BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
UNITED STATES DEPARTMENT OF TRANSPORTATION
WASHINGTON, D.C.

Pipeline Safety: Public Workshop on the Integrity Verification Process	Docket PHMSA-2013-0119

COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA ON THE PHMSA DRAFT INTEGRITY VERIFICATION PROCESS

Contents

Executive Summary

The Interstate Natural Gas Association of America (INGAA) is a trade organization that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America.

INGAA is comprised of 25 members, representing the vast majority of the interstate natural gas transmission pipeline companies in the U.S. and comparable companies in Canada. INGAA's members operate approximately 200,000 miles of pipelines, and serve as an indispensable link between natural gas producers and consumers.

While the safety performance of natural gas transmission pipelines has been improving steadily for decades, it is the goal of INGAA to continually improve. Appendix A depicts the present safety performance and provides a foundation to base further actions.

INGAA has a strong commitment to pipeline safety, and its members have publicly stated a goal of zero natural gas transmission pipeline incidents. This closely aligns with goals of both the Pipeline Safety and Hazardous Materials Safety Administration (PHMSA), as the federal pipeline safety regulator, and the expectations of the public. INGAA's members have articulated a set of specific commitments[1] to achieve that safety goal, a component of which is called "Fitness for Service for Reconfirming Maximum Allowable Operating Pressure,"[2] while continuing to transport natural gas reliably to their customers.

In late June, PHMSA issued a one-page flow chart reflecting its draft Integrity Verification Process (IVP) for natural gas transmission pipelines. The chart was published with no supporting technical documents.

PHMSA hosted a public meeting on August 7 to provide an overview of the draft process and seek input from stakeholders. PHMSA also presented the draft to the technical advisory committees on August 9, and it allowed members of the committees to provide input and perspectives. INGAA appreciates these and other opportunities to learn more about the rationale for the proposed process that is depicted in the flow chart.

Still, in writing these comments, INGAA had no comprehensive proposal on which to opine. As such, it will base its comments herein on its interpretation of the flow chart, open meetings and discussions with PHMSA staff.

Using this basis, INGAA believes the draft PHMSA IVP incorporates certain aspects of INGAA's Fitness for Service (FFS) process for reconfirming maximum allowable operating pressure

---

[1] Appendix B: Summary of INGAA Commitments

[2] The term "reconfirmation" is used as it is in the Pipeline Safety Act 2011, Section 23(a)(1)(A) to denote that operators will be reconfirming MAOPs that were confirmed in the early 1970s under 49 C.F.R. § 192.607.

(MAOP) and INGAA's Integrity Management Continuing Improvement (IMCI) initiative, which extends and improves integrity management beyond current High Consequence Areas (HCAs).

INGAA, following a two-year effort, developed the FSS process to reconfirm the MAOP of a pipeline as originally installed. The foundation of FFS is a proven, engineering-based set of processes used consistently for several decades by the energy and process manufacturing industries (refining, petrochemical, electric power, food, beverage, chemical, pharmaceutical, consumer packaged goods, and biotechnology, etc.) and now embodied in ASME B31.8 and B31.8S. INGAA utilizes FFS in this context as a one-time process for reconfirming MAOP.

INGAA's IMCI process is superior to PHMSA's proposal because it will permit operators and the regulator to prioritize work on highest-risk segments and minimize customer service interruptions, while still providing a comparable level of safety. The IMCI process does this by clearly separating MAOP reconfirmation from extending Integrity Management (IM). In contrast, PHMSA's process, as INGAA appreciates it, seems counterproductive because it requires work of increasingly diminishing value and frustrates prioritizing work on segments at greatest risk.

Based on its interpretations, INGAA offers the following high-level comments on PHMSA's IVP proposal:

1. MAOP verification and IM should not be combined into a single process.

PHMSA's apparent decision to combine MAOP verification and IM into a single process is troubling. Combining these two processes would create unnecessary complexity and would undermine both PHMSA's and the industry's ability to prioritize MAOP verification and IM work appropriately.

There are two primary reasons that IM and IVP should be addressed separately. Doing so would:

- **Enable appropriate prioritization.**
  INGAA does not believe that combining MAOP verification and IM in a single process will facilitate prioritizing pipeline safety work in a manner in which the highest priority projects in each category are addressed first. Instead, combining the two work streams into a single process may result in muddled prioritization and counterproductive tradeoffs. Addressing a threat such as external corrosion may require an operator to conduct an assessment (for INGAA members, typically using an in-line inspection (ILI) tool) sooner than a test for material strength would be conducted for MAOP reconfirmation. As a result, an operator would be unable to prioritize work on highest-risk segments. INGAA's IMCI commitments, in contrast, allow for such prioritization, while ensuring a comparable level of safety and minimizing customer service interruptions.

  Also, the IVP Engineering Critical Analysis option uses measures that are pertinent solely to IM, such as a Close Interval Survey (CIS) or an interference survey. Prioritization of those surveys may, and likely will, be different than material strength testing for MAOP reconfirmation.

Finally, the initial, or baseline, phase of the gas transmission sector's integrity management work in (HCAs) was completed on December 17, 2012. Prioritization of work on segments in HCAs is now done based on completion of the baseline. Work to be done for HCA segments that are untested or that lack records to reconfirm the established MAOP may need to be done using different criteria for establishing priority.

- **Lead to process simplification.**
  Reconfirmation of MAOP is a one-time process. By contrast, IM is an ongoing process for the life of the pipeline. Reconfirmation of a segment MAOP can be accomplished absent complete records. In fact, that is the basis of INGAA's approach, and it is the approach being used by the California Public Utilities Commission (CPUC) in that state.

  Based on INGAA's review of the IVP flow chart, it would appear that PHMSA frequently will need to make case-specific determinations about the required work to address particular elements in IVP for individual pipelines or even individual pipeline segments. For example, where validated, traceable material documentation is lacking or missing, IVP would require a case-specific approach to testing pipe properties. This has the potential to overwhelm PHMSA's already limited resources, and result in delays that would frustrate all parties concerned. Further, this process would be less transparent to pipeline safety stakeholders and has the potential to produce inconsistent and unpredictable results.

  Finally, MAOP reconfirmation work and IM require different activities. Conducting both with the same priority, at the same time, will make access to the segment more challenging and likely will cause more extended service outages, which may affect consumers. For all of these reasons, INGAA believes that separating IM from MAOP verification will greatly reduce the likelihood of these undesirable results.

2. INGAA fully supports extending and improving IM.

INGAA fully supports extending IM. The concept of Medium Consequence Areas (MCAs), which was unveiled in the IVP flow chart, appears consistent with INGAA's commitment to prioritize extending the application of IM principles to protect all people along the pipeline. As currently expressed in IVP, however, the designation of MCAs appears to rely on a combination of class location and application of the Potential Impact Radius (PIR) analysis. An approach relying solely on PIR would result in superior risk prioritization and allocation of resources.

INGAA recognizes that there are two dimensions to build upon the success of the baseline IM program:

1. Extending IM - Increasing pipeline mileage covered by IM; and

2. Improving IM - Determining what additional practices should be added to IM and establishing a risk-based analysis of where they should be added (e.g., applying IM principles to 90 percent of the population by 2012, and applying IM as defined by ASME B31.8S to 90 percent of the population by 2020).

PHMSA needs additional time to develop the specifics for extending and improving IM in order to craft a well-reasoned plan. INGAA supports PHMSA's stated intent to hold a public meeting to review the lessons learned from the first decade under the natural gas transmission IM rules and to formulate approaches for extending IM.

Pursuant to the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act of 2011), the Secretary is required to report to the Congress on whether to extend IM beyond HCAs within two years of enactment.[3] Absent a determination by the Secretary that a risk or imminent hazard exists, that law limits the ability to issue final rules extending IM until one year after completing the report to Congress or three years after enactment. Given this direction from Congress, it is premature to propose extending and improving IM as part of IVP.

PHMSA, in its IVP, identified it wanted a better understanding of the material properties of pipe. INGAA's members fully appreciate the importance of understanding what pipe is in the ground. One aspect of improving integrity management is ensuring that material records are available for use in risk assessment, assessment planning, anomaly evaluation and response, and selection of prevention and mitigation measures. Every time the pipe is exposed during an excavation for operations and maintenance or integrity-related activities, it provides another opportunity to confirm the material properties of the pipe when needed. These excavations, as part of IM, provide a sounds basis for confirming material properties and pipe condition. As a result, a better understanding of material properties should be part of PHMSA's effort to improve IM.

3. A single pressure test during a pipeline's life is an adequate basis for reconfirming an MAOP.

A single pressure test at 1.25 times MAOP during a pipeline's life adequately establishes strength for purposes of establishing a valid MAOP. This pressure test establishes a safety margin between the test pressure and the operating pressure (that is maintained for the life of the pipeline). This single test is adequate for establishing MAOP because the operator uses ongoing operation, maintenance, and integrity management activities to manage the condition of the pipeline. When the condition of the pipeline is found to have deteriorated, it is evaluated using proven methods to ensure safe continued operation, or repaired or replaced to ensure the safety margin is restored. Therefore, there is no demonstrated reason that pressure tests should be run on a recurring basis for MAOP reconfirmation.

[3] Appendix C: Selected Requirements in the Pipeline Safety Act

In cases where a pipeline has been pressure tested, but not to the level of 1.25xMAOP, that original test should be augmented with other testing and engineering analysis to confirm an appropriate safety margin, thereby reconfirming the MAOP.

4. FFS should be used as the basis for addressing previously untested pipelines and pipelines lacking adequate records.

Previously untested pipelines or those lacking adequate records to support a segment's MAOP can be addressed using an FFS process to establish the MAOP as originally installed. FFS is the pipeline's ability to operate in a manner that ensures the safety of the people that live and work nearby and protects the environment while allowing operators to dependably transport natural gas. FFS is based on established consensus standards, many of which PHMSA has incorporated into its regulations. Use of FFS is consistent with the Pipeline Safety Act of 2011, allowing for the use of hydrostatic testing and, alternatively, technology such ILI. In this context, INGAA utilizes FFS as a one-time process for reconfirming MAOP.

5. INGAA members will work with PHMSA to demonstrate use of ILI in lieu of hydrostatic testing.

INGAA members are working with the American Gas Association, ILI providers and research organizations such as the Pipeline Research Council International and the Gas Technology Institute to commercialize ILI for use in lieu of hydrostatic testing for reconfirming MAOP.

Unlike a hydrostatic test, which is simply pass-fail, ILI reveals information about the condition of the pipe, including sub-critical anomalies. It is in the mutual interest of operators and PHMSA to demonstrate the effectiveness of ILI to better understand risk and manage it.

6. Application of FFS has the desired effect of deleting provisions of the grandfather clause that cause concern to stakeholders.

