



The INGAA Foundation, Inc.

Technical, Operational, Practical, and Safety Considerations of Hydrostatic Pressure Testing Existing Pipelines

Prepared for The INGAA Foundation, Inc.

By: Jacobs Consultancy Inc. and
Gas Transmission Systems Inc.
December 5, 2013

INGAA Foundation Final
Report No. 2013.03

JACOBS Consultancy



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Foreword

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creations Act of 2011, which reauthorized the Natural Gas Pipeline Safety Act of 1968. The legislation amended many sections of the Act, including the addition of § 60139 - Maximum Allowable Operating Pressure, stipulating "...the Secretary shall issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of specified minimum yield strength...."

While the pipeline industry has significant experience in hydrostatic pressure testing pipelines, the testing of existing pipelines in suburban and urban areas can present many public and worker safety, environmental, technical and logistical challenges.

The INGAA Foundation, Inc. was formed in 1990 by the Interstate Natural Gas Association of America (INGAA) to advance the use of natural gas for the benefit of the environment and the consuming public. The Foundation works to facilitate the efficient construction and safe, reliable operation of the North American natural gas pipeline system, and promotes natural gas infrastructure development worldwide. In support of these aims, the INGAA Foundation commissioned a study directed at the use of hydrostatic pressure testing of existing natural gas transmission pipelines, the information necessary to conduct a pipeline hydrostatic test safely on an existing pipeline, and whether, with the test results, the operator would have the information necessary to assess the integrity or fitness-for-service of the pipeline.

Jacobs Consultancy Inc. and Gas Transmission Systems Inc. volunteered to develop a "White Paper" to address the technical, operational, practical and safety considerations of hydrostatic pressure testing existing natural gas transmission pipelines, and providing guidance to pipeline operators to determine applicability of hydrostatic pressure testing. While commissioned by the INGAA Foundation, this paper is an independent study, and its conclusions are based on the expertise of the authors.

We wish to acknowledge and express our appreciation to the members of the INGAA Foundation, INGAA, and the Steering Committee for their participation and feedback in the development of this White Paper, with special thanks to following individuals:

- Terry Boss, INGAA
- Mark Cabral, Gas Transmission Systems, Inc.
- Scott Clapp, Gas Transmission Systems, Inc.
- Terry Cole, Jacobs Consultancy Inc.
- Scott Currier, INGAA
- Narinder Grewal, Jacobs Consultancy Inc.
- Mark L. Hereth, Process Performance Improvement Consultants, LLC
- Larry Hoelscher, Williams Gas Pipeline
- Richard R. Hoffmann, INGAA Foundation
- David L. Johnson, Energy Transfer Partners, LP
- Cathy Landry, INGAA
- Raymond Lewis, Rosen USA
- Salvatore Marano, Jacobs Consultancy Inc.
- Christopher Pioli, Jacobs Consultancy Inc.
- Edward Wiegele, Willbros Group, Inc.

**TECHNICAL, OPERATIONAL, PRACTICAL AND SAFETY CONSIDERATIONS
OF HYDROSTATIC PRESSURE TESTING EXISTING PIPELINES**

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1 Introduction

1.1 Objective

Hydrostatic pressure testing of existing pipelines presents unique safety, operating, environmental and community liaison challenges beyond those encountered in commissioning new pipelines. In addition, outside the pipeline industry there is limited understanding regarding technical and practical considerations of conducting hydrostatic pressure testing of existing pipelines.

This White Paper addresses these matters by providing technical, operational, practical and safety guidance in the planning, design and execution of hydrostatic pressure tests of existing pipelines. This paper is directed toward natural gas transmission pipeline operators and other industry stakeholders interested in understanding the challenges and means of successfully conducting hydrostatic pressure tests of existing pipelines in densely populated areas. This paper will:

- Define and explain the mechanics of the hydrostatic pressure test process.
- Identify the risks associated with hydrostatic pressure testing of existing facilities in high consequence areas (HCAs).
- Describe the data and information about the pipeline and area along the pipeline that is necessary to prepare for a hydrostatic pressure test.
- Identify the data and information necessary to protect the public, workers and environment when conducting a hydrostatic pressure test.
- Present the communication and coordination efforts with state, local/public leaders and regulatory agencies.
- Address ways to mitigate public inconvenience during pre-test planning, site preparation, test execution and post-test restoration activities.
- Compare and contrast a successful test to an unsuccessful one and explain the respective results and consequences of each.
- Identify new technologies and research and development (R&D) in the works that might potentially supplement hydrostatic pressure testing.

The practice of hydrostatic pressure testing of new pipelines and of existing pipelines to assess pipeline threats as part of the Integrity Management Programs (Code of Federal Regulation, title 49, sec. 192, Subpart O) is well developed. This White Paper is not intended to duplicate the effort, but rather to specifically extend guidance on specific considerations to take into account during hydrostatic pressure testing of existing pipelines. It is noted, however, that many of the steps in this paper are applicable to any hydrostatic pressure test, regardless of why it is being conducted.

In addition to testing previously untested pipelines, there are segments of pipeline systems where records, surveys and other documents are not traceable, verifiable and complete, which

may raise concerns about the safe maximum operating pressure of the pipeline system. There are other reasons why a gas pipeline operator might consider a hydrostatic pressure test of existing pipeline, but they will not be addressed in detail in this White Paper (Table 1).

Table 1 – Reasons for Performing a Hydrostatic Pressure Test of Existing Pipelines

<ul style="list-style-type: none"> • Assess the stability of pipeline defects controlled by hoop stress (i.e. internal pressure).
<ul style="list-style-type: none"> • Establish/Validate/Increase the maximum allowable operating pressure (<i>Code of Federal Regulation</i>, title 49, sec. 192.619 and associated code sections).
<ul style="list-style-type: none"> • Re-qualify the pipeline after a class location change.
<ul style="list-style-type: none"> • Establish re-assessment intervals (<i>Code of Federal Regulation</i>, title 49, sec. 192.939).
<ul style="list-style-type: none"> • Verify pipeline integrity after a pressure excursion above the pipelines MAOP.
<ul style="list-style-type: none"> • Other operator specific assessment and safety programs.

1.2 Purpose and Need For Hydrostatic Testing

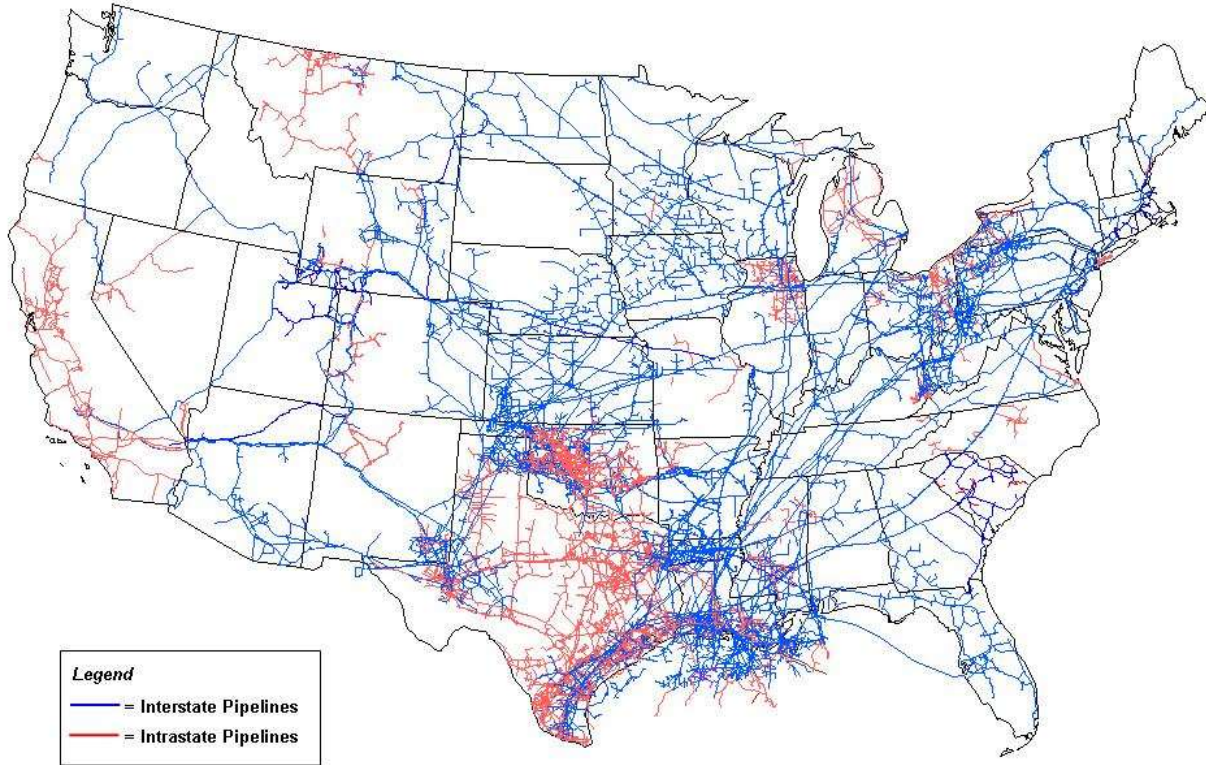
Hydrostatic pressure testing is a method used to perform strength and leak tests of a pipeline. The test involves taking the pipeline out of service, filling it with water, raising the internal pressure of the pipe to a designated pressure or stress level (hoop stress) and holding the pipe at, or above, the designated pressure for a prescribed period of time.

Hydrostatic pressure testing has long been used to commission new pipeline systems or facilities. Pipeline companies installing new pipelines perform a hydrostatic pressure test to identify flaws in manufacturing of the materials, injurious damages incurred during transporting the materials and defects caused in the course of constructing the facilities. A successful pressure test establishes a safety margin for pipeline operation and the maximum allowable operating pressure (MAOP). The safety margin is defined as the pressure difference between the successful test pressure and MAOP.

Gas transmission companies and local distribution companies operate over 299,614 miles of onshore interstate and intrastate gas transmission pipe (Figure 1). There are segments of the pipeline transmission systems in operation today that were installed in the early 1900s. It is important to note, as discussed in a study conducted by Kiefner and Associates for the INGAA Foundation, a “well-maintained and periodically assessed pipeline can transport natural gas indefinitely.”¹

¹ Kiefner, J.F. and Rosenfeld, M.J., “The Role of Pipeline Age in Pipeline Safety”, INGAA Foundation, Final Report No. 2012.04, November 8, 2012

Figure 1 – U.S. Natural Gas Pipeline Network



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

There also are segments of pipeline systems that were installed prior to state or federal regulations that may require a hydrostatic pressure test to be performed before operating the pipeline or establishing an MAOP. Still, many of these pipeline systems, constructed before regulations were enacted, were built to company standards and industry codes that required pressure testing.

2 Background

2.1 Hydrostatic Pressure Testing History^{2,3,4,5,6}

The origins of hydrostatic pressure testing can be traced back to the vessel industry prior to 1900. The natural gas pipeline industry adopted the hydrostatic pressure testing practice decades later. Hydrostatic pressure testing of cross-country transmission pipelines, that were several hundreds of miles in length, was a much more difficult task. Prior to 1955, the hydrostatic pressure testing, if performed, was usually performed utilizing the commodity being transported as the test fluid. To limit the loss of commodity in case of a failure, the testing pressures ranged between 5 psig to 50 psig, or 10 percent higher than the operating pressure of the pipeline. One of the first documented pressure tests using water occurred on the “Big Inch” and “Little Big Inch” product pipelines, known as “Inch Lines.” The lines were acquired on May 1, 1947, and the operator began the process of rehabilitating the product pipelines to transport natural gas.⁶ During the conversion process, the operator experienced numerous failures due to pipe manufacturing defects and pipe corrosion. In 1950, hydrostatic pressure testing of the pipelines was completed well above the MAOP, sometimes to 100 percent Specified Minimum Yield Strength (SMYS) or higher. As a result of this experience, the natural gas industry performed scientific studies between 1953 and 1968 to better understand the benefits, limitations and workings of hydrostatic pressure testing. Over time, operators began to adopt the practice of hydrostatic pressure testing with water to higher stress levels than had previously been customary.

In 1928, API published Standard 5L for Line Pipe, which recommended a hydrostatic test to a maximum of 60 percent of SMYS for pipes at the mill (“Mill Test”). In 1942, in the Fourth Edition of API 5L recommended hydrostatic testing of pipe to a minimum of 60 percent of SMYS and a maximum of 80 percent SMYS. In 1948, API Standard 5LX was introduced, where designation ‘X’ denoted stronger grade pipe, which recommended an 85 percent SMYS mill test. API 5L retained the 80 percent SMYS recommendation. In 1956 mill hydrostatic testing to 90 percent of SMYS was introduced. In 1983, API 5L and 5LX were combined in API 5L.⁷

The (American Standards Association) ASA B31.1 Code, prior to 1942, did not specifically recommend testing to establish the maximum operating pressures after the installation of the pipe. It also did not specify the duration of the pressure test.

