July 13, 2011

Ms. Linda Daugherty
Deputy Associate Administrator for Policy and Programs
Pipeline and Hazardous Materials Safety Administration
United States Department of Transportation
1200 New Jersey Avenue, S.E.
Washington, DC 2090

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

Dear Ms. Daugherty:

Pursuant to the notice of advisory committee meetings and request for comments published in the Federal Register on May 20, 2011 (76 Fed. Reg. 29333), the Interstate Natural Gas Association of America (INGAA) submits the following comments on “The State of the National Pipeline Infrastructure – A Preliminary Report”.

INGAA is a trade association representing approximately two-thirds of the nation’s natural gas transmission pipelines and over 85 percent of interstate pipelines. The INGAA membership consists of 26 different pipeline companies. There are approximately 300,000 miles of natural gas transmission pipelines in America, delivering one quarter of the nation’s energy.

In December 2010, INGAA’s board of directors established a board-level task force to pursue further improvements in the industry’s safety performance and expand public confidence in the natural gas pipeline infrastructure. INGAA’s commitment aligns with the call to action by the Secretary of Transportation at the April 18, 2011 National Pipeline Safety Forum. INGAA’s transmission company members will participate actively in responding to the secretary’s challenge.

We submit these materials for consideration by the subcommittee of the Technical Pipeline Safety Standards Committee (TPSSC) and the Technical Hazardous Liquids Pipeline Safety Standards Committee and are ready to discuss these matters further at your convenience.

Sincerely,

Terry D Boss

Terry D. Boss

Docket No. PHMSA-2011-0127 -- Submission by Interstate Natural Gas Association of America to "Pipeline Safety Report to the Nation" Docket – A Preliminary Report"

INGAA Submission #2 – July 13, 2011

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Docket No. PHMSA-2011-0127 -- TPSSC AND THLPSSC Subcommittee for the Preparation of the "Pipeline Safety Report to the Nation"

INGAA Submission #2 – July 13, 2011

Executive Summary

Interstate Natural Gas Pipeline Association of America (INGAA) is posting information in this docket to reflect a series of actions and commitments that will significantly improve pipeline safety for decades to come. INGAA's first submission into this docket on June 22 set the stage for these commitments. This docket submission INGAA submission #2 expands INGAA members' actions to include the following significant items:

Integrity Management Outside HCAs

INGAA members will apply integrity management principles to the entire natural gas transmission system operated by INGAA members. INGAA will use coverage of population as the basis for applying integrity management principles from American Society of Mechanical Engineers (ASME) B31.8S consensus standard to at least 70% of the population within the Potential Impact Radius (PIR) by 2020. INGAA will achieve coverage of 100% of this population group by 2030.

Corrosion Anomaly Management

INGAA members will mitigate corrosion anomalies outside of High Consequence Areas (HCAs) in accordance with the technically based criteria in ASME B31.8S. This will extend integrity management practices beyond the requirements of the Transmission Integrity Management Practices (TIMP) regulations (Subpart O) that only apply to pipelines within high consequence areas (HCAs), INGAA members will work collaboratively with stakeholders to develop methodologies to account for data uncertainties (e.g., tool accuracy and remaining strength methods). These "uncertainty methods" will be applied by INGAA's members using a consistent process or series of processes for defining the appropriate tolerances or "safety factors".

Fitness for Service for Pre-Regulation Pipelines

INGAA members will develop and apply guidance, including a process for systematically validating records and the maximum allowable operating pressure (MAOP), for their pre-regulation pipelines in HCAs. The process will address the NTSB recommendations to demonstrate traceable, verifiable and complete records with examples of the types of records. Where records do not meet this standard, a process that may include pressure testing will be applied within seven years, contingent upon the ability of an operator to meet customer delivery requirements.

Pipeline Isolation and Response

INGAA members will set a response-time goal of approximately one hour from incident recognition to the start of isolation procedures for a pipeline segment that includes an HCA. INGAA member's plans will use both response by local personnel to close valves and automation of valves to achieve this target. This commitment to response time will be a key element of improved response to pipeline incidents through isolation and emergency response planning. These plans will be developed and implemented on 70% of HCA pipeline segments within seven years and the remainder of the HCA segments within 10 years, using a risk-based sequence defined in an operator's IMP plan.

These commitments are highlights of a comprehensive plan that INGAA members are developing for their interstate natural gas transmission pipeline systems. There are several other elements of the overall INGAA plan that are further defined in following material. While not summarized above, these additional action plans are important to integrate members' overall strategies for improving pipeline safety.

INGAA is very interested in other stakeholders' views of proposed INGAA's actions and proposals. INGAA members welcome opportunities to engage interested parties. In this regard, INGAA members continue to participate actively in PHMSA-sponsored forums to learn from and inform other stakeholders.

Introduction

On June 22, the Interstate Natural Gas Association of America (INGAA) submitted material to this docket to inform stakeholders of its process for improving the safety of natural gas transmission pipeline infrastructure and for reinforcing public confidence in the safety of those pipelines. That docket submission is attached hereto as Appendix A, titled INGAA Submission #1 – June 22, 2011.

The purpose of this INGAA submission #2 is to provide more specific positions in connection with several of the action plans referenced in submission #1, and to provide information on additional INGAA action plans. A portion of submission #1 is included in the body of this document to provide context for the new material and to ease the reader's review.

INGAA is very interested in other stakeholders' views of INGAA's actions and proposals. Members welcome any opportunity to engage interested parties in any forum. While INGAA members have committed to move forward on these actions, they are open to feedback and suggestions. In this regard, INGAA members continue to participate actively in PHMSA-sponsored forums to learn from and inform other stakeholders.

Overview

The Interstate Natural Gas Association of America (INGAA) is a trade association representing approximately two-thirds of the nation's natural gas transmission pipelines and over 85 percent of interstate natural gas transmission pipelines. The INGAA membership consists of 26 different pipeline companies. There are approximately 300,000 miles of natural gas transmission pipelines in the United States, delivering one quarter of the nation's energy.

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

On March 2011, the INGAA Board of Directors adopted the following aspirational guiding principles, anchored by the goal of zero incidents.

Guiding Principles for Pipeline Safety

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

In order to achieve those goals, INGAA has proposed to implement several action plans.

The INGAA Action Plans

This submission covers nine of the INGAA Pipeline Safety Task Force action plans that have been approved by the INGAA Board. Four of these plans (A, B, C, & D listed below) were briefly described in submission #1. The current submission includes more specific positions in connection with these four plans as well as a discussion of all nine plans.[1] The nine plans are as follows:

A. *Expand Risk Management Beyond HCAs*

B. *Pipeline Anomaly Management*

C. *Demonstration of Fitness of Service on Pre-Regulation Pipelines*

D. *Pipeline Isolation and Response*

E. *Integrity Management Communication and Data*

F. *Implementation of the "Pipelines and Informed Planning Alliance" Guidance*

G. *Evaluate, Refine and Improve Threat Assessment and Mitigation*

H. *Implement Management Systems across INGAA Members*

I. *Stakeholder Engagement and Emergency Response*

A. Expand Risk Management Beyond HCAs

Docket Submission #2 Update

The PHMSA pipeline integrity management regulations (Subpart O), promulgated in 2003, require that integrity management principles be applied only to HCAs. INGAA members have assessed considerable portions of their systems utilizing integrity management principles, even though pipelines located in HCAs represent less than 5% of the total mileage.

These assessments have improved pipeline safety through mitigating anomalies that

[1] A total of 20 action plans were originally identified by INGAA in the integrity management continuous improvement initiative. Many of the 11 plans not included in submission #2 are still in progress and information may be provided on those at future submissions.

may eventually result in an incident or a leak. Clear evidence of this improvement is the number of anomalies per mile that required repair in the baseline assessment compared with the number of anomalies identified in reassessments, generally performed seven years later. The average number of anomalies reassessed and addressed per 100 miles of pipe located within HCA's assessed has decreased 80% as compared to the original baseline assessments.

To fulfill the INGAA Guiding Principle targeting zero incidents, INGAA members recognize further commitment is required:

A. INGAA will apply integrity management principles to the entire natural gas transmission system operated by INGAA members.
B. INGAA will focus on coverage of affected population as the basis for extending integrity management principles of B31.8S to at least 70% of the population within the PIR by 2020.
C. INGAA will achieve coverage of 100% of the population within the PIR by 2030, recognizing that a portion of systems will be difficult to assess and new technology will be needed.
D. In order to achieve this goal, INGAA will actively engage the research community to develop new inspection and assessment tools that effectively can address pipelines that currently are hard to assess. We will also encourage consensus standards groups to adopt standardized processes that encompass the new technologies.

The definition of an HCA is based upon the structure density inside a circle known as the Potential Impact Radius (PIR)[2]. The radius of the PIR around a gas transmission pipeline is determined by pipeline diameter and operating pressure, which represent a measure of the energy that could be released by a pipeline rupture. Consequently, the higher the potential release of energy from a rupture, the larger the PIR. The HCA definition also incorporates the concept of an "identified site" in recognition of the fact that periodic gatherings of people at such a place would increase the possible consequence of a pipeline failure. It is therefore a logical transition of describing the assessment progress utilizing the percentage of mileage assessed to a measure of the percentage of the population in close proximity (within the PIR) of pipeline segments that have been baseline assessed.

INGAA's proposes to develop a methodology for defining how structures and identified sites would serve as a surrogate for population density within the PIR.[3] This is a similar methodology that is embedded in the PHMSA regulations for determining HCAs. INGAA members will commit to extend integrity management principles to pipelines associated with 70% of the total population within a PIR by 2020.

[2] Appendix E to Part 192—Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

[3] The INGAA methodology assumes 2.5 people/structure, 20 people/identified site, and a means to account for multiple lines in the same right-of-way.

Pipelines in proximity to the remaining 30% of population are typically small or multi-diameter, low stress, short segments, station piping, or located in areas with few or no people in the PIR. INGAA recognizes that existing assessment technology may be ineffective to assess these pipelines properly. Therefore, INGAA will commit to identifying specific characteristics of these pipelines and work with the research and service provider community to develop reliable and accurate methods for assessing and mitigating these pipelines by 2030.

B. Pipeline Anomaly Management

Docket Submission #2 Update

The implementation of Subpart O beginning in 2003 required assessing pipelines within HCAs and also required repair, replacement, or reassessment as specified in the PHMSA regulation and referenced ASME B31.8S. For external corrosion, which has accounts for the largest number of required repairs since 2003, the criteria in ASME B31.8S supporting repair or reassessment decisions has worked successfully on INGAA member pipelines.

One of INGAA's Guiding Principles is to learn from experience. As such, INGAA members recognize that there are opportunities to learn and refine the overall process that supports decisions related to external corrosion anomalies. INGAA therefore believes that anomalies on pipelines outside HCAs should be mitigated utilizing the same technically based criteria as have been used within HCAs since 2003. INGAA also recognizes that current technology and methodologies for analyzing the severity of an anomaly can be improved.

In order to reduce the likelihood of any post-in-line inspection (ILI) corrosion failures both inside and outside of HCAs, INGAA makes the following commitments to improve anomaly evaluation processes:

A. Corrosion anomalies outside of HCAs, will be mitigated in accordance with the technically based criteria in ASME B31.8S (including any future enhancements or revisions).
B. INGAA members will work with PHMSA, ASME and other interested stakeholders to refine ASME B31.8S to include methodologies to account for data and measurement uncertainties when evaluating anomalies (e.g., tool accuracy, remaining strength methods).
C. These "uncertainty methods" for defining the appropriate tolerances or "safety factors" will be applied and updated through a consistent series of processes by INGAA's members.
D. INGAA recognizes that mitigation of anomaly categories for dents, pitting corrosion, expanded pipe, and selective seam corrosion (SSC) may require further refinement of technology or methods. INGAA's goal will be to define similar mitigation criteria to produce results comparable to those for

corrosion anomalies.