Following the San Bruno pipeline investigation, the National Transportation Safety Board (NTSB) recommended that PHMSA delete the "grandfather clause" and require a hydrostatic test.[4] INGAA proposes that PHMSA amend 49 C.F.R. § 192.619 to add a provision requiring pipelines to evaluate the fitness for service of previously untested pipelines. This would have the effect of removing the aspects of the grandfather clause that concerned NTSB, Congress and other stakeholders by ensuring that pre-1970 pipelines in HCAs, and Class 3 and 4 areas are tested for material strength.

---

[4] Appendix D: The National Transportation Safety Board's (NTSB) Recommendations Resulting from the Pacific Gas & Electric Company Incident in San Bruno, CA

7. PHMSA currently lacks a credible basis for establishing a cost-benefit analysis of IVP.

INGAA members have searched aggressively and diligently for records establishing the MAOPs for their pipelines. INGAA members reported the mileage of pipelines that are missing records in Part Q of PHMSA's annual report. INGAA members also reported the mileage of previously untested pipelines in Part R of the annual report.

Regrettably, the instructions for completing the annual report were inconsistent with the approach outlined in the IVP. In basic terms, the annual report guidance permitted an "either-or" verification proposition, while the IVP, in Diamonds 2-5, took an "and" approach, requiring four layers of records before the records for a pipeline were deemed acceptable. In addition, the annual report does not collect data that would permit PHMSA to analyze affected MCA mileage. More detail on PHMSA's conflicting actions is in Appendix E.

If PHMSA proceeds to issue a rule that incorporates the IVP, as proposed, it cannot rely on data from the annual report as the basis for its cost-benefit analysis of that rule. This is because the annual report data would grossly understate the pipeline mileage that would need to be tested pursuant to the IVP. Further, section 23(d)(3) of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pipeline Safety Act of 2011) requires the Secretary to consult with the chairman of the Federal Energy Regulatory Commission and state regulators to establish timeframes for the completion of testing that take into account potential consequences to public safety and the environment and that minimize cost and service disruptions. Again, the annual report data could not be the basis for the analysis in connection with this consultation because it would grossly understate the mileage for which testing may be required and, therefore, grossly understate potential costs and service disruptions.

8. Limit the scope of reconfirming MAOP.

During the August 7 public meeting, PHMSA stated that it intended to limit the scope of IVP to mainline pipe and associated valves and fittings. In other discussions, however, PHMSA has been more ambiguous with respect to the intended scope of IVP. INGAA believes PHMSA should clarify that IVP will be limited to mainline pipe and associated valves and fittings on the basis that other facilities and small appurtenances pose significantly lower risk to the public due to their proximity and design.

Background

A shared goal of zero

INGAA has stated consistently that the goal of the association and its membership is zero natural gas transmission pipeline incidents. This principle closely aligns with both PHMSA's goal as a federal regulatory agency and the expectations of the public. INGAA has articulated a vision on how to achieve that safety goal—its FFS program and other initiatives—while reliably transporting natural gas to its customers. INGAA's vision builds upon a firm foundation of pipeline regulations and an industry commitment to continued safety improvement. INGAA now seeks to augment and improve upon past processes that have contributed to achieving many safety goals. Since the development of the first federal pipeline safety regulations in 1970 and continuing through the implementation of the formalized Integrity Management Program, PHMSA and the industry cooperatively have developed programs and regulations to improve the safety of the public near natural gas transmission pipelines.

Recognition of recent pipeline incidents

Unfortunately, some tragic pipeline incidents still occur, affirming the need to reassess processes and practices used to manage the safety and integrity of the transmission system. One of the latest incidents was the tragic rupture and fire in San Bruno, California in 2010 that resulted in eight fatalities. This event spurred regulators, federal investigators, lawmakers and the industry to re-evaluate pipeline safety programs and work toward avoiding similar events in the future.

INGAA Commitments (IMCI)

For its part, INGAA initiated a set of activities to review the processes that natural gas system operators use to manage the integrity of their pipelines. This extensive effort was called the Integrity Management Continuous Improvement (IMCI) initiative. The focus of this effort was to affect changes to INGAA members' practices and processes to further improve pipeline integrity and consequence management. This two-year IMCI effort was informed by experience implementing the formalized integrity management programs, lessons learned from recent pipeline incidents, and input solicited from stakeholders, including pipeline safety advocates, regulators and others. The IMCI efforts resulted in the INGAA board of directors adopting pipeline safety commitments, which were anchored by a goal of zero pipeline incidents.

PHMSA embarked on initiatives to address concerns raised by NTSB's investigation of the San Bruno incident. It also prepared for regulatory action based on direction from Congress and advice from NTSB. Concurrently, Congress reassessed the roles and responsibilities of PHMSA and provided specific action items for the regulator in the Pipeline Safety Act of 2011.

PHMSA Integrity Verification Process (IVP)

PHMSA proposed a draft process entitled, the Integrity Verification Process (IVP), on June 28, 2013 to address many of the recommendations and mandates outlined by the NTSB and

Congress. The proposal has generated many discussions between PHMSA and stakeholders. PHMSA held a public meeting on August 7 to provide an overview of the draft process and seek input from stakeholders. PHMSA also presented the draft process to the technical advisory committees on August 9 and allowed members to provide input and perspectives. Still PHMSA has not yet provided any written material providing guidance for how pipeline operators would implement IVP.

INGAA, following a two-year effort, developed the FSS process to reconfirm the MAOP of a pipeline as originally installed. FFS is a proven, engineering-based set of processes used consistently for several decades by the energy and process manufacturing industries (food, beverage, chemical, pharmaceutical, consumer packaged goods, and biotechnology, etc.) and now embodied in ASME B31.8 and B31.8S.

Additional Technical Input Requested by PHMSA

During the August 7 public meeting, PHMSA requested input on specific technical requirements. PHMSA pointed out that certain aspects of the IVP were under development and staff requested input. INGAA seeks to answer questions posed by PHMSA during the public meeting in the sections below. The technical input provided below draws upon work by INGAA over the past 2.5 years. INGAA continues to advocate that its FFS process for reconfirming MAOP provides additional details lacking in the proposed PHMSA IVP.

How does a strength test relate to a pressure test?

The strength test, sometimes referred to as a "proof test," is the initial portion of a pressure test that is conducted at a desired pressure level, and often held for a specific period of time, to establish or provide "proof" of the strength of the pipe. Pressure tests conducted after the pipe is installed typically include a "leak test." This portion of the test, as the name denotes, is used to detect or confirm a leak. Leaks are indicated by a pipeline pressure drop. The drop in pressure may be gradual if the leak is small. By contrast, if a test failure in the pipe results in a rupture, the pressure will fall rapidly. Water leaking from the pipeline during a failed test will be found near the pipe perforation.

How is the duration of a pressure test determined?

The duration of the "proof" portion of the pressure test typically is the time required for the pressure to stabilize in the test section. The duration is a function of the test section's length, elevation changes on the section of pipeline and temperature. Typically, the segment to be tested is stabilized within 30 minutes to an hour of the test's start. In a report prepared for GRI in 2001, Robert Eiber and Brian Leis stated,

> Strength re-tests of pipelines should be conducted using high pressures (90-110% SMYS) and held for 30 minutes at maximum pressure. The pressure should then be decreased to 90% of the test pressure and held for as long as necessary

> for a leak check. This will eliminate defect growth during the leak check and minimize growth during the pressure test.[5]

In a paper at IPC in 2004, Brian Leis stated that,

> It is emphasized that a one-hour-long hold at maximum pressure remains a viable upper bound for typical ductile line pipe. As this hold time also leads to ductile tearing along the tips of the larger defects remaining in the pipeline, care must be taken to select the hydrotest parameters consistent with the purpose of the test and the properties of the line pipe body and seam.[6]

When a pipeline is tested at a manufacturing mill, a pipe joint (typically 40 feet in length) is tested for approximately ten seconds. This is the time needed to stabilize the pressure within the pipe joint. Pipe with a sufficiently large flaw in the pipe body or with a long seam that does not have sufficient strength will fail during the test pressure. The higher the test pressure, the smaller the flaw size required to fail a test. As soon as the pressure stabilizes at the desired level, the strength is established or the pipe fails. Therefore, the short duration mill test is as effective as a field pressure test for the purpose of establishing fitness for service for the long seam and pipe body.

A field-pressure test on multiple miles of installed pipe takes a longer period to stabilize. As stated above, the time required to stabilize a long-field test segment, while a function of the segment length, typically is 30-60 minutes.

Pressure Testing Level and Spike Testing

Why is a 1.25xMAOP pressure test sufficient for validating MAOP?

From an engineering standpoint, a pressure test of 1.25 times the MAOP establishes an adequate safety margin above the maximum operating pressure. Lower test pressures also may be acceptable under certain conditions, but the 1.25xMAOP test level has been shown effective in virtually all studies, and it has been accepted by safety and regulatory authorities as adequate under all conditions. The 2010 edition of ASME B31.8 requires a pressure test to 1.25 times MAOP in Class 1 and 2 locations.[7] This level of testing also matches the ASME B31.4 requirements for hazardous liquid pipelines.

Why shouldn't pressure tests for MAOP verification be repeated multiple times?

The current language in 49 C.F.R. § 192.619(a) imposes four criteria that potentially limit the MAOP. One of those four criteria is the highest operating pressure experienced in the five

---

[5] Eiber, Robert and Brian Leis, "Review of Pressure Retesting for Gas Transmission Pipelines," Battelle Memorial Institute, GRI-01/0083, Feb 2001. SMYS is the specified minimum yield strength.

[6] Leis, Brian, "Hydrotest Protocol for Applications Involving Lower Toughness Steels," IPC04-0665, ASME IPC Calgary, Sept 2004.

[7] American Society of Mechanical Engineers, B31.8, 841.3.2, Table 841.3.2-1, Test Requirements for Steel Pipelines and Mains to Operate at Hoop Stresses of 30% or More SMYS.

years immediately preceding July 1, 1970, unless the line was tested after July 1, 1965. This highest operating pressure criterion also is the basis for the stand-alone grandfather clause in section 192.619(c). The basic strength properties of steel pipe – yield strength, tensile strength, elongation, strain hardening, etc. – do not change with time. Therefore, INGAA sees no basis for limiting allowable tests to only those conducted after July 1, 1965.

A pressure test for which essential parameters can be determined should be regarded as a valid and compelling test, regardless of whether it was conducted in June or July of 1965, or at any other time. It is the test parameters, not the test date, that should be considered here for the establishment of MAOP.

Still, the validity of earlier tests for MAOP establishment or confirmation does not necessarily mean that no further tests are required. An additional test or periodic testing may be required to assure the continued integrity of the segment. Such additional tests, however, are managed within the operator's integrity management program and, while important, should not be subject to an inquiry about MAOP verification. They should be considered separately.