² “The Benefits and Limitations of Hydrostatic Testing” Pipeline Rules of Thumb Handbook

³ Rosenfeld, M. J. and Gailing, “Pressure testing and recordkeeping: reconciling historic pipeline practices with new requirements”, Pipeline Pigging and Integrity Management Conference, February 13-14, 2013

⁴ www.kiefner.com

⁵ “U.S. Oil Pipe Lines”, George S. Wolbert, Jr., API, 1979

⁶ “The Big Inch and Little Big Inch Pipelines” Texas Eastern Transmission Corporation, May 2000

⁷ Kiefner, J.F. and Trench, C.J., “Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction”, American Petroleum Institute, December, 2001

A new period of hydrostatic pressure testing for natural gas pipelines emerged after 1955. This time period incorporated major technical advancements in hydrostatic pressure testing. The American Standards Committee B31 was reorganized as ASME Code for Pressure Piping, under procedures developed by ASME and accredited by ANSI. The ASME B31.8 Code included pressure tests of new pipelines operating at 30 percent SMYS or greater to establish the MAOP. However, the code did not specify the duration of the pressure test. Four classes (Class 1, 2, 3 and 4) were defined based on the location of the pipeline and the density of dwelling units along it. MAOP was established by testing new pipelines to a higher pressure than the maximum operating pressure based on the pipeline's class location. In Class 1 location, the installed pipe was tested to 1.1 times the maximum operating pressure with water, gas, or air; in Class 2 location, the installed pipe was tested to 1.25 times the maximum operating pressure with water, gas or air; and in Class 3 and 4 locations, the installed pipe was tested to 1.4 times the maximum operating pressure with water. The pressure testing requirements from 1950s to present are summarized in Table 2 "Onshore Natural Gas Transmission Pipeline Pressure Testing Requirements of Vintage ASA/ASME B31.8 Editions."

The Natural Gas Pipeline Safety Act, which required the Secretary of Transportation to adopt interim rules on pressure testing, became effective August 12, 1968.. The safety standard for gas pipelines and mains, in the majority of the states, was the ASME Code for Pressure Piping, Gas Transmission and Distribution Piping Systems, B31.8; thus, the interim minimum safety standards were essentially B31.8 Code requirements. Between August 12, 1968 and August 12, 1970, the Office of Pipeline Safety (OPS) of the United States Department of Transportation (DOT) developed safety standards that would be applicable to gas facilities, with the exception of rural gas gathering systems. This eventually became the *Code of Federal Regulation (CFR)*, title 49, sec. 192 "Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards," which became effective November 12, 1970.

Unlike B31.8, *Code of Federal Regulation*, title 49, sec. 192 specified a duration of the hydrostatic pressure test – a minimum of eight hours for pipelines operating at a hoop stress of 30 percent or more of SMYS. The federal code also included a clause for pressure test ratios for Classes 3 and 4. For pipelines installed and tested prior to November 12, 1970, the test ratio was 1.4, and for the pipelines installed after November 11, 1970, the test pressure ratio was 1.5. For Classes 1 and 2, the test pressure ratios were 1.1 and 1.25, respectively (Table 2). These requirements for testing of the installed pipelines have remained unchanged to present-day.

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Table 2 – Onshore Natural Gas Transmission Pipeline Pressure Testing Requirements of Vintage ASA/ASME B31.8 Editions

Description of population density at time of construction		Pressure Test Description	Pressure Test Description operating over 30% SMYS				Present Pressure Test Description
Present Day	Pipeline was built under ASA B31.1 -1942	ASA B31.1 -1951 Pressure Test Description	ASA B31.1.1.8-1955	ASA B31.8-1958	ASA B31.8-1963	ASA B31.8-1968	Subpart J [192.505]; [192.619 (2) (i)]; [192.611]
Class 1	Division 2	Maximum Service Pressure plus 50psi	1.1 times MOP with water, gas or air		1.1 times MOP with water, gas or air except tie-ins	1.1 times MOP with water, gas or air except tie-ins	Installed before Nov 12, 1970 and after Nov 11, 1970 test pressure is 1.1 * MAOP for 8 hours
Class 2			1.25 times MOP with water or air			1.25 times MOP with water or air except tie-ins	<ul style="list-style-type: none"> - Installed before Nov 12, 1970 and after Nov 11, 1970 test pressure is 1.25 * MAOP for 8 hours - Upgraded pipeline is previously tested pressure of MAOP /8 for 8 hours.
Class 3	Division 1	1.5 times Maximum Service Pressure	1.40 times MOP with water		A 1.40 times MOP with water except tie-ins. 1.1 times MOP with air, if below 32 deg F at pipe depth or no water available <ul style="list-style-type: none"> - 1.2 times MOP with air if MOP<50% SMYS and longitudinal joint factor is 1. 	B Installed before Nov 12, 1970 test pressure is 1.4 * MAOP for 8 hours; Installed after Nov. 11, 1970 test pressure is 1.5 * MAOP for 8 hours. <ul style="list-style-type: none"> - Upgraded pipeline is previously tested pressure of MAOP /667 for 8 hours. 	
Class 4						<ul style="list-style-type: none"> - A plus 1.2 times MOP with air, if MOP<40% SMYS and longitudinal joint factor is 1. 	<ul style="list-style-type: none"> - B plus Upgraded pipeline is previously tested pressure of MAOP /5555 for 8 hours.

was 1.5. For Classes 1 and 2, the test pressure ratios were 1.1 and 1.25, respectively (Table 2). These requirements for testing of the installed pipelines have remained unchanged to present-day.

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30 percent or more of SMYS. The federal code also included a clause for pressure test ratios for Classes 3 and 4. For pipelines installed and tested prior to November 12, 1970, the test ratio was 1.4, and for the pipelines installed after November 11, 1970, the test pressure ratio was 1.5. For Classes 1 and 2, the test pressure ratios were 1.1 and 1.25, respectively (Table 2). These requirements for testing of the installed pipelines have remained unchanged to present-day.

Code of Federal Regulation, title 49, sec. 192 includes a “grandfather” clause that allows for continued operation of pipelines at the highest operating pressure experienced during the five years preceding July 1, 1970. A “grandfathered pipeline” refers to a line whose MAOP was established based on the maximum operating pressure history of the pipeline rather than a hydrostatic pressure test.

In January 2012, The “Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011” reauthorized the Natural Gas Pipeline Safety Act. The timeline of hydrostatic pressure testing history and regulations is summarized in Figure 2. The “Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011” requires operators to reconfirm MAOP of interstate and intrastate gas transmission lines in Class 3 and 4 locations and Class 1 and 2 HCAs with insufficient MAOP records.

Section 23, of the “Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011” states:

“(c) DETERMINATION OF MAXIMUM ALLOWABLE OPERATING PRESSURE –

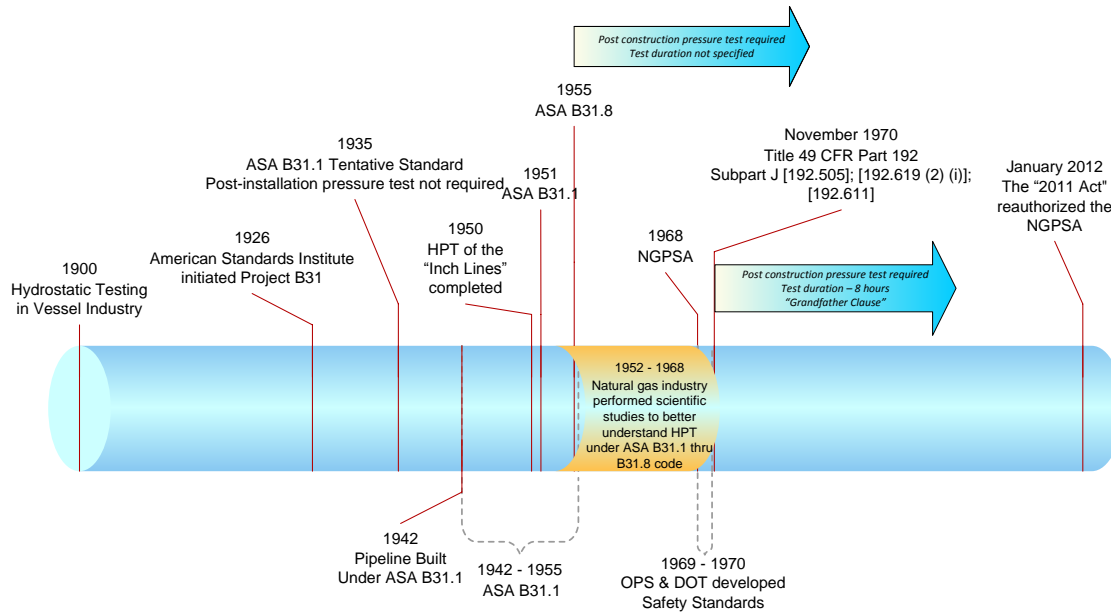
“(1) IN GENERAL – In the case of a transmission line of an owner or operator of a pipeline facility identified under subsection (b)(1), the Secretary shall -

“(A) require the owner or operator to reconfirm a maximum allowable operating pressure as expeditiously as economically feasible: and

“(B) determine what actions are appropriate for the pipeline owner or operator to take to maintain safety until a maximum allowable operating pressure is confirmed.

Also, the “Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011” requires DOT to issue regulations requiring operators to conduct tests to confirm the material strength of previously untested gas transmission lines in HCAs that operate at a pressure greater than 30 percent SMYS. Operators must consider safety testing methodologies, including hydrostatic pressure testing, and other alternative methods, including in-line inspection (ILI), determined by DOT to be of equal or greater effectiveness.

Figure 2 – Key Dates and Time Periods in Hydrostatic Pressure Testing History and Regulation⁸



Legend:

HPT = Hydrostatic Pressure Testing
 ASA B31.1 = American Standard Association, Code for Pressure Piping
 ASA B31.8 = American Standard Association, Code for Gas Transmission and Distribution Piping Systems
 ASME = American Society of Mechanical Engineers
 2011 Act = Pipeline Safety, Regulator Certainty and Job Creation Act of 2011
 NGPSA = Natural Gas Pipeline Safety Act

2.2 Impact and Magnitude of Testing Requirements

Of the 299,614 miles of onshore pipelines in the United States,⁹ almost half of U.S. transmission mileage was installed between 1950 and 1970, a time period during which the industry was still studying benefits and limitations of hydrostatic pressure testing. The cumulative percentage of transmission pipelines, by decade installed,¹⁰ is as follows:

- 12 percent of the pipeline infrastructure was installed prior to 1950.
- 37 percent was installed prior to 1960.
- 60 percent was installed prior to 1970.

Approximately 180,000 miles of pipelines were installed before 1970. Of these, according to DOT reports, 50,000 to 90,000 miles are either not hydrostatically tested, may not have been

⁸ For details refer to Table 2 - Natural gas transmission pipeline pressure testing requirements of Vintage ASA/ASME B31.8 Editions

⁹ PHMSA, 2011 Annual Report Mileage for Natural Gas Transmission & Gathering Systems, Forms F7100.2-1.

¹⁰ Kiefner, J.F. and Rosenfeld, M.J. "The Role of Pipeline Age in Pipeline Safety". The INGAA Foundation, Inc., November 8, 2012.

tested to the current Code of Federal Regulation, title 49, sec. 192 requirements in regard to duration and pressure test ratio, or do not have sufficient records of the test. PHMSA is in the process of developing a process to address such mileage, but the number of miles that will be affected, the specific requirements and timelines are yet to be defined.

Testing existing pipelines presents unique challenges not experienced when testing new pipelines.

- The line must be taken out of service for extended periods of time, requiring alternative supply, advanced planning to re-route the flow of gas or interruption of customers. Large water storage systems may be required to reduce outage times during fill and discharge.
- The line may have multiple diameters, wall thicknesses and grades that complicate pipeline cleaning and/or the design parameters of the test.
- The line may have internal contaminants. Consequently, water released during a failure could contaminate the environment if the pipeline were not cleaned in advance of the test. The cleaning process may generate hazardous waste streams that require permitted handling, transportation and disposal. Test waters may not be allowed to be discharged to ground and must be handled in accordance with environmental regulations.
- Existing pipeline may be in close proximity to the public. Notifications and/or evacuations may be required. Leaks and ruptures can be hazardous to the public if appropriate precautions are not taken since a large volume of water can be released.

Testing may heighten public interest and concern rather than abate it if it is not communicated properly. Venting and purging of natural gas from the line to prepare for the test may be confused with damaged and leaking pipelines, which can alarm the public.

3 Planning the Hydrostatic Pressure Test

3.1 Determination of Scope

Operators benefit from developing protocols to achieve desired objectives. The objective of the test must be understood so that minimum test pressure can be established. The benefit of testing to higher pressures to maximize MAOP, or to achieve larger test pressure to operating pressure ratios to extend Integrity Management (IM) reassessment intervals, must be balanced with the potential for added test failures.

For instance, it may be desirable to establish the highest possible operating pressure and/or to rule out as many defects as possible. However, the consequence of testing to pressures in excess of multipliers in Code of Federal Regulations, title 49, sec. 192.619 could result in failures without achieving desired benefits.

