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U.S Department of Transportation  
Advanced Notice of Proposed Rulemaking**

***Safety of Gas Transmission Pipelines***

**Docket No. PHMSA-2011-0023**

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**Interstate Natural Gas Association of America**

***Policy-Level Comments***

**November 2, 2011**

## Table of Contents

<b>OVERVIEW</b>	<b>1</b>
<b>EXECUTIVE SUMMARY</b>	<b>3</b>
<b>INGAA’s COMMITMENTS</b>	<b>3</b>
EXTENSION OF INTEGRITY MANAGEMENT PRINCIPLES BEYOND HCAs	4
INTEGRITY MANAGEMENT IS THE RIGHT REGULATORY MODEL TO MEET PIPELINE SAFETY GOALS	5
DEMONSTRATING FITNESS FOR SERVICE – PRE-REGULATION PIPELINES	5
INCIDENT MITIGATION MANAGEMENT PRODUCES THE RIGHT OUTCOME	7
INNOVATION AND TECHNOLOGY ARE ESSENTIAL FOR IMPROVING PIPELINE SAFETY	7
<b>INGAA POLICY-LEVEL POSITIONS ON SELECT ANPRM TOPICS</b>	<b>9</b>
<b>TOPIC A – DEFINING “HIGH CONSEQUENCE AREA” (HCA)</b>	<b>9</b>
<b>TOPIC N – EXEMPTION FOR FACILITIES INSTALLED PRIOR TO 1970</b>	<b>10</b>
<b>TOPIC H – VALVE SPACING AND REMOTELY OR AUTOMATICALLY CONTROLLED VALVES</b>	<b>12</b>
<b>TOPIC C – REPAIR CRITERIA (APPROPRIATE ANOMALY RESPONSE)</b>	<b>12</b>
<b>TOPIC E – RISK MODELS AND THEIR APPLICATION</b>	<b>13</b>
<b>TOPIC B – PREVENTIVE AND MITIGATIVE MEASURES FOR PIPELINE SEGMENTS IN HCAs</b>	<b>14</b>
<b>TOPIC D – COLLECTING, VALIDATING, AND INTEGRATING PIPELINE DATA</b>	<b>15</b>
<b>TOPIC F – APPLYING KNOWLEDGE GAINED THROUGH THE IMP PROGRAM AND BEYOND</b>	<b>15</b>
<b>TOPIC G – SELECTION AND USE OF ASSESSMENT METHODS</b>	<b>16</b>
<b>TOPIC I – CORROSION CONTROL AND SCC</b>	<b>16</b>
STRESS CORROSION CRACKING	17
<b>TOPIC K – UNDERGROUND NATURAL GAS STORAGE</b>	<b>18</b>
<b>TOPIC L – MANAGEMENT OF CHANGE</b>	<b>18</b>
<b>TOPIC M – QUALITY MANAGEMENT SYSTEMS</b>	<b>19</b>
<b>APPENDIX 1: THE BENEFITS OF PERFORMANCE-BASED REGULATION</b>	<b>21</b>
<b>OVERVIEW</b>	<b>21</b>
<b>PERFORMANCE-BASED SAFETY REGULATION IS MORE NIMBLE</b>	<b>21</b>
<b>PERFORMANCE-BASED SAFETY REGULATION SUPPORTS PROACTIVE, MULTIDIMENSIONAL RISK MITIGATION</b>	<b>22</b>
<b>PERFORMANCE-BASED SAFETY REGULATION WORKS</b>	<b>22</b>
<b>THE PATH FORWARD</b>	<b>23</b>
<b>ADEQUACY OF PROCESSES</b>	<b>23</b>
<b>ADEQUACY OF THE LAYERS OF PROTECTION</b>	<b>24</b>
<b>ACCOUNTABILITY UNDER PERFORMANCE-BASED SAFETY REGULATION</b>	<b>24</b>
<b>APPENDIX 2 - MANAGEMENT OF PRE-REGULATION NATURAL GAS TRANSMISSION PIPE</b>	<b>25</b>
<b>APPENDIX 3: DEFINITION AND APPLICATION OF FITNESS FOR SERVICE TO GAS PIPELINES</b>	<b>31</b>
<b>WHAT IS FITNESS FOR SERVICE (FFS)?</b>	<b>31</b>
<b>WHAT DATA AND INFORMATION DO FFS EVALUATIONS RELY ON?</b>	<b>31</b>
<b>HAVE FFS EVALUATIONS BEEN APPLIED IN OTHER INDUSTRIES?</b>	<b>31</b>
<b>IS EVALUATING FFS DIFFERENT FOR THE PIPELINE INDUSTRY?</b>	<b>32</b>

<b>EXAMPLES OF FFS EVALUATIONS FOR METAL LOSS/CORROSION</b>	<b>33</b>
<b>FFS APPLIED TO ENVIRONMENTAL-RELATED CRACKING</b>	<b>34</b>
<b>FFS APPLIED TO PRE-REGULATION PIPE</b>	<b>34</b>
<b><u>APPENDIX 4 – VALVE SPACING AND AUTOMATION</u></b>	<b><u>36</u></b>

**Docket No. PHMSA-2011-0023**  
**Response to Advanced Notice of Proposed Rulemaking on**  
**Safety of Gas Transmission Pipelines**

**Interstate Natural Gas Association of America**  
**Policy Level Comments**  
**November 2, 2011**

**Overview**

The Interstate Natural Gas Association of America (INGAA) is a trade association representing approximately two-thirds of the pipelines and over 65 percent of the mileage comprising the nation's natural gas transmission pipeline system. INGAA's 26 members operate approximately 200,000 miles of interstate transmission pipelines, delivering one-quarter of the nation's energy.

For INGAA and its members, pipeline safety is the top priority. In December 2010, INGAA's board of directors established a board-level task force to pursue further improvements in safety performance and to increase public confidence in the natural gas pipeline infrastructure. In March, INGAA's board of directors adopted the following aspirational, guiding principles, anchored by the goal of zero pipeline incidents:

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

On August 25, 2011, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published an Advanced Notice of Proposed Rulemaking (ANPRM) on the safety of natural gas transmission pipelines. After reviewing the ANPRM, INGAA decided to file its comments in two separate submissions. Today's filing will address ANPRM topics at a policy level. It is meant to inform other stakeholders of INGAA's positions and to provide a focal point for stakeholder

feedback. INGAA hopes this policy-level filing will facilitate consensus on how to move forward on these important safety issues. INGAA will make a second filing closer to the comment deadline to respond in detail to questions posed in the ANPRM.

The ANPRM is separated into 15 topics, summarized below:

- A. Modifying the definition of “high consequence area” (HCA)
- B. Strengthening requirements to implement preventive and mitigative measures for pipeline segments in HCAs
- C. Modifying repair criteria
- D. Improving requirements for collecting, validating and integrating pipeline data
- E. Tightening requirements related to the nature and application of risk models
- F. Strengthening requirements for applying knowledge gained through integrity management
- G. Strengthening requirements on the selection and use of assessment methods
- H. Valve spacing and the need for remotely or automatically controlled valves
- I. Corrosion control
- J. Pipe manufactured using longitudinal weld seams
- K. Establishing requirements applicable to underground gas storage
- L. Management of change
- M. Quality management systems
- N. Exemption of facilities installed prior to the regulations
- O. Modifying the regulation of gas gathering lines

In addition to providing policy positions on most of these topics, Appendix 1 to today’s filing addresses a theme running through several topics: the superiority of performance-based regulation over prescriptive regulation. Appendix 2 details a proposed approach to managing construction and material issues on the “pre-regulation” natural gas transmission pipe placed in service before 1970. Appendix 3 provides a framework for defining and determining “fitness for service,” both for pipelines in general and, more specifically, for pre-regulation pipelines. Appendix 4 addresses incident mitigation management as applied to valves and other aspects of incident response.

## **Executive Summary**

Pipeline safety has improved consistently over the decades through the application, continuous refinement and evolution of consensus standards, technology, law and regulation. Part of that evolution occurred in the 1990s, when a series of pipeline incidents highlighted a need to move toward a more proactive approach to managing safety.

Fixing discrete problems found as the result of rote, prescribed inspections is important, but concentrating only on discrete problems risks losing focus on the broader threats to pipeline integrity. Recognizing this, PHMSA moved toward a regulatory system that concentrated more on identifying a broad set of threats to integrity and developing and implementing management processes to address them. This shift ushered in the development of the integrity management process, which has greatly improved pipeline safety.

As it works to develop the next series of natural gas transmission pipeline safety regulations, PHMSA should place an even a greater focus on improving threat management through the integration of modern processes into management systems entailing an even greater involvement of operator personnel. Better-defined guidelines will be needed to verify performance. Operators have realized that integrity management enhances not only safety but business performance, too. The challenge for operators is achieving this integration and demonstrating performance. The challenge for regulators is determining how best to audit the process and verify performance. A redoubled emphasis on performance-based standards will allow both operators and regulators to take a proactive approach to improve pipeline safety continuously.

