COMPARISON OF INTEGRITY MANAGEMENT ASSESSMENT TECHNIQUES FOR NATURAL GAS TRANSMISSION PIPELINES

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EXECUTIVE SUMMARY

This report was prepared in order to provide a high level view of the integrity assessment process for pipelines operating under an integrity management program. Specifically, this report looks at the tools and processes used during the integrity assessment or inspection.

The pipeline industry has performed the necessary research to establish the technical basis for each of the integrity assessment techniques and tools. The research has been used to develop new consensus standards that address the use of the techniques and tools and provide industry-wide consistency in approach including acceptance criteria. These standards are briefly addressed in the body of the paper and more fully discussed in the appendices.

The techniques and tools address the assessment of all the identified threats to pipeline integrity including time-dependent, time-independent and stable threats. When considering all the threats discussed, the time-dependent threats of external and internal corrosion are the primary targets of the assessment tools prescribed in the legislation and regulations for integrity management programs.

ASME[1] B31.8S, “Managing System Integrity of Gas Pipelines” is the engineering standard created through the ANSI[2] consensus standard process to manage natural gas transmission pipeline system integrity. This document establishes the methodologies for integrity management and references individual and specific standards which provide the details of “how to” perform the necessary actions. B31.8S recognizes three assessment methodologies: Pressure Testing, In-line inspection and Direct Assessment. In addition, the standard provides for “Other” methodologies to be used provided they are proven to achieve the intended results. This encourages innovation, research and development as well as continual improvement.

Operators have been collecting information about these integrity assessments since 2004. Much of the information collected is reported to the Pipeline and Hazardous Materials Safety Administration (PHMSA)[3] on an annual basis. Other information is collected and retained by the company. The information in this section of the report is provided to show the extent of integrity management tool usage.

For the years 2004 through 2006, approximately 70,000 miles of pipe have been assessed out of the total transmission pipeline mileage of 295,000. Out of the total HCA[4] miles, approximately 50% has been inspected as of the end of 2006 (approximately 10,100 out of 20,220)

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[1] American Society of Mechanical Engineers
[2] American National Standards Institute
[3] Pipeline And Hazardous Materials Administration
[4] High Consequence Areas

Approximately 92.5% of the pipeline miles assessed from 2004 through 2006 were assessed using In-line Inspection tools. Pressure testing accounted for 3.5% of the miles assessed while Direct Assessment accounted for 4%.

Based on the results from the inspections conducted to date, it appears that the mandated interval for assessments and inspection is extremely conservative.

PURPOSE

The purpose of this report is to provide information on the integrity assessment process for pipelines operating under an integrity management program. Specifically, this report looks at the tools used during the integrity assessment or inspection.

While interstate natural gas pipeline companies have been utilizing risk management and have implemented integrity management programs within their companies, these programs were developed independently and were customized for a particular set of circumstances and experiences. In 2004 PHMSA adopted a regulation to mandate a specific integrity management program in High Consequence Areas (HCA).

The pipeline industry, through the Interstate Natural Gas Association of America (INGAA), the Gas Technology Institute (GTI), Pipeline Research Council International (PRCI), and Joint Industry Projects (JIPs), has performed research to establish the technical basis for each of the integrity assessment techniques and tools. The research has provided the background for several new consensus standards that address the use of the techniques and tools. These standards provide for industry-wide consistency in approach including acceptance criteria.

ASME B31.8S, “Managing System Integrity of Gas Pipelines” is the engineering standard created through the ANSI consensus standard process to manage natural gas transmission pipeline system integrity. This document establishes the methodologies for integrity management and references individual and specific standards which provide the details of “how to” perform the necessary actions. The document also contains a compendium of the research conducted and describes which research was used as the basis for the standards. This was the first time that there was a standardization of integrity management practices and reporting of integrity management results.

B31.8S recognizes three assessment methodologies: Pressure Testing, In-line Inspection and Direct Assessment. In addition, the standard provides for “Other” methodologies to be used provided they are proven to achieve the intended results. This encourages innovation, research and development as well as continual improvement.

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BACKGROUND

During the development of the background materials for Integrity Management Plan (IMP) , and based on work previously published by PRCI, it was determined that there were 21 identified causes for pipeline failures, with a 22nd cause being "unknown". Each of the 21 causes was determined to represent a threat to pipeline integrity that needed to be managed. These threats were grouped into nine categories of related failure types and further delineated by three time-variable defect types. Incident data has been organized by threat into a table in Appendix 1 for the five-year period 2002 to 2006 to show current trends.