This action plan is very important for producing a strong technical basis for decision-making on response to the discovery of anomalies. As smart pig technology (both detection and reporting) continues to improve, INGAA members believe that the best investment of resources is to replace, repair, or reassess based upon the best information produced by this technology, wherever reasonably possible. Improvements can be made in discrete identification and quantification of uncertainties in several of the steps in this process. INGAA will provide resources and leadership in working with stakeholders to improve these methodologies.

C. Demonstration of Fitness for Service on Pre-Regulation Pipelines

Docket Submission #2 Update

Pipeline safety regulations (49 CFR §192.619) provide both a design basis that relies on records and a testing basis that relies on pressure testing for establishing the maximum allowable operating pressure (MAOP) for a natural gas transmission pipeline. These requirements were established in 1970 after extensive public comment[4]. These regulations have resulted in operating safety records that do not show negative trends with the original rulemaking. While PHMSA has re-examined this issue on several occasions, [5] the requirements established in 1970 have essentially remained intact.

As a follow-up to the San Bruno incident in California, the National Transportation Safety Board (NTSB) issued three safety recommendations to PG&E, two of which were classified as urgent, directing the operator to do the following:

1. Conduct an intensive records search to identify all gas transmission lines that had not previously undergone a pressure testing regimen[6] designed to validate a safe operating pressure (urgent recommendation);
2. Determine the maximum operating pressure by engineering calculations based on the weakest section of pipeline or component identified in the records search referenced above (urgent recommendation); and
3. If unable to validate a safe operating pressure through the methods described above, determine a safe operating pressure by a specified testing regimen.[7]

INGAA agrees with the NTSB recommendations that recognize that an MAOP can be re-established with a valid pressure test. In addition, where population has grown

[4] PHMSA Docket OPS-3

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

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

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

around older pipelines, regulations already require that MAOP be re-validated and re-established through validation of pressure testing, replacement or pressure reduction. Finally, interstate transmission pipelines in high consequence areas (HCAs) are assessed using techniques designed to verify the safety of pipeline operations at MAOP, most commonly through in-line inspection, direct assessment or pressure testing.

INGAA members recognize the desire to define and implement a "fitness for service" protocol for pipelines built prior to the promulgation of regulations by PHMSA in 1970. INGAA members commit to the following:

A. Develop and apply guidance, including a process for systematically validating records and the MAOP, for their pipelines within HCAs.
B. The process will address the NTSB recommendations to demonstrate traceable, verifiable and complete records with examples of the types of records.
C. Where records do not meet this standard, a process will include a pressure testing protocol that will be applied within seven years, contingent upon the ability of an operator to meet customer delivery requirements.[8]
D. INGAA will reinforce its commitment to consider fatigue in pre-regulation pipe.

Appendix 2 is a draft of processes to evaluate records and establish MAOP within HCAs for pipelines constructed prior to the August 1970 effective date of PHMSA pipeline safety regulations. This draft reflects the progress within the Integrity Management Continuous Improvement team. INGAA members welcome and invite input and discussion with other stakeholders on how to improve these proposed processes.

D. Pipeline Isolation and Response

Docket Submission #2 Update

INGAA members are developing processes and technology to enhance the protection of both people and property adjacent to a pipeline following a pipeline incident. INGAA's initiatives are intended to align members on a standard goal that reduces the consequences of a pipeline rupture. These initiatives involve all steps in a response, including recognition of an incident and closing pipeline valves to stop the flow of gas.

Pipeline isolation valves are important for controlling pipeline flows during operation and maintenance. Valve installations are designed and constructed at locations along the pipeline as prescribed by PHMSA regulations, ASME B31.8S, or

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[8] There is precedence in the hazardous liquids pipeline regulations for a phased approach, i.e., testing over a number of years based on risk.

as deemed by the pipeline operator to be critical for operation of the pipeline segment. Valve spacing requirements primarily are determined by structure density (class location) along and adjacent to the pipeline at the time of construction. The primary purpose for pipeline valves is isolation of a particular pipe segment, stopping the continuous flow of gas within the pipeline and, if necessary, allowing the evacuation of gas within the isolated section. It may be necessary to stop flow within a pipeline during maintenance activities, anomaly assessments and repairs, leak assessment and repair and during the unlikely event of a gas release.

Valve operation fall into three primary categories:

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

Several research studies, including a PHMSA study in 1999, have analyzed the benefits of installing remote or automatic shut-off capability on pipeline valves. Those studies stopped short of recommending widespread deployment of remote and automatic control valve technologies. As a result, PHMSA regulations have not prescribed the type of valve operation or the pipeline operator's response timing to a pipeline incident. The exception is the category of new higher technology pipelines that are permitted by PHMSA to operate at higher stress levels.[9] Regulations and special permits issued before these regulations were adopted require that automated valves (remote or automatic) be installed if the time required for personnel to close the valves would exceed one hour from notification of an incident.

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

Based upon extensive evaluation of the best means to reduce both the primary and secondary consequences of an incident, INGAA's members commit to the following:

A. INGAA members will develop plans to set a response-time goal of approximately one-hour response from incident recognition to the start of isolation procedures of the pipeline segment located with an HCA.
B. INGAA members will use either the response by local personnel to close valves or automation of valves to achieve this target.
C. INGAA members recognize that this commitment to response time will be key to improving overall stakeholder response to pipeline incidents through detailed isolation and response planning.

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[9] § 192.328 Additional construction requirements for steel pipe using alternative maximum allowable operating pressure.

D. These plans will be developed and implemented on 70% of the pipeline segments that contain HCAs within seven years and the remainder within 10 years, using a risk-based sequence as defined in an operator's IMP plan.

In addition to this action plan specifically focusing on valves to isolate a pipeline in case of an incident, INGAA's action plan also addresses elements of emergency response planning, interaction with responders and communication with the public.

In 1998, PHMSA issued a final ruling referred to as the "Viking Order," resulting from a specific pipeline inspection, which required the addition of valves in certain circumstances related to a change in class location on that particular pipeline. INGAA believes that this requirement does not materially reduce the primary consequences of a pipeline incident and that PHMSA should not implement the requirements of this order on a widespread basis. INGAA members' proposed commitments would be far more effective in mitigating the consequences of a pipeline incident than changes to the current valve-installation regulations.

E. Integrity Management Communication and Data

Current Situation

PHMSA has required the reporting of pipeline incidents, and supplemental data related to the incident, since regulations were first issued in 1970. The transmission integrity management program (TIMP) regulations issued in 2003 expanded PHMSA's data reporting requirements to include basic metrics regarding the implementation and results of integrity management from the consensus standard, ASME B31.8S, *Managing System Integrity of Gas Pipelines*. While the consensus standard also required that operators maintain ASME B31.8S "Table 9" data, PHMSA did not require submission of that data.

PHMSA has refined its incident reporting criteria to provide greater clarity in defining the cause of an incident, and it has categorized incidents as either "significant" or "serious." In 2008, PHMSA proposed expansive new reporting requirements designed to capture more integrity management and incident data. These requirements were finalized in 2010 and will become effective with annual reports to be filed in 2011.

INGAA initiated a report in 2004 to capture the IMP-required basic metrics and B31.8S "Table 9" data for INGAA members. The annual reports containing these data have not been distributed widely, although some conclusions have been reported publicly that demonstrate the effectiveness of the TIMP in managing integrity.

INGAA's Objectives for Improvement

In 2010, INGAA initiated the Data Communications effort (DATCOM); an exercise intended to expand historical data collection and to report information of value to the industry, PHMSA and other stakeholders. Beginning in 2011 (based on 2010 data), INGAA will provide an annual progress report on extending IMP principles system wide, including key metrics illustrating the integrity improvements of INGAA member pipeline systems, so stakeholders can see progress toward the goal. The DATCOM group will collaborate with similar efforts like the API/AOPL Pipeline Performance Tracking System (PPTS) that reports hazardous liquid pipeline data and information and American Gas Association's Plastic Pipe Database.

The mission of DATCOM is to:

- *Develop, collect, analyze and communicate the results of INGAA-member company-provided data, including information on detection, remediation, prevention and mitigation actions undertaken related to pipeline safety activities.*
- *Improve pipeline safety by utilizing this data to measure the efficacy of our action and increase transparency through stakeholder communications.*

The goal of DATCOM is to report information on 100% of INGAA member pipeline systems. These systems represent roughly two-thirds of the natural gas transmission pipeline mileage regulated by PHMSA. Overall objectives include:

- Aggregating industry-wide incident and pipeline integrity data to identify both lagging and leading metrics. These metrics will include progress in assessing pipelines inside and outside of HCA and a summary of findings that includes the types of repairs and replacements.
- Using these metrics to identify improvements in present methods and procedures.
- Summarizing prevention and mitigation measures to help operators determine which measures are more effective.
- Improving the quality and transparency of pipeline safety and integrity communications by providing periodic reports to stakeholders.
- Making data available to support internal benchmarking efforts by INGAA members.
- Developing and refining practices that will reinforce the Quality Assurance of data submitted to PHMSA and the industry.
- Providing a forum and an administrative structure for responding to ad hoc data requests received by INGAA members.
- Supporting INGAA objectives to improve the communication of relevant information to all stakeholders.

In summary, INGAA commits to improving data collection and analysis by all members, converting this data into meaningful industry information and communicating it transparently to stakeholders.

Docket Submission #2 Update

Appendix 3, "*Results of Increased Pipeline Data Collection,"* is the first edition of information from the DATCOM action plan –. Please refer to this appendix for information on INGAA members' pipeline safety and integrity activities through 2010.

F. Implementation of PIPA

Current Situation

The Pipelines and Informed Planning Alliance (PIPA) produced a consensus report in November 2010. The report, entitled *Partnering to Further Enhance Pipeline Safety in Communities through Risk-Informed Land Use Planning*, was the product of nearly two years of work by a large and diverse group of natural gas transmission and liquid pipeline stakeholders. The goal in producing this report is as follows:

> *The goal of the Pipelines and Informed Planning Alliance (PIPA) is to reduce risks and improve the safety of affected communities and transmission pipelines through the implementation of recommended practices related to risk-informed land use near transmission pipelines.*[10]

The PIPA report identified 43 recommended practices for various stakeholders. Seventeen of the practices were intended to be used by stakeholders for future land use and development (Baseline Recommended (BL) Practices). The remaining recommended practices were intended to be used when new land use and development projects are proposed (New Development (ND) Practices).

While the report was being prepared, PHMSA awarded four community technical assistance grants to demonstrate and evaluate implementation of some aspects of the draft recommended practices. Those demonstration projects are essentially complete.

Beyond these demonstration projects, the report does not include specific guidance for implementation. Still, the following paragraph of the report speaks to implementation:

> *The PIPA participants encourage all stakeholders to consider adopting and integrating the PIPA recommended practices into the culture of their local communities, companies, and organizations in order to reduce risks, to enhance pipeline safety, and protect communities. PHMSA plans to enlist the help of PIPA stakeholders in maintaining the ideas and recommended practices developed to date. With the stakeholder participation, the ideas and*

[10] Pipelines and Informed Planning Alliance report. November 2010.

recommended practices will be refined over time, and new and better methods for coordinating pipeline safety and land use planning on a national basis will be developed.