### **INGAA's Commitments**

Because of the work of regulators and industry, and thanks to developments in new technologies and standards, pipeline transportation remains the safest method of moving energy supplies across the United States. Still, in the wake of the 2010 San Bruno incident, INGAA recognized that more needed to be done to improve the safety of natural gas transmission pipelines and to regain public confidence in the safety of our pipeline infrastructure. Last December, INGAA's board of directors established a board-level task force to pursue these objectives. This task force produced a set of aggressive guiding principles, anchored by the goal of zero pipeline incidents. In July 2011, INGAA outlined a strategy to reach its goal. The INGAA action plan includes commitments to do the following:

1. Apply risk management beyond HCAs to other places where people live.
2. Raise and harmonize the standards for corrosion anomaly management.
3. Demonstrate "fitness for service" of pre-regulation (or pre-1970) pipelines.
4. Shorten pipeline isolation and response time to one hour in populated areas.
5. Improve integrity management communication and transparency of performance.

6. Implement the Pipelines and Informed Planning Alliance (PIPA) guidance.
7. Evaluate, refine and improve threat assessment and mitigation.
8. Implement management systems across INGAA members.
9. Provide forums for engaging stakeholders and emergency officials.

For purposes of this policy-level filing, we will focus on just a few of these commitments.

### *Extension of Integrity Management Principles beyond HCAs*

The Integrity Management Program (IMP)<sup>1</sup> is the cornerstone of the pipeline safety enhancements included in the Pipeline Safety Improvement Act of 2002. The IMP requires operators to identify pipeline segments in populated areas (that is, HCAs) and to perform baseline assessments of all such segments by December 2012. IMP further requires operators to evaluate the results of assessments, to make repairs, to apply prevention and mitigation measures, and, based on each segment's condition, to define a reassessment interval of no longer than seven years. The baseline assessments are close to completion, and many segments already have been reassessed.

There are approximately 300,000 miles of natural gas transmission pipelines in the United States. Of this, about 18,000 miles, or six percent, are located in HCAs. Because in-line inspection (ILI) devices (commonly known as "smart pigs") are used most often for these assessments, and because practical considerations affect how these devices are inserted and retrieved from pipelines, pipeline operators ultimately will assess about 65 percent of the total natural gas transmission pipeline mileage by the end of next year. Completing the baseline assessments will be an important milestone. It is an opportune time to begin contemplating the next steps for natural gas transmission pipeline integrity management.

INGAA's members already have committed to go further and plan to extend integrity management principles beyond HCAs over time. INGAA originally proposed to apply integrity management principles beyond HCAs to cover 70 percent of the people who live or work in close proximity to pipelines by 2020. Since then, INGAA has reevaluated this goal based on more accurate member survey data, and specifically has defined integrity management principles to be the Integrity Management Supplement, American Society of Mechanical Engineers (ASME) B31.8S. Under INGAA's revised goal, ASME B31.8S (B31.8S) will now be applied to 90 percent of the people who live or work in close proximity to pipelines by 2020, and 100 percent of them by 2030.

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<sup>1</sup> IMP is used in this document to indicate the program required under 49 CFR 192, Subpart O; "integrity management" or "(IM)" is used in this document to describe the application of principles set forth in ASME B31.8S, which is the Integrity Management Supplement to ASME B31.8, *Gas Transmission and Distribution Piping Systems*.

While the initial focus is protecting people within pipelines' Potential Impact Radius (PIR) — a term defined in PHMSA's regulations — INGAA also is pursuing other improvements, such as emergency planning in dense population areas. INGAA operators believe additional work is necessary to determine if other consequence factors, separate from population, should be considered in the next phase of implementing integrity management. This work should be done in conjunction with local officials. INGAA members already have taken the first step, gathering with local officials in public meetings earlier this year. These efforts will continue for years ahead.

### *Integrity Management is the Right Regulatory Model to Meet Pipeline Safety Goals*

Integrity management draws upon a series of customized, multi-layered defenses against particular risks. It is the set of actions and protections, taken as a unified system, that when properly executed delivers the greatest risk reduction. Integrity management has worked, and it is clearly the right regulatory model to meet pipeline safety goals.

In this ANPRM, PHMSA asks about prescriptive regulatory choices. As detailed in Appendix 1, shifting back toward a prescriptive regulatory approach would be a mistake. It would ignore the benefits of the proactive integrity management program, which helps foster innovation and continuous improvement. A prescriptive set of requirements defines a single compliance path that can stifle innovation and focus safety efforts on “checking the box” rather than systemically improving practices, methods, activities and materials. Prescriptive requirements tend to stagnate over time, while proactive risk-based and performance-based approaches, such as integrity management, evolve as circumstances and technologies evolve. PHMSA should expand integrity management by expanding the elements to be covered in an integrity management plan and by providing more well-defined guidelines on what and how these expanded plans should evolve over time. Operators should be held accountable for these plans and their continuous improvement, and more process-oriented metrics should be developed to monitor overall safety performance.

### *Demonstrating Fitness for Service – Pre-regulation Pipelines*

The Natural Gas Pipeline Safety Act was enacted in 1968, and regulations implementing the new law took effect in 1970. Under the regulations, operators of pre-regulation pipelines had several options for confirming their lines' Maximum Allowable Operating Pressure (MAOP). Specifically, operators could determine MAOP through pressure testing and multiple record examinations, as is required of pipelines built after 1970, or they could determine MAOP by reference to verifiable records of past operating pressure. Many pre-1970 pipeline operators elected the second option, which has come to be known as the “grandfather clause.”

Fitness for Service (FFS) is the ability of a system or component, in this case a pipeline system or portion thereof, to provide continued service, within established regulations and margins for



safety, until the end of some desired period of operation or scheduled inspection and reassessment. FFS is a well-accepted approach to evaluate flaws that may be injurious to integrity in equipment, including pipelines, to determine acceptability for continued operation. For pipelines, FFS evaluations rely on a detailed threat assessment, risk analysis, the selection of appropriate inspection techniques, and flaw acceptance criteria. Results from FFS evaluations provide guidance on equipment inspection intervals and shape decisions to run, alter, repair, monitor or replace equipment.

About 60 percent of US natural gas transmission pipeline mileage was installed before 1970. Up until 1970, pipeline operators used the ASME B31.8 consensus standard and company procedures to determine a pipeline's "fitness for service," including its MAOP. Most of these pipelines are performing well and they have records showing that they were strength tested. INGAA supports a process for confirming the FFS of pre-regulation (or pre-1970) pipelines located in HCAs, and INGAA's response to topic N, together with Appendixes 2 and 3 below, presents a rigorous process for doing so. For all natural gas transmission pipelines operating in HCAs, an operator must either produce adequate records verifying a pipeline's FFS or reconfirm its FFS by pressure testing or utilizing an alternative technology.

Engineering and operational history shows that older pipelines are perfectly capable of safely remaining in service for many decades to come. Just as with an older home, pipelines that are well maintained can continue to provide reliable service. INGAA does not agree that older pipelines should be replaced simply due to their age. **FFS is the correct focus.** If a pipeline is unfit for service, then it must be repaired or replaced – regardless of age.

INGAA also recognizes the need to use progressively more advanced engineering critical assessments, within the framework of B31.8S, to develop a more rigorous application of FFS to pre-regulation pipelines. Operators' processes to verify this higher standard must inspire confidence.

There must be a workable timeframe for reconfirming pre-regulation pipelines' FFS. INGAA suggests such work in HCAs be completed by 2020.

INGAA supports a reasoned approach that evaluates the findings from work on pre-regulation pipe in HCAs and then relies on a risk-based approach, focused on protecting people, to determine testing beyond HCAs. A key "enabler" for expanding such testing will be the development and commercialization of smart pig technologies that are less costly, provide better data, and cause less disruption than a hydrostatic test. Smart pig research and development ultimately will be critical to meeting the goals for pre-regulation pipelines that the National Transportation Safety Board (NTSB) recommended in its San Bruno report.

INGAA's reliance on smart pig technology builds upon the extensive investment that INGAA members have made to make their systems "piggable." The alternative, universal hydrostatic testing, would result in widespread pipeline capacity constraints. Performing a hydrostatic test

requires completely removing the pipeline from service for up to several weeks. Universal testing thus will dramatically increase the likelihood and magnitude of transportation service disruptions (and consumer energy prices). Furthermore, with hydrostatic testing costs of approximately \$250,000 to \$500,000 *per mile* and with approximately 179,000 miles of pre-1970 natural gas transmission pipelines in the United States, the direct cost of such testing alone could have a significant impact on consumer energy costs when included in natural gas pipeline rates. Reconfirming MAOP for grandfathered pipe is clearly an area that should be subject to a rigorous cost-benefit analysis, where less costly and less disruptive alternatives to achieve the same safety goals should be considered.

### *Incident Mitigation Management Produces the Right Outcome*

While rare, pipeline incidents can have tragic consequences, including loss of life, injury or damage to property. **Avoiding incidents is the priority, but the importance of incident response, both planning and execution, is self-evident.**

Incident response should focus on performance, not specific technology. Automatic and remotely controlled valves may be part of improving response time, but they are not the only solution and they alone are not a complete solution. Valves cannot prevent an incident, nor are they likely to reduce the number injuries or fatalities in the unlikely event of a natural gas pipeline rupture and fire. Even with an automatic or remote controlled valve, a high-pressure natural gas pipeline can take significant time to depressurize following a rupture. Most of the human impacts from a rupture occur in the first few seconds, well before any valve technology could reduce the flow of natural gas. It is important for policymakers to understand that the primary benefit of isolating a damaged pipe segment – either through personnel or through automation – is to mitigate fire damage and allow emergency responders access to the impacted area.

Incident Mitigation Management (IMM) goes beyond placing and operating isolation valves. It employs integrated planning and implementation to develop means for detecting ruptures and determining which valves to close. IMM also includes improved operator coordination with first responders and with other stakeholders, including the public. IMM is consistent with INGAA's commitment to shorten pipeline isolation and response time to one hour in populated areas, and IMM will produce a far better public safety outcome than prescriptive valve placement requirements.