The identification and management of threats was fundamental to the development of the ASME B31.8S (supplement to ASME B31.8), "Managing System Integrity of Gas Pipelines". This document along with the regulations contained in PHMSA 49CFR Part 192, Subpart O, is the basis for the development of a pipeline operator's integrity management program. In addition to threat identification, the supplement also addresses risk assessment, integrity assessment, responses to integrity assessment and mitigation (repair and prevention).

REVIEW OF THREATS TO THE PIPELINE

Management of Threats

In developing the alternative risk-based approach, a company must evaluate the full range of threats to pipeline integrity identified in ASME B31.8S. The threats to pipeline integrity are generally categorized as follows:

1. Time-dependent,
2. Stable, and
3. Time-independent.

Time-dependent threats include internal and external corrosion as well as stress corrosion cracking (SCC). These are the primary threats addressed by ongoing and periodic assessments, including in-line inspection tools, direct assessment, and in some instances, pressure testing. A company must implement selected risk-control activities and will implement others to manage these threats, including in-line inspection per the IMP Regulation.

Stable threats include manufacturing and construction defects, and as the term “stable” denotes, they remain stable and benign unless activated by a change in operations or the surrounding environment. Stable threats are best managed by monitoring the pipeline’s operations and its surrounding environment following a post-construction pressure test, also known as a proof test. This test demonstrates or proves the initial integrity of the pipeline.

A review of the operating pressure history for gas transmission pipelines indicates that pressure cycles are minimal in both magnitude and frequency. Therefore, the pipe segments have not experienced cyclic fatigue. Consequently, since these threats are not occurring, the manufacturing defect threat is considered stable.

Time independent threats include those related to outside force, operator error, and excavation damage. Outside force is managed in a manner that also monitors the pipeline’s environments to ensure that external loads are not impacting its structural integrity. Operator error is managed through programs established under Part 192 including; Subpart-I “Requirements for Corrosion Control; Subpart-L “Operations”; Subpart-M “Maintenance”; and Subpart-N “Qualification of Pipeline Personnel”.

Excavation damage, the leading cause of incidents on natural gas transmission systems, is most effectively managed through prevention. This is exemplified by the fact that all but one incident on natural gas transmission systems from 1999 through 2006 has resulted in an immediate leak or rupture; with only one delayed failure resulting from pipe previously damaged by excavation during this period. This experience supports the contention that prevention is the primary means of controlling excavation damage., rather than periodic inspection.

A company may run geometry tools as part of the IMP program. Geometry in-line inspection tools are used to inspect for mechanical damage on the pipeline such as dents that may be caused by a third party striking the pipeline. Indications of dents greater than 2% with metal loss on the top two-thirds of the pipe are investigated, because there is a good probability of excavation damage.

When considering all of the threats discussed above, the time dependent threats of external and internal corrosion are the primary targets of the assessment tools prescribed in the legislation and regulations for integrity management programs.

INTEGRITY MANAGEMENT

The integrity management process consists of following specific and rigorous steps. The first step is the identification of susceptibility to each of the threats along a pipeline system. In general, operators elect to consider their entire pipeline system subject to external corrosion, as there is the potential for coating deterioration, even for modern coatings such as fusion-bonded epoxy (FBE).

In addition, there may be cathodic protection interruptions or the pipeline may be subject to cathodic protection shielding. Internal corrosion and SCC are evaluated on a case-by-case basis considering factors that are known to allow susceptibility. These factors may include poor gas quality for internal corrosion; and high operating temperatures and non-FBE coated pipe for SCC. Operators often consider their systems susceptible to internal corrosion, especially if they elect to use ILI since it detects both external and internal anomalies.

Systems are generally viewed in terms of discrete segments, and the second step in integrity management is to prioritize segments based on the risk posed by the threats described above when viewed collectively as part of a risk assessment.