Is a pressure reduction an option for MAOP reconfirmation?

A target pressure reduction of 20% of the current MAOP has the effect of making the current pressure equivalent to a test of 1.25 times the reduced MAOP. Because the lower pressure would build in a safety margin, such a reduction should be sufficient to reconfirm the MAOP. An operator choosing this option should be able to bring other data and analyses to bear in determining whether the pressure reduction should perhaps be greater or less than 20%. Such data or analysis might include operating history, test history, failure history or ILI results that may be indicative of the strength of the pipe.

How should spike testing be used?

In the investigation report of the incident on PG&E's system in San Bruno, NTSB recommended use of a spike test for previously untested pipelines. A spike test is one of the tools to be considered in planning for and conducting a hydrostatic test. Spike testing is the best means of testing a pipeline with environmental cracking, such as stress corrosion cracking, that has developed while in service.

However, a pressure test to 1.25xMAOP is adequate to address the strength of a pipeline for establishing or validating an MAOP. Pipelines, at the time of installation, generally do not include cracks. However, should an operator need to conduct a pressure test on a line previously untested or lacking records to validate MAOP, it is possible that including a spike test could be useful if the line has been identified as requiring an SCC (stress corrosion cracking) assessment. In this case, the pressure test would serve a dual purpose of validating MAOP while providing an SCC assessment. We note, however, that an SCC assessment would occur under an operator's IM plan and, therefore, should not be prescribed for all MAOP verifications.

A spike test may be of value for some in-service pipelines, specifically where metallurgical fatigue is of concern. An example would be on a line that undergoes significant pressure cycling. Gas pipelines typically do not undergo significant pressure cycling and their fatigue lives can be hundreds of years in duration. PRCI sponsored a study of fatigue behavior on in-service gas pipelines conducted by Kiefner and Associates in 2006. That study confirmed that gas pipelines, absent significant pressure cycling, have long fatigue lives.[8]

The type of test and the pressure-testing level determine the fatigue life and the length of time until the next test. This is referred to as a "retest interval." A spike test to levels over 100% of SMYS establishes a longer fatigue life and retest interval than a test to 1.25xMAOP (which is equivalent to a 90% SMYS test in a Class 1 area operating at 72% of SMYS). A test to 90% SMYS can provide a sufficiently long retest interval for a typical natural gas pipeline.

Even so, fatigue must be considered for a pipeline. The 2006 PRCI study provided guidance for operators to define the operating regime in which an in-depth evaluation of fatigue should be considered. This is embodied within ASME B31.8S and is an essential part of managing the ongoing integrity of a pipeline system.

How should long-seam types in early vintage line pipe be addressed for previously untested pipe and those lacking records?

The INGAA FFS process applies special diligence if the segment contains pipe that has a weld-seam type that has experienced known integrity issues. These seam types include low-frequency electric resistance welds (LFERW), direct-current electric resistance welds (DC-ERW), electric fusion or flash welds, furnace butt-welds and lap welds.

What is an appropriate basis for prioritizing MAOP reconfirmation?

INGAA's risk-based FSS process draws upon the approach developed for previously untested hazardous liquid pipelines in the 1990s. Those specific regulatory requirements are found at 49 C.F.R. § 195.303. The liquids pipeline regulation based its risk-based approach on close proximity to population. In addition, the approach allowed for the use of ILI assessments in lieu of a pressure test. INGAA recommends a similar approach for natural gas transmission pipeline systems.

Can ILI be used in lieu of pressure testing for MAOP reconfirmation?

ILI is nearly commercially viable for MAOP reconfirmation. It will likely require two distinct types of sensors as well as improvements in analytical techniques, both of which require additional demonstration, and ultimately acceptance by PHMSA and state regulators.

[8] Kiefner, J.F. and M.J. Rosenfeld, Basics of Metal Fatigue in Natural Gas Pipelines – A Primer for Gas Pipeline Operators, Pipeline Research Council International, Inc., Catalog No. L52270, June 2006.

ILI could be used to identify defects that would just survive a hydrostatic test. The reason for using the hydrostatic test as the comparison is that it represents a standard for our regulators and knowledgeable members of the public. While pressure testing can be used for MAOP reconfirmation, it is simply a pass-fail test. It does not provide detailed information about the pipeline; it simply confirms its strength.

In some cases, ILI may be superior to pressure testing. For example, identification of long-seam weld anomalies requires use of transverse-oriented magnetic flux leakage (MFL) technology on an ILI tool. Axially and transverse-oriented sensors have been shown to provide additional data to supplement MFL technology for seam-weld assessments. Alternatively, ultrasonic technology (UT) can be used; however, there has been limited application of UT technologies for seam-weld assessment on natural gas transmission pipelines. The transverse-oriented technology is available only in selected diameters. UT requires use of a liquid couplant, making its applicability limited.

An added benefit of employing ILI is that it can detect anomalies smaller than the large anomalies that would result in a failed pressure test. HCAs and class locations serve as the means to help calculate risk by prioritizing probability of consequences; ILI, meanwhile, is used to prioritize the probability of failure.

INGAA members are working with the American Gas Association, ILI providers and research organizations, such as the Pipeline Research Council International and the Gas Technology Institute, to improve the identification and characterization of long-seam anomalies that could pose a threat to integrity by taking advantage of multiple technologies. It is anticipated that the technologies and their analysis processes will continue to improve during the timeframe in which HCAs are being addressed and operators begin to apply integrity management techniques to pipelines located in Class 3 and 4 areas.

What is an appropriate threshold level for low-stress pipelines?

PHMSA proposed 20% SMYS as the low-stress threshold in the IVP but has not provided support in the docket as of the submittal of these comments. There are many years of precedence with the low-stress threshold being established at 30% SMYS, including PHMSA’s own regulations. PHMSA established 30% SMYS as a low-stress threshold for integrity assessments in the gas integrity management regulations at 49 CFR § 192.941(a). In addition, the level of 30% SMYS is generally accepted to be the “low-stress” boundary between leaks and ruptures for likely pipeline defects.

Moreover, ASME B31.8, in 841.3.2 establishes the threshold at 30% SMYS. The basis of this approach is that preventing ruptures represents a much higher consequence priority than preventing leaks on transmission pipelines. Leaks are important and addressed through a variety of ongoing activities along the pipeline rights-of-way by operators, including leaks surveys, patrols and maintenance work on the pipeline system.

In applying the 30% SMYS low-stress threshold, INGAA members recognize that the threshold presumes an understanding of the minimum level of toughness and the knowledge of pipe diameter, wall thickness and other metallurgical properties, such as the grade of pipe. Operators are encouraged to evaluate whether adjustments should be made to the 30% low-stress threshold level for the pipe segment being evaluated.

Should there be a date before which pressure tests cannot be used?

No. Pressure tests have been used extensively as part of a Quality Management System to validate pipeline material and construction standards. They are also used to validate pipeline integrity. Appendix F describes in detail the processes that have been used in the past to ensure quality.

The current language in 49 C.F.R. § 192.619(a) imposes four criteria that potentially limit the MAOP. One of those four criteria is the highest operating pressure experienced in the five years immediately preceding July 1, 1970, unless the line was tested after July 1, 1965. This highest operating pressure criterion also is the basis for the stand-alone grandfather clause in section 192.619(c). If section 619 is modified to require material strength testing of previously untested pipelines, thereby removing use of the highest operating pressure experienced in the five years immediately preceding July 1, 1970, then it would be reasonable to remove the corresponding restriction from 619(a) as well, along with the limitation on test dates.

The basic strength properties of steel pipe – yield strength, tensile strength, elongation, strain hardening, etc. – do not change with time. Therefore, INGAA sees no basis for limiting allowable tests to only those conducted after July 1, 1965. A pressure test whose essential parameters can be determined should be regarded as a valid and compelling test regardless of whether it was conducted in June or July of 1965, or in 1960 or at any other time. The test parameters, not the test date, should be considered here for the establishment of MAOP. INGAA also emphasizes that recognition of the validity of earlier tests for MAOP establishment or confirmation does not necessarily mean that no further tests are required. An additional test or periodic testing may be required to assure the continued integrity of the segment. Such additional tests, however, are managed within the operator's integrity management program and, while important, are not the subject of this inquiry and should be considered separately.

Appendix A: Documenting Natural Gas Transmission System Improvements in Public Safety Performance

INGAA analyzed the average number of leaks per mile in onshore natural gas transmission pipelines by cause since 1984, based on information pipelines submit annually to PHMSA, as illustrated in the chart below.[1] The data encompasses reportable leaks from all PHMSA-regulated transmission pipelines in service at the time of filing the annual report, which notably includes both pre-regulation and post-regulation pipe. These particular leak statistics have been reported in a fashion that permits statistical analysis by cause of the leak since reporting year 1984[2]. INGAA categorized the number of reported leaks into three causes to analyze general causes of pipeline leaks, and measure improvements in safety performance:

- External and Internal Corrosion
- Material and Construction Damage, and
- Outside Force Damage.

INGAA normalized the annual report data to illustrate the number of leaks per thousand miles of natural gas transmission pipeline in service during each reporting year. Accordingly, this chart is illustrative of the average number of leaks along any one thousand miles of natural gas transmission pipeline in the United Stated during a reporting year.

Why choose leaks as a safety performance metric?

INGAA member companies are committed to zero pipeline incidents, and recognize the importance of preventing incidents on natural gas pipelines. Nonetheless, analyzing the reduction in the number of ruptures per year is a statistically inappropriate way to measure the industry's safety management system since very few incidents occur each year. Rather, analyzing the number of leaks on natural gas transmission pipelines is a better predictor of future performance. Leaks, as reported annually to PHMSA, are a superset of unplanned gas releases, which include other smaller gas releases that may not be reportable incidents and ruptures.