### *Innovation and Technology are Essential for Improving Pipeline Safety*

A key benefit of using risk-management approaches to pipeline safety is the creation of an environment conducive to innovation. New technologies will play a critical role in helping to chart a practicable and achievable course for reaching the pipeline safety goals all of us share. Smart pig and similar research and development is critical to achieving these goals. It will be

important for industry, government and other pipeline stakeholders to work together closely to develop an R&D road map for needed pipeline safety technologies, an efficient and effective work plan for developing and deploying these technologies, and a means to fund this important R&D work. Using prescriptive standards in areas where technology is constantly changing generally limits industry's ability to make the best safety choices.

## **INGAA Policy-Level Positions on Select ANPRM Topics**

The ANPRM invites comments on 15 topics covering most aspects of gas transmission pipeline integrity and safety. INGAA has chosen to provide a policy-level response roughly one month in advance of the comment deadline to inform other stakeholders and to solicit feedback. INGAA's responses appear in their order of significance.

### **Topic A – Defining “high consequence area” (HCA)**

**Modification is unnecessary.** HCAs, as defined under Part 192 ([Subpart O--GAS TRANSMISSION PIPELINE INTEGRITY MANAGEMENT](#)) have provided an effective basis for prioritizing integrity management activities. **There is value in using HCAs, as currently defined, as a jumping off point to expand integrity management. INGAA members have voluntarily committed to applying integrity management principles to the entire transmission system they operate, and to phase in this expansion based on protecting people who live near the pipelines. INGAA's members have a strategic and logical basis for extending these additional protections on a risk-prioritized basis. Improved risk assessment will allow us to produce findings that will drive better-informed decisions on the need for additional assessment, prevention and mitigation, including pipe repair and replacement.**

INGAA proposes using the protection of people living near pipelines (that is, within the Potential Impact Radius, or PIR) as the basis for extending the use of improved integrity management principles.

- **90 Percent of Population — Integrity Management Principles by 2012**
  - By the end of 2012, INGAA members will have applied some degree of integrity management on pipelines covering roughly 90 percent of the population living within the PIR.
    - Pipe inside an HCA will be subject to the processes required in 49 CFR Part 192, Subpart O
    - Integrity management for pipe outside an HCA will range from full Subpart O, to either full B31.8S or a focus on the most significant threats (e.g., Stress Corrosion Cracking (SCC) or corrosion).
  - To cover 90 percent of population within the PIR, INGAA members will apply integrity management principles to roughly 60 percent of their total pipeline mileage.
  
- **90 Percent of Population — Complete B31.8S by 2020**
  - By 2020, INGAA operators will perform “*Integrity Management*” on pipelines covering 90 percent of the population living within the PIR.
  - At a minimum, all B31.8S requirements will be applied, including mitigating corrosion anomalies and applying integrity management principles.

- **100 Percent of Population — Integrity Management Principles by 2030**
  - By 2030, INGAA’s goal is to apply integrity management principles to pipelines covering 100 percent of the population living within the PIR.
    - The integrity management principles applied to the increment between 90 percent and 100 percent of the population will range from B31.8S to new pipeline assessment technology utilizing integrity management principles.
    - To cover 100 percent of population within the PIR, INGAA members will apply integrity management principles to roughly 80 percent of their total pipeline mileage.
  
- **Remaining 20 Percent of Pipeline Miles with No Population**
  - The remaining 20 percent of pipeline miles with no population within the PIR pose a low risk to the public. In addition, this mileage poses significant technical challenges due to a number of factors, e.g., small diameter pipelines, multi-diameter pipelines, pipelines lines with low flow rate, complex geometry, and single-source feeds to customers (necessitating complete service disruptions). INGAA’s members are committed to applying improved integrity management principles to these pipelines after 2030.

To help meet this aggressive goal, INGAA is engaging the research community and technology providers to develop new inspection and assessment tools (platforms as well as sensors) that can reliably address hard-to-assess areas. This effort is consistent with Recommendation P-11-39 from NTSB’s San Bruno investigation report, which asks INGAA and AGA to report on the development and introduction of innovative ILI platforms, including a timeline for implementation of the advanced platforms. INGAA has begun developing an R&D road map.

## **Topic N – Exemption for facilities installed prior to 1970**

In the ANPRM, PHMSA asks what increased safety evaluations should be completed to permit pre-regulation pipelines to continue operating at pressures higher than would have been allowed under regulations promulgated in 1970. At issue is the “grandfather clause,” 49 CFR section 192.619(a)(3), which permits pipelines that had operated at or above 72 percent specified minimum yield strength (SMYS) to continue to do so based on the five-year pressure operating history prior to the regulations being promulgated. Recommendation P-11-14 from NTSB’s report on the San Bruno incident asks that 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.”*

**The grandfather clause must not be removed or modified without acknowledging that a more rigorous fitness for service (FSS) evaluation can be applied to determine whether grandfathered pipes can continue to be operated safely and reliably.** Many of the “grandfathered” pipelines operating at and above 72 percent SMYS have been strength tested

to levels providing a safety margin commensurate with operation at these higher stress levels (specifically, a margin of 1.25 times MAOP). The safety performance of these pipelines is as good as or better than overall industry performance.

- In material provided in its July 13, 2011 filing in the “Report to America” docket, INGAA described a broad draft approach to achieve integrity of pre-regulation pipelines described.
- INGAA members will use an FFS analysis for pre-regulation pipe that rigorously focuses on material and construction, the primary threats to pre-regulation pipelines. All other threats to these pipelines are correctly addressed through Subpart O or B31.8S. This approach is consistent with the shared goal of PHMSA, NTSB, INGAA and others: demonstrating that pipeline systems are fit for service. An expanded discussion of this topic appears in Appendix 2.
- FFS analysis is an accepted set of processes to demonstrate the mechanical integrity of in-service equipment, including pipelines. FFS analysis is specifically designed and has been demonstrated to support decisions on future disposition of equipment. See Appendix 3.
- Implementing the FFS protocol will require time to manage customer service impacts and acquire necessary resources.
- The right place to start is pipelines within HCAs that have incomplete strength test records. The testing, repair, remediation or replacement of these pipelines within HCAs will be accomplished over seven years, and during that period findings will be continually evaluated to derive lessons learned for future work.
- In parallel, consistent with NTSB’s goal of making systems piggable and advancing research, INGAA and its members will work to commercialize ILI technologies that can more rigorously demonstrate FFS, from the standpoint of construction and material threats, for pre-regulation pipe. Innovative ILI technologies will be incorporated into the FFS protocol on a risk-prioritized basis.

Consensus standards for line pipe have required “mill tests” (pressure tests for each piece of pipe released from a pipe manufacturing facility) since 1928. Based on available information, the material that failed in San Bruno would not have passed a mill or a field pressure test under the prevailing standards of that time. INGAA members believe the pipes and components in their systems were manufactured to prevailing standards and INGAA members are working diligently to validate those records. Records verification is necessary to achieve confidence in the integrity of pre-regulation pipelines. Absent verifiable records, INGAA members will apply the diligent FFS evaluation described above.

## **Topic H – Valve spacing and remotely or automatically controlled valves**

Manual, remote and automatic valves are used to isolate a pipeline section after an incident occurs. While isolation valves will not prevent an incident or its initial consequences, these valves are effective in mitigating secondary damage and making an area safe for emergency responders. **While valves, spacing and selection are important, public safety requires a broader review of incident responses and consequences. Performance-based Incident Mitigation Management (IMM), using valves and other tools, is the appropriate approach to improving incident response, reducing incident duration and minimizing adverse impacts.**

IMM plans identify comprehensive actions that improve mitigation performance and minimize overall incident impact. These plans cover various aspects of response, including how operators detect failures, how they place and operate valves, how they evacuate natural gas from pipeline segments, and how they determine priorities in their coordination efforts with emergency responders.

- Rapid recognition and response are essential elements of incident management and automation can be part of an effective response. In populated areas, INGAA members have committed to having personnel on scene within one hour to coordinate with first responders and isolate failures. Where personnel cannot respond promptly, automation is the best solution.
- Performance-based IMM plans prioritize the deployment of incident mitigation measures, applying them first where the consequences of a failure are greatest.
- IMM plans will be developed and implemented on pipelines in HCAs, with 70 percent of HCAs completed in seven years and the remainder within 10 years, using a risk-based sequence defined in each operator's IMP plan.
- In areas of significant population density, operators will consult with emergency responders in forming their mitigation plans.
- Where local officials identify significant consequence factors, such as critical infrastructure, INGAA members will accelerate the IMM process.

An expanded discussion of this topic appears in Appendix 4.

## **Topic C – Repair criteria (appropriate anomaly response)**

Two sets of considerations are made following an integrity assessment. The first are anomaly response criteria, which are performance tools that help determine the actions that need to be taken based the results of integrity assessments. B31.8S sets out anomaly response criteria, including timing criteria for determining when to make excavations to evaluate FFS and when to continue monitoring. The second are repair criteria for a pipeline to be fit for service and

continue operating. The most often used repair criteria is the assessment of corrosion deterioration.

