deep anomalies grow, they grow in depth, will perforate, and result in a leak. Short, deep anomalies that grow in length and depth will likely grow in a manner that is modeled by the methods applied in Figure 4, and should be identified before they result in a rupture.

ASME B31G also specifically addresses short deep anomalies. One of the steps in the evaluation process is the determination of the maximum allowable longitudinal extent of corrosion, as described in Figure 1-2, page 6. If the length of the corrosion is less than or equal to the value calculated in Part 2 (or found from the table), then the operator is to arrest further corrosion and return to service.

While the results of many of the ILI runs that have conducted on natural gas transmission systems within the past decades have shown the long term effectiveness of the corrosion protection systems in mitigating corrosion, the industry has chosen to utilize conservative default corrosion (not protected by corrosion protection systems) rates where additional information is not available.

Consider an example with 30-inch diameter pipe with 0.281-inch nominal wall thickness. This is a worst-case example of a typical pipeline that will utilize ILI technology, as this example has a higher diameter/thickness ratio of 107 than most pipelines in service and therefore has less wall thickness. PHMSA personnel have expressed concern about the growth of even a 60% of wall thickness deep pit to a leak or failure prior to the next ILI assessment. The anomaly that is 60% in depth has approximately 112 mils of pipe wall material remaining.

If one uses a conservative corrosion growth rate of 12[3] mils per year, this results in 9.3 years to perforation (leak), and with 9 mils per year, this results in 12.4 years to perforation; both of which are greater than default seven years assement period required by the IMP rule, so

[3] Typical corrosion rates for unprotected, pipe with a coating defect have been observed in the range of 1 to 6 mils per year. PHMSA personnel frequently quote 16 mils per year used in the NACE ECDA RP 0502. The rate of 16 mils was to be applied as a default rate where no other information were available; 12 mils could be used where the system had been under cathodic protection for much of its life. It is important to note that the rate used in the NACE RP was selected through consensus to represent a very conservative position since ECDA was a new method. It is inappropriate, or at best overly conservative to apply these rates when evaluating ILI data.

these corrosion anomalies would be observed again during a future ILI run, prior to the possibility of perforation (leak) due to non-protection by corrosion protection systems. A refined and localized "assumed corrosion rate" can be utilized to optimize this determination but additional location specific information is needed.

In developing this proposal, INGAA considered a number of examples and found that while the timeframe to grow to 80% in depth may be shorter may be slightly shorter than to rupture, given the conservatism built into Figure 4 and the fact that the growth is developed to 1.1xMAOP, and not to failure, use of timing in Figure 4 is appropriate.

After considering the historical perspective, available data and the conservative nature of the approach, INGAA believes **reaffirmation of Figure 4 for scheduling anomalies remains a sufficiently conservative and appropriate basis.**

To further provide clarity on this subject, the ASME B31 Committee will consider an (AI) on this topic. INGAA members believe that this type of change is best undertaken through the deliberative process undertaken under the ANSI-based consensus standards development code. INGAA expects that members of the Committee (including PHMSA) and INGAA staff will apprise PHMSA of progress. In addition, the Committee will benefit from the presence of Mr. Mike Israni, of the PHMSA staff, on this and others matters under consideration as a member of the Committee.

It is important to understand that the current consensus standards and PHMSA regulations recognize that leaks will occur and are managed by operators. INGAA recognizes the concern with leaks that might be hazardous to people and property. The current regulations address management of leaks through prevention, patrolling and leak surveys. In addition, in the MAOP NOPR, PHMSA proposed more stringent design construction operation and maintenance requirements to address corrosion issues. One of those practices is more frequent patrolling as well as more frequent leak surveys. INGAA members agree that the frequency must be increased and provided specific criteria in their comment responses.

Differences between discovered anomalies in High Consequence Areas (HCAs) versus non-covered segments, i.e., those outside of HCAs.

In general, there are none. INGAA members expect to treat time-dependent anomalies the same. **It is important to note that for non-covered segments, i.e., outside of HCAs, the standards and regulation are performance based, and do not specifically require the use of B31.8S.** INGAA members' offering to apply Figure 4 outside of HCAs is not required by PHMSA and is believed to be prudent. As such, while members have largely elected to adopt the use of B31.8S, and specifically Figure 4 and Table 3 for anomaly evaluation and response, operators can modify their approach, even relying on B31.8S to account for local conditions, predicted corrosion rates and other factors.

<u>Repair and Mitigation</u>

INGAA Proposal: Time dependent anomalies identified by the "anomaly evaluation and reponse process" will be visually examined and those found to have a safe operating pressure less than or equal to MAOP will be repaired or cut out. Time-dependent anomalies that are found to have a safe operating pressure greater than MAOP can be recoated, backfilled and returned to service.

Technical Basis: The examined pipe will be repaired to maintain integrity based on the Specified Minimum Yield Strength (SMYS), which is a conservative measure of the strength of the material. For pipe that has a safety design factor of 72% the repair threshold would be 1.39xMAOP. Conversely, for a 0.6 design factor it would be 1.67xMAOP and 2.0xMAOP for a 0.5 design factor. Under all circumstances, the pipe, whether repaired, cut out and replaced, or left in place following examination, is recoated with brand new materials, reestablishing the first line of defense in corrosion control and be subject to a review of the effectiveness of the corrosion protection system.

INGAA Proposal: In areas where the "class bump" has been taken to maintain the original MAOP as provided for in 49 CFR 192.611, the repair will be made to SMYS based on the established MAOP.

Technical Basis: The basis for this is established in ASME B31G, Part 4.

Differences between defects in High Consequence Areas (HCAs) versus non-covered segments, i.e., those outside of HCAs.
The repair criteria are the same. There are differences in the preventive and mitigative measures used within HCAs, as they are managed to a higher standard, a greater level of care. The preventive and mitigative measures are set forth in ASME B31.8S, Section 7.7, and specifically in Table 4, and in 49 CFR 192.935. It is important to note that there are preventive and mitigative measures that are applied in non-covered segments as established in ASME B318 and 49 CFR 192, Subpart I – Requirements for Corrosion Control, including requirements for coating, cathodic protection, monitoring of cathodic protection, isolation and management of interference currents and periodic testing of potentials to ensure adequate coverage. In either case, there is a broad array of preventive and mitigative measures used.

Summary

In summary, INGAA concludes and recommends the following:

1. ASME B31.8S Figure 4 and accompanying material are valid the timing of responses to corrosion anomalies found by ILI.

2. RSTRENG and ASME B31G are valid methods for determining the calculated failure pressure of corrosion anomalies and defects.

3. Short, deep features (> 80% wall loss) with a relatively high FPR should be treated as a near term leak and evaluated using criteria similar to those for reporting a safety-related condition. Further, if the operator has information suggesting such features are stable rather than active, and they do not meet the action criteria, they may be treated as monitored.