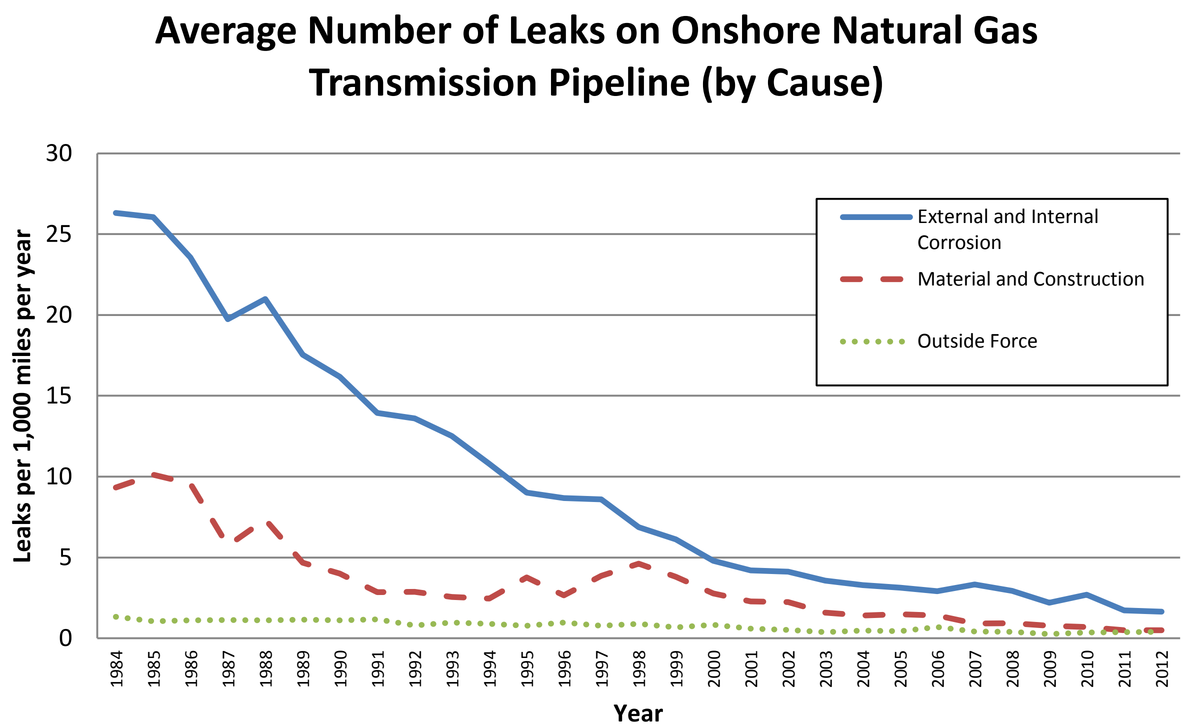
Further, unlike Department of Transportation reportable incidents,[3] the PHMSA annual reports require pipelines to report all known leaks regardless of volume, damage cost or personal injury threshold levels. Moreover, as noted above, pipelines have been reporting leaks by source consistently since 1984, which provides a good starting point for data analysis to determine a

[1] Transmission pipelines, as defined by 49 C.F.R. § 192.6, must report comprehensive pipeline safety data to PHMSA annually.

[2] INGAA started its analysis with reporting year 1984 since this was the first year that the annual report required that pipelines break down leak by cause. While INGAA broke down casues intow three categories for purposes of this analysis, PHMSA requires pipelines to report annually leak data in greater granularity.

[3] 49 C.F.R. § 191.5.

long-term trend. Accordingly, since pipelines report all known leaks to PHMSA in their annual reports, leak data provides the best data to determine whether an industry's safety management system is achieving its goal.



Source : INGAA, analysis based on PHMSA Annual Report data from 1984-2012

What are the performance metrics that are depicted?

To demonstrate the performance of natural gas transmission companies in managing safety, INGAA categorized the sources of pipeline leaks into three causes. INGAA used annual report data to move all reported leaks into one of the following three categories.

1. **Material and Construction Anomalies** - Leaks attributed to material and construction anomalies typically result from flaws in the manufacturing and construction processes. This cause is classified as being "stable" for properly constructed natural gas transmission pipeline system unless acted upon by an outside interactive force. (The pipeline does not get worse with age unless acted on by an outside force, such as backhoe damage, a flood, or a hurricane.) Pipelines use Quality Management System (QMS) procedures during construction to minimize the formation of these flaws. QMS also include detailed Quality Assurance/Quality Control (QA/QC) processes, which are applied during the design of the pipeline, material specification, manufacturing, construction of the pipeline, and the final hydrostatic test.

2. **External and Internal Corrosion** - Leaks attributed to external and internal corrosion result from the loss of steel due to the time-related action of external or internal

corrosion. These causes are classified as being “time dependent” and always have been the focus of pipeline corrosion-control programs under a pipeline’s umbrella safety management system. Corrosion is a major focus of a pipeline’s Integrity Management Program (IMP), which call for periodic inspections of pipelines that have entered service. External corrosion-control programs historically have relied on coating, cathodic protection, interference surveys, and close interval surveys to manage external corrosion. Internal corrosion-control programs rely on gas quality monitoring, insertion coupons and additives. The advent of in-line inspection (ILI) and continual improvement of its effectiveness have enabled operators to identify and repair anomalies before they become leaks. This has resulted in continuing to improved pipeline safety performance. IMPs developed in the early 2000s took full effect in 2004 and helped reduce leaks due to corrosion. IMPs built upon corrosion-control programs and formalized risk-assessment processes by applying greater rigor in using ILI and pressure testing and adding an additional tool—direct assessment—for un-piggable pipelines.

3. **Outside Force Damage -** Leaks attributed to outside force damage result from an external force being applied to the pipeline that was greater than that anticipated in the original design. Damage may include excavation damage, weather-related events, such as hurricanes, flooding, lightning, ground movement, and vandalism. These types of leaks are time independent, largely outside the control of the operator and, therefore, often are difficult to predict when and how they will occur. Nonetheless, pipeline operators attempt to minimize outside force damage by increasing education and emphasis on excavation damage prevention by adopting Common Ground Alliance (CGA) best practices, and increasing surveillance of the pipeline route, including ground patrols. Also, with regard to outside-force damage caused by ground movement and weather-related events, pipelines use ILI to identify damage.

What do these performance metrics show?

Material and Construction

Natural gas transmission operators significantly and continuously have improved the management of leaks caused by material and construction anomalies from the period of 1984 through 2012.

External and Internal Corrosion

Natural gas transmission operators significantly and continuously have improved the management of leaks caused by internal and external corrosion anomalies during the period 1984 through 2012.

Corrosion, whether external or internal, has been well-documented to cause time-based deterioration in steel pipelines. Pipelines utilize corrosion-control processes, such as installing cathodic protection beds and pipeline coating, to prevent corrosion on the pipeline. Companies also use technology to detect and mitigate corrosion before it results in a leak. If this threat is not managed correctly, one would expect to see the leak rate rising as the infrastructure ages. The average age of the natural gas transmission infrastructure in 2001 was 35 years old. The average age of the infrastructure in 2012 is now 41 years old. Yet, as the chart shows, despite the fact that the average age of the infrastructure is rising, the corrosion-leak rate has not and, to the contrary, has declined significantly.

The corrosion-leak rate has declined significantly due to improvements in safety-management systems employed by operating pipelines (both those installed before 1970 and those installed after 1970) during this time period (1984 through 2012). New technology and processes—such as the widespread use of improved cathodic protection monitoring systems, updated coating systems, improved construction QA/QC processes, ILI, pressure testing and direct assessment processes—have contributed to this improved performance.

Outside Forces

Leaks due to outside forces have remained relatively constant and low for the period reviewed.

As mentioned earlier, outside-force events are not easily predicted since they are not within the control of the pipeline. As a result, pipelines must work with cooperating stakeholders to improve performance. The primary component of outside force damage to the underground and above-ground pipeline infrastructure is caused by excavators or vehicle operators. The main tools to prevent outside-force leaks are increased surveillance of activity around the pipeline and the improvement of underground excavation-damage-prevention systems. The second major component of this category is leaks caused by natural events, such as floods, tornados, earthquakes, hurricanes and land movement.

Leaks caused by outside forces, which traditionally had a lower frequency rate than leaks caused by material and construction and corrosion, have not seen the same sort of risk reduction as the other two major causes. INGAA attributes this to the fact that pipeline operators have more control over leaks caused by material and construction and external and internal corrosion than leaks caused by outside forces.

What conclusions can be drawn from these results?

- Natural gas transmission pipeline operators have improved their safety performance even as the pipeline network ages and expands.
- When pipeline operators are solely responsible for managing pipeline safety for predictable causes, safety-management systems and programs focused on those threats have resulted in significant reductions in the leak rate, yielding public safety improvement.
- When pipeline operators have a shared responsibility with outside stakeholders for managing pipeline safety, or it is difficult to predict when a natural disaster will occur which will result in a pipeline leak, it has been harder for pipeline operators to achieve comparable levels of safety performance improvements.

Appendix B: Summary of INGAA Commitments

In December 2010, INGAA's board of directors established a board-level task force to signal its commitment to improving the industry's safety performance and restoring public confidence in natural gas pipelines. In March 2011, INGAA members formally adopted a set of Guiding Principles for pipeline safety, which included a primary goal of zero incidents– a perfect record of safety and reliability for the nation's onshore natural gas transmission pipelines. In July 2011, INGAA members agreed to a multi-facetted action plan to achieve this aggressive safety goal. The commitments resulting from this action plan are provided below (items in bold are directly relevant to PHMSA's proposed IVP process):

Demonstrate Fitness for Service on Pre-Regulation Pipelines

INGAA members commit to a systematic validation of records and maximum allowable operating pressure (MAOP) for their pipelines in highly populated areas that pre-date federal regulation. The process will address National Transportation Safety Board (NTSB) recommendations issued in the wake of the San Bruno, California, pipeline accident to evaluate and ensure the safety of member pipelines.

- Reference:
    - White Paper: *Definition and Application of Fitness for Service to Gas Pipelines*, dated May 31, 2012
        - Docket ID: PHMSA-2013-0119-0005
    - *Fitness for Service: Defined and Explained*, dated April 2012
        - Docket ID: PHMSA-2013-0119-0006
    - Summary: *Resident Manufacturing and Construction Threats,* dated January 7, 2013
        - Docket ID: PHMSA-2013-0119-0008

Extend and Improve Risk Management

INGAA members commit to apply integrity management principles – currently required only for the six percent of natural gas transmission pipeline located within highly populated areas – to the entire transmission system operated by INGAA members. This expansion will be focused on population within the Potential Impact Radius (PIR) along the pipeline. INGAA members will expand the program to 90 percent of the population within the PIR by 2020, and 100 percent by 2030.

- Reference
    - Summary: INGAA Members Commitment for Expanding Integrity Management Principles Beyond High Consequence Areas (HCAs)
        - Docket ID: PHMSA-2013-0119-0004

Raise the Standards for Corrosion Anomaly Management

INGAA members commit to managing all corrosion anomalies found during inspection—both inside and outside of HCAs—in accordance with technically based consensus standards and to refine the direction on application of assessment technology.

Shorten Pipeline Isolation and Response Time to One Hour

INGAA members commit to developing processes and technology to enhance the protection of people and property located adjacent to a pipeline, including setting a response-time goal of one hour from incident recognition to the start of valve-closure procedures in highly populated areas and improving communication with responders prior to and during an incident.