**INGAA members commit to mitigate corrosion anomalies, both inside and outside of HCAs, in accordance with the technically based criteria in B31.8S (including any future enhancements or revisions).** This commitment raises the level of corrosion protection both in quality and in timeliness of repair. **INGAA members also commit to improve the mitigation of dents, pitting corrosion, expanded pipe corrosion and selective seam corrosion (SSC) by developing and using criteria comparable to those for corrosion anomalies.**

The B31.8S protocol produces a strong technical basis for decision-making in response to the discovery of anomalies. As smart pig technology (both detection and reporting) continues to improve, the best investment of resources is to replace, repair or reassess based upon the information produced by this technology wherever reasonably possible.

- Uncertainties in ILI tools and the B31.8S protocol are being identified and quantified. INGAA members have collaborated with Pipeline Research Council International (PRCI) to commission a research report *“to refine and extend the technical bases for responding to corrosion anomalies identified primarily by ILI. These technical bases will provide the operator with guidance regarding the determination of both what anomalies require a remediation response and the timing of that response, and will include consideration of measurement, corrosion growth, and analytical (model) uncertainties.”* The report is scheduled for completion in first quarter 2012.
- Upon completion of the PRCI research report, INGAA members will work with ASME to refine B31.8S to include anomaly evaluation methodologies that account for data uncertainties (including tool accuracy) by applying a consistent process or series of processes across its membership.

The goal continues to be no failures of anomalies identified by ILI technology. Future required reassessments outside of HCAs should be risk-based utilizing present and future B31.8S criteria.

### **Topic E – Risk models and their application**

Risk management is a process of identifying risks and applying management systems to control them. Good, performance-oriented, risk management systems evolve as new information is gathered and understood. Prescriptive management systems are task oriented and therefore do not adjust easily to new information or knowledge. As detailed in Appendix 1, prescriptive systems are easier to audit, but not as effective as performance-based systems. **Continuing the performance-based regulatory approach, exemplified by integrity management, is critically important to improving pipeline safety.** Enhanced performance is dependent on



improved technology and processes. Prescriptive requirements inhibit innovation, and could thwart safety improvements.

The pipeline integrity management programs in place today are similar to the Process Safety Management System (PSM) that the Occupational Safety and Health Administration (OSHA) requires of many facilities and the Safety Management System (SMS) used by the Federal Aviation Administration. (At the NTSB hearing on the San Bruno incident, NTSB Board Members called IMP “the pipeline industry’s SMS.”) These and other regulatory approaches to complex, high-risk industrial operations are highly regarded and have achieved demonstrable success.

For regulatory oversight of risk-management systems, the acknowledged challenge is being able to validate the adequacy and even the robustness of the engineering and management processes that operators use to make safety decisions. This challenge is not insurmountable. There are ways to preserve the benefits of proactive thinking and encourage innovation and flexibility while addressing the challenges of holding operators accountable through the inspection and enforcement process.

- PHMSA’s enforcement challenge is to determine whether an operator’s goals, planning, documentation, measurement, and evaluation processes are sufficient to execute safety decisions effectively.
- PHMSA’s integrity management regulations and inspection protocols should provide explicit criteria and guidelines on techniques for operators to demonstrate safety decision processes.
- Issuing more detailed guidelines on specific integrity management plan elements would enhance PHMSA’s the current, performance-based approach and generate additional benefits that the public and operators desire.

## **Topic B – Preventive and mitigative measures for pipeline segments in HCAs**

**INGAA strongly agrees with the necessity of applying preventive measures to address identified threats. In addition to IMM planning (discussed under topic H), guidance is provided in Table 4 and Section 7 of B31.8S. Enhancing these standards—perhaps by adding a decision tree or flow chart—will help operators systematically apply this requirement.** PHMSA also would benefit by using this guidance to implement enforcement objectives.

Excavation damage to pipelines is the most significant cause of serious pipeline incidents (those involving injuries and deaths). **PHMSA can improve the prevention and mitigation of excavation damage substantially by fully implementing its state damage prevention programs.** Opportunities to enhance current damage-prevention programs include expanding enforcement provisions associated with one-call programs, eliminating exemptions currently

granted under some state's one-call regulations, and promoting greater consistency and standardization of state program best practices.

The US Department of Transportation (DOT) can also enhance damage prevention programs by broadening public education efforts supporting 811 and one-call program. Even with vigorous 811 education campaigns, a significant number of pipeline incidents still occur because the excavator did not use the One Call system. **DOT should promote 811 public service announcements at the national, state and local level, in a manner similar to the extremely effective seat belt campaign.**

### **Topic D – Collecting, validating, and integrating pipeline data**

A key to a well-run risk-management system is quality information about the inventory and characteristics of the pipeline. Knowledge gained during investigations of pipeline failures can help focus pipeline data collection efforts. **Data collection and analysis are essential to effective risk assessment.**

B31.8S emphasizes the importance of collecting and utilizing data. One of the key lessons learned from the first 10 years of applying integrity management is the importance of collecting the right data. It also is imperative that the *right* data is integrated into an overall risk assessment. INGAA members are working collaboratively to develop tools and methods to better integrate data, not only to support risk analysis, but also to support decisions concerning the selection of post-assessment excavation sites and the prevention and mitigation measures that better manage threats to integrity.

The data integration process must demonstrate how risk analysis is being applied on an ongoing and consistent basis. It must be reviewed and monitored by executive management. INGAA believes a need exists to apply progressively more advanced engineering and critical assessments within the framework of B31.8S and its revisions. Any system should include a basis for analyzing interacting threats.

### **Topic F – Applying knowledge gained through the IMP program and beyond**

Integrity management has improved pipeline safety by increasing knowledge and understanding. INGAA members independently apply knowledge gained during assessments and remediation of pipelines in HCAs to the remainder of their systems. This not only improves pipeline system integrity: it is also good business. **INGAA has committed to a more rigorous and structured approach to manage knowledge gained, through the IMP program and beyond, and to share those results with others.**

INGAA members will make information regarding assessments as well as mitigation available as part of our commitment in the fifth guiding principle to engage our stakeholders. This includes

periodic, formal reports demonstrating greater transparency so that our stakeholders will understand the performance of our systems (and not just HCAs). We began demonstrating this in our June 22, 2011, filing in the docket for Secretary LaHood's "Report to America."

### **Topic G – Selection and use of assessment methods**

An operator develops an assessment process model by balancing one or more reliable inspection methods, each based upon anticipated threats, with available technology and the physical limitations of the pipeline. Information generated from the model is integrated with information previously generated from current analysis techniques. A great advantage of the integrity management structure, as opposed to a prescriptive regulatory regime, is the creation of an environment conducive to technological development, innovation and improved knowledge. **INGAA and its members are committed to work with technology providers and researchers to improve the integrity management assessment capabilities of its members. Further, INGAA members are sharing their experience with applying these new and improved assessment methods to specific threats.** These types of gains can continue through performance-based regulation, while allowing some prescriptive oversight of the processes.

### **Topic I – Corrosion Control and SCC**

Corrosion is one of the most significant time-based deterioration mechanisms on steel transmission pipelines; corrosion control is an intricate process to manage it. Our response covers two items: corrosion control under Part 192, Subpart I; and stress corrosion cracking (SCC).

#### Subpart I Corrosion Control

INGAA members have had good success managing corrosion anomalies within HCAs through ILI inspection and direct assessment. **INGAA members commit to mitigating corrosion anomalies, both inside and beyond HCAs, consistent with B31.8S.** This commitment raises the level of protection, both in quality and in timeliness of repair, in areas outside HCAs.

Enhanced external corrosion management methods, such as close interval surveys and post-construction coating surveys, have proven effective in helping identify and mitigate certain corrosion damage conditions. That said, these methods can be redundant or inferior when combined with other assessment techniques. **Enhanced external corrosion management methods, such as close interval surveys and post-construction coating surveys, should not be required singularly and arbitrarily by new prescriptive regulation.** Rather, these methods should continue to be used by operators on a threat-specific basis, as is currently practiced under performance-based regulations and consensus-based IM programs.

Common principles for applying and using close interval surveys are addressed in consensus standard NACE SPO207: *Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines*. Operators should continue to use this standard.

### Stress Corrosion Cracking

SCC occurs in isolated areas under specific operating conditions. INGAA members have been involved closely with SCC threat-management processes since the first SCC failure on a pipeline was identified. The following describes just some of the focus INGAA members have placed on SCC management:

- Ten members of INGAA formed a Joint Industry Project (JIP) in 2006 to review historical experience and evaluate ways for improving current standards and guidance. The JIP met for two years, documenting incident experience, developing methods for selecting excavations for SCC direct assessment (DA) and reviewing experience with hydrostatic testing, DA, and emerging ILI technologies such as the electro-magnetic acoustic transducer (EMAT). The JIP developed a method for conducting a spike pressure test for SCC and the basis for defining the appropriate reassessment interval for hydrostatic testing. Finally, the JIP developed specific guidance on near-neutral SCC, as the original version of B31.8 did not explicitly address near neutral conditions. The JIP has made a number of recommendations to the B31.8 Committee for inclusion into B31.8S.
- API 1110, a recommended practice that can be applied to both natural gas and hazardous liquid pipelines, was revised in 2009 to provide specific detail on conducting spike pressure testing. The revision addressed test level and duration, as well as leak checking. B31.8S was revised in 2010 to address near-neutral SCC. In addition, there were other clarifications made to ensure consistent application of the process.
- A second JIP was formed in 2010 to analyze and evaluate recent SCC experience, including incidents, hydrostatic testing experience and the use of ILI. Protocols have been developed for analyzing and evaluating ILI data and data from excavations. These protocols serve as a basis for operator's procedures. In addition, the JIP compared SCC fitness for service methods with other methods (for other types of cracks), providing operators with guidance on their application.
- INGAA operators have also engaged in the following:
  - Supporting ILI vendors, both individually and via the EMAT User Group, to achieve improved accuracy and reliability for SCC detection and severity assessment.
  - Most INGAA members support projects aimed at SCC prevention, detection, assessment and mitigation through their membership in PRCI.