The third step is the integrity assessment or inspection using one of the assessment tools, the subject of this paper. The results of the inspections are indications of anomalies that are analyzed in order to determine if the indication may be an anomaly warranting action; either on an immediate (more urgent) or scheduled basis (over a longer time horizon). The anomalies that fail criteria based solely on the data from the inspection become actionable anomalies. These are then categorized to determine when examination and evaluation is required. The actionable anomalies are then examined by experts and evaluated against long-established criteria such as ASME B31G and Modified B31G, or RSTRENG in order to determine the pipeline’s remaining strength. Based on the criteria, they are determined to be an imperfection or defect, some of which may require remediation. Depending on the inspection tool used, the defects are categorized based on follow-up response time. Figure 1 shows the integrity assessment hierarchy.

Remediation, including replacement or repair, is determined based on operator-specific criteria as well as regulations and standards. These activities are not addressed in this report.

Prevention activities or tools are based on operator specific-criteria as well as regulations and standards. These activities are also not addressed in this report.

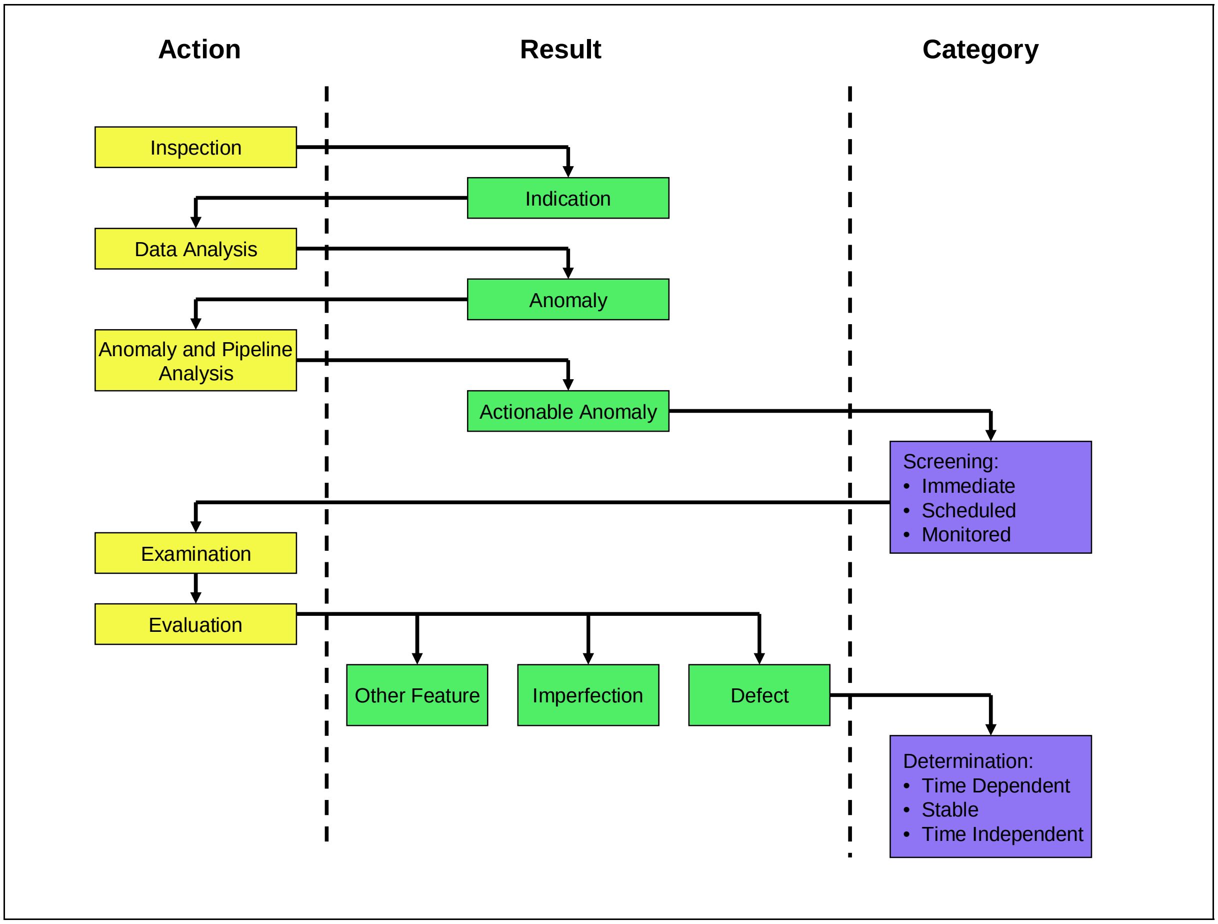

Figure 1
Hierarchy of Terminology for Integrity Assessment

Assessment Tools in the Pipeline Life Cycle

ASME B31.8S provides for the use of three integrity assessment methodologies: pressure testing, in-line inspection, and Direct Assessment. These three methodologies are treated as essentially equivalent when assessing time dependent threats (See Figure 2). Each technology verifies the integrity of the pipeline for a period of time as outlined in the standard. Pressure testing is considered to measure the strength of the pipeline in order to contain its contents under higher than normal pressures. In-line inspection technologies determine the thickness of the pipe's remaining wall and some newer technologies have improved the location and assessment of cracks and other physical damage.