Improve Integrity Management Communication and Data

INGAA members commit to improving data collection and analysis, converting this data into meaningful industry information and communicating it to stakeholders.

Implement the Pipelines and Informed Planning Alliance (PIPA) Guidance

INGAA members commit to building an active coalition of INGAA member representatives to implement PIPA recommended practices and identifying selected locations for application of PIPA recommended practices. Members also commit to collaborating with PIPA stakeholders to increase awareness and adoption of PIPA recommended best practices.

Evaluate, Refine and Improve Threat Assessment and Mitigation

INGAA members commit to enhancing threat assessment by completing a comprehensive review of consensus threat and mitigation standards, and conducting critical, in-depth reviews of significant threats and root-cause analysis of incidents.

Foster a Culture of Continuous Improvement

INGAA members commit to raise the standard for use of management systems across the gas transmission industry to ensure better control of pipeline integrity and system reliability and provide guidance in practices and indicators to be used.

Engage Pubic Officials and Emergency Responders

INGAA members commit to finding new and innovative ways to inform and engage stakeholders, including emergency responders, public officials, consumer and safety advocates and members of the public living in the vicinity of pipelines.

Appendix C: Selected Requirements in the Pipeline Safety Act

The President signed the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 in January of 2012 (PLSA 2011). Section 23 of the PLSA 2011 first required operators to conduct a verification of their records in Class 3 and 4 and Class 1 and 2 HCAs by July 2012, and report to the Secretary on segments for which records were insufficient to confirm the MAOP by July 2013.

Section 23 of the PLSA 2011 also required the Secretary to promulgate regulations for conducting tests to confirm the material strength of previously untested pipelines in HCAs operating greater than 30% of the specified minimum yield strength (SMYS). This section provided for alternative methods including in-line inspection.

The Integrity Verification Process (IVP) as drafted has several components that are related to the **H.R.2845 -- Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.**

Expanding beyond high consequence areas

The first major concept identified in the IVP diagram is the **Moderate Consequence Areas (MCA).** This appears to be the same subject addressed in PLSA 2011 Section 5.

SEC. 5. INTEGRITY MANAGEMENT.

(a) Evaluation- Not later than 18 months after the date of enactment of this Act, the Secretary of Transportation shall evaluate--

(1) whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and

(2) with respect to gas transmission pipeline facilities, whether applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

(b) Factors- In conducting the evaluation under subsection (a), the Secretary shall consider, at a minimum, the following:

(1) The continuing priority to enhance protections for public safety.

(2) The continuing importance of reducing risk in high-consequence areas.

(3) The incremental costs of applying integrity management standards to pipelines outside of high-consequence areas where operators are already conducting assessments beyond what is required under chapter 601 of title 49, United States Code.

(4) The need to undertake integrity management assessments and

repairs in a manner that is achievable and sustainable, and that does not disrupt pipeline service.
(5) The options for phasing in the extension of integrity management requirements beyond high-consequence areas, including the most effective and efficient options for decreasing risks to an increasing number of people living or working in proximity to pipeline facilities.
(6) The appropriateness of applying repair criteria, such as pressure reductions and special requirements for scheduling remediation, to areas that are not high-consequence areas.

(c) Report- Not later than 2 years after the date of enactment of this Act, the Secretary shall submit to the Committee on Transportation and Infrastructure and the Committee on Energy and Commerce of the House of Representatives and the Committee on Commerce, Science, and Transportation of the Senate a report, based on the evaluation conducted under subsection (a), containing the Secretary's analysis and findings regarding--
(1) expansion of integrity management requirements, or elements thereof, beyond high-consequence areas; and
(2) with respect to gas transmission pipeline facilities, whether applying the integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

(d) Data Reporting- The Secretary shall collect any relevant data necessary to complete the evaluation required by subsection (a).

INGAA comments that the Act refers to a Report to Congress that PHMSA must provide regarding extending integrity management. The Act then discusses a review period by Congress after receipt of the report.

(f) Rulemaking Requirements-
(1) REVIEW PERIOD DEFINED- In this subsection, the term `review period' means the period beginning on the date of enactment of this Act and ending on the earlier of--
(A) the date that is 1 year after the date of completion of the report under subsection (c); or
(B) the date that is 3 years after the date of enactment of this Act.
(2) CONGRESSIONAL AUTHORITY- In order to provide Congress the necessary time to review the results of the report required by subsection (c) and implement appropriate recommendations, the Secretary shall not, during the review period, issue final regulations described in paragraph (3)(B).
(3) STANDARDS-

(A) FINDINGS- As soon as practicable following the review period, the Secretary shall issue final regulations described in subparagraph (B), if the Secretary finds, in the report required under subsection (c), that--

(i) integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and

(ii) with respect to gas transmission pipeline facilities, applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

(B) REGULATIONS- Regulations issued by the Secretary under subparagraph (A), if any, shall--

(i) expand integrity management system requirements, or elements thereof, beyond high-consequence areas; and

(ii) remove redundant class location requirements for gas transmission pipeline facilities that are regulated under an integrity management program adopted and implemented under section 60109(c)(2) of title 49, United States Code.

(4) SAVINGS CLAUSE-

(A) IN GENERAL- Notwithstanding any other provision of this subsection, the Secretary, during the review period, may issue final regulations described in paragraph (3)(B), if the Secretary determines that a condition that poses a risk to public safety, property, or the environment is present or an imminent hazard exists and that the regulations will address the risk or hazard.

(B) IMMINENT HAZARD DEFINED- In subparagraph (A), the term `imminent hazard' means the existence of a condition related to pipelines or pipeline operations that presents a substantial likelihood that death, serious illness, severe personal injury, or substantial endangerment to health, property, or the environment may occur.

INGAA comments that the Act states that PHMSA may act before the report is due if PHMSA determines that there is an imminent hazard. INGAA asserts that there is no such imminent hazard and, therefore, there is no need for PHMSA to act before it issues the report.

Verification of MAOP

INGAA comments that the second major concept addressed in the IVP process that was addressed in PLSA 2011 is the **verification** of MAOP. This terminology is distinct and different from the wording in the former regulations, 49 C.F.R. §§ 192.607 and 192.619, which uses the word **determined**.

SEC. 23. MAXIMUM ALLOWABLE OPERATING PRESSURE.

(a) In General- Chapter 601, as amended by this Act, is further amended by adding at the end the following:

Sec. 60139. Maximum allowable operating pressure

(a) Verification of Records-

(1) IN GENERAL- The Secretary of Transportation shall require each owner or operator of a pipeline facility to conduct, not later than 6 months after the date of enactment of this section, a verification of the records of the owner or operator relating to the interstate and intrastate gas transmission pipelines of the owner or operator in class 3 and class 4 locations and class 1 and class 2 high-consequence areas.

(2) PURPOSE- The purpose of the verification shall be to ensure that the records accurately reflect the physical and operational characteristics of the pipelines described in paragraph (1) and confirm the established maximum allowable operating pressure of the pipelines.

(3) ELEMENTS- The verification process under this subsection shall include such elements as the Secretary considers appropriate.

(b) Reporting-

(1) DOCUMENTATION OF CERTAIN PIPELINES- Not later than 18 months after the date of enactment of this section, each owner or operator of a pipeline facility shall identify and submit to the Secretary documentation relating to each pipeline segment of the owner or operator described in subsection (a)(1) for which the records of the owner or operator are insufficient to confirm the established maximum allowable operating pressure of the segment.

INGAA comments that the regulation below, which was eliminated in 1996, refers to the former 49 C.F.R. § 192.607. The regulation provided a requirement for how pipelines should determine MAOP under Office of Pipeline Safety regulations.

*a) Before April 15, 1971, each operator shall complete a **study to determine** for each segment of pipeline with a maximum allowable operating pressure that will produce a hoop stress that is more than 40 percent of SMYS-*

1. The present class location of all such pipeline in its system; and

2. Whether the hoop stress is corresponding to the maximum allowable operating pressure for each segment of pipeline is commensurate with the present class location.

*b) Each segment of the pipeline that has been **determined** under paragraph (a) of this section to have an established maximum allowable operating pressure producing a hoop stress **that is not commensurate with the class location of the segment of pipeline and that is found to be in satisfactory condition, must have the maximum allowable pressure confirmed or revised in accordance***

with 49 C.F.R. § 192.611. *The confirmation or revision must be completed not later than December 31, 1974.*

c)Each operator required to confirm or revise an established maximum allowable operating pressure under paragraph (b) of this section shall, not later than December 31, 1971, prepare a comprehensive plan, including a schedule for carrying out the confirmations or revisions. The comprehensive plan must also provide for confirmations or revisions ***determined*** *to be necessary under 49 C.F.R. § 192.609, to the extent that they are caused by changes in class locations taking place before July 1, 1973.*

INGAA comments that listed below are the applicable sections in the present regulation, 49 C.F.R. § 192.619, utilizing the word **determined**.

§192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure ***determined*** *under paragraph (c) or (d) of this section, or the lowest of the following:*

INGAA comments that Congress then proceeded further in Section 23 to discussed new testing regulations.

(d) Testing Regulations-

(1) IN GENERAL- Not later than 18 months after the date of enactment of this section, the Secretary shall issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of specified minimum yield strength.

(2) CONSIDERATIONS- In developing the regulations, the Secretary shall consider safety testing methodologies, including, at a minimum--

(A) pressure testing; and

(B) other alternative methods, including in-line inspections, determined by the Secretary to be of equal or greater effectiveness.

(3) COMPLETION OF TESTING- The Secretary, in consultation with the Chairman of the Federal Energy Regulatory Commission and State regulators, as appropriate, shall establish timeframes for the completion of such testing that take into account potential consequences to public safety and the environment and that minimize costs and service disruptions

INGAA comments that Congress stipulated that PHMSA should **confirm** the material strength of **previously untested pipelines** located in **HCAs** that **operate greater the 30% SMYS.**

Appendix D: The National Transportation Safety Board's (NTSB) Recommendations Resulting from the Pacific Gas & Electric Company Incident in San Bruno, CA

The NTSB, the federal agency responsible for investigating transportation-related incidents, made an initial set of recommendations to PG&E and the regulatory bodies regarding the September 9, 2010 PG&E incident in San Bruno, CA. These initial, and later modified, recommendations were issued on January 3, 2011 to PG&E, the Department of Transportation, PHMSA, the California Public Utility Commission (CPUC) and industry trade associations.[1]

Subsequently, PHMSA and the CPUC separately took administrative and investigative actions regarding the tragic incident.

On June 8, 2011, in its final investigative report, the NTSB made new recommendations to PG&E, the Department of Transportation, PHMSA, the CPUC and industry trade associations.