Many federal and state jurisdictional regulations come into play in the planning, design and execution of a hydrostatic pressure test. Pipeline operators need to investigate and incorporate specific jurisdictional requirements into their hydrostatic pressure testing plans.

3.2 Risks Associated with Testing Existing Pipelines

This paper focuses on the risks unique to hydrostatic pressure testing of existing pipelines. Fundamentally, hydrostatic pressure testing involves the same construction risks associated with installing pipelines such as trenching, shoring and working near other infrastructure. In addition, when testing existing pipelines the following risks should be considered:

- 1.) Pipeline Failures – The risk associated with pipeline test failures can be categorized into buried and exposed.
 - Buried Pipeline – Failure on a buried pipeline may result in water breaking the surface of the ground or paving. Subsequent erosion may occur in steep areas and/or loose soils. Pipeline contaminants could also be released into the environment, if not planned for and mitigated.
 - Exposed Pipeline – In addition to the risks associated with a buried pipeline, a failure on an exposed pipeline subjects people and equipment to the initial release of energy. The pipeline and associated equipment may move or jump as a result of the water blast if not planned for and mitigated.
- 2.) Public Safety – Strength testing in populated areas exposes the public to the failure mechanisms mentioned above. Patrolling standards should be considered for the pipeline while under test, and safety zones should be established to prevent public access within a set distances from buried and exposed piping. (The test pressures, percent SMYS and test media should be considered in the development of the policies).

The use of barricades, barriers and blast mats as mitigation measures should be explored when safety zones cannot be enforced.

- 3.) Worker Safety – The INGAA Construction Safety Consensus Guideline, “Pressure Testing (Hydrostatic/Pneumatic) Safety Guidelines,” is a good source for identifying and mitigating these risks; a copy of the document is included in Appendix C.

In particular, when hydrostatically testing existing pipelines, access to exposed and pressurized piping and testing equipment should be limited to only those employees necessary to perform the work. Training programs should be reviewed and revised accordingly. Safety practices should include the design and review of test manifolds, pig traps, temporary manifolds, etc. Special attention should be given to worker and public safety during the depressurization and dewatering steps, due to the temporary nature of the equipment and the possibility of unsecured piping jumping during discharge. Training, qualifications, and design safety requirements and policies should be extended to contractors performing the work.

3.3 Planning the Test

Once the objective and scope has been determined, the operator must consider the physical aspects of the line (pipeline attributes) and plan the logistics required to complete the test. Likewise, environmental attributes such as location, proximity to water sources, elevation changes, customer impacts, outage duration, spill prevention and safety must be considered and planned for in the design and execution of the test. As a result, preparing to test a clean 1960 vintage pipeline, in an agricultural field, may require a far different approach than a contaminated 1940 vintage pipeline in an urban or environmentally sensitive area.

3.3.1 Corrosion and Damage History

The history of corrosion-related leaks and/or damage should be evaluated and considered during the planning phase. Review of maintenance records and ILI data (if available), and discussion with operating personnel should be conducted and considered in development of the plan. If the leak/damage history is significant, it must be addressed with preventative measures, such as performing ILI runs, to locate and repair anomalies prior to the test, or increasing spill-response measures employed to react to the higher probability of a failure.

Leak history related to third-party damage should also be carefully assessed, especially when a pipeline traverses active agricultural areas or urban areas in which the pipeline occupies rights-of-way or franchise areas with other underground utilities. Again, available ILI data should be assessed. Based upon the results of these assessments, performing an ILI run prior to testing should be considered.

3.3.2 Equipment and Construction Issues

Operators should review records, purchasing, construction and maintenance practices to identify any facility issues that may affect test success. Examples would be:

- Dresser® Couplings may not be rated for the maximum test pressure and could result in a leak, failure or damage under test.
- Abandoned taps might affect the test if they are not mapped, or if the tap involves a buried valve that is not rated for the maximum test pressure.
- Miter and wrinkle bends are a concern if they are located in close proximity to the test-head location. These bends do not experience axial loads during operation, but will under test if they are located close to exposed ends.
- Field constructed fittings, such as fish mouth tees and mitered elbows pose a concern because of the lack of manufacturing quality control and rating.

Section 4.0 of this report provides further information on assessing and addressing these issues during engineering and design

3.3.3 Logistical Issues

Several logistical issues also affect the duration of the service outage, construction impacts and cost to achieve a successful test. Consideration must be given to the following:

- Proximity to each of the identified sections of pipeline requiring testing.
- Proximity to water source/discharge location.
- Proximity to sufficient laydown/staging to support construction and water storage tanks (e.g. work sites of up to two or more acres can be required).
- Elevation changes within identified segment and commensurate static head.
- Piggability; multi-outside diameters (ODs) within identified test section, valves and fittings, large degree miters or mechanical fittings.
- Customer supply impacts within test section and within pipeline outage limits.
- Operational considerations due to having pipeline out of service for one to three weeks or more and impact to other planned outages and work (i.e. transmission and distribution planning issues).
- Incorporation of other operations and maintenance (O&M), capacity, ILI, or other operator work.
- Temporary gas requirements; including CNG, LNG, by-pass, backfeed requirement, back-ties, etc.

3.4 Environmental Permitting Issues

Testing existing pipelines offers the possibility of avoiding direct impacts to the environment if the test can be lengthened to place testing equipment in environmentally innocuous locations. This avoidance strategy may marginally increase costs but promote environmental stewardship.

When testing existing pipelines, the potential of releasing contaminated water can be substantial and must be considered. The cost of cleaning lines to remove contaminants prior to filling with test water should be balanced against generating waste streams from the cleaning effort as well as the consequence of an environmental spill, should a failure occur.

To ensure that discharge water meets environmental permit requirements, it is important to establish a sequence of water sampling protocols to rule out sources of contamination. Hydrotest water can be contaminated via a number of sources. Water sampling is further discussed in the Section 5 of this paper.

3.5 Outage Management

Operators should consider establishing policies defining what customer types may be impacted and for how long. If applicable, customer contracts, rates and tariffs should be reviewed and a determination made if the appropriate clauses can and will be exercised. Methods to manage outages include:

- Scheduling work with customer planned outages.
- Coordinating with other Work Through Gas System Operators.
- Use of LNG/CNG.
- Temporary bypasses and backfeeds.
- Compression from distribution or lower-pressure lines.

3.6 Communications

A Communication Plan is needed to keep the public, jurisdictional authorities and appropriate company personnel informed about the hydrostatic pressure testing. It is important to provide essential information and set expectations for the pressure test to all stakeholders. Communications should be conducted periodically as required, and when requested, to ensure that the stakeholders have current information about the pressure test.

The Communication Plan should establish key contacts and protocols that can be employed to defuse situations before and during the design, permitting and execution of the hydrostatic pressure test. A good Communication Plan and outreach strategy can improve interaction with the community and local agencies, thus avoiding time-consuming and costly complications.

A Communication Plan for hydrostatic pressure testing should address:

- External communications to landowners and tenants along pipeline, state and federal authorities, public officials, local and regional emergency responders, and the general public.

- Internal communications to employees and contractor personnel involved with various aspects of hydrostatic pressure testing.

The operators should provide the following **basic information** to all stakeholders, and answer the following questions:

- Why is a hydrostatic pressure test required?
- What is a hydrostatic pressure test?
- How does the test ensure safety and integrity of the natural gas system?
- What happens during a test and what should be expected?
- How long will the hydrostatic pressure test last?

A Communication Outreach sample is include in the Appendix B and can be found on the INGAA Foundation website www.ingaa.org/hydrotest.

3.6.1 External Communications

In addition to **basic information**, specific messages for the various target audience groups should be included:

Landowners and Tenants Along the Pipeline

Communicating with landowners and tenants is of particular importance, especially in densely populated urban and suburban areas. Impacts to landowner operations may affect the project schedule. Additional workspace beyond existing pipeline easements may be required. Involving land owners early can prevent complications, delays and claims.

The operators should provide the following information to this group:

- Company name, test location and contact information.
- Contact phone numbers, both routine and emergency.
- General location information and more specific location information, or where maps can be obtained.
- Temporary traffic detour, landlord access to property, ingress and egress for operator and contractors' personnel.
- The materials in use, machinery and support equipment to expect, temporary noise level, and occasional odor of natural gas.

It is expected that some dialogue may be necessary between operator and the public in order to convey the operator's confidence in the integrity of the pipeline, as well as to convey the operator's expectations of the public during the test. Operators should take such opportunities to talk with the public as they provide an forum to help protect assets, people and the

environment. Informing the community and neighborhoods is an important step in building support. Operators may use the following to reach an affected community:

- Town hall meetings.
- Door hangers and targeted mailings.
- The use of social media, such as commercials, web sites and informational videos.

Governmental Agencies and Public Officials Other Than Emergency Responders

Various federal, state and local agencies may be involved in the approval and permitting process associated with hydrostatic pressure testing. Identifying the agencies with jurisdiction, and then discussing plans and objectives often streamlines the permitting process and creates a spirit of cooperation. Contacts can be established to deal with policy-level issues that are difficult to address at a working level.

Information that should be provided to this group includes:

- Company name, test location and contact information.
- Summary of emergency preparedness.
- Environmental issues and risk-mitigation plan.

Local and Regional Emergency Responders

Identifying the emergency responders assigned to various jurisdictions is important in developing response plans. The operator should name a liaison officer to maintain contact with all emergency responders, including local emergency planning commissions, regional and area planning committees, jurisdictional emergency planning offices and others. Informing these groups of the work methods to be employed, the potential hazards and failure mechanisms allows them to prepare for an efficient response. Notification policies, key contacts and status reporting should be included in these plans.

Other information that should be communicated to this group includes:

- Company name and contact numbers, both routine and emergency.
- Local facility maps.
- Facility description and that the commodity transported is natural gas.
- General information about operator's preventative measures.
- Summary of operator's emergency capabilities.
- Coordination of operator's emergency preparedness with local officials.
- Training on the potential environment responders will encounter should a response be needed.
- Discussion on what happens when a release occurs during a test

General Public

The operators should provide the following messages to this group:

- Information regarding operator's efforts to support pressure-test notification and other preventative initiatives.
- Company name, contact and emergency reporting information, including general business contact.
- Note that they may smell a natural gas odor or hear loud noise.

3.6.2 Internal Communications

The Internal Communications Plan helps keep management and other appropriate company personnel abreast of the status of hydrostatic pressure testing activities and changes. This communications plan should include personnel in the following internal departments: Operations, Engineering and System Planning, Gas Control, Integrity Management, Community Relations, Government Liaison, Corporate Media, Call Centers, and Health & Safety. The Communication Plan should also include appropriate external contractor personnel.

Company employees can serve as excellent ambassadors to the community. They are credible community members and neighbors. Consideration should be given to training workers who may be questioned regarding the objective and need for the hydrostatic pressure testing. Training and orientation for workers should include what questions can be answered and how to direct the public to more appropriate resources. The use of an information card is a good tool in this regard. The card can answer frequently asked questions and direct the public for additional information.

4 Pressure Test Engineering, Design and Risk Mitigation Considerations

4.1 Gather Existing Pipeline Feature Data

Prior to beginning the engineering and design of a pressure test on an existing pipeline section, irrespective of the purpose of the test determined in Section 3, Determination of Scope, in this document, pipeline operators must gather available data on the pipeline section and appurtenances that will be subjected to the proposed hydrostatic pressure test. This data generally can be grouped into data related to the physical characteristics of the pipeline features, down to the component level, historical operations and maintenance data and pre-test evaluations.

Primary sources of pipeline characteristic data are:

- Pipeline feature studies utilized in MAOP validation.
- Operator's Geographic Information Systems (GIS).
- Alignment sheets and/or transmission plat sheets.
- As-built documentation.
- Prior hydrostatic pressure test reports.
- Mill Test reports for pipe and manufacturer test reports for fittings.
- Material purchase records; contracts, purchase orders, requisitions, etc.
- Industry vintage pipe reports

4.1.1 Historical Operation & Maintenance Data

Historical operations and maintenance data on the test section provides useful information in support of engineering and design of the test. This information provides the pipeline operator with an indication of the condition of the pipeline and the feasibility of a successful test, the potential for having a test failure and can detect areas of concern that should be assessed prior to hydrostatic pressure testing, or that may limit maximum and spike test pressures. Pipeline operators should carefully review and analyze:

- Pipeline leak history.
- Prior hydrostatic pressure test failures.
- Cathodic protection surveys.
- Valve maintenance history.
- In-line inspection data.
- Pipeline survey and patrol data (for indications of potential third party or right-of-way encroachment damage).

4.1.2 Pre-test Inspections

Pipeline operators have identified the use of the following pre-test inspections/evaluations to identify potential pigging impediments and potential failure points:

- Cleaning pigs - brush or squeegee to remove debris and scale from pipeline.
- Geometry pigs – gauge, caliper, or high-resolution deformation to ensure the passage of fill and dewatering pigs and identify pipeline damage that may require removal.
- Metal loss pigs – axial or transverse Magnetic Flux Leakage (MFL) tools to identify corrosion and third party damage that may not survive test pressures.
- Crack detection pigs – EMAT or ultrasonic to identify potential failure points in longitudinal seam and welds.