Direct assessment integrates the operational records of the pipeline segment and knowledge of the immediate surface environments exposed to corrosive electrolytes. These relationships are used to prioritize the expected performance of the corrosion protection systems at spots along the pipeline that have the highest potential for external or internal corrosion or stress corrosion cracking. DA excavations refine and corroborate the predictive process as well as mitigate or prevent future corrosion through coating replacement or other appropriate repair responses.

All three assessment processes have the ability to determine a failure pressure for the assessed pipeline segment. These assessment methodologies have been validated through decades of testing on real and simulated pipe defects and in real situations.

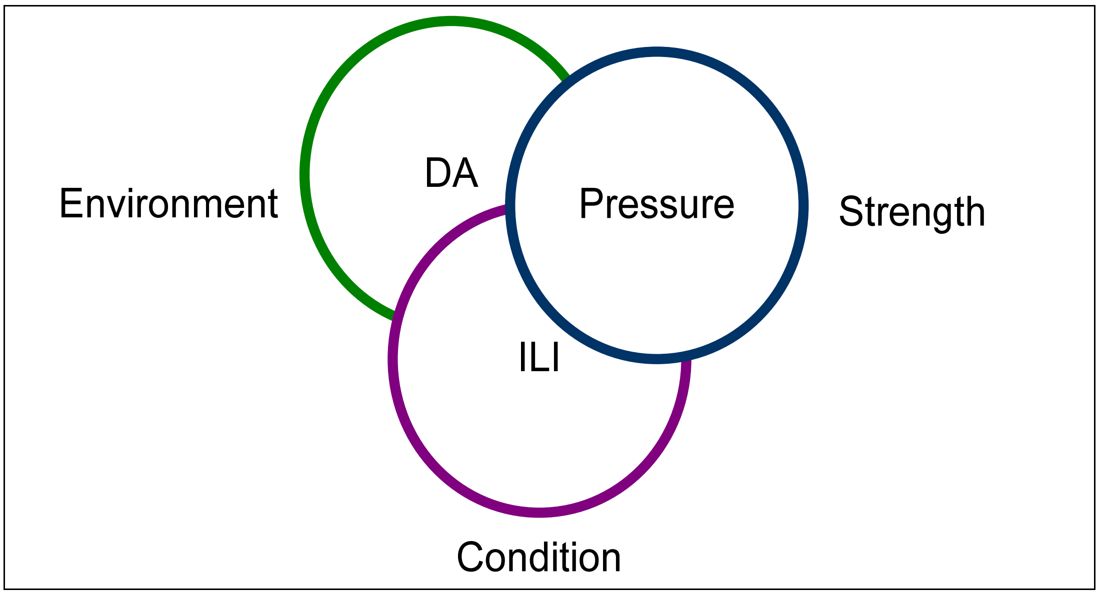

Figure 2
Stylized Integrity Assessment Inter-Relationships

The assessment tools, in-line inspection, pressure testing, and direct assessment, are applied at appropriate points in time of the life cycle of the pipeline.

In practice, the integrity assessment methodologies serve as "confirmatory tools"; that is, results that confirm the effectiveness of tools and work practices that are routinely used in between assessments. The assessment tools, particularly in-line inspection and direct assessment, help to identify where tools and work practices have not been sufficient and require evaluation and change. The way in which the threats are managed across the life cycle is reviewed in Table 1: Threat Matrix for Tool Selection. The role of the assessment tools, in-line inspection, pressure testing, and direct assessment, is placed in context. An understanding of the threats, the tools used to find and evaluate the threats, and incorporation of prevention, mitigation, and repair practices allows an operator to effectively manage the integrity of the pipeline throughout the pipeline's useful life.