INGAA is commenting below on select recommendations to demonstrate where the NTSB recommendation was meant to apply to PG&E only, and not intended to extend to the entire transmission pipeline industry, and where the draft IVP extends beyond the NTSB recommendation. INGAA also identifies below where and how INGAA's Fitness for Service (FFS) proposal meets NTSB's goals of verifying MAOP and/or extending IM. INGAA has bolded certain language within the recommendations for emphasis.

New NTSB Recommendations to the Pipeline and Hazardous Materials Safety Administration (PHMSA)

NTSB Recommendation P-11-14

The NTSB issued the following recommendation to PHMSA:

> Amend Title 49 Code of Federal Regulations 192.619 to delete the grandfather clause and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.

[1] NTSB conducted an investigation of the "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire" that occurred in San Bruno, California on September 9, 2010. http://www.ntsb.gov/doclib/reports/2011/PAR1101.pdf The specific recommendations by NTSB are summarized at http://www.ntsb.gov/investigations/summary/PAR1201.html.

INGAA comments that the NTSB asserted that the grandfathered PG&E pipe had not seen a test pressure above the MAOP. The NTSB stated in its accident report three reasons why the grandfather clause should be repealed.

- The pipe in the San Bruno accident would have failed a higher pressure test that was not required of pipelines that had been grandfathered.
- Present PHMSA regulations allow over pressuring a pipeline up to 1.1 times MAOP in an emergency.
- Immediate repair condition criteria utilized in IMP allow continued operation using a 1.1 times MAOP factor.

INGAA asserts that the INGAA-AGA proposal to amend 49 C.F.R. § 192.619 to add a provision requiring pipelines to evaluate the fitness of service of previously untested pipelines would have the effect of removing the aspects of the grandfather clause that concerned NTSB by ensuring that pre-1970 pipelines in HCAs, and Class 3 and 4 areas are tested for material strength. The recommendation also was directed only at PG&E.

Further, INGAA recommends that PHMSA address the IM issues raised by NTSB as part of its review of the IMP.

NTSB Recommendation P-11-15

The NTSB issued the following recommendation to PHMSA:

> Amend Title 49 C.F.R. Part 192 of the Federal pipeline safety regulations so that **manufacturing- and construction-related defects can only be considered stable** if a gas pipeline has been subjected to a **post construction hydrostatic pressure test of at least 1.25 times** the maximum allowable operating pressure.

INGAA's FFS methodology is designed to address NTSB's recommendation above.

New NTSB Recommendation to the Pacific Gas and Electric Company (PG&E)

NTSB Recommendation P-11-29

The NTSB issued the following recommendation to PG&E:

> Assess every aspect of your integrity management program, paying particular attention to the areas identified in this investigation, and implement a revised program that includes, at a minimum, (1) a revised risk model to reflect the Pacific Gas and Electric Company's actual recent experience data on leaks, failures, and incidents; (2) consideration of all defect and leak data for the life of each pipeline, including its construction, in risk analysis for similar or related segments to ensure that all applicable threats are adequately addressed; (3) a

> revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats; and (4) an improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment.

INGAA comments that this NTSB recommendation applied to PG&E only and that the NTSB did not recommend that this process apply to all transmission pipelines. Nonetheless, INGAA supports extending and improving IM. INGAA believes, however, that PHMSA needs additional time to develop a plan for doing so.

Modified NTSB Recommendation to the CPUC

Following its initial investigation, National Transportation Safety Board made the following modifications to its previously issued safety recommendations.

NTSB Recommendation P-10-6

The NTSB issued the following recommendation to the CPUC:

> Develop an implementation schedule for the requirements of Safety Recommendation P-10-2 (Urgent) to Pacific Gas and Electric Company (PG&E) and ensure, through adequate oversight, that PG&E has aggressively and diligently searched documents and records relating to pipeline system components, such as pipe segments, valves, fittings, and weld seams, for PG&E natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing as outlined in Safety Recommendation P-10-2 (Urgent) to PG&E. These records should be **traceable, verifiable, and complete**; should meet your regulatory intent and requirements; and should have been considered in **determining** maximum allowable operating pressures for PG&E pipelines. (P-10-5) (Urgent)
>
> If such a document and records search cannot be satisfactorily completed, provide oversight to any spike and hydrostatic tests that Pacific Gas and Electric Company is required to perform according to Safety Recommendation P-10-4. (Urgent)

INGAA comments that this NTSB recommendation is to the CPUC only, with a focus on PG&E. The NTSB recommends that CPUC oversee the PG&E records search and analysis. Moreover, this was the first time the term "**traceable, verifiable and complete**" was used by NTSB regarding transmission pipelines. It appears that PHMSA adopted this language in their advisory notices. For MAOP, the NTSB also utilized the term "**determining**" in its

recommendation to PG&E, which was the requirement applicable under 49 C.F.R. § §192.611 and 192.619 , and the former regulation, 49 C.F.R. §192.607.
By contrast, the Pipeline Safety Act of 2011 used the term, "re-confirm" MAOP. PHMSA should reassess its methodology in IVP adopting the concept of "re-confirming" MAOP.

Modified NTSB Recommendations to the Pacific Gas and Electric Company

NTSB Recommendation P-10-2

The NTSB issued the following recommendation to PG&E:

> Aggressively and diligently search for all as-built drawings, alignment sheets, and specifications, and all design, construction, inspection, testing, maintenance, and other related records, including those records in locations controlled by personnel or firms other than Pacific Gas and Electric Company, relating to pipeline system components, such as pipe segments, valves, fittings, and weld seams for Pacific Gas and Electric Company natural gas transmission lines **in class 3 and class 4 locations and class 1 and class 2 high consequence areas** that **have not had a maximum allowable operating pressure established through prior hydrostatic testing.** These records should be **traceable, verifiable, and complete**. (Urgent)

INGAA comments that this NTSB recommendation is to PG&E only on its records search and analysis. This recommendation also utilized the terminology "**traceable, verifiable and complete.**" It only included all pipe in the referenced locations that **did not have a hydrostatic pressure test to establish an MAOP**. The initial process to determine an MAOP for pre-regulation pipe is defined in 49 C.F.R. § 192.607,[2] but this recommendation did not state that the pipeline had to have specific records for 49 C.F.R. § 192.619 (a) (1), as is presented in the draft IVP. The NTSB recommendation did not state that the hydrostatic pressure test used by PG&E to establish its MAOP was the lowest of the 49 C.F.R. § 192.619 (a) (1) through (a) (3), as is presented in the draft IVP.

NTSB Recommendation P-10-3

The NTSB issued the following recommendation to PG&E:

> Use the **traceable, verifiable, and complete records** located by implementation of Safety Recommendation P-10-2 (Urgent) to **determine** the valid maximum allowable operating pressure, based on **the weakest section of the pipeline or component** to ensure safe operation, of Pacific Gas and Electric Company natural gas transmission lines **in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable**

[2] This regulation was subsequently removed.

> **operating pressure established through prior hydrostatic testing.** (Urgent)

INGAA comments that this NTSB recommendation is to PG&E only and describes how the traceable, verifiable and complete records should be used to determine the weakest section of a pipeline or component in the referenced locations only in sections that **did not have the MAOP established by hydrostatic pressure test**. It did not refer to a particular minimum hydrostatic test pressure that a pipeline had to conduct in order to exclude the pipe from this analysis, as required by the draft IVP.

NTSB Recommendation P-10-4

The NTSB issued the following recommendation to PG&E:

> If you are unable to comply with Safety Recommendations P-10-2 (Urgent) and P-10-3 (Urgent) to accurately determine the maximum allowable operating pressure of Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing, **determine the maximum allowable operating pressure with a spike test followed by a hydrostatic pressure test**.

INGAA comments that this NTSB recommendation is to PG&E only and recommends how PG&E should address pipeline segments and components only in sections that do not have the MAOP established through a prior hydrostatic pressure test. It did not refer to a particular minimum test pressure or a spike test process, as is presented in the draft IVP.

Appendix E: PHMSA Administrative Activities

PHMSA issued an Advisory Bulletin regarding MAOP confirmation and records verification utilizing traceable, verifiable, and complete (TVC) acceptance criteria on January 10, 2011 (ADB-11-01).[1]

The INGAA board embraced these recommendations and undertook an initiative to address the recommendations. The board codified the Guiding Principles, and, later in 2011, embraced a series of commitments, including those related to pipe lacking records to support an MAOP and testing of previously untested pipeline using demonstrated Fitness for Service (FFS) methods.

On May 7, 2012, PHMSA issued a second Advisory Bulletin to provide additional detail regarding its interpretation of TVC records (ADB-12-06).[2] Pipeline operators have since focused significant efforts in identifying records used to establish the original MAOP, essentially a "reconfirmation" of work conducted in the early 1970s under 49 C.F.R. §§ 192.607, 192.619.

PHMSA issued a notice on January 10, 2011 seeking comment on changes to the annual report to address data needed to address Section 23 of the Pipeline Safety Act of 2011. INGAA met with PHMSA on several occasions and submitted comments on May 7, 2012. PHMSA issued an additional notice regarding the annual report changes also noting that the submission date would be moved back to June 15, 2013. In submitting data in the annual report, operators would meet the requirement of Section 23 of the PLSA 2011, requiring reporting on those segments lacking records to support the MAOP.

The results of the extensive records verification efforts undertaken by INGAA members were reported by operators in Part Q of the annual report submitted on June 15. In general, the results show that MAOP confirmation records do exist for the majority of pipeline mileage using the instructions provided in the annual report.

Regrettably, the instructions for completing the annual report were inconsistent with the approach outlined in the IVP. In basic terms, the annual report guidance permitted an "either-or" verification proposition, while the IVP, in Diamonds 1-6, took an "and" approach, requiring four layers of records before the records for a pipeline were deemed acceptable. In addition, the annual report does not collect data that would permit PHMSA to analyze affected MCA mileage.

If PHMSA proceeds to issue a rule that incorporates the IVP, as proposed, it cannot rely on data from the annual report as the basis for its cost-benefit analysis of that rule. This is because the

[1] Jan 10,2011 Advisory Bulletin 11-01
[2] May 7, 2012 Advisory Bulletin 12-06

annual report data would grossly understate the pipeline mileage that would need to be tested pursuant to the IVP

Appendix F: Historical Construction and Material Integrity Validation Requirements and MAOP Determination Requirements

High-pressure natural gas transmission pipelines use conservative engineering design criteria and redundant inspections and tests during the pipe's manufacture and construction to validate the pipeline's pressure-holding capability.

Two key processes have been put in place to assure the quality of the installed pipeline to match or exceed the design pressure:

1. **Manufacturing specifications for pipeline material.**
   While there are many different specifications for manufactured material installed in pipelines (e.g. pipe, valves and fittings) the predominant material used is line pipe. Natural transmission gas pipelines predominantly use American Petroleum Institute-specified line pipe.