The initiative to implement PIPA has been led in several venues by PHMSA and the Pipeline Safety Trust (led by its executive director, Carl Weimer) and other groups. Mr. Weimer has spoken frequently about the critical need to implement the PIPA practices fully, most recently on June 16 at a hearing before the Subcommittee on Energy and Power of the U.S. House of Representatives.[11]

<u>INGAA's Objectives for Improvement</u>

INGAA members and staff were active participants in preparing the PIPA guidance. INGAA's overall objective is to have all its members implement PIPA recommended practices in the "real world" by identifying pilot sites and practices and reaching out to involve stakeholders in those areas. INGAA has developed an action plan and has enlisted the leadership of PST's Carl Weimer and PHMSA in this endeavor. INGAA's members are committing to the following:

- Building an active coalition of INGAA member representatives who have the authority and the means to implement PIPA recommended practices within the member companies.
- Participating in any collaborative efforts of PIPA stakeholders to develop greater awareness and adoption of PIPA recommended practices. Help lead the establishment of such a group, if needed.
- Developing and implementing an INGAA communications strategy to promote PIPA across the pipeline industry.
- Developing a toolbox to assist INGAA members in raising awareness and implementing PIPA recommended practices.
- Utilizing the required public awareness communications (API 1162) as a venue to promote PIPA and the recommended practices to public stakeholders.
- Demonstrating the implementation of some recommended practices on member pipeline systems by engaging local government officials, community planning representatives, and property developers, and providing feedback to other stakeholders.

The PIPA recommended practices are designed to transform the management of development around pipeline corridors. INGAA members support the best practices and are committed to both leading the implementation effort and communicating actively with all stakeholders to encourage implementation by other affected parties.

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[11] Testimony of Carl Weimer before the Energy and Power Subcommittee of the Committee on Energy and Commerce of the United States House of Representatives – June 16, 2011.

G. Evaluate, Refine and Improve Threat Assessment and Mitigation

Current Situation

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

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

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

INGAA members have applied the threat assessment and mitigation required by ASME B31.8S to pipelines in HCAs since 2003 and has therefore generated extensive experience. PHMSA has conducted numerous audits of operators' procedures and application of these requirements.

In January 2011, PHMSA issued an advisory bulletin in response to the San Bruno incident *"Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation."* This advisory bulletin alerted operators to "to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures."

With this experience and direction from PHMSA, challenges have emerged that warrant further study. Some of these challenges may suggest revision or enhancement of Subpart O or ASME B31.8S will be appropriate to:

- Fully understand threat interaction.
- Provide a recommended practice for data integration models.
- Validate the principle of stable threats (stable unless acted upon by outside environment).
- Validate the overall threat matrix.

INGAA's Objectives for Improvement

INGAA members have assessed and mitigated threats on over 9,000 miles of transmission pipelines located within HCAs since 2003 (totaling both baseline and reassessment). This experience has yielded extensive learning and opportunities for improvement. INGAA's members are committing to the following: Complete a comprehensive review of ASME B31.8S and prepare recommendations to ASME for revision or enhancement of the consensus standard including:

- Review of the overall threat matrix for clarity and consistency of application.
- The improvement of definitions and terminology, if warranted.
- Critical in-depth reviews of several of the significant threats.
- Review the principle of stable threats (unless acted upon) and material fatigue based upon operators experience and an examination of technical studies that provided the original basis for these concepts in B31.8S.
- A formal technical study on threat integration and mitigation.
- Root cause analysis of historical incidents to learn from and enhance threat assessment.
- A framework of a "best-in-class" data integration model, based upon the experience of pipeline operators and PHMSA since 2003.

H. Implement Management Systems across INGAA Members

Current Situation

As INGAA members have interfaced with other industries where the consequences of failure can be considered unacceptable, the importance of comprehensive management systems to supplement regulatory compliance has become apparent. Many industries such as chemical manufacturing, petroleum refining, nuclear power, aviation and the medical field have embraced the importance of a strong safety culture as the foundation for performance excellence.

Substantial academic study and experience across a range of industries exists to define an effective safety culture. Investigative reports from numerous incidents including the North Sea Piper Alpha production platform in 1998 and the BP Texas City refinery in 2005 identified the lack of a strong safety culture as a major causal factor in the accidents. While safety culture is the foundation for operational excellence, there is an accompanying recognition that comprehensive management systems also are required to yield success. For example, systematic hazard assessment and mitigation and management of change are key systems.

INGAA members have responded to challenges from PHMSA and the NTSB to increase knowledge and awareness of these principles. In 2008, INGAA sponsored a Safety Culture Workshop that brought industry, academic and regulatory experts together to inform and challenge its membership. Several INGAA members have embraced the safety culture as part of their systematic management systems.

INGAA Objectives for Improvement

INGAA members are committed to provide leadership to the gas transmission industry to enhance management systems in support of pipeline integrity and system reliability improvements. INGAA's members commit to the following:

- Publish INGAA member views of on safety culture. This document and a complementary self-assessment tool will challenge all INGAA members to continue the journey to operational excellence through the foundation of a strong safety culture.
- Define key management systems to educate and inform members in support of the INGAA Pipeline Integrity Guiding Principles.
- Provide educational materials and reiterate member company commitment to these principles to their service, material and equipment providers through the INGAA Foundation.
- Consider alternatives to elevate the performance of all member companies through commitment to management systems and safety culture. These alternatives will include a member's commitment to implement the INGAA Guiding Principles.

Appendix 4 is INGAA's *Integrity Management Continuous Improvement – Foundation for an Effective Safety Culture.* This document remains in draft to invite discussion and input from other stakeholders.

I. Stakeholder Engagement and Emergency Response

Current Situation

Recognizing the hazards and potential consequences of a pipeline failure, INGAA members have committed to prepare emergency responders and the public on how to respond to pipeline accidents. PHMSA regulations consistently have required advance planning and interaction with these stakeholders. In addition to Part 192 regulations, PHMSA adopted the API *Recommended Practice (RP) 1162 – Public Awareness Programs for Pipeline Operators* in 2005. This RP set standards for engagement with the public in the vicinity of pipelines, state and local emergency response and planning officials, local public government officials, and excavators. API 1162 also establishes requirements to measure the effectiveness an operator's engagement and to adjust its programs accordingly.

Notwithstanding the regulatory requirements and commitments by pipeline operators, response to major incidents has been inconsistent. The recent NTSB hearings on the pipeline failure in San Bruno, California identified challenges faced by the industry. While API 1162 set standards to measure the effectiveness of an operator's programs, these efforts are in the early stages and INGAA members have established a team specifically to share experiences to improve their programs and refine the RP.

INGAA Objectives for Improvement

INGAA action plan, *Pipeline Isolation and Response,* discussed earlier in this document, states the commitment from INGAA members on isolation and emergency response planning. Beyond valve closure, INGAA will pursue the following actions that apply to emergency responders and public officials and to the public living in the vicinity of a pipeline.

- Once a pipeline system is isolated, operators will communicate the time to cessation of fire to emergency responders based on site-specific criteria.
- Operators will prepare personnel to act through improved situational awareness in emergency situations.
- In their response planning, pipeline operators will acknowledge and communicate with emergency responders regarding primary damage and secondary impacts and will prioritize those sites where secondary impacts could be most severe.
- INGAA will identify individuals and organizations representing local communities, safety groups and public advocates to collaborate with INGAA members.
- Pipeline operators will engage stakeholder groups "on their turf" to educate them on pipeline operations and also to listen to their concerns and perceptions regarding natural gas pipelines.
- INGAA members will identify leading practices and new ways to engage the public.
- INGAA members will use experiences in implementing API 1162 to identify improvement opportunities and recommendations to enhance this recommended practice.
- INGAA will help amend the natural gas pipelines section of the PHMSA Emergency Responder Guidebook – a key reference used by fire and emergency responders.

INGAA recognizes that the presence of pipelines is not always obvious or apparent to the public or many emergency responders until there is an incident. While this awareness challenge is considerable, INGAA members are committed to finding new and innovative means to inform and engage these stakeholders.

Appendix 5 provides an overview of the present natural gas pipeline public awareness and engagement.

Appendix 6 is a draft of a *Pipeline Emergency Response Flow Chart* that provides analysis of the potential for improved incident response both by operators and emergency responders. INGAA will use these documents and other information as it engages stakeholders on improvement methods and opportunities.

Conclusion

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

Appendix 1

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

June 22, 2011

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

June 22, 2011

Overview

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

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

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

<u>Guiding Principles for Pipeline Safety</u>

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*

<u>The INGAA Approach</u>

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

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

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

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

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

8. *New Construction*: Fully implement the 2010-2011 INGAA Foundation Pipe Quality and Construction Action Plans
9. *Gas Storage:* Review and evaluate integrity management and risk mitigation programs and practices to enhance the public safety, environmental stewardship and service reliability of natural gas storage facilities.

Action Plan Information

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

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

Action Plan 2 –Expand Risk Management Beyond HCAs

Current Situation

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

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

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

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

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

INGAA's Objectives for Improvement

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

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

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

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

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

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

- *How could this model be used to establish the gradient for consequences to guide future assessments?*
- *What other consequence factors could be considered (e.g., locations with historical, recreational or economic significance)?*

5. *What new assessment technologies and processes could be useful in expanded areas?*
6. *What additional data reporting requirements, if any, should be applied to all pipelines including those outside of HCAs?*

Action Plan 3 – Pipeline Anomaly Management

Current Situation

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

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

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

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

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

INGAA's Objectives for Improvement

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

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

- Corrosion – general, pitting, selective[12]
- Expanded or low strength pipe
- Dents – plain, with corrosion metal loss, with mechanical damage metal loss

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

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

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

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

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

Current Situation

Pipeline safety regulations (49 CFR §192.619) provide both a design basis relying on records and a testing basis relying on pressure testing for establishing the maximum allowable operating pressure (MAOP) for a natural gas pipeline. These requirements were established in 1970 after extensive public comment[13]. While PHMSA has re-examined this issue on several occasions, [14] the requirements established in 1970 have essentially remained intact.

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

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

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

4. Conduct an intensive records search to identify all gas transmission lines that had not previously undergone a pressure testing regimen[15] designed to validate a safe operating pressure (urgent recommendation);
5. Determine the maximum operating pressure by engineering calculations based on the weakest section of pipeline or component identified in the records search referenced above (urgent recommendation); and
6. If unable to validate a safe operating pressure through the methods described above, determine a safe operating pressure by a specified testing regimen[16].

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

[13] PHMSA Docket OPS-3

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

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

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

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

INGAA's Objectives For Improvement

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

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

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

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

Action Plan 7 – Pipeline Isolation Valves

Current Situation

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

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

Valves fall into three primary categories:

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

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

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

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

INGAA Objectives for Improvement

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

- Improve coordination with emergency responders to raise their awareness and preparedness[17] for response to an incident.
- Evaluate potential enhancements that would accelerate all stages of the response to a pipeline rupture – rupture detection, the decision to close valves, and the time needed to reach valves, close them and evacuate the gas from the pipeline.
- Evaluate potential improvements in valve operation by adding remote or automatic capability, particularly in areas of high consequence or other locations of strategic importance.
- Determine the relative benefits of quicker valve operation versus shorter valve spacing intervals on mitigation of consequences.
- Recommend enhancements to operator's preparedness capability in order to improve valve-closing response during an incident. Weigh the reliability of automated valves (including the consequences of nuisance failures). Provide comprehensive and systematic guidance for INGAA operators that meet these objectives acknowledging the unique configuration of each pipeline system.