A threat matrix for pipelines with the appropriate assessment tool based on present technology is shown below and summarizes the life cycle assessment.

Table 1: Threat Matrix for Tool Selection[5]

Threat	Assessment Tool	Typical Results
Time-dependent		
External Corrosion	MFL Inspection, DA or Pressure Test	Indications categorized as Immediate, Scheduled or Monitored
Internal Corrosion	MFL Inspection, DA or Pressure test	Indications categorized as Immediate, Scheduled or Monitored
Stress Corrosion	MFL Inspection, DA or Pressure Test	Assessment Planned if failure or leak experienced
Time-independent		
Operator Error	Audits	Process changes, training
Outside Force	Monitoring	Soil and other stresses not indicated
Excavation Damage	MFL Data and Data Integration or Caliper Inspection	Indications categorized as Immediate, One-year or Monitored
Stable		
Equipment	Inspection	No safety issues
Materials	Pressure Test	No test failures
Construction	Pressure Test	No test failures
Fatigue[6]	Analysis of Data	Cycles are insignificant

As can be seen from the matrix, the time-dependent threats of external corrosion and internal corrosion can be assessed through in-line inspection with Magnetic Flux Leakage (MFL) type tools, Direct Assessment (DA) or pressure testing. Continued operation of the pipeline through the use of the company's procedures in their Operations and Maintenance (O&M) Manual should prevent the threats and minimize any deterioration.

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[5] The threat matrix for tool selection is provided as an example and not intended to imply that the tools for each threat are the only tools allowed or recommended.
[6] Fatigue is not actually a threat but the outcome of the interaction of changing internal hoop stress or external loads (either increasing or atypical) acting on one of the other threats enumerated in the table.

A second matrix is provided that shows what threats can be assessed with present technology tools.

Table 2: Tools Matrix for Threats[7]

Assessment Tool	Threat Assessed	Method of Assessment
MFL	Internal and External Corrosion	Metal loss
Ultrasonic, Compression Wave	Internal and External Corrosion	Metal loss
Ultrasonic, Shear Wave	Internal and External Corrosion, SCC	Metal loss, crack detection
Transverse Flux	Internal and External Corrosion, SCC	Metal loss, crack detection
Deformation or Geometry	Excavation Damage, Outside Force Damage, Construction	Deformation of pipe cross section
Pressure Testing	Manufacturing, Construction, External Corrosion, Internal Corrosion, SCC, Excavation Damage	Strength test
ECDA	External Corrosion	Indirect assessment, examination, evaluation
ICDA	Internal Corrosion	Identification of susceptible locations, examination, evaluation
SCCDA	SCC	Identification of susceptible locations, examination, evaluation

[7] The tools matrix for threats is provided as an example and not intended to imply that the tools for each threat are the only tools allowed or recommended. Other uses for the tools and other tools may be acceptable.

The External Corrosion DA (ECDA) process requires the use of two or more complementary above ground indirect assessment tools. Present ECDA indirect assessment tools include the following:

- Close Interval Survey (CIS)
- Direct Current Voltage Gradient survey (DCVG)
- Alternating Current Voltage Gradient survey (ACVG)
- AC current attenuation survey
- Pearson survey
- Cell-to-cell survey

The Internal Corrosion DA (ICDA) process requires the collection and analysis of historic and current data to establish if water was ever present, determines the locations along the length of pipe that are most likely to first accumulate water, and provides for a detailed examination and evaluation of those locations.

The Stress Corrosion Cracking DA (SCCDA) process requires the collection and analysis of historic and current data to prioritize potentially susceptible segments of pipelines and help select specific sites for examination and evaluation.