2. **Post-construction strength tests to higher levels than the pipeline will operate.**
   The predominant standard for post-construction strength testing was ASA B31.1, which eventually was renamed ASME B31.8. The pressure test level used and duration of the test changed through the decades.

American Petroleum Institute (API) Line Pipe Specifications

Since 1928, the API has produced a set of specifications that pipeline operators could use to validate the quality of manufactured steel pipe purchased for use in high-pressure transmission pipelines. These specifications, plus a pipeline operator's own requirements, form the basis for the Quality Assurance (QA) requirements for the manufacture of high-quality steel pipe for natural gas transmission pipelines. The API standards include specifications for material composition and strength and specify QA tests throughout the manufacturing process. The API pipe manufacturing specifications, which have been periodically updated to reflect changes in technology and processes, are incorporated by reference in the PHMSA pipeline safety regulations. Pipe segments (joints) rejected by tests conducted at the pipe mill are not used by the purchaser for pipeline construction. Accordingly, the purchaser of the material can be assured of the quality of the final pipeline segments they receive.

Examples of QA requirements throughout the decades are shown in Tables 1 and 2 and include strength tests, consisting both of hydrostatic pressure tests and tensile tests of samples of the pipe material. As illustrated in the tables, even before federal regulation in 1970, pipelines were subject to numerous and extensive quality specifications.

Table 1: Pipe Mill Pressure Testing and Tensile Testing Requirements Vintage API 5L Editions

Edition	Effective Date of Standard	Hydrostatic Pressure Test as a % of SMYS	Time Duration of Hydrostatic Pressure Test (sec)	Rate of Tensile Tests (test per joints)
1	Jan 1 1928	60	5	2 of 200
2	Jan 1 1929	60	5	2 of 200
3	Jan 1 1930	60	5	2 of 200
	sup February 1931	60	5	2 of 200
4	July 1 1931	80	5	1 of 100
	Sup July 1 1932	80	5	1 of 100
5	January 1 1934	80	5	1 of 100
6	August 1 1935	80	5	1 of 100
	Sup 3 Sept 1938	80	5	1 of 100
	Sup 6 Sept 1939	80	5	1 of 100
7	April 1 1940	80	5	1 of 100
	Sup No 2	80	5	1 of 100
8	May 1 1942	80	5	1 of 100
	sup 1 War Measures	80	5	1 of 100
9	August 1 1944	80	> 5 allowed	1 of 100
10	August 1 1945	80	> 5 allowed	1 of 100
	Sup July 1 1946	80	> 5 allowed	1 of 100
11 to 14th	March 1 1955	80	10	1 of 100
15	March 1 1956	80	10	1 of 100
16	April 1 1957	80	10	1 of 100
17	March 1 1959	80	10	1 of 100
18	February 1 1960	80	10	1 of 100
	sup January 1961	80	10	1 of 100
19	March 1962	80	10	1 of 100
20	March 1963	80	10	1 of 100
21	March 1965	80	10	1 of 100
22	March 1967	80	10	1 of 100
23	March 1968	80	10	1 of 100
24	April 1969	80	10	1 of 100
25	April 1970	80	10	1 of 100
26	April 1971	80	10	1 of 100
27	April 1973	80	10	1 of 100
	Sup to 27th	80	10	1 of 100
28	March 1975	80	10	1 of 100
29	March 1977	80	10	1 of 100
30	March 1978	80	10	1 of 100
31	March1980	80	10	1 of 100
32	March 1982	80	10	1 of 100

Table 2: Pipe Mill Pressure Testing and Tensile Testing Requirements Vintage API 5LX Editions

Edition	Effective Date of Standard	Hydrostatic Pressure Test as a % of SMYS	Time Duration of Hydrostatic Pressure Test (sec)	Rate of Tensile Tests (test per joints)
1	February 1948	85%	5	2 of 100
2	May 1949	85%	> 5 allowed	2 of 100
	sup December 1949	85%	> 5 allowed	2 of 100
3	March 1951	85%	> 5 allowed	2 of 100
	sup January 1952	85%	> 5 allowed	2 of 100
4	March 1953	85%	> 5 allowed	2 of 100
	sup February 1954	85%	> 5 allowed	2 of 100
5	November 1954	85%	10	2 of 100
6	February 1956	90%	10	2 of 100
7	April 1957	90%	10	2 of 100
8	March 1958	90%	10	2 of 100
	sup March 1959	90%	10	2 of 100
9	March 1960	90%	10	2 of 100
	sup January 1961	90%	10	2 of 100
10	March 1962	90%	10	2 of 100
	sup July 1962	90%	10	2 of 100
11	March 1963	90%	10	2 of 100
	sup March 1964	90%	10	2 of 100
12	March 1965	90%	10	2 of 100
13	March 1966	90%	10	2 of 100
14	March 1967	90%	10	2 of 100
15	March 1968	90%	10	2 of 100
16	April 1969	90%	10	2 of 100
17	April 1970	90%	10	2 of 100
18	April 1971	90%	10	2 of 100
	sup April 1972	90%	10	2 of 100
19	March 1973	90%	10	2 of 100
20	March 1975	90%	10	2 of 100
	sup March 1976	90%	10	2 of 100
21	March 1977	90%	10	2 of 100
22	March 1978	90%	10	2 of 100
23	March 1980	90%	10	2 of 100
	sup March 1981	90%	10	2 of 100
24	March 1982	90%	10	2 of 100
API 5L collected	back to 5L for 5LX, 5LS, & 5LU			
33	March 1983	90%	10	2 of 100
34 to 41	March 1984 to 95	90%	10	2 of 100
39	June 1991	90%	10	2 of 100

Design, Construction and Testing Standards were defined in ASME B31.8 and its predecessors

High-pressure natural gas transmission pipelines built before adoption of the ASA B31.1 engineering standard, utilized engineering specifications, processes and procedures that were developed by individual pipeline companies based on previous practices in other industries that utilized pressured piping (ASME Pressure Pipe Code B31) as a model.

As additional pipelines were built, these processes and practices were shared among pipeline operators. In order to promote common pipeline safety standards, an effort under the American Society of Mechanical Engineers (ASME), and through the American Standards Association (ASA/ANSI), was formed to develop a specific section for natural gas pipelines. The following excerpt from the testimony to the Federal Power Commission (FPC) documents the adoption and maturation of the standard.

> Safety Record Is the Product of Continuous Effort and Surveillance
> The gas pipelines' safety record results from a continuous effort to establish and abide by a code for the safe design, construction and operation of natural gas pipelines. In March 1926, Project B3l to write a code for all types of piping systems was undertaken. The first tentative standard was published in 1935; a revision to this standard was undertaken in 1937. This revision provided greater uniformity between sections of the code and resulted in the 1942 American Standard Code for Pressure Piping. Supplements to the 1942 code appeared in 1944 and 1947.
>
> By 1950, the tremendous expansion of the gas pipeline industry made it apparent that a separate document was required for gas piping. In November 1951, the B3l Committee authorized a separate publication of a gas piping code and designated it as Section 8. The first publication of Section 8 was made in 1952, consisting of material in the previous Section 2 combined with fabricating and comparable details from Sections 6 and 7.
>
> A new Section 8 Committee was organized in 1952. This committee numbered seventy-two individuals who represented not only gas pipeline and distribution companies but manufacturers of materials, government agencies, research organizations, the National Board of Fire Underwriters, engineering consultants and national organizations such as the American Petroleum Institute, the American Society of Mechanical Engineers and the American Society of Civil Engineers. After one and one-half years of concentrated effort, a draft of cod$ was approved by the committee in August of 1954 and by the' B31 Committee in October 1954. This Code was submitted by the American Gas Association to its member companies and overwhelmingly approved by 150 companies out of 154 who voted.

The full Section 8 Committee has met once a year since the initial publication of the Code in 1955 and has kept the Code current and abreast of the times based on new materials, new techniques and new information. Revised editions were published in 1958 and 1963.

The Code's acceptability as a proper standard is evidenced by its adoption by twenty-four state regulatory commissions*. Other state commissions presently have under consideration the adoption of the Code as a standard.

The interstate natural gas transmission pipelines that were regulated by the Federal Power Commission (the FPC is the precursor to the Federal Energy Regulatory Commission) utilized these ASA standards for the design, construction, operation and maintenance processes. On June 30, 1966 the FPC issued Order 324 to prescribing the maximum safe operating pressure for new pipelines built under the Commission's jurisdiction. In that order, the FPC stipulated that the determination should follow the ASA methodology in order to get prompt approval and significant justification was needed to vary from that methodology.

In the 1966, the FPC published a report for Congress titled "Safety of Interstate Natural Gas Pipelines," a review of the state requirements for the regulation of natural gas pipelines was documented in a table and 26 had adopted ASA B31.8 . Congress recognized the value and recommended to the Office of Pipeline Safety (OPS), the precursor to the present PHMSA, adopt the 1968 Edition of ASME B31.8 as the interim pipeline safety standards. In 1970, OPS rewrote sections of the interim Federal pipeline safety standards and established the present Part 192.

Criteria for the design pressure of natural gas transmission pipelines under ASME B31.8 was based on the internal design pressure and conservative factors added for population density around the pipeline, outside force interaction and corrosion protection.

Design Pressure and MAOP Criteria Based on Material Strength and Population Density

Initially, the design-pressure criteria of ASME B31.1 was based on the population density near the pipeline at the time of construction; with Division 1 being roughly equivalent to today's Class 3 and 4 and Division 2 being equivalent to Class 1 and 2. The Barlow formula supplanted the ASME pressure vessel code design for Division 1 locations in 1942 ASA Edition of B31.1 and has been standardized as the design formula of steel pipelines since then. The Barlow formula utilizes the specified minimum yield strength (SMYS) based on the material purchased by the pipeline operator as referenced in the API pipe specifications (5L).

The concept of Maximum Allowable Operating Pressure (MAOP) was introduced in the first published edition in 1942. At the issuance of the ASA B31.8 (1955 Edition), these two location distinctions used for design were further subdivided into four class locations that are roughly equivalent to the present PHMSA class-location descriptions. An important distinction from the present ASME code and the regulations is that these were simply design requirements. O&M practices were not adjusted for future population density changes, and there were exclusions for pipeline segments with design pressures at low-stress levels (<40%SMYS). In addition to these changes, there was an increasing requirement for a pressure test differential at the commissioning of the pipeline, as shown in Table 3.