4.2 Validate Pipeline Feature Characteristics

Once the pipeline operator gathers the existing pipeline feature characteristics, O&M and pre-test data deemed appropriate for the planned test section, the data must be organized in such a manner that it is useful and available to engineering and design personnel to validate all pipeline features and their location within the proposed test section. This cataloguing of pipeline features and characteristics typically would take the form of a pipeline features list or study. Some of this information is the same information that pipeline operators must obtain for their MAOP verification to confirm their established MAOP for pipelines operating in Class 3 and Class 4 locations, and Class 1 and Class 2 locations in HCAs, as imposed by the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011.

Validation of pipeline features encompasses reviewing feature data to confirm, as appropriate for each feature, the outside diameter (OD), wall thickness (WT), grade, seam type, rating, manufacturing information, its location within the test section, identification of any unpiggable features, features that limit test pressure, and features or fabrication and construction threats that may be more susceptible to failure. The location, characteristics, specifications and ratings of each of the following should be identified, to the extent possible, prior to engineering and designing of a hydrostatic pressure test on an existing pipeline (see section 4.3 below):

- Line pipe
- Elbows, tees, flanges, and other fittings
- Valves
- Taps
- Casings
- Spans and other exposed piping
- Sleeves and patches or other repairs
- Mechanical couplings
- Wrinkle or greater than 3 degree miter bends
- Expansion joints

- Non-standard fittings (i.e. fabricated elbows, reducers, etc.)

4.2.1 Guide to Conservative Assumptions

At the outset of any data validation effort, consideration should be given to the development of a guide to conservative assumptions that the pipeline operator may need to use, if there is insufficient data to definitively determine all characteristics of a pipeline feature. This guide is necessarily specific to the pipeline operator based upon the operator's historical purchasing policies and records, design and engineering standards, specifications and standard practices. For example, if a pipeline operator has adequate documentation that it purchased no less than Grade B pipe and fittings (35,000 SMYS), per its historical design standards and specifications since 1950, and all other attributes, such as OD, WT and seam type are known, it may have sufficient documentation to confirm that the most conservative SMYS of the feature is 35,000 and not 24,000,¹¹ as required by code, for use when SMYS is unknown. Consultation with the operator's legal and regulatory compliance personnel, and perhaps its regulator, must be performed prior to implementing such a guide, but for those with sufficient documentation, such a guide can prove valuable when validating pipeline features for hydrostatic pressure testing.

4.2.2 Resolving Unknown Feature Characteristics

When a pipeline's feature characteristics cannot be confirmed via data validation or the use of a guide to conservative assumptions, to a degree that the test pressure will be limited to less than that required to meet the hydrostatic pressure-testing objective, excavation and assessment of the feature may be a viable alternative to consider.

Various testing methodologies are available to determine the characteristics of an unknown feature, including:

- OD and WT can be readily determined via physical measurement and ultrasonic thickness gauging.
- The presence or type of seam may be readily evident via visual examination or may require more in depth investigation, such as radiography, etching or other NDE techniques.
- Confirmation of yield strength is difficult to confirm without destructive testing. However, non-destructive technologies for confirming yield strength that show promise are available, and may become acceptable means for confirming, if not determining, yield strength.

¹¹ Code of Federal Regulations, Transportation, title 49, sec. 192.107

The Gas Technology Institute has recently completed a study to develop a procedure to determine yield strength without the need for a shutdown.¹² While this process is not yet approved or incorporated into regulations by PHMSA, it has been used as the basis for a special permit request to determine yield strength. In many cases, confirming only two or three attributes, and using minimum assumptions (per code or operator standard) for yield strength and/or joint efficiency, provides sufficient information to satisfy the operator that the feature no longer limits the hydrostatic pressure testing of the proposed test section.

During data validation, every effort should be made to identify pipeline sections with potential fabrication and construction threats, such as Oxy-Acetylene welds, bell-bell chill ring (BBCR) joints, bell and spigot joints, early vintage arc welds, etc. Depending on operator standard practice, these threats may warrant consideration of replacement in lieu of hydrostatic pressure testing or invoke additional constraints on the hydrostatic pressure test procedure.

4.3 Assess and Address Features

The first step in designing a hydrostatic pressure test for an existing pipeline is assessing features to ensure that the pipeline is piggable. All unpiggable features should be removed or replaced that might impede the passage of fill and dewatering pigs. When operators encounter unpiggable features that are otherwise fit for service, they may find it economical to remove the unpiggable feature, install a spool, or short section of new pipe, to facilitate testing, test the unpiggable feature separately from the planned test, and reinstall it upon completion of the hydrostatic test during tie-in. The operational disadvantage of this methodology is that upon completion of the hydrostatic test, the pipeline remains unpiggable for future ILI inspections. The method of removing and spooling, a feature for hydrostatic pressure testing, also can be employed at features, such as valve sets and taps where dewatering and drying of the valve set or tap piping may be difficult and result in free water remaining in the test section. Additionally, valve shell test pressures may be below desired test pressures for the existing pipeline being tested, or operator specifications for new installations may prescribe higher test pressures for those assemblies, and require them to be tested separately. After all unpiggable features have been identified, the operator's engineers can employ appropriate design to mitigate these features in accordance with the operator's design, construction and operating standards.

The pipeline features list or study, which contains all of the validated features included in the test section, must be reviewed in detail by the operator's engineers to determine if the feature is appropriately designed to operate at the MAOP to be established, limits the maximum test pressure or poses an unacceptable risk of failure during the hydrostatic test. Even though a feature may have met the code in force when it was constructed, the operator should consider whether the feature poses a risk to the continued safe operation of the pipeline or unacceptable risk to the pipeline, environment, workers and public in the event of failure during the hydrostatic

¹² FINAL REPORT: Establishment of Yield Strength Using Sub-size Samples without Gas Line Shutdown (Mini, Full-Wall Longitudinal Specimens), Operations Technology Development (OTD), NFP, Project No. 4.7.g / GTI Project No. 20568; Report Issued: March 4, 2011.

pressure test. Where the feature is non-commensurate with the MAOP to be established limits the test pressures below the operator acceptance criteria established for the test purpose or poses unacceptable risk, the feature should be removed or replaced.

4.4 Establishing Minimum Test Pressure and Control Point

The minimum test pressure for a hydrostatic pressure test is controlled by *Code of Federal Regulation*, title 49, sec. 192 for establishing or reconfirming the MAOP of a pipeline. The table in §192.619(a)(2)(ii) provides the minimum test pressure to MAOP ratio required depending on class location and year installed, or converted from service other than natural gas, and class location. Some operators may be regulated by state jurisdictions that require more stringent test pressure to MAOP ratios. However, when an operator plans to incur the expense of testing an existing pipeline, there are additional considerations.

The National Transportation Safety Board (NTSB) in its Safety Recommendation P-11-15 of September 26, 2011, recommended that PHMSA “amend *Code of Federal Regulation*, title 49, sec. 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects only can be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP.” Consequently, pipeline operators should consider testing to no less than 1.25 times MAOP whenever possible in Class 1 locations, where elevation differences within the test section do not cause the test section to be broken into uneconomic test sections to account for hydrostatic head.

Determination of minimum test pressure should also consider, but not limited to, the following:

- Current MAOP.
- MAOP of connected pipelines.
- Potential for changes in pipeline demand or delivery pressures.
- Potential for future class location change.
- Presence of HCAs.
- Any specific threats or anomalies whose elimination or absence thereof is being confirmed by the test.

Prior to establishing minimum test pressure for the hydrostatic pressure test of an existing pipeline in HCA, the pipeline operator should consult its integrity management (IM) department to determine if it is appropriate and beneficial for the test to serve as an IM re-assessment. It may be beneficial for the operator to test to higher than the minimum requirements of §192.619(a)(2)(ii) in order to satisfy any additional IM program assessment or reassessment requirements arising from *Code of Federal Regulation*, title 49, sec. 192, Subpart O.

Regardless of whether the pipeline operator wishes to establish an IM re-assessment interval, per *Code of Federal Regulation*, title 49, sec. 192, the operator may want to consider testing to as high a minimum test pressure as can be achieved, without exceeding the operator’s

protocols for maximum test pressure and providing an achievable range between minimum and maximum test pressures. Higher test pressures result in smaller sub-critical anomalies surviving the test and more effectively stabilizes them from pressure-driven growth,¹³ thus providing a greater factor of safety. Flaws that survive test pressures in excess of minimum requirements will take a longer time to reach critical size than those that survive a test performed to minimum requirements.

4.5 Determine Maximum Test Pressure and Control Point

When establishing the maximum hydrostatic test pressure for an existing pipeline section, operators must consider that the maximum pressure control point is not always at the lowest elevation as is typical of post-construction strength tests. Existing pipeline tests can contain sections designed and installed to meet prior code requirements, and the potential exists for the test section to include multiple installations due to main extensions, relocations, repairs, etc., that heighten the importance of the validation of the pipeline component characteristics, as discussed in the Validate Pipeline Feature Characteristics section of this paper. The maximum pressure control point for an existing hydrostatic pressure test is the point within the test section, taking static head into consideration, where the test pressure produces stresses commensurate with the established test criterion. The maximum test pressure must not be set so high as to potentially damage the pipe or any component being tested. If operators choose or are required to include a spike test, the spike test pressure will be the maximum test pressure.

When testing existing pipelines, the operator must consider the benefits of testing to the highest possible pressure, and resulting benefit of smaller remaining sub-critical anomalies surviving the test, versus the risk of failure. API Recommended Practice 1110,¹⁴ Section 5.1.10, contains a comprehensive list of considerations for determining maximum test pressure. When establishing maximum test pressure on existing pipelines, operators should pay particular attention to the following considerations:

- Elevation difference within test and resultant static head,
- Mill Test pressure, if known, or probable Mill Test pressure of all pipe segments,
- Available ILI data,
- Maximum pressure of any prior test(s),
- Pressure ratings and manufacturer test pressure of rated fittings,
- Leak history – frequency and characterization,
- Repairs – type and location,
- Proximity of test section to public, structures and environmentally sensitive areas,

¹³ Kiefner, J.F., “Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines”, U.S. DOT, Final Report No. 05-12R, April 26, 2007.

¹⁴ API RECOMMENDED PRACTICE 1110, SIXTH EDITION, FEBRUARY 2013, Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide.

- Engineering evaluation of suitability of non-standard components to withstand the test pressure, wrinkle bends, greater than 3 degree miters, mechanical couplings, expansion joints, etc, and
- Mill Test records (if available).

Prior to engineering a pressure test on an existing pipeline, operators should consider developing a protocol to establish the maximum test pressure that addresses the considerations above appropriate for their pipeline systems and engineering and operating philosophies. Establishment of a protocol promotes engineering and design consistency, streamlined approvals and it helps ensure engineering, IM and operational considerations are appropriately weighed and addressed by the test and provide justification and clarity to regulators.

The range between minimum and maximum test pressures, or post-spike test pressures (discussed later in this section) at the test station, taking elevation differences into account, can be very narrow, and in practice ranges in the 25 psig to 35 psig can be achieved without excessive bleeding or addition of test water. This is important for operators who desire, or are required, to include a spike test on their existing pipeline tests. A narrow test pressure range facilitates achieving the desired spike pressure and provides for sufficient decrease in pressure to maximum post-spike pressure to attain the maximum benefit of the spike test.

The test pressure range can be minimized by following a comprehensive test plan and carefully monitoring test pressure and temperature during the test period. Ensuring sufficient temperature stabilization time between completion of fill and initial pressurization can facilitate test pressure ranges as narrow as 20 – 30 psig.

4.5.1 Spike Testing

The spike test is a variant of the hydrostatic test in which the pressure is initially raised to a prescribed level above the minimum test pressure, or stress level, for a short period then reduced for the remaining duration of the test. A spike test's purpose is two-fold: the spike portion will induce failure in the pipe where significant defects may be present, while the subsequent reduction of pressure allows any surviving cracks to stabilize and avoids subcritical crack growth during the hold period to detect leaks.¹⁵

Employing a minimum spike pressure of at least 5 percent, and preferably 10 percent¹⁶ or higher over the minimum test pressure as described in Section 4.4 above, and holding for a period of up to 30 minutes (ASME B31.8S recommends minimum 10 minutes)¹⁷ is sufficient

¹⁵ Rosenfeld, M.J., "Hydrostatic Pressure Spike Testing of Pipelines – Why and When?", Presentation to American Gas Association, Operations Conference, Orlando, May 22, 2013.

¹⁶ Rosenfeld, M.J., Ibid.

¹⁷ Paragraph A-3.4.2(b), "Managing System Integrity of Gas Pipelines", Supplement to B31.8, ASME, B31.8S-2012.

when testing existing pipelines to eliminate manufacturing-related, construction-related and corrosion defects that might otherwise grow to failure during the test period.