Assessment Tools under Development

Guided Wave Ultrasonic Testing (GWUT) is a tool that is under development and for which a standard or recommended practice will be developed. An INGAA work group was formed in 2007 to evaluate the technology and define a basis for standardization of the application of this technology. This group worked with PHMSA personnel to develop an interim set of procedures captured in a document addressing 18 specific points. One essential aspect of the approach adopted by the INGAA work group was to base anomaly evaluation and response on the equivalence to a pressure test; that is, ensure that the technology, when applied, identified defects that would fail a pressure test. GWUT applies to all parts of a pipeline or pipeline facility that remain inaccessible to other inspection techniques that make it near impossible to conduct wall loss assessments. These include long ICDA potential segments, penetrations of concrete walls, cased and uncased road crossings, line pipe, pump station piping, terminal piping, compressor station piping, metering station piping, delivery station piping, regulator station piping, appurtenances connected to line pipe, appurtenances connected to facility piping, fabricated assemblies, valves, tees, elbows, reducers, flanges and any other pipeline equipment or appurtenances. The range is a function of the thickness and sound dampening of the applied coatings and the constraint of the soil or other features constraining the pipe. More information on this tool is provided in Appendix 9.

Examination and Evaluation Tools

There are many tools used during the examination and evaluation steps of the integrity assessment process. These include corrosion evaluation for both internal and external corrosion, magnetic particle and dye penetrant inspection for cracks, and dent and gouge evaluation for mechanical damage and outside force damage. These tools are not discussed in this report, however; standards used for acceptance criteria are discussed in the consensus standard portion of this report. A recent review of these techniques was published by PRCI in Report L52047e, “A Pipeline Repair Manual”, by CC Technologies.

CONSENSUS STANDARDS

Summary of Consensus Standards Requirements

ASME B31.8S provides information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes. Section 6 of that document discusses conducting the integrity assessment. The document is being revised to include references to recently developed consensus standards that provide specific details for conducting the assessments. The current and future referenced documents are identified below with more specific details provided in Appendixes 2-8.

<u>In-line Inspection</u>**:**

There are presently three standards covering the performance of In-line Inspections. They are:

1) *API[8] 1163–2005 - Qualification of In-Line Inspection Systems*
2) *NACE[9] RP0102–2002 – Standard Recommended Practice- In-Line Inspection of Pipelines* (Updating & revisions are due in 2007 to match the standards below.)
3) *ASNT[10] ILI PQ-2005- In-Line Inspection Personnel Qualification & Certification*

API 1163 is the “umbrella” standard for conducting in-line assessments and incorporates the other two standards by reference.

NACE RP0102 is the standard which addresses tool selection and usage.

ASNT ILI - PQ 2005 is the standard that specifies personnel qualifications. There are two categories of required qualified personnel: Tool Operators and Data Analysts. Both have three levels of qualification; I, II & III.

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[8] American Petroleum Institute
[9] National Association of Corrosion Engineers
[10] American Society of Non-destructive Testing

Direct Assessment:

There are presently three standards covering the performance of Direct Assessment. They are:

1) *NACE RP050–2002– Pipeline External Corrosion Direct Assessment Methodology*
2) *NACE RP0204-2004 – Stress Corrosion Cracking (SCC) Direct Assessment Methodology*
3) *NACE RP0206-2006 - Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Gas (DG-ICDA)*

NACE RP0502 is the standard for conducting external corrosion direct assessment (ECDA). This standard states that the provisions of the standard should be applied under the direction of competent persons who are qualified to engage in the practice of corrosion control.

NACE RP0204 is the standard for applying the stress corrosion cracking direct assessment (SCCDA) process on pipelines. This standard states that the provisions within should be applied under the direction of competent persons who are qualified to engage in the practice of corrosion control.

NACE RP0206 is the standard for applying the DG-ICDA process on pipelines. This standard states that the provisions of the standard should be applied under the direction of competent persons who are qualified to engage in the practice of corrosion control.

Pressure Testing:

There is presently one standard being developed that will address pressure testing of pipelines and includes pressure testing for maintenance and integrity management purposes:

API Recommended Practice 1110, Pressure Testing of Steel Pipelines for Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide

API 1110 is expected to be published in 2007. The standard states that operator personnel and contractors involved with designing, planning and conducting, or approval of a pressure test should be qualified.

Examination and Evaluation Standards for Acceptance Criteria

There are presently two standards that establish acceptance criteria for defects.

ASME B31G-1991 – Manual for Determining the Remaining Strength of Corroded Pipelines

ASME B31.851.41-2003 – Definitions of Injurious Dents and Mechanical Damage

Two other methodologies documented in research documents, not standards, are typically used to establish acceptance criteria for corrosion defects: Modified B31G or RSTRENG.