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

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

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

7. *How should automation of valves be considered versus reducing valve spacing?*

Conclusion

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

Appendix 2

Records and MAOP Verification, and Management of Pre-Regulation Pipe – INGAA IMCI

July 2011

INGAA IMCI Team 4 - Records and MAOP Verification, and Management of Pre-Regulation Pipe

July 7, 2011

Draft – Work in Progress

Records and MAOP Verification and Managing Pre-Regulation Pipe

- Start by confirming that records exist (Records Process – Slide 5)
- Where traceable, verifiable and complete records exist to establish MAOP under 49 CFR 912.619, continue to operate under 49 CFR 192.
- Where records do not exist or are incomplete, if there is a pressure test to 1.25xMAOP in Class 1 and 2, or 1.5xMAOP in Class 3 and 4, continue to operate under 49 CFR 192.
- Where records do not exist or are incomplete, if the pressure test does not meet above criteria or there is no historical pressure test, apply Process For Managing Pre-Regulation Pipe – Slides 6 and 7.
- Where records do not exist or are incomplete for a segment containing short sections of pipe such as 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).

Records and MAOP Verification

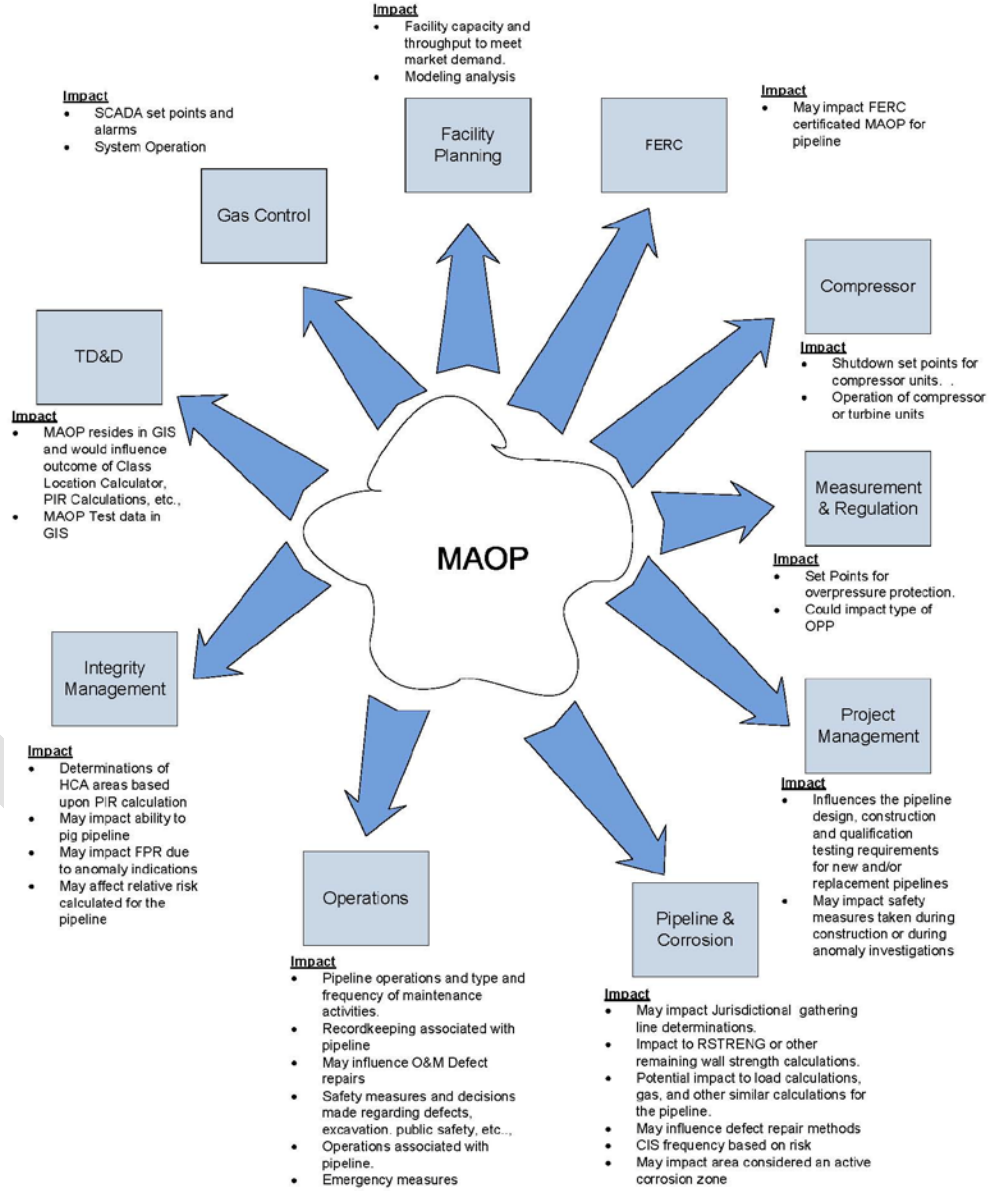
Significant Focus on Records and MAOP

- NTSB Advisory Bulletin
- PHMSA Advisory Bulletin
- California MAOP Order

MAOP impacts numerous key functions

- Various functions dependent upon valid MAOP

"Traceable, verifiable and complete" records requirement

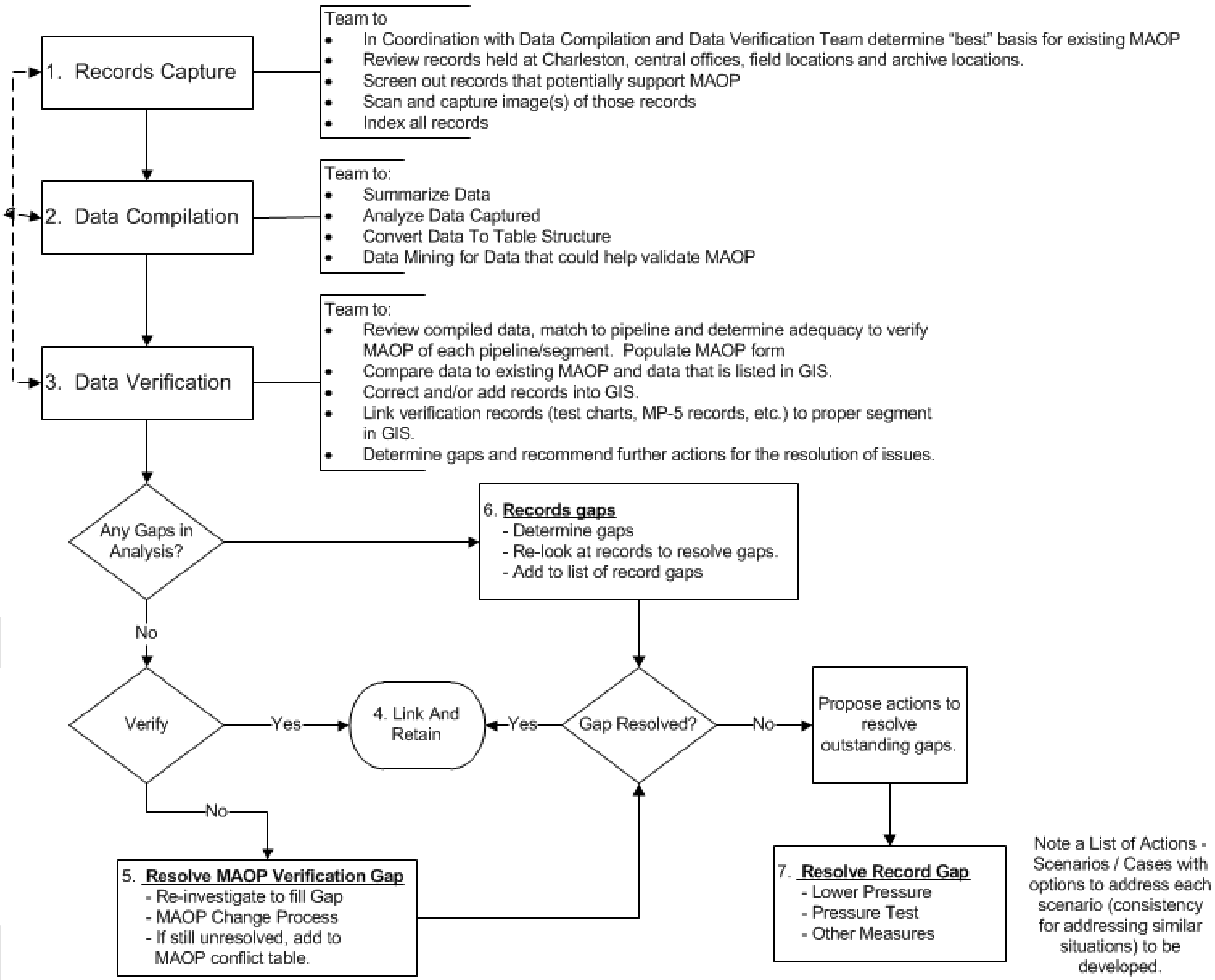


Definitions

- ***Traceable*** means that the origin of the record can be determined.
- **Verifiable** means that the record can be confirmed by supporting documentation or credible statements that have been recorded.
- ***Complete*** means that the record was complete according to the requirements in place at the time the data was created.
- Requirements include both regulations and company policies, procedures and practices.

Records and MAOP Verification

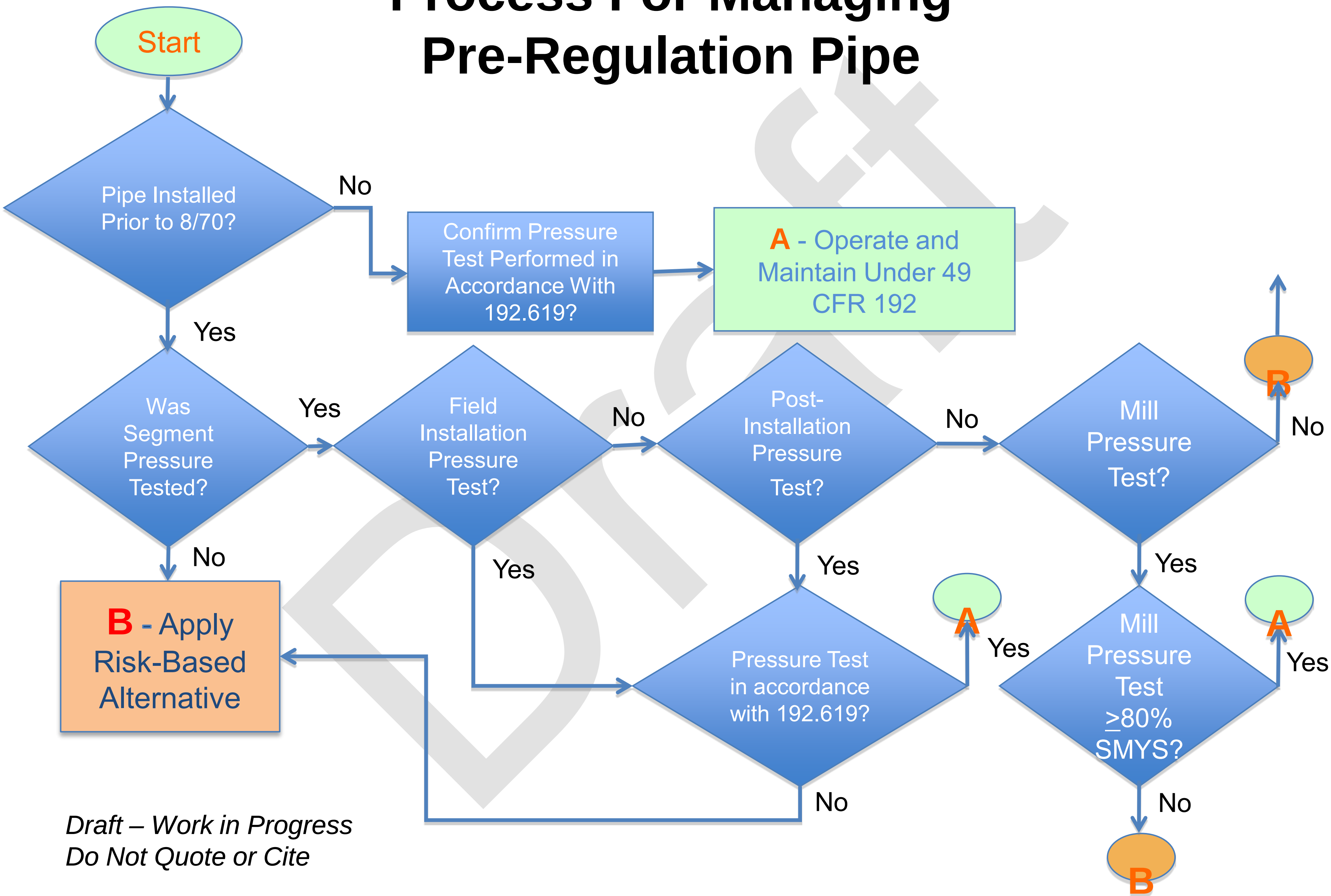
- Disciplined Process Being Developed
  - Prioritization
  - Standards
  - Procedures
  - Chain of Custody
  - Management of Change
- Technology to Ensure Traceability and Transparency