In order to achieve the desired result, the spike test pressure should be lowered at least 5 percent, but a reduction of 10 percent¹⁸ is preferred to prevent subcritical crack growth during the remainder of the prescribed test period.

Incorporating a spike test may be advisable when testing existing pipelines with a test pressure to MAOP ratio less than 1.4, and for pipelines that have experienced seam weld failures or contain seam weld types that have exhibited susceptibility to seam cracks or failures.¹⁹

Including a spike test also provides operational benefits. Stand-by construction crews, and other leaks/ruptures response teams can be released after completion of the spike period. The impact and inconvenience to the public may be reduced as the threat of failure is essentially eliminated because, if properly executed, there should be limited if any sub-critical crack growth during the post-spike hold period.

Spike testing originated as a means to increase the time to failure after hydrostatic pressure testing of pipelines affected by SCC. Spike testing as high as possible, within the range of 100 percent to 110 percent of SMYS, is typically recommended for assessing SCC to maximize the retest interval and not result in significant deformation.²⁰

4.6 Test Duration and Timing

Test duration is governed by the requirements of *Code of Federal Regulation*, title 49, sec. 192, Subpart J when establishing MAOP of an existing pipeline via hydrostatic testing.

The timing of the hydrostatic test can be an important consideration. Most operators surveyed for this paper indicated that they seek to conduct tests during daylight hours. Testing during the day can make patrols more effective and limit the inconvenience to residents around the test section. However, circumstances may dictate that testing be done at night to limit the impact on traffic, businesses or the public. Testing pipelines in areas with very high daytime temperatures also may lead an operator to conduct tests at night when the thermal effects can be minimized.

The best time for any test will depend upon the specific circumstances of the test under consideration and impacted by permitting, safety, and the potential effects on businesses, residents and the public.

¹⁸ Rosenfeld, M.J., Ibid.

¹⁹ Rosenfeld, M.J., Ibid.

²⁰ Fessler, R, Batte, D, and Hereth, M, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas," ASME STP-PT-011, 2008, ASME, New York.

4.7 Engineering Factors for Consideration

Testing existing pipelines requires the operator to address engineering considerations that may not be typical for testing new pipeline installations. These can be summarized as follows:

- Selection of practical, safe and cost-efficient test sections.
- The location, accessibility and impact of the test manifolds on landowners, businesses and the public.
- Trade-off between accessibility and constructability of aboveground test manifold installations and additional safety and reduced impact of belowground installations.
- Test station location and safety.
- Availability of safety exclusion areas around pressurized piping and test stations and potential for evacuations.
- Selecting the longest practical test section versus the number of isolation points (taps, cross-ties, etc.) and their impacts to service and temporary gas requirements.
- By-pass, temporary crossties, backfeeds, cross-compression or other means to provide continued service to meet contracts requirements.
- Test manifold and pig launcher/receiver designs.
- Number of unriggable components and/or their limitations on desired test pressures.
- Limitations posed by valve assemblies on riggability and test pressures.
- Test section isolation from the pipeline and returning to service of the pipeline either side of the test while test is performed.
- Isolation cap design.
- Pigging challenges associated with cleaning, fill, and dewatering due to pipeline features that cannot be removed prior to testing.
- Assessment and possible removal of anomalies identified by any pre-test ILI runs.

Engineering evaluation and considerations of specific pipeline features.

- Spanned sections must be analyzed to ensure that the combined stresses do not exceed (American Society of Mechanical Engineers) ASME B-31.8 requirements.
- Assessing waterway crossings and potentially limiting stress limits during testing. Identification of impacts of test failure in waterway crossing to environment, commerce, etc. Contingency measures in the event of failure of waterway crossing, material availability, crossing design, emergency permitting, and contractor availability.
- Review of casings within test section, confirmation of casing isolation from pipeline, and contingency measures in event of failure within cased section.
- Removal of any drips from the test section and potential for long lead-time permitting to access and remove drip legs/piping.

Removal or limitations posed by fabrication and construction threats.

- Mitered welds or wrinkle bends.
- Mechanical fittings and couplings.
- Excessive pups or joiners.
- BBCR and bell and spigot joints.
- Oxy-Acetylene or early vintage arc welded joints.
- Other non-standard fittings.

Design of temporary test piping to locate test manifolds where desired, for by-pass piping or isolation of laterals.

- Design with sufficient factor of safety over most restrictive design factor of existing pipe within test section to ensure against failure.
- X-ray of all temporary welds is suggested.
- Determine limitations, if any, on reuse of temporary test piping (i.e. limit number of times tested over prescribed percent SMYS).
- Design piping to limit number and orientation of angles considering water hammer, surging, and impact of pigs coming into test manifolds, launchers and receivers during cleaning, filling and dewatering.
- Proper anchoring of unrestrained piping.

4.8 Possible Components of Engineered Drawings

In addition to the operator's standard title page, general notes, work summary, sequence of operations, specific notes and details, legends and symbols, and other sheets included in their standard drawing template, when preparing drawing sets for hydrostatic pressure testing, consideration should be given to include the plan, profile, location sketches, bill of material, material of record, construction details and as-built information. Ensuring that this information is contained within the drawing package generally provides sufficient information for the drawings to be used for permitting, construction, temporary and permanent easements, and provides a basis to ensure that the as-built documentation is traceable, verifiable and complete.

4.8.1 Plan

Plan view with horizontal stationing and detail call-outs for test ends, isolation points, locations requiring removal/replacement of unspiggable features, or to draw attention to locations of interest during testing. The pipeline location and cadastral information is typically obtained from operators' GIS system. Cadastral information is readily available to operators via the internet if needed.

4.8.2 Profile

Profile view containing pipeline stationing and identifying all pipe specifications, lengths, and their location within the test section, as well as the type, specifications, location and number of components, original installation job number, year installed, current class location and limits of HCA within the test section. This information generally is pulled from pipeline features studies and verified by engineering during the design of the hydrostatic pressure test. Profile information can be obtained via as-built information, GIS, or other sources and does not necessarily require a centerline survey. However, sub-meter accuracy may be required when testing to pressures close to 100 percent SMYS, or when elevations, within the test section, limit the test pressure range and pose risk to over pressurization due to static head and thermal effects. When these risks are present, the operator should consider requiring a surveyed profile.

4.8.3 Location Sketches

Location sketches of all work areas provide for operators' engineers to identify temporary construction easements, locate and identify bell-hole size, spoils storage, laydown and staging areas, access roads, construction parking, environmental exclusion areas, and areas of impact to be used to obtain encroachment, environmental and other jurisdictional permits, temporary and permanent land rights, and for construction.

4.8.4 Bills of Material

Bills of Material, as typical with any typical construction drawing, include any temporary hydrostatic pressure test piping that may be reused.

4.8.5 Material of Record

A Material of Record, or summary, of all materials to be included in the hydrostatic pressure test and depicted in the Profile in tabular format is recommended. The table would typically include the feature specifications, length or number included in the test, and identifiers that relate to the features location within the test section and depicted in the Profile.

4.8.6 Construction Details

Construction details, sections, and elevations as required to detail the installation of test manifolds, depict any pipe installed to remove unpiggable features, detail test isolation from laterals, taps, services, etc., show new or replacement installations (valves, regulation stations, ETS stations, line markers, etc.), typical trench and bell-hole details, and any other installations the operator wishes to include.

4.8.7 As-built Drawings

Operator requirements of the as-built package is an important consideration when developing drawings for testing existing pipelines. Having as-built documentation of hydrostatic pressure tests on pipelines, existing and new, that are traceable, verifiable and complete is essential. Accuracy of the as-built documentation is important and can be easier and accelerated if the

requirements are given proper consideration during the design process. Ensuring that test locations are correctly tied into the operators' GIS and coordinate systems utilized will help ensure easy correlation to tie test documentation to the operator's pipeline documents of record. Exact footages of tie-in piping, their location within the test section, whether included in test piping or tested separate, the tie-in weld locations within the pipeline, as well as weld and X-ray mapping can be accommodated by having a sound set of design drawings.

Operators are required by *Code of Federal Regulation*, title 49, sec. 192.517 to retain for the life of the pipeline a record of each test performed that contains the following:

- The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
- Test medium used.
- Test pressure.
- Test duration.
- Pressure recording charts or other record of pressure readings.
- Elevation variations, whenever significant for the particular test.
- Leaks and failures noted and their disposition.

Operators should have clear standards on the type and calibration requirements of pressure and temperature recording devices to be utilized for documenting the hydrostatic pressure test.

5 Hydrostatic Test Execution

5.1 Site Specific Plans

The use of detailed procedures is an effective way to ensure that the required elements of a test are completed in the proper sequence. Operators also can incorporate hold points to ensure that critical actions are completed prior to moving to the next step. Furthermore, application of procedures can ensure that a test is completed and documented sufficiently to meet company and regulatory requirements before the test is completed. This reduces the potential for re-work.

Every test is unique and therefore site-specific plans should be developed. Operators should consider including the following sections in their site-specific test plans:

5.1.1 Test Data

A description of the pipeline facility involved in the test with beginning and ending points described by (Global Positioning System) GPS locations, accurate mile points, field stations or other means should be included.

5.1.2 Authorization and Distribution

Inclusion of a review and authorization section is encouraged. The plan should be routed to key operating departments and support organizations to ensure department specific elements are included and the working group is authorized to proceed. A distribution list will ensure that all affected departments receive a copy and are aware of the upcoming test.

5.1.3 Notifications

A list of all agencies requiring notifications, and contact information, should be included. Space should be provided to record when the notifications were made and by whom.

5.1.4 Roles and Responsibilities

Designation of key personnel and a definition of their responsibilities. This ensures roles are understood and reduces the potential for miscommunication. Examples include Test Supervisor, Patrol Leader, Spill Response Leader, Safety Lead, Test Technician, etc.

5.1.5 Spill Response

A section of the procedure should be dedicated to planning for the containment of a spill should a failure occur. Required equipment such as vacuum trucks, waddles, booms, etc. should be identified and staged at strategic locations.

5.1.6 Equipment Required on Site

It is recommended that the equipment required to complete the test be identified and confirmed to be onsite prior to initiating the test. For example, specialty pigs to clean or fill the line should be confirmed prior to cutting the line.

5.1.7 Test Equipment and Calibrations

A listing of the testing equipment utilized, make model, range, serial number, accuracies and calibrations should be included. A review and audit of this equipment by a company representative is advisable.

5.1.8 Establish Safety Zones

Consider the consequences of a failure and establish appropriate safety zones. Access to the safety zone should be limited to only those persons who are necessary to perform the work. Safety zones may vary depending on exposure to risk and the operation taking place at the time. For instance, exposure to a failure of a buried line poses less consequence than that from exposed piping. Exposures are greater during the testing and dewatering process, and safety zones may need to be increased during those periods.

5.1.9 Pre-fill Sequence

This section will include the steps required by the operator prior to filling the pipeline with test water. The source water should be sampled to ensure it does not contain constituents injurious to the pipeline or that exceed local discharge requirements. The sequence should include procedures for clearing the pipeline and proving fill pigs will pass. It is also applicable to running any pre-assessment tools, such as geometry pigs. This is a valuable and critical section for pipelines that have internal contamination. If the operator suspects that its pipeline may contain contaminants, development of appropriate chemical cleaning protocols should be developed. The operator can then perform a cost-benefit analysis of performing chemical cleaning versus handling potentially large volumes of contaminated test water.

Pressurizing equipment, hoses and other associated equipment must be visually inspected and determined to be in good working condition before the test. Make sure the equipment is properly sized and rated.

5.1.10 Fill Sequence

This section describes the step-by-step procedure to ensure the pipeline is completely filled and pig speed is controlled. Operators may wish to be prescriptive in this section the type of pig to be used (foam, cup, poly, bi-directional, etc.), which end to launch from, minimum and maximum fill rates, whether contingency measures are necessary, such as holding back a pig in the fill manifold (sleeper pig), etc. A leak characterization water sample should be obtained at this step to be used for reporting in the event of a test failure.

5.1.11 Test Sequence

Topics included in this section are a review of equipment to confirm pressure ratings, procedures to reach temperature and pressure stabilization and leak detection prior to pressurization. Test equipment locations and relationship to elevations along the test section. Spike pressure and hold points are also described in this section. Procedures for gathering documentation and confirming the test is successful are also included in this section.

5.1.12 Depressurization

When preparing this section, consideration should be given to the following: outlet pressure, elevation difference, water hammer, pig velocity, discharge rate, force on elbows, etc. Be sure that adequate valves are planned to safely throttle-down the pressure. Make sure the equipment is properly rated and safety precautions are included. Establish effective anchoring systems based on expected forces and to prevent whipping of discharge piping.

5.1.13 Dewater and Dry

This section should include procedures for dewatering the line, as applicable, dewatering speed, running swab pigs, including number of pig runs or company standard for acceptable moisture penetration, requirements for dehydrated or compressed air, use of drying chemicals, minimum dew point requirements, and any other operator pipeline drying standards.