- Some INGAA members also have in-house research projects aimed at delivering specific improvements in SCC management. The information gained from these projects is generally shared with other operators through the various joint-industry forums.

INGAA members are fully committed to all the activities associated with delivering continuous improvements in SCC management performance. **PHMSA should incorporate the new SCC-management provisions in B31.8S as the basis for identifying and mitigating SCC.**

**Also, PHMSA should be responsive to further enhancements.** Current standards have improved the management of SCC conditions in natural gas transmission pipelines; but zero is INGAA’s target. More research work needs to be done.

INGAA members are committed to enhance consensus standards to prevent in-service failures due to SCC. Evergreen standards such as B31.8S, NACE RP 0402-2004 and API 1110 are updated continually with current research from PRCI, PHMSA, JIPs and individual company research. **INGAA members are committed to continuing to lead these R&D efforts and to getting the results promptly incorporated into consensus standards.**

### **Topic K – Underground natural gas storage**

Over the decades, operators of underground natural gas facilities have benefited greatly from technological advances and they have improved their standards and practices continually. **To promote and enhance public safety further, INGAA supports the development and adoption of minimum federal consensus standards, — specifically, high-level, performance-based, minimum guidelines — governing the operational integrity of interstate underground gas storage facilities.** Compliance with the federal standards should not be voluntary; however, in order to be effective and efficient, the federal standards should allow established, regionally-appropriate monitoring and assessment methods, currently followed by INGAA member storage operators, to continue to be used. **If PHMSA adopts regulations incorporating these federal standards, the agreement provisions of 49 CFR Sections 60105 and 60106 could be used to allow state agencies to become PHMSA’s agents in administering the federal program.** INGAA further cautions that PHMSA’s regulations incorporating the federal standards should not conflict with any existing federal regulations or the Natural Gas Act.

### **Topic L – Management of Change**

According to B31.8S, management of change is *“a systematic process ... to ensure that, prior to implementation, changes to pipeline system design, operations or maintenance are evaluated for their potential risk impacts, and to ensure that changes to the environment in which the pipeline operates are evaluated.”*

**INGAA members are committed to clarifying and expanding the use of a formal “management of change” process, and to facilitating its consistent application as a key management system. INGAA believes that the full adoption of B31.8S will facilitate the widespread application of these principles.**

Management of change (MOC) originated in the petrochemical and oil and gas exploration segments of oil and gas industry, following a cyclohexane vapor cloud explosion in Flixborough, UK in 1974 and the Piper Alpha explosion in the North Sea in 1988. OSHA, working with the oil and gas industry, included MOC when it implemented its PSM regulations (29 CFR 1910.119).

The authors that developed the original MOC section in B31.8S represented a wide cross section of industries, including petrochemicals, petroleum refining, and coal and nuclear power generation. PHMSA already has incorporated the MOC concept within its regulations.

- INGAA members have applied MOC for HCAs, per 49 CFR 192.911(k), since the regulations went into effect in 2004.
- Many members have applied MOC since publication of B31.8S in 2002 and even earlier, when MOC was adopted by their corporate families.
- MOC will be also be implemented as part of PHMSA’s control room management regulations (49 CFR 192.631), which became effective on August 15, 2011.

## **Topic M – Quality Management Systems**

**Implementing a quality management system (QMS) on pipeline construction projects improves material and construction quality by providing a structured approach to quality management. INGAA intends to clarify and improve its application of QMS.** Through effective QMS, pipeline construction project sponsors can improve both their conformance to project specifications and standards and their regulatory compliance. All industry sectors (operators, contractors and suppliers) need to work together to embrace higher standards of quality through the application of QMS principles.

Achieving a consistent and uniform level of quality management across the pipeline construction industry is a challenge well suited for the INGAA Foundation, Inc. (Foundation). INGAA formed the Foundation in 1990 by to advance the use of natural gas and to facilitate the efficient construction and safe, reliable operation of the North American natural gas pipeline system. The Foundation has proven to be an effective forum to tackle construction issues because all key industry sectors are represented. The Foundation has sponsored and will continue to sponsor workshops aimed at achieving a consistent and uniform level of quality management across the pipeline construction industry.

The Foundation also has successfully addressed similar challenges in other areas, including environmental construction requirements promulgated by the Federal Energy Regulatory Commission, project permitting and pipe quality. The Foundation will publish five white papers related to QMS in early 2012, each addressing different elements of improved construction practices. These Foundation white papers are:

- Overview of Quality Management Systems – Principles and Practices for Pipeline Construction
- Pipeline Construction, Fabrication, and Testing – Training Guidance for Construction Workers and Inspectors for Welding and Coating
- Best Practices of Field Applied Coatings
- Best Practices in Applying API 1104, Appendix A
- Standards for Procurement and Installation of Field Segmented Bends

## **Appendix 1: The Benefits of Performance-Based Regulation**

### **Overview**

At several points in the ANPRM, PHMSA asks whether it should be taking a more prescriptive approach to pipeline safety regulation, either by imposing more prescriptive standards than currently exist or by imposing prescriptive standards in areas currently subject to more open-ended, performance-based regulation. INGAA strongly urges PHMSA to expand its use of performance-based regulation for several reasons:

- Performance-based regulation recognizes and incorporates technological advances more quickly, fostering safety innovation.
- Performance-based regulation supports proactive, multidimensional planning, operations and accountability, consistent with today's business practices.
- Performance-based regulation has an established track record of success as illustrated several federal agencies' highly regarded regulatory programs and documented through industry studies.

Properly applied, a performance-based regulatory approach can reap these benefits without compromising public safety.

### **Performance-Based Safety Regulation Is More Nimble**

When it first promulgated Part 192 in 1970, PHMSA's predecessor adopted the majority of ASME B31.8, a set of standards that a majority of the natural gas pipeline industry deemed useful in achieving a common level of safety performance in the design, construction, operation and maintenance of natural gas transmission pipelines. Although these practices were often driven by risk-based thinking, when they were assembled into ASME B31.8 many of them were translated into minimum prescriptive standards, which continue in Part 192 today.

Experience demonstrates that prescriptive regulatory standards cannot keep up with technological advances. ASME B31.8 has been updated a number of times to incorporate new processes and technologies. When updates have been released, PHMSA and its predecessors have worked to incorporate the ASME B31.8 revisions into Part 192. However, Part 192 can be updated only through a rulemaking proceeding, and rulemaking proceedings are inherently lengthy. Where prescriptive regulations are employed, the lag between technological innovation and regulatory change is unavoidable, and in many cases this unavoidable lag inhibits the development and adoption of technologies and processes that may improve safety performance.

There is no lag in performance-based regulation. The regulation identifies an objective to be achieved, leaving the regulated community to determine the means for achieving it.



Technological advances do not change the identified regulatory objective, so industry can adopt them immediately, without waiting for the rulemaking process to catch up. Where prescriptive standards inhibit innovation, performance-based standards foster innovation by encouraging advances that allow performance objectives to be achieved more effectively and efficiently.

### **Performance-Based Safety Regulation Supports Proactive, Multidimensional Risk Mitigation**

Beginning in the 1990s and continuing through PHMSA's adoption of the various IMPs, policy makers have identified the need to be more proactive and innovative in managing safety, and, specifically, in risk mitigation risk. Even then, the need for something beyond the existing requirements was evident.

Prescriptive regulations emphasize conformity over creativity, prescribing detailed process requirements enforced through inspections and the prospect of remedial action. By specifying decision the criteria an operator must follow, prescriptive regulations necessarily imply that an operator's existing process for making safety decisions is inadequate. Compliance is essentially reactive and one-dimensional.

As the IMPs illustrate, performance-based regulation concentrates more on the processes comprising risk mitigation than the achievement of prescribed parameters. In response to the performance-based provisions of the integrity management regulations, operators have developed customized, multi-layered processes to identify risks and defend against them. Standing alone, each process may have gaps, but taken together, taken as a coordinated, comprehensive and integrated set, the processes merge into a strong set of protections. It is the set of actions and protections, operating as a unified system, that should deliver the greatest risk reduction when properly executed.

More can be done. Prescriptive regulations undermine the benefit of proactive and multidimensional risk assessment and remediation. Wherever possible these regulations should be replaced with performance-based standards that will allow a more complete integration of risk mitigation processes and an even greater involvement of all operator personnel. Operators have realized that IMP enhances not only safety but business performance, too. A performance-based approach keeps this momentum and helps operators be innovative and proactive.

### **Performance-Based Safety Regulation Works**

The performance-based elements of PHMSA's integrity management regulations are similar to highly regarded risk mitigation programs at other federal agencies:

- The Process Safety Management System (PSM) adopted by the Occupational Safety and Health Administration
- The Risk Management Process (RMP) adopted by the Environmental Protection Agency

- The Safety Management System (SMS) adopted by the Federal Aviation Administration

Experience with these complex, high-risk industrial operations prompted these diverse regulators to choose risk performance-based approaches over prescriptive approaches to improve safety. The same is true for PHMSA. During the latter 1990s, PHMSA was active in promoting risk management demonstration programs, where pipelines added flexible practices and procedures on top of the prescriptive Part 192 regulations. Today's IMPs trace their origin to these demonstration programs. In fact, at the NTSB's recent San Bruno pipeline hearing, several members called IMP the pipeline industry's SMS.