"Traceable, verifiable and complete" records requirement

July 7, 2011

Process For Managing Pre-Regulation Pipe

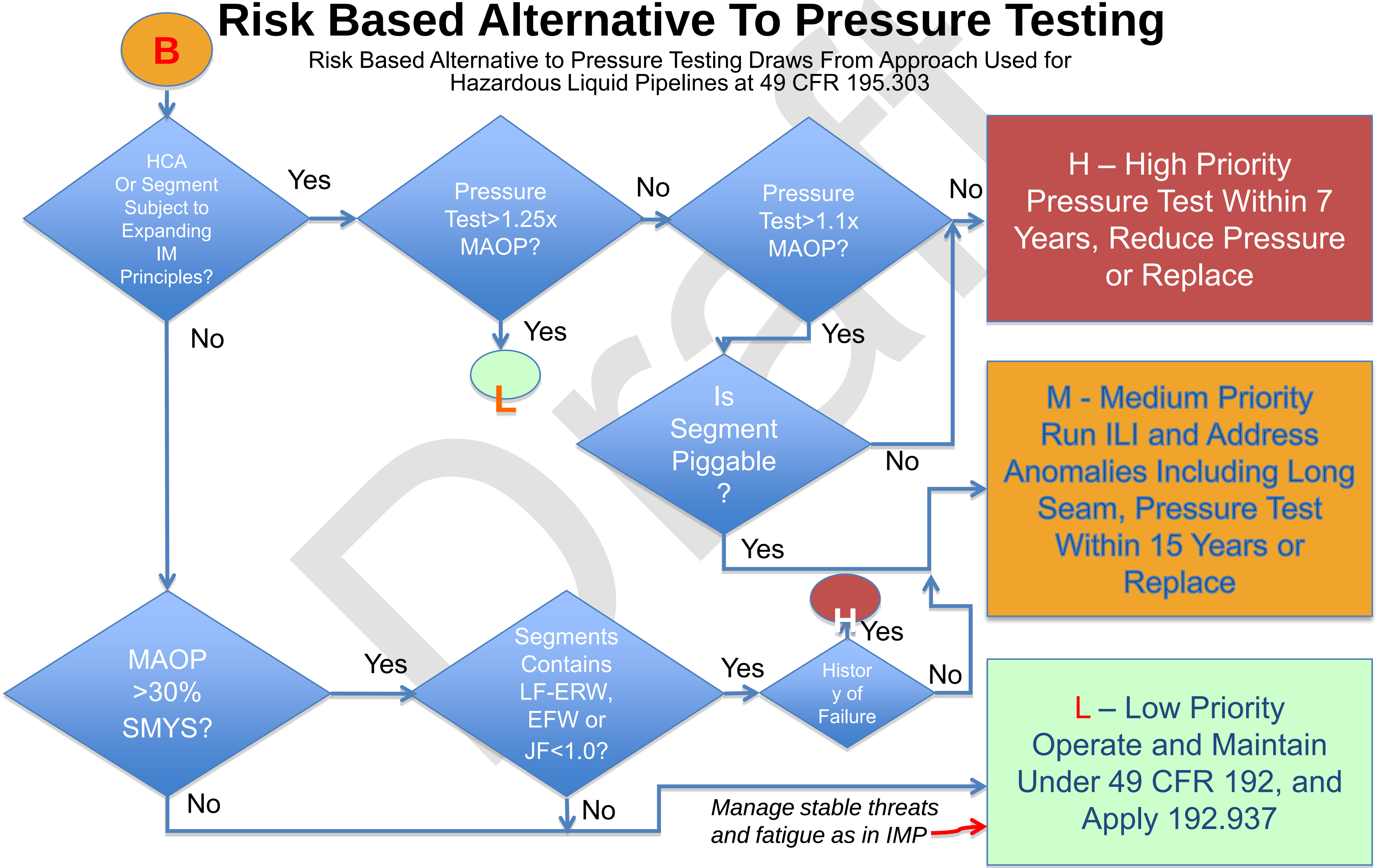


Draft – Work in Progress
Do Not Quote or Cite

Process For Managing Pre-Regulation Pipe (Continued) – Risk Based Alternative To Pressure Testing

July 7, 2011

Risk Based Alternative to Pressure Testing Draws From Approach Used for Hazardous Liquid Pipelines at 49 CFR 195.303



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

INGAA – Results of Increased Pipeline Data Collection

July 2011

Interstate Natural Gas Association of America
20 F Street, N.W, Suite 450, Washington, D.C. 20001
phone: 202.216.5900 **www.ingaa.org**

Results of Increased Pipeline Data Collection

A strategic plan by members of the Interstate Natural Gas Association of America

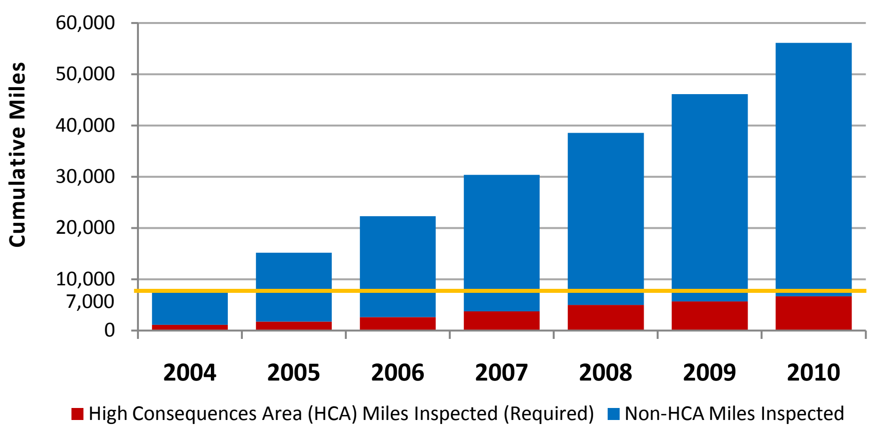
Interstate Natural Gas Association of America (INGAA) has undertaken a pipeline data collection initiative. The intent is to provide a clear and accurate picture of the condition of our natural gas pipeline systems, as well as the detection and maintenance practices of INGAA members.

Miles included in these metrics represents 64% of all PHMSA interstate natural gas transmission pipeline miles.

The data collection team will be working with the Pipeline and Hazardous Materials Safety Administration (PHMSA) to analyze data collected from INGAA members, and to reach consensus on the types of data needed and best collection methods. The overall purpose is to further improve the integrity of natural gas pipeline systems, and protect the people who live and work near them.

We inspect more pipeline annually than regulations require, on track to achieve full IMP assessment by 2012

IMP Baseline Assessment - Total Cumulative Miles (2004 – 2010)



The chart shows that more than 7 times the miles required have been inspected.

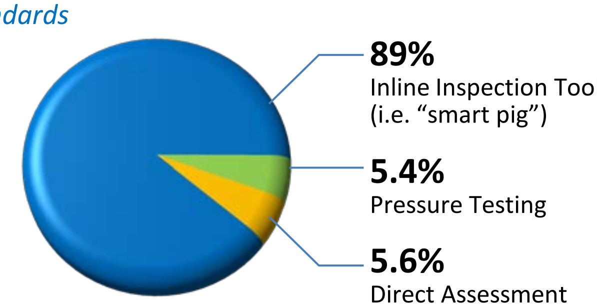
More than 90% of the HCA pipeline miles have been inspected through 2010.

The chart does not include IMP re-inspections and inspections outside of the IMP program.

We conduct assessments using preferred methods and standards

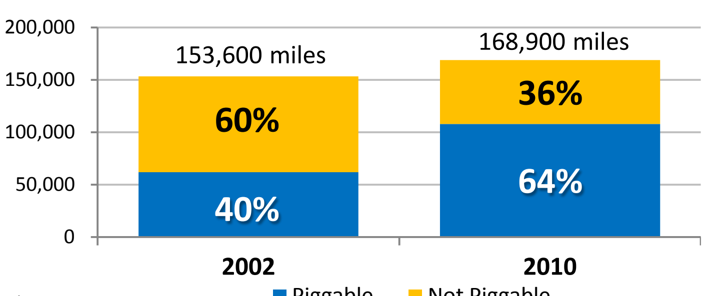
Methods of Assessment (2004 – 2010)

The majority of INGAA members' baseline assessments of reported miles over the past 7 years have been with pipeline inspection tools called smart pigs. These are mobile units operators run through pipelines to inspect the pipelines structural integrity. Smart pigs are widely regarded as the most effective inspection devices available.



We have made significant improvement in pipeline accessibility to inline inspection tools

Pipelines Accessible to Inline Inspection (2002 vs. 2010)



Currently, nearly two-thirds of INGAA members' reported miles are able to accommodate PIGs. That is a 50% increase since 2002, and that trend is expected to continue.