5.2 Testing Location and Equipment

5.2.1 Test Station Location

The test station typically is located at the end of the test where the water source and fill pumps are positioned. This provides for efficient and immediate communication between test supervision and construction personnel, control of water addition or removal, and reaction to a pressure-loss situation, should one arise.

Operators surveyed for this paper reported that safety zones of minimum 50 feet are typically employed around pressurized piping. The test station should be located outside of the safety zone. Care must be given to protect instrumentation hoses and connections and they may need to be covered or otherwise shaded so they are not affected by thermal effects, as appropriate. This is particularly true if larger safety zones are required by site conditions or operator standard practice.

5.2.2 Charts and Dead Weight Testers Test Instruments

A pressure record should be maintained and documented during the entire testing period. A chart or digital printout with appropriate intervals and pressure range is required. When testing over 90 percent SMYS, an electronic pressure recorder or dead weight tester is advisable.

Pressure gauges and or a reference chart should be installed at the remote end of the test section or at maximum or minimum elevations of the test section. These gauges are for information purposes only. However, the reference chart could be used as a substitute for the official test chart if necessary.

5.2.3 Temperature Probes

Temperature probes provide data for relating variations in pressure with respect to temperature changes. It is important that probes adequately represent the temperature of water in the test section and that the probes are not affected by changes in ambient temperature. Installing the probe(s) away from exposed pipe and as near as possible to the pipeline is advisable. Installing the probe 100 feet or more away from exposed piping in a post-hole sized excavation filled with sand is a good method. The probe should be installed prior to the test to allow sufficient time (typically eight hours) for temperature stabilization.

5.2.4 Use of Electronics

Electronic pressure and temperature recorders should record at a minimum of every 15 seconds and print out the recordings a minimum of every 15 minutes.

5.2.5 Calibrations and Certifications

Pressure recording devices should be accurate within +/- 0.5-1.0 percent (depending on device), checked every six months, and calibrated yearly. Dead weight testers should be calibrated within 12 months of each use. Calibration certifications should be gathered and included in the documentation package.

5.2.6 Correlating Test Site Elevation to Maximum and Minimum Control Points

Once the test location is determined, the minimum pressure at the maximum elevation and the maximum pressure control point values must be correlated to the test elevation considering hydrostatic head. Head pressures are subtracted when the test locations is lower than a control point and added when it is higher. For water, the head pressure is calculated by multiplying the elevation change by 0.433psi/ft.

5.3 Pipeline Clearing/Cleaning

Prior to filling, the pipeline should be cleared of any debris and obstructions that may adversely affect the effectiveness of the fill pigs. Pipeline contaminants obtained from the clearing run should be sampled and tested to determine their effects on fill water and the environment should a release occur. There are numerous pigs and cleaning methods available for this purpose and a comprehensive description is beyond the scope of this report. In extreme cases, multiple runs with solvents or detergents may be required. Local jurisdictional ordinances should be reviewed to determine these values.

Requiring the use of internal tracking devices in pipeline pigs is recommended. Tracking devices will assist in locating a stuck pig and can be used to monitor fill and discharge rates. Understanding the travel speed of pigs is extremely valuable during cleaning operations. The pigs must travel at a speed that will provide for sufficient contact time of the cleaning batch and keep solids in suspension. Gelled solvents should be considered in extreme cases.

5.4 Pre-assessment

If the pipeline history is uncertain, and/or the consequence of a failure is unacceptable, it may be prudent to perform a pre-assessment of the pipeline. The pre-assessment method should be selected based upon the specifics of the line and the flaws/threats to be detected. Methods range from identifying simple protrusions and obstructions by the use of gauge pigs to running in-line inspection (ILI) tools. A description of these methods is beyond the scope of this report.

5.5 Pipeline Fill

The test section must be completely filled with water to limit stored energy being released should a failure occur, facilitate the efficient pressurization of the test, and ensure that an acceptable pressure volume plot of the test can be achieved. A pig must be run ahead of the water to force as much air as possible out of the test section. For test sections where a pig cannot be used, the air must be vented at the high points. Fill the test section from one direction, preferably from the low end. When testing existing pipelines, it may be desirable to fill and dewater in the same direction to jump water to an adjacent test section, due to space constraints for water containment or availability of a suitable discharge location at the low end. During the fill, open and close valves slowly to prevent pressure surges resulting from rapid changes in velocity.

Size the fill pumps considering static head, due to elevation difference in the test section and the fill time desired. Maintain backpressure on the fill pig by controlling a valve at the discharge end. This is particularly important when the test section has downslope elevation changes because the head pressure may propel the pig faster than the rate of the fill pump and cause water by-pass.

5.6 Leak Detection and Pressure Stabilization

Prior to pressurization, all connections should be inspected for leaks. A practical method for determining leaks is to record the pressure in the line upon completion of the fill. Fill pumps typically produce pressures in the 125 to 150-psig range. Trap the pressure in the line by closing valves and installing caps or plugs. Record the pressure again after the temperature stabilization period is over. Any unexplainable pressure reduction should be investigated prior to pressurization. If accessible, bleed-off any air that has migrated to high points in the test during pressure stabilization prior to pressurization.

5.7 Temperature Stabilization and Effects on Pressure Readings

Variations in water temperature produce changes in pressure readings. The resulting pressure variations may be interpreted as a leak if the pressure is decreasing. Changes in pressure increase the difficulty of controlling spike and post-spike maximum and minimum control pressures. Use of an analytical program to identify leaks is dependent on accurate temperature measurement. Allowing the water to reach equilibrium will greatly reduce these impacts. Temperature stabilization time varies with the difference in water and ground temperatures. The greater the difference, the longer the stabilization time required. Pipeline diameter is also a major contributor. Monitor temperature and begin pressurization after temperatures become consistent. Eight hours is generally sufficient to reach stabilization.

5.8 Pressurization

Pressurize the test section slowly while continuously monitoring the test section pressure and then maintain the test pressure within the upper and lower bounds of the test as specified by the procedure. Consider a hold period at 75 percent of the minimum test pressure for one hour. The hold period will allow for final leak identification prior to going on test.

Pressurize short test sections slowly and cautiously as the pressure can build-up quickly. If necessary, nitrogen can be used to pressurize the test sections once the test section has been filled with water and pressure and temperature stabilization are achieved.

5.9 Discharge Rates and Safety Considerations

Ensure the written Dewatering Plan is followed on the jobsite. Install the temporary dewatering piping per the written plan. The field supervisor should inspect the dewatering piping and the anchoring system before dewatering. Clear the safety zone, except for those persons who are necessary to perform the dewatering work. When removing the water from long test sections with a pig, control the pig speed between two to five miles per hour by controlling the discharge valve and monitoring the discharge flow rate. Ensure that the discharge rate complies with the written Dewatering Plan and discharge permit (if applicable). It may be necessary to validate water treatment processes by sampling treated water prior to discharge to comply with water disposal regulations or permits.

5.10 Locating Failures and Leaks

5.10.1 Locating Failures

Most failures can be identified via standard patrolling methods because the released water will manifest itself on the surface. However, failures may not be obvious in wet areas. Test water dye additives are available for this purpose. However, communication with the public and agency personnel is important because the colored water may be confused with pipeline contaminants. In some cases, discharge permits may restrict the use of dye additives.

5.10.2 Locating Leaks

There are various techniques for locating leaks and difficult-to-find failures. For example:

- Tracer gases can be added to the test water in anticipation of leaks or the line can be dewatered and tracer gas included, if an unanticipated leak is discovered. The tracer gas is detected with aboveground sampling equipment.
- Helium can be an effective solution in locating leaks. The small, light molecule readily migrates to the surface and can be detected with instruments. However, unlike tracer gasses, helium is mixed with air, thereby requiring the line to be dewatered and re-pressurized with an air helium mixture.
- Freeze plugs are used to create a frozen plug in the pipeline to isolate the leaking section. The frozen plug is created by installing a clamp on the line that circulates low-temperature fluids. Typically, the technique is employed on long sections of line. The line is sectioned in half and water pressure monitored on both sides. Once it is determined which half is experiencing the leak, the section is halved again until the section is short enough that other techniques can be used with precision.
- Geophones, or other acoustics devices, have proven effective for finding and pinpointing leaks. Listening for a leak with such a device may not be efficient in finding leaks in a stand-alone application, but when used to investigate an area of concern, such as where prior leak repair has been performed, or section of pipe with suspect seam, they can be effective in finding or ruling out leaks. Used in conjunction with tracer gas or helium, which identify an area where the leak is located, the acoustic devices can be very effective in definitively locating leak.

5.11 Repairing Failures

Conventional cutting and welding techniques require the line to be free of water at the repair point. This can be accomplished by either pigging the line free of liquids or isolating water from the failure point.

- Isolating water from the failure point requires an obstruction be installed in the line. Freeze plugs may be used for this purpose at a point where the line is still completely full of water. Foreman's plugs may also serve this purpose if the failure is large enough to accept them. In most all cases, the water will have to be pigged from the line in order to facilitate a repair.
- Pigging the line free of liquids can be problematic because test water will escape at the failed section. In addition, compressed air used to propel the pig will escape at the failure point once the pig has passed. The first step is to excavate the failed location and pump out the water. Water must be captured and handled per the discharge permit. A patch is typically installed over the failure to limit water discharge. A repair sleeve jacked onto the line is a good method. However, it may be necessary to reshape the failed pipe such that a sleeve can be installed. This could adversely affect failure forensics. Consult with engineering prior to reshaping the failed area.

- Pressure test failures should be compiled and recorded. It is important to categorize the cause of the failure utilizing the same cause categories as in-service failures, and documenting whether the failure was a leak or a rupture. This information is important for calibrating and validating the success of the operator's integrity management program.

5.12 Post Test Leak Monitoring

Operators should consider including procedures for checking for gas leaks shortly after the pressure test when the pipeline is back in service. Even though most small water leaks can be found during the hold period, there is a possibility that very small leaks may not be identified, and may only be found after the pipeline is put in service utilizing standard gas leak surveys.

5.13 Successful Test Documentation and Determination

When testing vintage existing pipelines, operators should consider requiring the test to be certified via use of a third-party consultant or utilization of available programs that calculate the theoretical stress and strain of the pipeline due to internal pressure and thermal effects on unrestrained piping during pressurization and throughout the test duration. This is typically depicted by a pressure versus volume graph. These programs typically plot the actual test values in real time and generate theoretical water gain/loss depending on the change in temperature. Utilizing a program to plot the pressure-volume graph, as the test is proceeding, has the advantage of immediately identifying when pressure gain is not commensurate with the volume of water contained, which is indicative of a potential leak or material yielding. Additionally, if the program indicates that the pressure and volume values adjusted for temperature are within tolerances, the operator can have confidence that there is no leakage or yielding. The key advantage of using a program versus manually calculating via a spreadsheet is that minor deviations away from theoretical that are not leak related, but typically temperature-stabilization related, can be explained and confirmed as the parameters stabilize.

An additional benefit of using a program as described above is that some tests may not stabilize during the specified minimum test duration. By increasing the duration of the test and allowing more time for temperature stabilization, a test that would otherwise fail can be certified.

5.13.1 Successful Test Documentation

To confirm a successful test, an operator's technical or engineering personnel should ensure the following documentation have been performed/completed prior to releasing the test pressure:

- Test pressure logs and pressure and temperature charts are verified and quality checked.
- Test report is complete and, at minimum, the information required in *Code of Federal Regulation*, title 49, sec. 192.517 is included.

- Confirm that no leaks were observed or any leaks identified during the test were satisfactorily repaired.
- Minimum test pressure at the control point, considering static head, was maintained for the specified test duration.
- Spike test pressure, as applicable, was reached at the minimum test pressure control point, considering static head and maintained for the specified duration.
- Maximum pressure at the control point, when no spike test was specified and considering static head was not exceeded during the duration of the test.
- For tests, including a Spike Test, the Maximum Post-Spike pressure at the minimum test pressure control point, considering static head, was not exceeded for the remaining period of the test after the spike test period.
- Pressure versus volume plot confirming that the test did not contain any leaks nor yield the pipeline.

Test failure analysis should be performed for any leaks or ruptures experienced. The analysis should utilize design and material information, if available, “as found” material and construction information, and characterize the failure cause utilizing PHMSA incident causes and type of test failure (e.g. leak or rupture). As applicable, the Test Certification Report from third-party contractor confirming all of the above.

5.13.2 Successful Test Determination

Success in hydrostatic pressure testing existing pipelines is defined a bit differently than in many other kinds of tests. Of course, a test is successful if the target test parameters are achieved and the test is satisfactorily documented. However, hydrostatic pressure tests may be interrupted by leaks or ruptures, commonly called test “failures.” This does not necessarily constitute a failed test. In such cases, the required repairs or replacements are made, and the test is restarted. This process is repeated until the test is concluded with the target test parameters achieved. This scenario also represents a successful test – the strength and pressure-containing capability of the segment have been demonstrated and any impediments to that capability have been removed. Thus, a hydrostatic pressure test that is ultimately completed is successful, regardless of interruptions due to leaks or ruptures.