Industry studies document the benefits of performance-based approaches to safety regulation. In the mid-1990s, the American Institute of Chemical Engineers surveyed 25 companies on the benefits of a systems approach to safety. Respondents were gas plants, chemical facilities and refineries, all with operations similar to pipelines and all subject to OSHA's PSM and EPA's RMP. Respondents ranged in size from small companies to those with annual revenues of up to \$10 billion per site.

Half of the respondents said that even in the very early years following regulation the process developed under PSM and RMP paid for themselves. The primary benefit was avoided incidents, which translated into avoided impacts on operations; avoided environmental damage; avoided personal injuries, hospitalizations and deaths; avoided litigation; and avoided evacuations and sheltering in place. Some respondents cited a rebirth in innovative thinking as an important benefit. Additional benefits were improvements in product quality and productivity, lower insurance cost and reduced workman's compensation payments. Similar benefits will be gained by preserving IMP as a non-prescriptive regulation and allowing integrity management to expand and improve.

### **The Path Forward**

The benefits of expanded performance-based regulation are clear. The question is how to frame the regulations to foster risk-mitigation and provide regulators a means to audit it effectively. The next generation of performance-based, integrity management regulation should focus on three areas: the adequacy of the safety management process, the adequacy of the resulting layers of protection and the adequacy of measures and processes for assuring accountability.

### **Adequacy of Processes**

Regulations should ensure that an operator has the goals, planning, documentation and evaluation processes necessary to execute safety decisions well. PHMSA should provide more explicit criteria and guidelines documenting operators' safety decision processes. Potential areas for performance-based, process regulations include whether there is appropriate management commitment and involvement, whether an operator is using data appropriately to support risk assessment conclusions, whether there is a system in place for taking action to

minimize risks and mitigate failures, and whether there is an evaluation process to determine if measures to prevent or mitigate risk are adequate.

### **Adequacy of the Layers of Protection**

Recognizing that risk mitigation is a multi-layered process, performance-based regulation should examine whether these processes work together to deliver improved safety decisions. Using performance metrics, the regulations should place a premium on seamless process integration.

### **Accountability under Performance-Based Safety Regulation**

There are ways to preserve the benefits of proactive thinking, encouraging innovations and flexibility in alternative options, while addressing the challenges of holding operators more accountable through the inspection and enforcement process. For example, INGAA recently adopted five guiding principles for pipeline safety. These principles act like a code of conduct, specifying industry commitments and guiding industry behavior. Having these guiding principles promotes better operating practices, good quality consultation among operators and benchmarking.

Performance-based accountability regulations would require operators to demonstrate how they adhere to these principles and the effectiveness of the resulting mitigation efforts. For example, operators could be required to measure the effectiveness of continuous improvement efforts.

## **Appendix 2 - Management of Pre-Regulation Natural Gas Transmission Pipe**

INGAA: November 2, 2011

# Overarching Principles



- A provision in the regulations entitled, “*Initial Determination of Class Location and Confirmation or Establishment of Maximum Allowable Operating Pressure*”, at 49 CFR 192.607, was in effect in 1970. This required operators to confirm their MAOPs for half of their system by January 1, 1972 and remaining portion of the system by January 1, 1973. 49 CFR 192.607 was removed from the regulations in 1996 because the compliance dates had long passed.
- In 2011, operators have started by confirming that records exist (Records Process: pages 27-28)
- Where traceable, verifiable and complete records exist to establish MAOP under 49 CFR 912.619, continue to operate under 49 CFR 192.
- Where records are incomplete, if there is a pressure test to 1.25xMAOP, continue to operate under 49 CFR 192.
- Where records are incomplete, if the pressure test does not meet above criteria or there is no historical pressure test, apply Fitness For Service (FFS) Process For Managing Pre-Regulation Pipe: pages 29 and 30.
- Where records do not exist or are incomplete for a segment containing short sections of pipe in a replacement project or tie in of a line or appurtenance prior to the Federal regulations coming into effect, assign the segment as a high priority for hydrostatic testing, direct examination and testing or replacement (San Bruno Provision – High Priority: page 30).
- INGAA is working with others to develop alternative technology.

Management of Pre-Regulation Natural Gas Transmission Pipe: November 2, 2011

# Proposed Definitions



- **Traceable** – the record can be tied to a facility and traced back to the origin of the data.
- **Verifiable** – the record can be confirmed by supporting documentation, credible statements that have been recorded, or field verification through inspection and testing.
- **Complete** – the record was complete according to the requirements in place at the time the data was created or it provides sufficient information to determine or confirm a parameter.

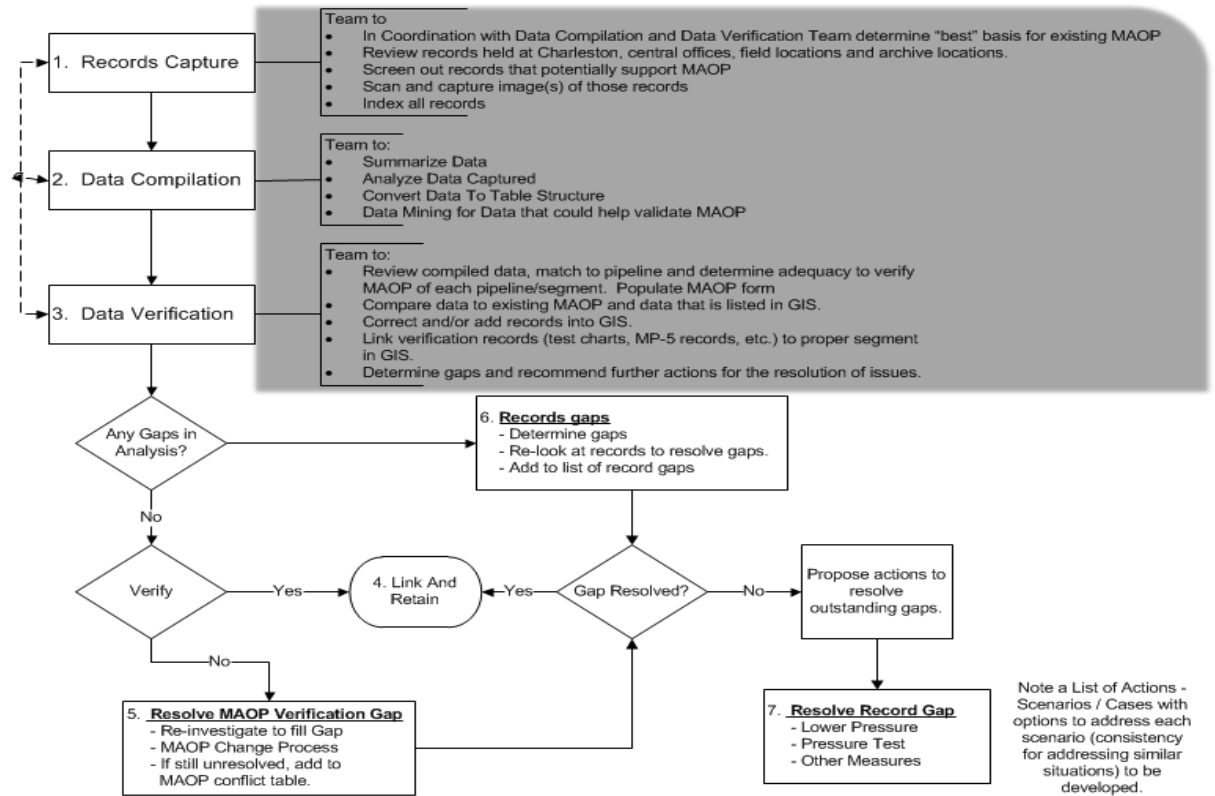
## Additional Descriptors:

- Time – records cover all in installation, modification, and repair projects completed over the life of the facility,
- Extent – records cover the pipeline without gaps from beginning to end, and
- Content - content is complete according to the requirements in place at the time the record was created.