Our pipeline "piggability" has increased by 50% since 2002

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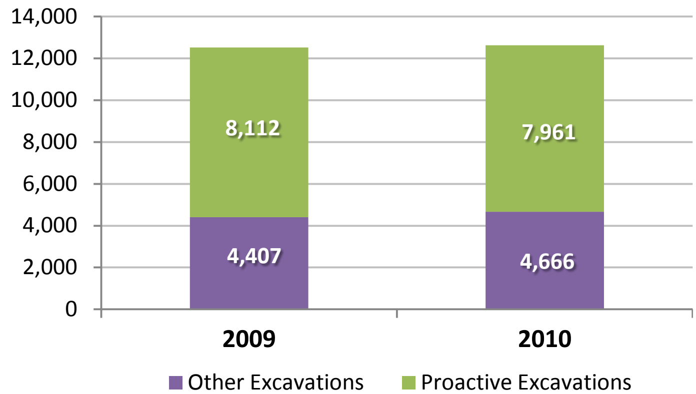
We examine a large sample of pipe through excavation, providing a good idea of overall pipeline condition

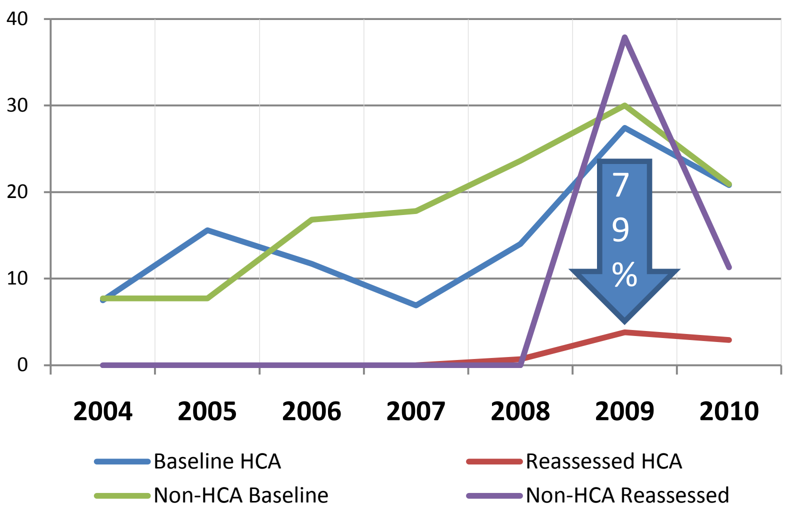
Pipeline Excavations (2009 – 2010)

INGAA members excavated (dug down to) pipelines to inspect, re-apply protective coating or perform repairs. They performed about 25,000 pipeline excavations (1 per 7.5 miles) in 2009 and 2010. Nearly 16,000 were proactive decisions to uncover the pipeline for recoating, visual confirmations, repairs or to adjust the depth of cover.

Other reasons for pipeline excavations include third-party construction and line crossings.



Repairs per 100 Miles Inspected



There has been an increase in the number of pipeline repairs. Reasons for the increase include improved pipeline inspection technology and more frequent inspections. However, repairs resulting from re-inspections have decreased by 79% in HCAs.

For 2010, 0.06% of the 20,700 miles of pipe inspected required repair or replacement.

We believe prevention and mitigation are key components of pipeline safety

Pipeline Patrols are Performed Above and Beyond Requirements (2010)

INGAA members are committed to the safe operation of their pipelines and are active participants in the state one call programs. Over 55% of pipeline miles reported are patrolled more frequently than required by regulation. Patrolling is an effective method to detect and halt potential third party damage – which is the primary cause of serious incidents. Patrol frequency is particularly important in highest consequence (densely populated or critical) areas along with one call programs.

Appendix 4

INGAA – Integrity Management Continuous Improvement: Foundation for an Effective Safety Culture

June 2011

INTEGRITY MANAGEMENT CONTINUOUS IMPROVEMENT

Foundation for an Effective Safety Culture

July 2011

"Foundation for an Effective Safety Culture" describes the key elements of organizational culture and business processes that have led to dramatic improvements in safety and operational performance in a range of industries where the consequences of failure can be unacceptable, including the chemical manufacturing, petroleum refining, nuclear power, aviation, and medical field. These industries have found that when people in an organization believe that safety is an important value, they behave with care and concern about how they do their jobs, and how they protect colleagues, customers, and the public. They understand that what their leaders, managers and employees believe about the importance of safety may be one of the largest determining factors in their success. When we speak of "safety," we mean it in the broadest possible sense – safety of employees, customers, the public and the environment, as well as a reliable pipeline system that delivers natural gas for heating and cooling and for industrial energy and manufacturing feedstock.

Purpose of this Document

The purpose of this paper is to describe an "effective safety and operational culture" and to convey the extent to which the Interstate Natural Gas Association of America (INGAA) is committed to helping its members achieve this goal. INGAA assists in educating, promoting, reporting, sharing, learning, and evaluating the overall safety performance of the industry and creating an atmosphere that is conducive to technical exchange. This includes both the pipeline operators who compose INGAA and the members of the organizations that serve the pipeline operators and members of the INGAA Foundation.

INGAA members strive for perfect performance in safety, a commitment made in the INGAA Guiding Principles. By focusing on a safety culture, we intend to improve our safety and operational performance. We are committed to the increased use of leading indicators in managing our performance. We recognize that we are on a journey and that this is not a short-term initiative. It has become clear that compliance with regulations is not enough and does not prevent failure. We have found that we cannot simply "proceduralize" our desire to enhance our safety culture.

While the application of risk management principles and advances in other management processes and systems have led to improved performance, we cannot anticipate every possible event. We want, therefore, to do everything possible to prepare our workforce to recognize adverse situations at the earliest opportunity and enable them to respond directly and at every level of the organization. This includes planning and preparedness for day-to-day emergencies to catastrophic events, incorporating decision-making support, practice scenarios, and established relationships with emergency responders.

While an effective safety culture depends on good decisions, a strong culture alone is not enough. A robust culture is one that is supported by management systems, such as asset integrity management, information technology, risk management, change management, and communication.

We strive to shape a culture that drives continuous improvement. We do not accept the idea that safety and compliance are a tradeoff with production and profit. We believe that strong safety practices will result in the success of our business. We instill in our employees a sense of situational awareness and preparedness to make decisions in the interest of safety when adverse events occur.

The challenge is that there is no simple solution, as every operator's risk profile is different. In this document, we present a working definition of safety culture, describe the role of leadership and characteristics of an organization with a safety culture, define its key elements and indicators of effective implementation.

What is Safety Culture?

Safety Culture is the sum of all safety-related assumptions, beliefs, attitudes and values displayed through the behaviors and actions of the leaders, managers, first-line supervisors and general employee population of an organization.

Safety is perceived as an organizational value only when organizations and their leaders consistently demonstrate that safety is valued. When it comes to safety, there must be "constancy of purpose." Achievement of this goal will determine the ultimate success or failure of the organization. When the employees of a company identify with safety, it is contagious – employees interact with each other and reinforce this value. Sharing it creates a sense of purpose and influences how employees conduct everyday work. While employees performing tasks safely is important, how they "own" and maintain the company infrastructure is at least as important. Every action on a piece of the infrastructure or decision made on behalf of the system at large is seen as connecting to the safety of the public or to the customer as well as themselves. The ongoing practice of caring about safety strengthens the overall organization's belief in its value and acts as a unifying force. When the value is shared extensively in every level of the organization, and a widespread level of commitment to overall safety performance is expected, then everyone is doing what is right, even when no one is looking. Then we can say a safety culture thrives.

A positive and effective safety culture is critical to achieving long-term sustainability in an organization and industry. Observing and understanding our safety culture provides a window into the inherent beliefs, attitudes and values of the employees of pipeline operators, service providers and construction companies … and, ultimately, our industry as a whole.

Role of Leadership

Strong leaders create organizations that are caring and responsible. To do so, they lead by example, convey a sense of ethical responsibility and always practice good process.

Leaders produce a clear set of priorities, accountabilities and a framework in which to allocate resources, commensurate with risk to the employees, the customers and the public. This is especially important in an industry that deals with technologically complex matters where the risk of failure may be unacceptable. Employees, in turn, are inspired by the climate of commitment and are motivated to accomplish the leaders' desired results. Safety tasks and the employees who oversee them are given a very high status by the leaders. This is equally true of those responsible for safety as well as for the reliability and sustainability of the infrastructure.

We recognize the role of informal leaders. Informal leaders are those people who are recognized as providing leadership to employees because of their longevity, knowledge, experience, personality, and strength, among other factors. It is critical that they become a part of telling the story, connected to the assets they've maintained, conveying the sense of ownership and ethical responsibility and always practicing good process. Their role is so critical that they often remain a part of the organization after the senior- and executive-level management officials are gone.

Characteristics of the Organization

The organization that has embarked on this journey of change aligns with the essential beliefs and actions of the leaders. Its decisions and behaviors reduce risk and have a positive and direct impact on safety performance and operational effectiveness. A mature organization gathers the right business information and uses it within supporting management systems to identify, characterize and manage both internal and external risks, prioritized based on likelihood and consequence. The empowered employee openly reports safety and reliability issues and works with colleagues and management to resolve them. New employees are provided an orientation that provides a foundation in safety and reliability, and it is reinforced through ongoing training and development. Business practices are consistently guided and executed according to clear direction, integrated consistently across the organization.

When unwanted events occur, the organization determines causes and corrective measures necessary to prevent recurrence, utilizes improvement processes as needed to rectify the problem(s), and institutionalizes the lessons learned within information systems that are fully accessible to all. Employees have confidence that their management will respond fairly to open and honest communication and will provide positive reinforcement for reporting issues and taking actions to resolve them.

What are the Elements of an Effective Safety and Operational Culture?

We believe there are six essential elements. Each of the six elements presented in this paper is characterized by a set of indicators that describe what the element looks like when implemented in an organization. Taken as a whole, these elements and indicators provide an operational definition of an "effective safety culture." These elements and their associated indicators will be used as the basis for a companion self-assessment tool that INGAA will develop for member companies to use to assess their safety culture and management processes and to develop targeted improvement programs. Each element includes indicators of effective implementation in operations, i.e., "what good looks like."

The essential elements are:

1. Consistent, strategic leadership, in which leaders demonstrate an uncompromised commitment to safety and operational excellence.
2. Policy, process and what is measured guide operational performance.
3. A mutually trusting organization, in which a culture of openness and trust engages the workforce, and safety is understood as a shared responsibility.
4. Continuous organizational learning, internally and externally, from adverse and positive events.
5. The organization manages risk systematically against an integrated framework provided by leadership.
6. Workforce investment is an ongoing management focus.

KEY ELEMENTS AND INDICATORS:

1. Consistent, strategic leadership in which leaders demonstrate an uncompromised commitment to safety and operational excellence.

Executives and managers at all levels constantly and consistently send the message that the organization is fully committed to safety in the broadest sense, for employees, customers and the public … and that accidents are both preventable and unacceptable.

<u>Indicators</u>

Leadership:

- Sets an explicit vision for the organization for safety and operational performance excellence and the reliability of its infrastructure and assets.
- Works constantly to build trust in the workforce that the organization is fully committed to this excellence; demonstrates commitment by visible, personal example and frequent, substantive contact with employees on safety and risk issues.
- Understands that recognition of excellent safety performance is most powerful; ensures that robust reward/discipline programs are in place and consistently applied; creates and nurtures a just culture where everyone understands and supports the expected code of practices.
- Assigns accountabilities; sets and communicates performance standards and objectives that will drive progress toward the vision.
- Makes safety and reliability integral to business decisions; ensures sufficient allocation of human, information and financial resources to meet goals.
- Communicates clear expectations for employees to report unsafe or risky conditions, to stop work that they consider unsafe, and to never leave a question about reliability in the ground.
- Educates managers in safety culture, vision, expectations, accountabilities and systematic management; includes safety and reliability performance in manager’s job descriptions; replaces managers who do not respond to ongoing safety performance erosion and invests in preparing the organization for situational awareness.
- Promotes a strategic plan and framework for risk prioritization and allocation of funds.
- Adequate support systems are in place to ensure that the organization can fulfill all tasks to achieve its goals.

2. Policy, process and what is measured guide performance	Business practices consistently guided and executed according to clear definition and direction, evolved from thoughtful analysis.