The operator may encounter a test as described above where the number of test “failures” is of sufficient quantity that the prudent economic decision is to stop the retest cycle and replace the pipeline. This situation would constitute a failed test.

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6 New Technologies

As stated in the “Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011,” under section 23: Maximum Allowable Operating Pressure – part (d) Testing Regulations, the Act requires the Secretary of the Department of Transportation to consider “safety testing methodologies, including, at a minimum....other alternative methods, including in-line inspections, determined by the Secretary to be of equal or greater effectiveness.” These “safety testing methodologies” are intended to provide a method to “confirm the material strength” of natural gas transmission pipelines without having to introduce water into a pipe segment and perform a hydrostatic pressure test.

With the intention of the Pipeline Safety Act language in mind, many R&D consortiums in coordination with trade associations, such as INGAA, have spearheaded efforts to develop alternative technologies that can “confirm the material strength.” One such initiative is INGAA’s Integrity Technology Development (ITD) effort. Through ITD, INGAA has identified the need for in-line inspection technology that can identify material and construction anomalies that would fail a 1.25 times the MAOP pressure test. Different variations of the identified technology are required for various seam-types; however, in working with ILI technology providers, INGAA has determined that the technologies can make it to market within a reasonable timeframe with adequate funding.

INGAA’s ITD effort is also in the early stages of working with ILI vendors, GIS specialists, and metallurgists to develop what has been referred to as an “as-built” tool. Such a tool would be useful in identifying unknown properties of a pipeline for use in risk assessments or in the planning of pressure tests. The “as-built” inspection device would work by inspecting known areas where records are presently incomplete, taking a snapshot of the pipe, and then referencing those snapshots against signatures of known pipe with known properties/characteristics.

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Appendix A – Abbreviations

ANSI	American National Standards Institute
API	American Petroleum Institute
ASA	American Standards Association
ASME	American Society of Mechanical Engineers
BBCR	Bell-Bell Chill Ring
CFR	Code of Federal Regulations
CNG	Compressed Natural Gas
DOT	United States Department of Transportation
EMAT	Electro Magnetic Acoustic Transducers
ERW	Electric Resistance Welded
ETS	Electrolysis Test Station
FFS	Fitness-for-Service
GIS	Geographic Information Systems
GPS	Global Positioning System
GPTC	Gas Piping Technology Committee
GTS	Gas Transmission Systems, Inc.
HCA	High Consequence Area
ILI	In-line Inspection, commonly referred to as “Smart Pig”
IM	Integrity Management
INGAA	Interstate Natural Gas Association of America
ITD	Integrity Technology Development
LNG	Liquefied Natural Gas
MFL	Magnetic Flux Leakage

MOP	Maximum Operating Pressure experienced by the pipeline based on historical experience or lowest MAOP on a pipeline system. The MOP may be equivalent to the MAOP, but not greater.
MAOP	Maximum Allowable Operating Pressure, as established by Code of Federal Regulations, title 49, sec. 192.619
NDE	Non-Destructive Evaluation
NTSB	National Transportation Safety Board
O&M	Operations & Maintenance
OA	Oxy Acetylene
OD	Outside Diameter
OPS	Office of Pipeline Safety
PHMSA	Pipeline and Hazardous Materials Safety Administration
R&D	Research & Development
SAW	Submerged Arc Weld
SCC	Stress Corrosion Cracking
SMYS	Specified Minimum Yield Strength
US	United States
WT	Wall Thickness

Appendix B – Glossary

A

Alignment Sheets - Pipeline alignment sheets or maps provide a bird's eye view of the line itself and all of its components. The purpose of this sheet is to display engineering data in relation to the pipeline location and land base features. It shows the route of the pipeline and virtually all the knowledge for that pipeline. Alignment sheet typically contains a landowner's name and a space designating his ownership. It may indicate whether the land is forest or in cultivation. Other typographical features might be listed as well such as type of soil, hilly, rolling hills, wetlands, right-of-way, temporary work easements, etc.

B

Bell & Spigot Joints - A mechanical connection between two sections of pipe, the straight spigot end of one section is inserted in the flared-out end (bell) of the adjoining section; the joint is sealed by a fillet weld, a caulking compound or with a compressible ring depending on operating pressure.

Bell-Bell-Chill Ring – Bell to bell joints welded together with the use of an internal chill ring (also called backup ring or spacer) that is machined to conform to the inside diameter of the pipeline and dimensions of the joint design used.

C

Casing – A length of pipe used for encasing a smaller diameter carrier pipe for installation under a road, waterway, rail, or other foreign crossing.

Containment Boom – A temporary barrier used to contain a hazardous liquid spill.

Cross compression – Compressing gas from one isolated segment of pipeline to another to minimize the release of methane to atmosphere during pipeline shutdowns. Or, boosting pressure from lower pressure supply to high pressure discharge to maintain service to customers during a pipeline shutdown.

D

Dresser Couplings – A coupling comprised of one cylindrical middle ring, two follower rings, two resilient gaskets of special Dresser compound, and a set of steel trackhead bolts. The middle ring has a conical flare at each end to receive the wedge portion of the gaskets. The follower rings confine the outer ends of the gaskets. As the nuts are tightened, the bolts draw the follower rings toward each other, compressing the gaskets in the spaces formed by follower rings, middle ring flares and pipe surface thus producing a flexible, leak-proof seal on the pipe joint.

E

Etching – Controlled preferential attack on a metal surface for the purpose of revealing structural details. (ASTM Standard E-7 Standard Terminology Relating to Metallography)

ETS – An electrolysis test station terminal support/site is used in connection with measurement of voltage difference and/or current flow between an underground pipe and ground potential.

F

Fish Mouth Tees – Fabricated tee constructed by splicing two pipe segments to form a tee. The end of the branch segment is cut to fit perpendicularly into the header segment which is cut to receive the branch laterally. The two pieces are then arc welded together to create a pressure carrying fitting.

Foreman's Plugs - Temporary mechanical closure not designed to retain line pressure.

Freeze Plug – Mechanical device that utilizes flow of liquid nitrogen through an external pipeline sleeve, thereby freezing the water contained within the pipe at a fixed location.

G

Geometry Pigs - A geometry pig (pipeline inspection gauge) is a configuration pig designed to measure inside geometry of the pipeline, such as dents, wrinkles, ovality, bend radius and angle, and occasionally indications of significant internal corrosion.

I

In-line inspection (ILI) – In-line inspection is internal pipeline inspections by use of computerized inspection tools, known as smart pigs, to verify the integrity of its pipelines. The smart pigs inspect the pipelines for corrosion, dents, and other conditions or restrictions in the pipeline that may affect safe pipeline operation.

M

Mill Test – Short duration hydrostatic test performed at the manufacturer’s facility in accordance with the requirements of API Specification 5L.

Miter Bends/Elbows – Two or more straight sections of pipe matched and joined on a line bisecting the angle of junction so as to produce a change in direction.

O

Oxy-Acetylene Welds - A welding process that uses fuel gas (acetylene) and oxygen to heat two pieces of metal, the base metal and welding rod, to a temperature that produces a shared pool of molten metal. Oxy-Acetylene welds are characterized by susceptibility to brittle failure and sensitive to longitudinal strain. Oxy-Acetylene Welds were used on high pressure pipeline systems prior to the advent of arc welding.

P

Pig Traps/Launcher/Receiver - An ancillary item of pipeline equipment with associated pipework and valves for introducing a pig into a pipeline or removing a pig from a pipeline.

Pressure Reversal – Occurs when a defect survives a given pressure level only to fail at a lower pressure level upon subsequent pressurization from 0 pressure.

Pup – A short length of pipe required between two pipe joints, two fittings, a pipe joint and fitting, a fitting and a flange, or between two flanges to make up a required dimensional distance (also called a can).

Purging - The act of replacing the atmosphere within a container by an inert substance in such a manner as to prevent the formation of explosive mixtures.

S

Static Head (Hydrostatic Head) – The height in feet of a column of water at rest that would produce a given pressure head.

Surging – See water hammer

T

Test Manifold/Head – Temporary piping installed at the test end points designed to provide connection points for pigging operations, test medium fill and discharge, and test instruments sample ports and designed to withstand the hydrostatic test pressure.

Tracer Gas – Chemical gas added directly to the test water as it is introduced into the pipeline during line fill. Trained field technicians collect and analyze samples along the pipeline right-of-way in the event of a test failure. The detection of tracer chemicals indicate the location of leakage.

Transmission Plat Sheets – See Alignment Sheet

V

Venting/Blowdown – Controlled release of gas from a pipeline to atmosphere leaving 100% natural gas at atmospheric pressure in the pipeline. For subsequent removal of residual gas see Purging.

W

Water Hammer – In fluid flow, the result of a rapid increase in pressure which occurs in a closed piping system when the liquid velocity is suddenly changed by sudden starting, stopping, or change in speed of a pump; or sudden opening or closing of a valve which may cause a pressure surge in the system.

Wattles – An environmental control measure consisting of permeable barriers of woven mesh netting filled with straw or hay used to detain surface runoff and trap sediments.

Wrinkle Bends – An obsolete practice of bending generally used prior to the advent of smooth bending techniques. The bends consist of circumferentially oriented “wrinkles” produced by a field machine or controlled process that result in localized plastic deformation and prominent contour discontinuities on the inner radius which shortens the intrados and changes the pipeline direction without use of a manufactured elbow.

Appendix C – Understanding Hydrostatic Pressure Testing (Communication Brochure)

[outside]

Understanding
Hydrostatic Pressure Testing





Hydrostatic Pressure Testing

Public safety is the pipeline industry's number one priority. The men and women working at the companies that build and operate North America's interstate natural gas pipeline system have created the safest mode of energy transportation in the world today. Ensuring the integrity of the natural gas system is a key part of this commitment, and hydrostatic testing is one tool used by pipeline operators to do just that.

What is Hydrostatic Pressure Testing ?

Hydrostatic pressure testing is one of several methods a pipeline company may use to reconfirm the structural integrity and safety of its natural gas pipeline. The test involves filling a pipeline segment with water until it is at a pressure that is higher than the pipeline will ever operate with natural gas. This allows the pipeline company to validate the safe operating pressure of the pipeline and ensure that the line does not leak.

To learn more about hydrostatic pressure testing, pipelines and pipeline safety, please visit our web site at www.ingaa.org/hydrotest



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What Happens During a Test?

Performing a hydrostatic test involves the following steps:

- 1** The pipeline company obtains all required work permits and coordinates activities with local authorities.
- 2** The nearby community, landowners and local agencies are informed using the pipeline company's established outreach processes.
- 3** In most cases, the company ensures that customers will receive gas from an alternate source to limit service disruptions.
- 4** The section of the pipeline to be tested is taken out of service. The company removes all gas from the section safely through a process called "controlled venting."
- 5** The pipeline section may be cleaned prior to testing.
- 6** The pipeline section to be tested is sealed on both ends and filled completely with water.
- 7** The pipeline section is pressurized to a specified level higher than the

pressure it normally operates with natural gas.

- 8** The test pressure is held and monitored for a set time period, typically at least eight hours.
 - 9** Any pipeline sections that leak during the test are repaired or replaced with new pipe.
 - 10** Once the pipeline section successfully passes the test, the section is emptied of water, dried thoroughly and placed back in service.
- Work can continue for about one to four weeks, depending on the test results. Some work may occur at night as well as during the day in order to ensure that pressure in the pipeline is held for the recommended time period.
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- "Ensuring the integrity of the natural gas system is a key part of our industry's commitment to pipeline safety, and hydrostatic pressure testing is one tool used by pipeline companies to do just that."

What Can I Expect During a Test?


Extensive record checking and planning takes place long before a test is performed. This helps minimize inconvenience to customers and local neighborhoods. The test is conducted with public safety in mind, and the pipeline company makes the community a priority in all of its operations, and testing procedures. Depending on the location of staging or work areas at both ends of the pipe section to be tested, you may notice the following:

- Sight**
 - If necessary, temporary traffic safety cones and/or detour signs will be in place.
 - Pipeline and contractor personnel will be onsite.
 - Testing equipment, such as above-ground pipes and valves, may be visible, along with machinery and support equipment such as excavators, trucks and water tanks.
 - If a pipe leaks or breaks during the test, you may see water on the ground or spraying out over the ground. This water may be colored, as a non-toxic dye is sometimes added to the test water to make it easier for crews to find small leaks. Do not go near any standing water as the test water may conceal a deep hole.

- Water used during the test may be moved to an adjacent test area or may be discharged on the ground in a controlled manner
 - You may see helicopters, which may be used to monitor the test results.
 - Sound**
 - Temporary elevated noise levels may be experienced in the locations where test equipment is set up and where personnel are working.
 - You may hear a loud, steady noise as natural gas is safely vented to prepare the line for the test.
 - You may hear helicopters
 - Smell**
 - You may smell the rotten egg scent of odorized natural gas occasionally, particularly as natural gas is vented to prepare the line for testing.
- These sights, sounds and smells are common during this test and may vary depending on the location of the work and weather patterns. Residents with questions or concerns during the test are invited to contact the pipeline company.