Table 3: Onshore Natural Gas Transmission Pipeline Pressure Testing Requirements of Vintage ASA/ASME B31.8 Editions

Current class designations	ASA B31.1 -1942 Description of population density at time of construction	ASA B31.1 - 1951 pressure test description	ASA B31.1.8-1955 pressure test description operating over 30% SMYS	AS B31.8-1958 Pressure test description operating over 30% SMYS	AS B31.8-1963 Pressure test description operating over 30% SMYS	USAS B31.8-1968 Pressure test description operating over 30% SMYS	Present pressure test description Subpart J [192.505]; [192.619 (2) (i)]; [192.611]
Class 1	Division 2	Maximum Service Pressure +50psi	1.1xMOP with water, gas or air	1.1xMOP with water, gas or air	1.1xMOP with water, gas or air except tie-ins	1.1xMOP with water, gas or air except tie-ins	Installed before Nov. 12, 1970 Test pressure is 1.1 * MAOP for 8 hours Installed after Nov. 11,1970 Test pressure is 1.1 * MAOP for 8 hours
Class 2	Division 2	Maximum Service Pressure +50psi	1.25xMOP with water or air	1.25xMOP with water or air	1.25xMOP with water or air except tie-ins	1.25xMOP with water or air except tie-ins	Installed before Nov. 12, 1970 Test pressure is 1.25 * MAOP for 8 hours Installed after Nov. 11,1970 Test pressure is 1.25 * MAOP for 8 hours Upgraded pipeline is previously tested pressure of MAOP /.8 for 8 hours
Class 3	Division 1	1.5 times Maximum Service Pressure	1.40xMOP with water	1.40xMOP with water	1.40xMOP with water except tie ins. 1.1xMOP with air if below 32 deg.at pipe depth or no water available. 1.2xMOP with air if MOP<50% SMYS and longitudinal joint factor is 1.	1.40xMOP with water except tie ins. 1.1xMOP with air if below 32 deg. at pipe depth or no water available. 1.2xMOP with air if MOP<50% SMYS and longitudinal joint factor is 1.	Installed before Nov. 12, 1970 Test pressure is 1.4 * MAOP for 8 hours Installed after Nov. 11,1970 Test pressure is 1.5 * MAOP for 8 hours Upgraded pipeline is previously tested pressure of MAOP/.667 for 8 hours
Class 4	Division 1	1.5 times Maximum Service Pressure	1.40xMOP with water	1.40xMOP with water	1.40xMOP with water except tie ins. 1.1xMOP with air if below 32 deg. at pipe depth or no water available. 1.2xMOP with air if MOP<50% SMYS and longitudinal joint factor is 1	1.40xMOP with water except tie ins. 1.1xMOP with air if below 32 deg. at pipe depth or no water available. 1.2xMOP with air if MOP<40% SMYS and longitudinal joint factor is 1	Installed before Nov. 12, 1970 Test pressure is 1.4 * MAOP for 8 hours Installed after Nov. 11,1970 Test pressure is 1.5 * MAOP for 8 hours Upgraded pipeline is previously tested pressure of MAOP/.5555 for 8 hours

An important change to the ASA B31.8 occurred in 1968 when that edition of the code dictated that pipeline companies should survey for population density changes along operating pipelines and adjust the operating pipeline safety factor calculations accordingly. At the time, there were not a set timeline for the class-location identification or making pipe line segments commensurate with the new safety factors. The anticipation of this change and subsequent adoption of the B31.8 code by the Office of Pipeline Safety as an interim safety standard, created a significant amount of replacement, retesting and rerating of pipeline segments among INGAA membership as shown in Table 4.

Table 4: Summary of Replacement and Testing Mileage as a result of 1968 ASA B31.8

	1967 (miles)	1968 (miles)	1969 (miles)	1970 (miles)
Retesting Existing Pipelines	2,660	2,538	3,855	1,812
Replacing	342	289	413	201

(18 INGAA companies reporting [April 1971])

OPS proposed the initial Part 192 pipeline safety regulations[1] in 1970 under the direction of Congress, which clearly stated that design, material and construction practices only be applied to pipelines built after the promulgation of the regulations[2]. Operation, inspection and maintenance requirements under the regulations would cover all pipelines in service.

OPS proposed a change to the class-location definition under Docket OPS-3D in 1970, requiring a re-designation of pipeline class locations established under the ASA 1968 B31.8 Edition and adopted in the subsequent interim PHMSA regulations.

Concurrently, OPS initiated a rulemaking under Docket OPS-3E that established the requirement to establish the MAOP of pipeline segments in service. The original OPS NOPR established a strict design-based process for future pipelines as envisioned by Congress, but left no solution for a significant amount of pipe that was already operating safely at that time. After significant public debate and a risk assessment by PHMSA, the present 49 C.F.R. § 192.619 was adopted.

49 C.F.R. § 192.619 in conjunction with new 49 C.F.R. § 192.607 allowed a transition time for pipeline segments that were deemed to not be commensurate with the new class-location requirements to either be replaced, tested or the MAOP established at a lower level than the design pressure. Pipeline segments that were deemed lower risk (MAOP<40% SMYS, Class 1 segments and pipelines with a design pressure that was commensurate with the new class location definition) were excluded from any of this activity. The regulations required that pipeline segments that were not commensurate to pass through the new design-based criteria under the 49 C.F.R. § 192.619 (a) sections.

[1] OPS-3 Transportation of Natural and Other Gas by Pipeline; Minimum Safety Standards; June 12, 1970
[2] INGAA Comments to OPS-3E docket (April 1971)

There was a lot of conjecture on the ability of the pipeline companies to conduct all this activity in the time provided, as the final rule 49 C.F.R. § 192.607 demanded a two-step deadline. As a result, future hearings[3] were established to review these schedule deadlines after the level of effort was determined under application of the new class-location definitions and MAOP determination requirements. INGAA presented testimony of the estimated activity as shown in Table 5.

Table 5: Comments by INGAA on Pipe Replacement Estimates Due To Class Location Changes

Pipe Replacement Estimates Due To Class Location Changes		
Segments	Mileage	
1,274	754	
Retesting Estimates Due to Class Location Changes		
Segments	Mileage	
966	4,045	
Pipe Replacement and Retest Estimates Due to Multiple Occupancy		
Multiple Locations	Replacement Mileage	Retest Mileage
846	158	293

49 C.F.R. § 192.607 was then modified under a subsequent rulemaking[4] to require the process to be completed by 1974. 49 C.F.R. § 192.607 was removed from the regulation in 1996 since the time for the applicability in the initial determination of MAOPs had long since passed.

Interaction of the Regulatory Process after the Adoption of 49 C.F.R. § 192.6, .607, .611, and .619

The original regulations included 49 C.F.R. § 192.607, which required operators to determine the class location of their pipelines and to review the design factors for their pipe to determine if they were commensurate with the requirements of 49 C.F.R. § 192.111 (Class 1 – 0.72; Class 2 – 0.60; Class 3 – 0.50; Class 4 – 0.40). This review was limited to pipe with a MAOP that produced a hoop stress more than 40% SMYS, and was to be completed by April 15, 1971. If the design factor was commensurate, no further action was required. If the design factor was not commensurate, the operator was required to follow the requirements in 49 C.F.R. § 192.611. Presumably, this study was only required for "grandfathered" pipelines, since any MAOP based on 49 C.F.R. § 192.619(a) (1-3) would have had a design factor commensurate with the regulations and would have been pressure tested.

Operators were required to complete confirmation or revision of the MAOP of at least 50% of their systems by January 1, 1972 and the remainder by January 1, 1973. Later rulemaking extended this deadline to December 31, 1974. Since all action required by 49 C.F.R. § 192.607

[3] OPS – 3E Public Hearings

[4] Amendment 192-5; Docket No. OPS-11

was to be completed by January 1, 1974, it became irrelevant after that date. It was removed from Part 192 in 1996.

Operators conducted the required evaluation and the required pipe replacement or pressure testing. A substantial amount of pipe replacements, hydrostatic testing and MAOP reductions occurred as a result of the requirements of 49 C.F.R. § 192.607. Many operators prepared a comprehensive study to document the work performed to meet these requirements.

49 C.F.R. § 192.611

If design factors were commensurate at the time of the study required by 49 C.F.R. § 192.607, no further action was required. This provision allowed non-tested pipe in all class locations, provided that the design factors were commensurate with the class location.

If the design factors were not commensurate with the design factor required for the class location in 1970-1974, and the pipe had been hydrostatically tested, the following limitations applied:

1. The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

2. If the pipe had not been tested, operators could test the pipe to meet the requirements of 49 C.F.R. § 192.611 within the limits noted in #1, above. As a result, operators tested a substantial amount of pipe in the early 1970s.

3. If the design factor exceeded the limitations in #1 above, the pipe would have to be replaced or the MAOP derated. As a result, operators replaced a substantial amount of pipe in the early 1970s.

49 C.F.R. § 192.619

The MAOP requirements in the 1970 regulations were very similar to those in effect today. Operators could establish their MAOP under 49 C.F.R. § 192.619(a) (1-4) (design, pressure test, highest pressure) or under 49 C.F.R. § 192.619(c), the “grandfather” clause.

Conclusions

As a result of the historical industry actions:

- The pipeline industry recognized the need and hence developed consensus engineering standards to improve the safety of natural gas transmission pipelines.

- The API specifications always have required that line pipe be subject to pressure tests and material strength sampling to assure quality at the pipe mill.
- Pipelines built under ASA/ASME B31.8 standards were subject to various levels of pressure tests at the time of construction. Pipeline built within populated areas required a greater pressure test level.

As a result of historical actions by state regulators and the FPC:

- ASA/ASME B31.8 standards and API line pipe standards were incorporated into various state and FPC regulations.

As a result of the historical actions taken by OPS/PHMSA:

- PHMSA addressed MAOP determination in a series of rulemakings when the federal pipeline safety regulations were initiated (in the 1970s) and made risk-informed decisions regarding the transition from standards-based implementation to regulatory oversight.
- Over a period of time, PHMSA permitted pipeline companies time to replace, retest and rerate pipeline systems to comply with the federal regulatory mandate.
- Class 1 locations were not (and are still not) addressed in 49 C.F.R. § 192.611, so no action was required if the pipe was not commensurate with Class 1 design factors. Accordingly, pipelines in Class 1 locations are allowed to have a grandfathered MAOP above 72% SMYS under 49 C.F.R. § 192.619(c).
- All pipe in Class 2, 3 and 4 locations must be commensurate with the design factor relevant for that class or be compliant with 49 C.F.R. § 192.611.
- Pipe with a design factor commensurate with its relevant class location did not have to be pressure tested in 1971-1973 pursuant to Subpart J. Barring any changes to the class location, the pipeline segment can continue to operate without a pressure test.

Any pipe in Class 2, 3 or 4 locations that is not commensurate with the design factor for the current (2013) class, and is not compliant with 49 C.F.R. § 192.611, is out of compliance under current regulations. This is true for pre-regulation and post-regulation pipe.