Indicators

- Uses objective and independent assessments to sustain progress and create ongoing momentum; understands that process improvement is never-ending.
- A balanced set of metrics exists, including process measures that tie employees to the long-term reliability and sustainability of the company's infructure and assets and public safety at large.
- Uses the continuous improvement process to implement and make ongoing progress toward the vision.
- Understands the proper pace of implementation of new management processes for the organization.
- Processes and procedures are documented and accessible and implemented in a comprehensive and integrated manner across the organization.
- Roles, responsibilities and accountability are clear.
- Required competencies for jobs are defined; training and development programs address identified gaps in qualifications, and refreshers and other performance support are provided.
- Consistent execution of well-defined processes and balanced metrics, based on achieving strategically planned goals and priorities.
- Disciplined management of change processes are consistently used to control the unintended consequences of changes.
- Performance monitoring programs are rigorous and risk-based; increased use of leading performance indicators and assessment programs; include corrective action processes that address deficiencies.

3. A culture of openness and trust engages the workforce, and safety is understood as a shared responsibility.

Employees trust their management to “walk the talk” and to back them on identification and resolution of safety issues; management trusts their employees and empowers them to “do the right thing.”

Management understands that the alternative to an organization that learns rapidly from front-line employees about risk is an organization that learns painfully, slowly and with great cost.

Indicators

- Employees are confident that a just system exists where safety issues can be raised without fear of reprisal.
- Employees have the necessary authority and resources to be successful in identifying and managing risks.
- Management encourages and rewards the sharing of safety concerns and creates an environment where employees feel comfortable “raising their hand” to identify risks; employees understand the risk reporting system and feel comfortable using it to surface risks.
- There is strong emphasis on the importance of rapid communication of information on safety and risk concerns. Efficient communication channels exist up, down and horizontally throughout the organization.
- Management provides timely response to identified issues and positive reinforcement for employees that surface major issues.
- Employees accept and carry out safety responsibilities for themselves, colleagues, customers and the public and reliability responsibilities for the pipeline system
- The workforce understands the importance of work processes and procedures and the potential consequences of risky shortcuts.
- The workforce consistently maintains a heightened vigilance and sense of vulnerability regarding identifying risk and seeing through the remediation, including consideration of the low-frequency, high-consequence event.

4. Continuous organizational learning, internally and externally from adverse and positive events.	The organization shares learnings from adverse and positive events, from observations, errors, near-misses, incidents, benchmarking, and activities in trade and public interest organizations and meetings. Lessons are captured and effectively shared. <u>Indicators</u> • The right information is gathered and used to manage risk. • Adequate decision support is available. • Incidents are investigated for root cause; corrective actions are defined and tracked to completion • There is a sharing of learning in a timely fashion. • Incident investigations focus on finding the causes of incidents and learning from them, not on assigning blame. • Lessons from past incidents (both internal and external to the organization) are institutionalized in training to combat complacency about risk and to reinforce the need to stay engaged. • Organization is committed to benchmarking externally and applying lessons learned and actively participates in industry associations and research programs. • Organization is committed to engaging with the full range of public and private sector stakeholders and acting on learning.

5. The organization manages risk systematically against an integrated framework provided by leadership.

The organization has sustainable, disciplined management processes to control risk and continuously improve performance.

<u>Indicators</u>

- Planning based on prioritizing the likelihood and consequence of adverse events and allocating resources accordingly.
- Processes and procedures are documented and accessible.
- A systemic approach to risk management involves all employees and ensures that the process from risk identification through assessment, characterization, funding, and mitigation or no action, is a transparent process.
- A long-range risk management plan exists which results in the risk prioritization and characterization, decisions regarding a treatment or mitigation, funding, execution and evaluation.
- Roles and responsibilities are clear; required competencies for jobs are defined; training and development programs address identified gaps in qualifications.
- Adequate resources are allocated to meet objectives.
- Disciplined management of change processes are consistently used to control the unintended consequences of changes.
- Performance monitoring programs are rigorous and risk-based; use leading and lagging performance indicators and self-assessment programs; include corrective action processes that address deficiencies.
- Continuous improvement processes are integrated into all work processes and programs.
- Regular executive review is in place to monitor organizational safety and operational performance, that the highest priority initiatives are addressed, and progress on risk reduction is continuous.

6. Workforce investment is an ongoing management focus	Processes to enhance the effectiveness of employee performance are embedded in the strategic plans of the organization.

Indicators

- There is recognition that sustaining safety and operational performance means the qualification, preparation and empowerment of the workforce, including situational awareness.
- There is recognition that excellence requires ongoing focus on supporting employee performance with training, refreshers, tools, clear procedures and standards, exercises and drills.
- Even when the company has achieved an excellent safety record, there are continuing programs to foster and improve the safety and operational culture and maintain vigilance.
- There are processes in place for continuous monitoring of learning of all employees, including use of performance indicators and culture surveys of employee perceptions regarding safety.
- Secure channels for reporting of safety risks are provided.
- New employee orientation includes substantive focus on the importance of safety to the organization and how safety is an essential element to "the way things are done around here."
- A long-term training strategy exists and is funded on a long-term basis.
- A long-term personnel development and succession plan exists and is activated, from entry level up.
- All training programs have been reviewed and requirements determined for training, through job task analysis for all levels, and implemented on a comprehensive, systematic and integrated basis.
- Emphasis has been placed on assessing the characteristics required for leadership, as well as other requirements for first-line supervisors, and appropriate programs have been developed and delivered to meet their needs.
- Succession planning is an ongoing consideration and recruiting the right people is always a priority.

Appendix 5

INGAA – Natural Gas Transmission Pipeline Public Awareness and Engagement

June 2011

INGAA

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Natural Gas Transmission Pipeline Public Awareness and Engagement

Pipeline Safety: A Shared Responsibility

Everyone plays a role in pipeline safety, including pipeline company personnel, the federal and state agencies that oversee natural gas pipelines, public safety officials, excavators and the public. Serious accidents on interstate natural gas pipelines are rare, but the natural gas transmission industry is committed to continuing to improve our engagement with the public in order to ensure their awareness of pipelines. Members of the public can help reduce pipeline risks by working closely with pipeline companies.

Public Awareness Key to Reaching Our Core Goal of Zero Incidents

Quality pipeline awareness programs are key to reaching our industry's goal of zero pipeline incidents. These programs inform people who live, work and congregate near pipelines, excavators, emergency responders and public officials on:

- The purpose, need and reliability of underground pipelines
- Pipeline safety and how to recognize, respond to and report abnormal conditions or questionable activities near pipelines
- Potential hazards and prevention measures taken by pipeline operators
- Emergency phone number and notification
- An overview of Integrity Management Plan
- Information on Emergency Response Plans
- National Pipeline Mapping System (NPMS) for pipeline locations and contact information
- Pipeline markers
- Development or construction activities that could cause third-party damage or inhibit an operator's ability to respond to potential emergencies

Supporting Public Safety Initiatives

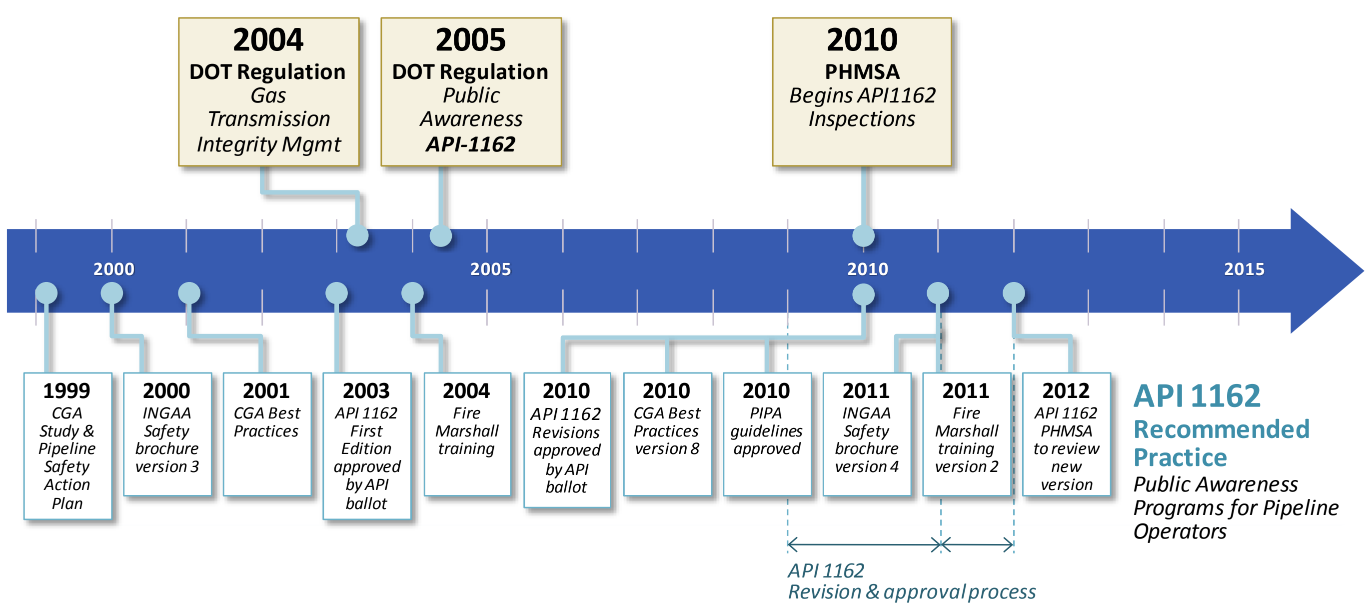
Our industry's commitment to safety is illustrated by our commitment to collaborative programs that help improve public awareness of pipelines. Examples include:

The Pipelines and Informed Planning Alliance, which provides a set of recommended practices to allow communities to make risk-informed decisions on land use planning and development near pipelines.

"Call Before You Dig," a federally mandated program that provides the public and workers a toll-free number – 811 – to call before beginning a digging project.

Common Ground Alliance, an association dedicated to reducing damage to all underground facilities through shared responsibility among stakeholders.