[inside]

Appendix D – Hydrostatic/Pneumatic Safety Guidelines

 <p>Construction Safety Consensus Guidelines</p>	<h3>Pressure Testing (Hydrostatic / Pneumatic) Safety Guidelines</h3>		
	The INGAA Foundation, Inc.	Document: CS-S-9	Revision: 0
<p>1.0 ACTIVITY DESCRIPTION</p> <p>1.1 This document provides basic safety guidelines for the safety of all personnel and the general public during pressure (e.g., hydrostatic, pneumatic) testing operations.</p> <p>1.2 Plan and implement each pressure-testing event in a manner that mitigates unnecessary exposure to procedural hazards.</p> <p>1.3 All pressure tests must be conducted with due regard for the safety of life and property.</p> <p>1.4 All personnel have, and should use, "Stop Work" authority whenever there is concern for safety during pressure testing operations.</p> <p>1.5 This document is not meant to supersede or replace regulatory requirements, nor is it intended to be all inclusive of the applicable regulatory requirements. It is intended to be supportive and complimentary to such requirements.</p> <p>2.0 HAZARD ASSESSMENT</p> <p>2.1 Hazard assessments are performed to identify and mitigate perceived and actual environmental and operational hazards.</p> <p>2.2 A Job or Test Plan, including procedures and controls related to safety, is prepared prior to conducting pressure testing.</p> <p>2.3 Hazard assessments are performed at the beginning of each shift.</p> <p>2.4 Review and update hazard assessments when:</p> <ul style="list-style-type: none">• Each new task is begun.• There is a change in how a task is performed.• Changes in site or environmental conditions occur.• A specific need or concern is identified (i.e., as needed to ensure the safety of personnel or property). <p>3.0 ROLES AND RESPONSIBILITIES</p> <p>3.1 Management Responsibilities <i>(includes all personnel with a supervisory role)</i></p> <p>3.1.1 Empower all personnel with the authority to "Stop Work" whenever hazardous conditions or potentially hazardous conditions are identified.</p>			



- 3.1.2 Provide for and require that signs, barricades or other protective barriers are placed in a manner and at a distance sufficient to demarcate a safe zone to protect personnel and the public from unanticipated pressure release or equipment failure.
- 3.1.3 Provide for and require the installation of devices that mark the limits of the exclusion zone.
- 3.1.4 Keep unauthorized personnel out of the test area.
- 3.1.5 Inform all affected site and community personnel of the planned test.
- 3.1.6 Provide for and require that equipment and materials are arranged to give unobstructed access/egress during testing and in the event of an emergency.
- 3.1.7 Establish lines of communication between the Owner/Facility, Contractor, and local authorities.
- 3.1.8 Provide for and require the use of reliable transportation and communication systems during all aspects of the testing event.

3.2 Health & Safety (H&S) Responsibilities

- 3.2.1 A Health and Safety Professional is involved with performing the hazard assessment.
- 3.2.2 Provide technical support for interpretation of pressure testing safety guidelines.
- 3.2.3 Evaluate the effectiveness of the job-specific safety plan (or equivalent).
- 3.2.4 Immediately stop and correct any safety related non-compliant activities.

3.3 Employee Responsibilities

- 3.3.1 Do not enter or otherwise be present at a pressure-testing event unless you are part of the testing team.
- 3.3.2 Personnel performing the test should approach the pressured line only in the performance of their duties. Where possible, personnel should use safety barriers for protection from the pressurized line and position the testing equipment in such a manner so as to minimize potential hazards.
- 3.3.3 Review safety requirements of the site-specific test plan (see Section 4.6).
- 3.3.4 Do not work over or near where pressure testing is being conducted.
- 3.3.5 Wear the PPE as appropriate for the task being performed.
- 3.3.6 Attend required training before working on the task (see Section 5).
- 3.3.7 Report any non-compliant H&S activities to a Supervisor.



4.0 HAZARD MITIGATION

4.1 General

- 4.1.1 Suspend a test when the testing personnel (including but not limited to: contractor, contractor's agents) or equipment are not working in a safe manner.
- 4.1.2 Consider the forces that would be present if any portion of the system failed while filling, under test, depressurizing or dewatering. Also consider potential for water hammer, potential for leakage of isolation valves, variable system pressures, potential for fill and dewatering pig velocity changes and other site specific conditions.
- 4.1.3 When performing pneumatic tests, the piping shall be inspected to determine if the inside surfaces are contaminated with a combustible or flammable material (e.g., iron oxide, condensate). If found, remove such materials prior to air testing.
- 4.1.4 Never tamper with or tighten any fittings (i.e., connections, bolts, hoses) while component is under any pressure.
- 4.1.5 Never tighten connections that are under pressure. If a leak develops, you must depressurize to a safe level and then re-tighten.
- 4.1.6 Wear hearing protection (which may include double hearing protection) that is adequate to reduce the noise below 80 decibels.
- 4.1.7 The pressure recorders and deadweight gauge shall be located at a safe distance least 100 feet from the facility being tested.

4.2 General Worksite Safety

- 4.2.1 Incorporate general worksite safety precautions and procedures, as applicable.
- 4.2.2 Verify that test equipment and materials are rated to withstand the test pressures.
 - Verify that all supply lines and hose connections are secure with retaining devices before and during the test.
 - Visually inspect and ensure soundness and proper installation and valve positioning of all equipment used.
- 4.2.3 Adequate lighting shall be available throughout testing operations.
- 4.2.4 Safety equipment and supplies should be readily available and should include, but are not limited to:
 - Emergency spill kit.
 - Fire extinguisher.
 - Ladders.
 - Mobile light plants.
 - Whip checks.



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Document: CS-S-9

Revision: 0

Publication Date:
September 2012

- Warning signs and barricades.

4.2.5 Install mats or utilize secured ladders for access to test header valves. If using mat bridges across the excavation, handrails must be installed if elevated 6' above a lower level.

4.2.6 Restrain or otherwise secure fill and discharge lines and/or hoses.

4.2.7 Verify the pressure ratings of hoses, fittings, gaskets, and other manifold materials.

4.2.8 Verify pressure rating of facility being tested.

4.3 Signage

4.3.1 During pressure testing events, distinct warning signs, such as DANGER – HIGH PRESSURE TESTING IN PROGRESS must be posted at the test site and additional locations identified in the job specific safety plan.

4.3.2 When testing in a populated area, an extensive public relations campaign (e.g., warning signs, barricade tape, strobe lights, and/or security guards) may be required to inform and protect the public from hazards associated with testing activities.

4.4 Exclusion Zone

4.4.1 Precautions should be taken to see that persons not directly engaged in the testing operations remain out of the test area during the test period.

4.4.2 A minimum distance of 100 feet shall be maintained between facilities that are being tested and the personnel conducting the test. The safe distance may be increased and the temperature probe, manifold and recorders may have to be set back further than 100 feet due to potential projectiles or extreme volume/pressure.

4.4.3 Restrict access to the immediate area involving the pressure test (i.e., test shelter, manifolds, pressure pumps, instruments, etc.) to only those persons actively engaged in the testing operation.

4.5 Notification

4.5.1 Residents within close proximity of the facility being tested, and state and local enforcement agencies, if applicable, shall be advised by the Owner/Operator of the testing program and kept informed of the progress, as necessary.

4.6 Safety Planning / Site-Specific Test Plan

4.6.1 Develop and deploy a site-specific test plan including descriptions of safety procedures and requirements.

4.6.2 Before attempting any test, the Testing Supervisor will review the test specifications and procedures with the Test Inspector, Chief Inspector, and any other relevant personnel to be certain that all equipment is adequate and duties are organized and understood.

4.6.3 Inform all personnel of assignments, responsibilities, and test requirements.

4.6.4 Precautions associated with potential weather extremes should be considered and addressed in the site-specific test plan.



4.7 Pre-Test Checks and Inspections

4.7.1 Prior to commencing testing operations, the Company Representative and /or Contractor shall inspect test heads to confirm all components are in good condition and meet working pressure requirements.

4.7.2 Confirm that the following conditions are checked prior to testing:

- There are no unrestrained or Victaulic™ (or equivalent) coupled fill lines.
- Fill lines are able to contain initial water pack pressure.
- Manifolds and other facilities are properly installed and will be adequately protected from damage in the event that violent failures or water surges occur.
- Methods of isolating facilities being tested from test equipment and pumps are adequate.
- Adequate methods for verification of pig position in the manifolds are in use. The exact location of the pig(s) shall be measured when loaded in the test header. The position, type, and direction of the pig(s) shall be indicated with a permanent type marker on the outside of the test header.
- Dewatering discharge lines are properly restrained, cribbed or anchored.

4.7.3 Inspect and x-ray all temporary welds on test headers subject to test pressures.

4.8 Pressure Testing Safety Issues and Mitigation Recommendations

Test Manifold Construction

4.8.1 A welded connection is recommended as the first connection to the test manifold.

4.8.2 Prior to commencing hydrostatic testing operations, the Company Representative and /or Contractor shall inspect test heads to confirm all components are in good condition and meet working pressure requirements. This will include an inspection and test of heads / manifolds to ensure that no components (e.g., gaskets, o-rings, fittings, valves) will leak or cause loss of test water and that the components conform to specified safety requirements.

4.8.3 If the 1st connection to the manifold is screwed, the following should be performed after each test:

- Break apart the manifold equipment.
- Reassemble the manifold with new equipment.
- Inspect/test the equipment to confirm all pieces are structurally sound and functioning properly.

4.8.4 High-pressure pipe and fittings shall be used for connection of the pressure pump, manifolds, and test equipment.

4.8.5 If the testing manifold contains a longitudinal seam, the test equipment shall be located on the side opposite the seam, if possible.



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- 4.8.6 Inspect the make-up of all screwed connections.
- 4.8.7 Material certifications should be confirmed as appropriate for use in pressure testing operations.
- 4.8.8 Vent valves shall be installed and opened at the appropriate time when stored energy can be isolated and/or trapped between two points such as valves, skilllets, etc.
- 4.8.9 When using a pressure relief valve (pop-off valve), it should be set to a pressure just above maximum test pressure. This will ensure that the pipeline and testing equipment will not exceed its maximum pressure ratings.
- 4.8.10 During pneumatic tests, a regulator shall be installed in line to protect testing equipment and the facility being tested.

Depressurizing / Dewatering

- 4.8.11 All temporary fill and dewater piping should be connected with welded/screwed joints.
- 4.8.12 Verify the length and integrity of welded/screwed connections prior to depressurizing.
- 4.8.13 Properly de-pressurize connecting lines before attempting to seal or break joint components.
- 4.8.14 When bleeding the pressure from a section of the line, use extreme caution, especially when deflectors such as ells are used. Slowly bleed pressure following a test.
- 4.8.15 Confirm that the diversion of water and/or gas will follow a safe pathway (e.g., use of 90° or 45° angles).
- 4.8.16 Always verify that complete depressurization has occurred through the use of pressure gauges and visible checks.
- 4.8.17 The atmosphere shall be monitored for safety during any blow down, bleed off or depressurization.
- 4.8.18 During the initial planning stage of a de-watering operation, an analysis of the existing and temporary piping system should be performed to identify the pressure associated with fluids and other forces that could adversely affect the integrity of the pipeline or the stability of the drainage and its components.
- 4.8.19 Securely support and tie down dewatering lines at the discharge end to prevent uncontrolled movement during dewatering.
- 4.8.20 The following guidelines should be followed in de-watering activities:
 - **Anchor the de-watering lines.** It is accepted industry practice to adequately anchor or secure de-watering piping to prevent movement and separation of the piping. Establish effective anchoring systems based on expected forces and ensure that the systems are used during de-watering projects.
 - **Ensure condition of couplings and parts.** All couplings and parts of the de-watering system need to be properly selected for their application. The associated piping which the couplings connect is a significant variable in the entire mechanical piping system.



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The couplings are manufactured in a controlled environment, and variations in the quality of the couplings should be limited. Ensure that couplings are within manufacturer's tolerances and free of damage that may result in connection failure.

4.8.21 Notify all personnel that the area is all clear.

5.0 TRAINING

- 5.1 Employee training should highlight the hazards of hydrostatic testing, dewatering facility designs and techniques, piping coupling and anchoring methods, hazard identification and mitigation.
- 5.2 For individuals involved with de-watering activities, provide adequate employee training on de-watering installation designs and techniques, including proper coupling and anchoring methods. Ensure that personnel understand the potential hazards of improperly installed de-watering systems, provide personnel a means of determining whether the pipe groove meets manufacturer's tolerances, and the procedures they should implement to protect themselves and others working around them.

6.0 REFERENCES

Current versions of the reference automatically supersede the reference listed below.

6.1 Occupational Safety and Health Administration (OSHA)

- 6.1.1 *Hazards Associated with De-Watering Pipe Lines*, Safety and Health Bulletin SH 1B 06-21-2004 / Advisory Bulletin ADB-04-01

7.0 HISTORY OF REVISIONS

Number	Date	Description
0	September 2012	Initial publication of this INGAA Foundation Construction Safety Consensus Guidelines document.