# Improvement Process for Traceable, Verifiable and Complete Records



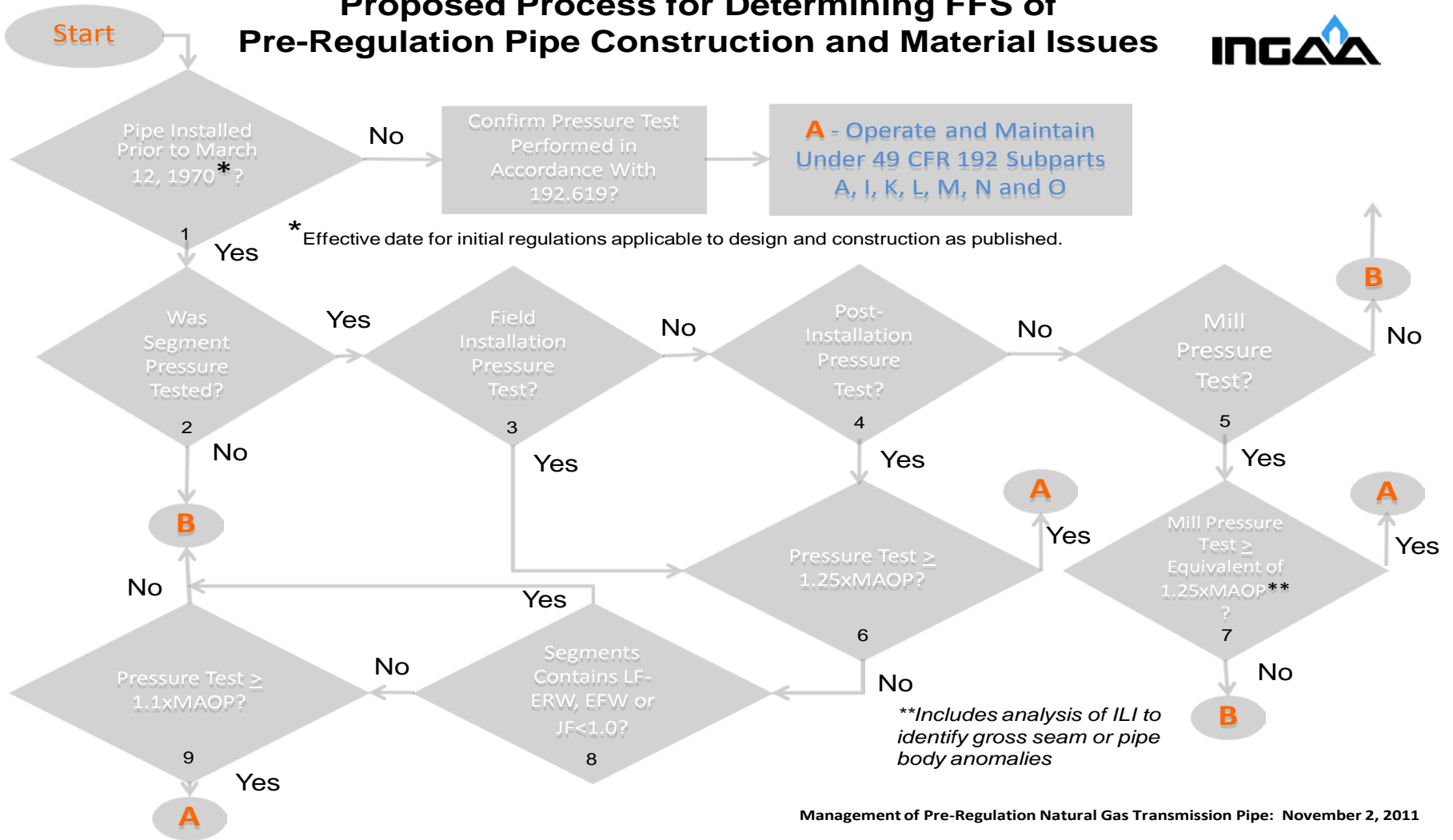
- Disciplined Process
  - Prioritization
  - Standards
  - Procedures
  - Chain of Custody
  - Management of Change
- Technology to Ensure Traceability and Transparency



**“Traceable, verifiable and complete” records requirement**

Management of Pre-Regulation Natural Gas Transmission Pipe: November 2, 2011

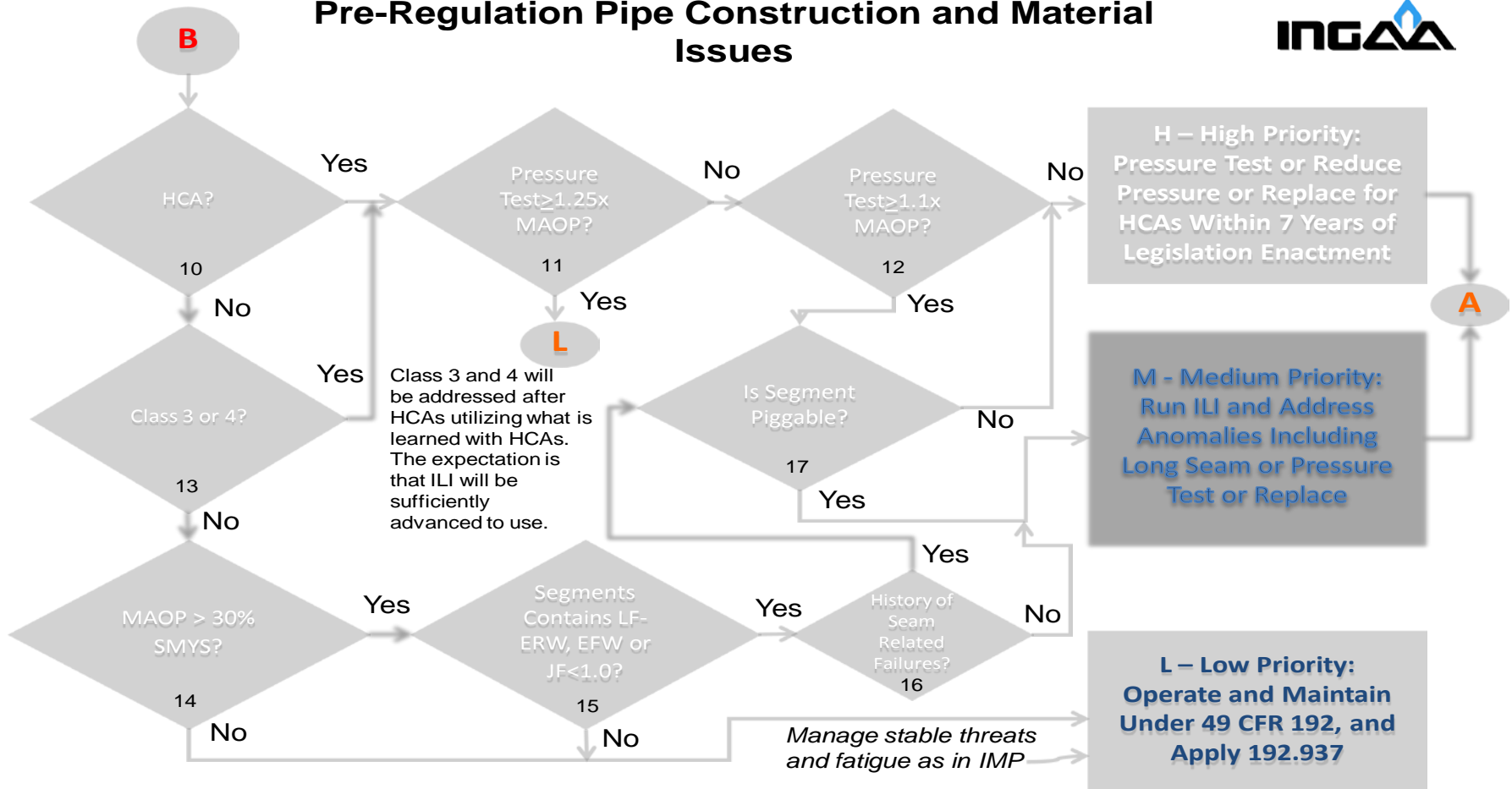
# Proposed Process for Determining FFS of Pre-Regulation Pipe Construction and Material Issues



Management of Pre-Regulation Natural Gas Transmission Pipe: November 2, 2011



## Proposed Process for Determining FFS of Pre-Regulation Pipe Construction and Material Issues



LF-ERW is low frequency electric resistance welded; EFW is electric fusion or flash welded; and JF is joint factor as defined at 49 CFR 192.113

## **Appendix 3: Definition and Application of Fitness For Service to Gas Pipelines**

### **What Is Fitness for Service (FFS)?**

FFS is the ability of a system or component, in this case a pipeline system or portion thereof, to provide continued service, within established regulations and margins for safety, until the end of some desired period of operation or scheduled inspection and reassessment. FFS is a well-accepted approach to evaluate flaws that may be injurious to integrity in equipment, including pipelines, to determine acceptability for continued operation. The FFS approach is used extensively throughout the world in transportation, energy, construction and many other industries.

FFS evaluations for pipelines rely on a detailed threat assessment, risk analysis, the selection of appropriate inspection techniques, and flaw acceptance criteria. Results from FFS evaluations provide guidance on equipment inspection intervals and shape decisions to run, alter, repair, monitor, or replace equipment.

FFS was the key criteria behind the development of the first ASME B31.8 consensus standards. Through prescriptive recommendations, those initial standards laid out how a pipeline should be designed, constructed, operated and maintained so the pipeline could be judged fit for service. Eventually, PHMSA and its predecessors imported many of these practices into 49 CFR Part 192 as the Minimum Pipeline Safety Standards in effect today. Subsequent ASME editions modified and improved the initial standards and methods. The most recent version, ASME B31.8S, is the latest step in improving FFS.

### **What Data and Information Do FFS Evaluations Rely On?**

FFS evaluations employ a review of historical performance, among other things, to identify threats that have and could pose a risk to the safe operation of the facility. Technical analyses, including stress analysis and fracture mechanics, are then employed to evaluate each of the threats and the associated physical flaws (for example, locally thin areas and cracks, or damage such as dents, bulges, and distortions or conditions such as outside/dynamic loads.

### **Have FFS Evaluations Been Applied in Other Industries?**

The methods currently used in FFS evaluations have been applied in the petroleum refining, petrochemical, nuclear, paper and steam electric power industries since the 1980s. One of the first acknowledged incident threat specific applications was actually in the pipeline industry with the development of B31G, a method for calculating the remaining strength of pipelines in areas with metal loss, first published in 1984.

In the absence of federal regulations covering analysis of complex systems, subject matter experts across a number of these industries decided to create a compendium of the methods to address a breadth of defect types in the late 1990s. The document was first published in 2000, as American Petroleum Institute (API) Recommended Practice (RP) 579. It was updated in 2007 through a joint effort between API and ASME and published as API RP 579-1/ASME FFS 1.