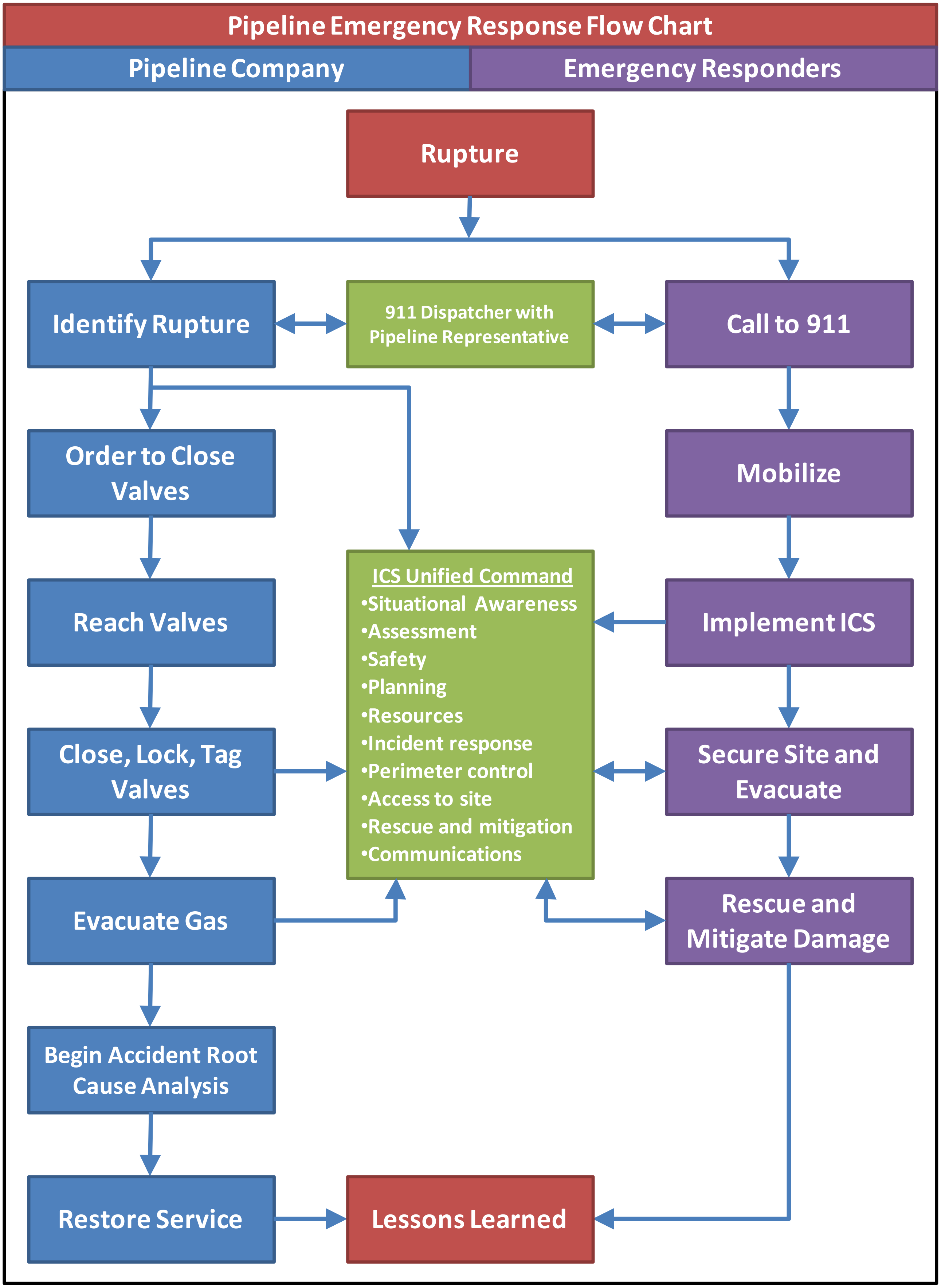
Our Journey of Continuous Improvement in Public Awareness and Engagement



Appendix 6

INGAA – Guidance on Emergency Response Time Reduction

July 2011


Pipeline Emergency Response Flow Chart
Pipeline Company
Emergency Responders
Rupture
Identify Rupture
911 Dispatcher with Pipeline Representative
Call to 911
Order to Close Valves
Mobilize
ICS Unified Command
•Situational Awareness
•Assessment
•Safety
•Planning
•Resources
•Incident response
•Perimeter control
•Access to site
•Rescue and mitigation
•Communications
Reach Valves
Implement ICS
Close, Lock, Tag Valves
Secure Site and Evacuate
Evacuate Gas
Rescue and Mitigate Damage
Begin Accident Root Cause Analysis
Restore Service
Lessons Learned

Pipeline Company		
Improvement Area	**Activities During Event**	**Improvement Considerations**
Pre-Incident	N/A	• Where using ASV's/RCV's, operate with crossovers closed where possible • Companies take FEMA 100, 200 and 300 courses in Incident Command System

Identify Rupture	Company and public are trying to determine whether the event is associated with pipeline company assets and to determine the location of the rupture.	• Develop situational awareness within pipeline companies that drives toward a decision to close valves based on limited information
		• Establish company specific rupture determination and decision making guidelines by controller coverage zones (develop decision tree[s])
		• Add SCADA points/alarms to better focus controllers attention on safety
		• If preliminary information appears to identify a potential rupture
		  o Call local emergency dispatch
		    ▪ 1) inform actively seeking to confirm
		    ▪ 2) Request information on citizen reports
		    ▪ 3) Call back to emergency dispatch to confirm
		• Examine crossover settings (closed or automated)

Order to Close Valves	Make the decision and give the order to close valves to isolate the rupture.	• Enable empowerment through training on situational awareness around the decision to close valves based on limited information.
		• Re-educate customers on culture change
		• If personnel response time to mainline valves on either side of a high consequence area exceeds one hour (under normal driving conditions and speed limits) from the time the event is identified in the control room, provide remote valve control through a supervisory control and data acquisition (SCADA) system, other leak detection system, or an alternative method of control.
		  • Beginning from the time the event is identified (for example when Gas Control is convinced of the rupture).
		    o Ending when personnel arrive at the valve (and begin to close the valve)

Pipeline Company		
Improvement Area	**Activities During Event**	**Improvement Considerations**
Reach Valves	Dispatch personnel to reach manually operated valves.	• Install ASV/RCV in HCA's where reaching valve is greater than 1 hour (consider pipeline flow conditions when deciding which technology to use) • Consider dispatch of multiple employees to valves (rupture site, upstream and downstream valve, backup sites) • Improve on-call availability • Enlist local emergency dispatch for assistance getting to the site, as necessary (addresses traffic and weather) • GIS on company vehicles for knowing who is most favorably located to respond • Pre-establish process for critical staff to enter site (e.g. natural disaster or tight security event)
Close, Lock and Tag Valves	Closing, locking and tagging manually operated valves or the time that it takes for ASV/RCV valves to actuate and reach closure.	• Valves with OD ≥ 20" equipped with an assisted operator to speed valve closure (e.g. push button operation, commercially available turn reduction technology, portable operators) • Ensuring devices for assisting in valve operation are properly supplied for use (e.g. portable operators, reservoir tanks for pneumatic operators, etc.) • Mobilize to lock out and tag out. • Provide guidance on staying away from site until lock out and tag out is complete.

Evacuate Gas	Once valves are closed there is a time lag that is necessary for the natural gas product, which is lighter than air, to blow down to atmospheric pressure. As the pressure drops in the isolated segment, the flame impact radius will be reduced to a point where emergency crews may begin to encroach the vicinity of the rupture by communicating with the pipeline company.	• Operator should provide information regarding timing of valve closure and cessation of gas flow
		• Open blow offs (where safe) to assist with evacuation of gas
		• Run downstream compressor or meter stations to assist with evacuation of gas
		• Use threaded versus flanged blow off caps
		• For replaced pipe, establish valve spacing following guidance in ASME B31.8-2010, paragraph 854.4(b) which references the following:
		    o Where a short section of line is replaced additional valves would normally not be required.
		    o Where the replacement section involves a contiguous mile or more of transmission line, additional valve installation shall be considered to conform to the spacing requirements for new pipeline construction in 192.179.

Pipeline Company		
Improvement Area	**Activities During Event**	**Improvement Considerations**
Begin Accident Root Cause Analysis	Evaluate the cause of the accident sufficiently to determine if it is safe to restore service.	• Make an initial review of the cause of the accident. • Interview eye witnesses. • Collect damaged sections of pipe for later analysis. • Determine if it is safe to restore service
Restore Service	Restore service to a pressure based on safety, regulator input and other factors.	• Agree on a plan to safely restore service involving regulators and the customers. • Execute the plan.
Lessons Learned	Meet with emergency responders and local officials to determine lessons learned.	• Meet as soon as practical following the incident to determine what went well and what can improve.

Emergency Responders		
Improvement Area	**Activities During Event**	**Improvement Considerations**
Pre-Incident	N/A	• Train 911 dispatchers in pipeline emergency response (include in API 1162 Public Awareness programs) • Make street level maps available to county local emergency planning center (MAOP's, diameter, valve location, centerline) – shape files and pdf • Include in street level maps Potential Impact Radius (PIR) calculation, estimate for timing of valve closure, dissipation time following valve closure, and heat factor of gas (e.g. varies depending on type of gas) • Promote National Pipeline Mapping System (NPMS); better distribution of NPMS; more information on NPMS • Include in street level maps Potential Impact Radius (PIR) calculation, estimate for timing of valve closure, dissipation time following valve closure, and heat factor of gas (e.g. varies depending on type of gas) • Develop industry standard incident response checklist (pamphlet) for frontline emergency responders. [emphasize safety of people] • Develop mobile apps with detailed information for emergency responders • Develop clear list of contacts for local emergency responders • Develop site specific emergency response plans (for company, facility and emergency responders) for locations with confined personnel (e.g. detention center, nursing home, etc.)

Call to 911	Calls made to the 911 dispatch center and there is some confusion as to whether this is a pipeline rupture or something else. The location of the incident is being determined.	• Pipeline company call 911 to tell that there "may" be an event
		    o Pipeline company request 911 to identify whether received calls about an incident in area
		    o Pipeline company establish point of contact for 911 dispatcher
		    o Pipeline company work with 911 dispatcher as initial point of contact to initiate situational awareness. Pipeline representative to review with 911 dispatcher PIR, timing of valve closure, dissipation time and heat factor.

Emergency Responders		
Improvement Area	**Activities During Event**	**Improvement Considerations**
Mobilize	Emergency Response forces are mobilized to the rupture site. Initially, there is not full knowledge of what type of emergency this is. Initially setting up the Incident Command.	• Company representatives join unified incident command at the incident site within 30 minutes to an hour • Pipeline company work with emergency responders to assist getting to the site • Reference industry standard checklist for actions to take in responding to incident (to be developed). • Refer to mobile app with detailed information for emergency responders (to be developed)

Implement Incident Command	Implement the Incident Command System.	• Establish Unified Command with pipeline operators and utilities
		    o Pipeline company immediately connect with responder's incident command
		    o Pipeline company to establish method with responders for sustaining situational awareness
		• Reference list of company contacts provided to county emergency personnel.

Secure site and Evacuate	Emergency Responders set up a secure perimeter around the rupture site to keep the public safe and begin the process of evacuating people from the rupture site.	• If ignited, reverse 911 to initiate evacuation to an established list • If not ignited, escape without creating ignition sources • Establish a perimeter to keep people out based on PIR, valve closure timing, gas dissipation rate, heat factor, and local variables such as climate, topography, population density, demographics, and suppression methods available • Review risks with emergency responders through direct and effective communications • Establish process for critical company staff to enter site • Reminder on training of local officials and responders on our operations (facilities, expectations)
Rescue and mitigate damage	Begin the process of rescuing personnel first and beginning the process of mitigating damage second.	• Refer to site specific emergency response plans (for company, facility and emergency responders) for locations with confined personnel (e.g. detention center, nursing home, etc.) • Improve awareness and pipeline emergency response plans for detention centers, etc. • Enter area to rescue and mitigate damage once valves are closed, locked and tagged and gas has been evacuated.

Emergency Responders		
Improvement Area	Activities During Event	Improvement Considerations
Lessons Learned	Both emergency responders and pipeline company personnel develop lessons learned from an incident. Pipeline company communicates to its employees lessons learned and conveys those pertinent lessons learned to the emergency response community. In addition, the emergency response community communicates lessons learned within the emergency response community and shares those with pipeline companies.	• Following any incident develop lessons learned • Develop learning site or leverage a site like Lessons learn.gov • Incorporate emergency response to pipeline incidents into Emergency Responders' toolkit in Ready.gov • Improve use of mock drills and include emergency responders • Incorporate HSEEP (Homeland Security Exercise Evaluation Program) methods and evaluation into mocks • Support PIPA (Pipeline Informed Planning Alliance) • Training to emergency responders by industry (traffic control, fire, evacuation, etc.) • Continually evaluate emergency response and public awareness effectiveness • Initiate decision-support from senior leadership to gas operations when decisions were made to shut-in service to protect public safety