API RP 579-1/ASME FFS 1 provides for three levels of analysis based on the amount of available data, depth of knowledge, and the degree of conservatism desired:

- Level 1 is used for rapid evaluation, requires the least number of measurements, the few key parameters, and is quite conservative, i.e., it provides for a relatively large safety factor.
- Level 2 requires a deeper analysis and therefore more measurements to establish the actual remaining cross sectional area. It is generally less conservative than Level 1 because of the added depth of analysis and the additional knowledge and information required.
- Level 3 relies on stress analysis to provide an even more in-depth examination of metal loss. Level 3 requires an intensive quantification of measurement, loading stresses, and material properties, to meet the detailed needs of a finite element analysis.

### **Is Evaluating FFS Different for the Pipeline Industry?**

Yes and no. The process is the same, but the setting is not. In every other industry where FFS evaluations are applied, the equipment being evaluated is generally within a fence line. This means that the environment around the equipment including piping can readily be monitored and quite often controlled.

FFS evaluations for pipelines are different in that they rely on a detailed threat assessment, risk analysis, selection of appropriate inspection techniques, and acceptance criteria for non-injurious defects.

Where other facilities subject to FFS assessment generally are accessible and geographically contained, pipelines typically are buried, traversing linearly through the countryside, passing through a variety of soil types and geological conditions while encountering flooding, storm damage and other environmental challenges. Burying minimizes some environmental threats, but burying also subjects pipelines a variety of ground movements such as subsidence, vibration effects and even damage through direct contact and disturbance from excavation

work.<sup>2</sup> Evaluating a pipeline's FFS thus requires an operator not only to understand threats to integrity, but also to assess a pipeline environment spanning tens, hundreds and often thousands of miles.

Risk assessment is essential in prioritizing and managing preventive and mitigation measures. A complete understanding of the threats to integrity is essential including the potential contribution of the surrounding environment. Risk assessment is most effective when available data, including data specific to individual operating environments, is examined as an integrated whole. FFS evaluations use data from assessments, as well as from routine maintenance activities, often to identify areas warranting further investigation through excavation and inspection. FFS methods are used in these excavations to evaluate fitness based on a pipeline segment's actual, as-found condition.

Assessment tools and engineering methods are imperfect, so an operator will integrate the data collected during an excavation with other information (such as coating condition and as-found pipe to soil potentials) to form the analytical foundation for making decisions on preventive and mitigation measures. Finally, as part of a continuing desire to improve processes and achieve the target of zero incidents, the as-found conditions and results of evaluations are fed back into the threat assessment and risk analysis processes. Lessons learned from the findings and analyses are shared throughout the organization and, where applicable, throughout the industry.

### **Examples of FFS Evaluations for Metal Loss/Corrosion**

The corrosion evaluation method, ASME B31G, is a Level 1 type method. It is used for rapid evaluation of a concern; it requires data for just a few key parameters; and it is quite conservative in that it provides for a relatively large safety factor. RSTRENG applied in two parameter mode is also a Level 1 method. RSTRENG applied using a metal loss profile (sometimes referred to as a "river bottom" analysis) is a Level 2 method. API RP 579-1/ASME FFS 1, which is described in detailed above, is a Level 3 method.

Pipeline operators also apply a variety of techniques to assess a pipeline segment's physical condition. ILI with high-resolution magnetic flux leakage sensors are used to identify, characterize and measure metal loss. High-resolution geometry sensors are used to identify, characterize and measure deformations in pipelines.

The FFS evaluation results in an estimate of a segment's remaining strength, which can be characterized by a predicted failure pressure ratio. Operators use the predicted failure

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<sup>2</sup> While the NTSB concluded that pipe bursting activities nearby the transmission line did not contribute to the San Bruno failure, the fact that it was the subject of significant fact gathering and analysis in their investigation provides a key lesson learned: Pipeline operators must be aware of excavation and construction work around their facilities, and of equal importance, entities planning to work around underground facilities, including pipelines, must contact One Call.

pressure ratio, a measure of the margin above the MAOP, and the calculated pipeline strains to determine whether to excavate. Where an excavation is made to evaluate the metal loss, an indentation or both, FFS methods are then applied using actual measurements to determine a safe operating pressure. These comparative measurements are then used to improve ILI technology. Where excavation is not warranted, the operator uses the predicted failure pressure ratio to define an interval where the segment will be monitored pending the next assessment.

It is important to understand that operators do not rely simply on one measure or one tool. The corrosion control methods in ASME B31.8, which are in large part incorporated into 49 CFR 192 Subpart I, provide for “layers of protection” from failure.

The concept of “layers of protection analyses” or LOPA was first described in the chemical industry in the mid-1990s. It was recognized as a way of demonstrating while failures are so infrequent, while assessing the rare failures both to diagnose what occurred and to identify measures to prevent recurrence. LOPA was first captured in a book entitled, Inherently Safer Chemical Processes, published by the Center for Process Safety (part of the American Institute of Chemical Engineers). LOPA approach “designs in” redundancy, so failure is prevented even if one layer of defense is weakened or lost.

### **FFS Applied to Environmental-Related Cracking**

There are FFS methods available for evaluating environmental-related cracking, including stress corrosion cracking (SCC). SCC direct assessment (DA) prioritizes locations along the pipeline for investigative excavations. Nondestructive evaluations and measurements on the exposed pipe provide the inputs for FFS evaluations that estimate a segment’s remaining strength and predicted failure pressure ratio. As was the case with metal loss and indentations, the operator uses the results of the FFS evaluation to determine whether to excavate and, where there is a sufficient margin of safety, to define a future interval to the next assessment.

### **FFS Applied to Pre-Regulation Pipe**

There are approximately 179,000 miles of on-shore natural gas transmission pipe installed prior to pipelines safety regulations (1970) out of a total 300,000 miles. INGAA operates approximately two-thirds of this mileage.

INGAA conducted a survey of its members in April 2011 and found that about 91% of the pipeline mileage located within HCAs has readily available documentation showing that the segment was pressure tested after construction at least once. Outside of HCAs, the corresponding figure was about 77%. This particular survey result did not include pressure testing of the pipe that was conducted in the pipe mills during the manufacturing process. This process will be defined in detail in the White Paper titled “Management of Pre-Regulation Natural Gas Transmission Pipe”. A process flow diagram within the paper has been developed by the INGAA membership to organize the myriad of records that can be used singularly or in

unison to verify that the pipe was pressure tested at one time during its lifetime to address construction and material defects. This multipath process also establishes alternative ILI processes that can be used to verify the quality of pipe utilizing developing technology and available records as a surrogate for the pressure test.

## **Appendix 4 – Valve Spacing and Automation**

While spacing, selection and operation e.g., remote or automatic capabilities, are important but only addresses one aspect of mitigating the consequences of an incident. Public safety requires a broader review of incident consequence and response factors. To achieve the comprehensive response this issue deserves, pipeline companies should prepare Incident Mitigation Management (IMM) plans that incorporate the same risk management principles and performance objectives underlying operators' baseline assessment plans and other elements of the integrity management program.

The IMM plans would use information from previous risk assessments to help drive decisions for targeting mitigation improvements. These decisions would include various components of incident management, including methods for detecting ruptures; decision criteria for activating mainline isolation valves; standards governing the placement, automation and remote operation of valves; procedures for quickly evacuating affected segments making affected locations safe for responders; and procedures that strive to expand operators' coordination efforts with emergency responders. IMM is consistent with INGAA's commitment to shorten pipeline isolation and response time to one hour in populated areas, and IMM will produce a far better public safety outcome than prescriptive valve placement requirements

Operators would integrate IMM plans with existing IMP and risk management plans, with all of them designed both to quantify risk and design appropriate prevention and mitigation efforts. IMM plans would also incorporate the portions of operators' public awareness plans addressing outreach and communication with various emergency responders. IMM plans would set out approaches that, in the unlikely event of a failure, would maximize the mitigation of consequences. Each plan would contain an implementation priority, so its substantive provisions would be implemented first where consequences of a failure are greatest. While the initial effort would focus on pipeline in HCAs, operators would strive to consult with emergency responders to see if any priorities should be adjusted.

IMM plans would include:

- Criteria governing the operator's decisions on types and locations of automatic and/or remote valves, including crossover operation
- The location of any connecting distribution lines and the potential for back flow
- Standards for operating looped lines or other take offs as common or separate and the effect on identifying a rupture
- Standards for preparing gas controllers to act on valve closure, including decision support
- Plans for responding to specific locations, including after-the-fact evaluation of response times
- Priorities for automating valves currently not automated

- The design philosophy for how a type of operator is chosen (manual, automatic control or remote control)
- Procedures for evacuating gas and rendering locations safe for responders, including the use of blow-off valves
- An analysis of component and system reliability and an overall hazard assessment that considers potential nuisance failures of automated valves, including consideration of the relative consequences of a delayed closure vs. an unintended, inappropriate closure
- A planned, coordinated communication process with emergency responders
- A training process for improving the situational awareness of gas controllers
- A process for consulting with local 911 districts on notification procedures
- An approach to increasing the awareness of first responders to pipeline location, product, diameter; the location of valves, boxes and vaults; the approximate time to isolate; and any other factors determined to be of interest at the local level
- A plan for training, tabletop and full-scale emergency exercises with responders, planned on a risk-tiered basis