ASME B31G is the standard for determining the remaining strength[11] of steel pipelines that have experienced corrosion. The methodology determines acceptance criteria based on what pressure the pipeline could safely experience without leak or failure. Other methodologies provide alternate analysis techniques of the corroded area to determine remaining strength. The more rigorous methodologies often used in the pipeline industry are RSTRENG and Modified B31G.

Paragraph 851.41 in *ASME B31.8* provides acceptance criteria for dents on pipelines. The standard states what dents are injurious and must be repaired. ASME B31.8 also provides information on acceptable repair and remediation methodologies for these dents.

Presently, there is not a consensus standard for the determination of when a crack is injurious. Criteria for assessing the criticality of cracks resulting from SCC have been proposed as part of a JIP on SCC in 2007. Evaluation and response, as well as repair criteria, have been proposed and are in consideration by the ASME B31.8 Committee. It is anticipated that criteria will be published in *B31.8S* in 2007 or early 2008.

RESULTS OF INTEGRITY ASSESSMENTS UTILIZING THESE TECHNIQUES

There are four case studies that illustrate the success of these integrity management techniques. The first case shows the results of the IMP programs based on information provided to PHMSA as part of the IMP reporting requirements. The second case shows the results of an INGAA survey of types of defects found as a result of the IMP program. The third case shows the results of an INGAA survey of the implied rate of external corrosion based on defects found as part of the IMP program. The fourth case shows the benefit of the IMP program results to help influence regulations.

PHMSA Pipeline Integrity Management Regulations

While interstate pipeline companies have been utilizing risk management and have implemented integrity management programs within their companies, these programs were developed independently and were customized for a particular set of circumstances and experiences. In 2004 PHMSA adopted a regulation to mandate a specific integrity management program in High Consequence Areas (HCA). This was the result of a mandate from Congress in 2002. This program is the first time that there was a standardization of integrity management practices and reporting of integrity management results. Operators have been collecting information about these integrity assessments since 2004. Much of the information collected is reported to PHMSA on an annual basis. Other information is collected and retained by the company. The information in this section of the report is provided to show the extent of integrity management tool usage.

[11] Ability to safely contain natural gas at elevated pressure levels

<u>IMP Results from All Transmission Companies</u>

PHMSA obtains and retains information about company IMP programs. These metrics are collected twice per year and are summarized on an annual basis. The result of the first three years of integrity assessments (2004 to 2006) is shown in Table 3.

During these three years, the total miles of pipe inspected within HCAs using integrity assessment tools was 10,100. The total miles inspected (HCA and non-HCA) was 69,832. This shows that companies are assessing much more pipe with integrity management tools than required by the regulations (i.e. over inspecting) by approximately a factor of 7.

Table 3
2004 – 2006 PHMSA Integrity Management Metrics

PHMSA METRIC Onshore & Offshore Pipelines	2004	2005	2006
Total Onshore & Offshore Gas Transmission Miles	296,740	295,613	288,765
Total Miles Inspected	30,398	19,669	19,765
Miles of HCA Pipe	21,727	20,116	18,830
HCA Miles Inspected	3,956	2,739	3,406
Number of Immediate Repairs in HCAs	101	237	158
Number of Scheduled Repairs in HCAs	595	403	405
Number of Leaks in HCAs	117	105	86
Number of Failures in HCAs	8	20	11
Number of Incidents in HCAs			
Time Dependent	2	0	1
Time Independent	5	8	7
Stable	1	2	3

With this consolidated data, some key observations can be made:

Total Onshore & Offshore Gas Transmission Miles should stay rather constant over a period of years. Changes in the mileage will occur due to reclassification of transmission vs. distribution pipe, abandonments, and new construction, all of which will counteract each other and eventually lead to an increase in the total mileage of gas transmission pipelines in the U.S.

Total Miles Inspected will vary per year based on the number of miles that are scheduled to be inspected and how much over-testing[12] occurs. During these three years of the IMP program, the

[12] Pipeline segments within HCA areas are not contiguous and therefore integrity tools like ILI tools that traverse long distance during an inspection run will inspect non-HCA areas.

total miles of pipe inspected within HCAs using integrity assessment tools was 10,100. The total miles inspected (HCA and non-HCA) was 69,832. This shows that companies are assessing much more pipe with integrity management tools than required by the regulations (i.e. over inspecting) by approximately a factor of 7.

Miles of HCA Pipe will vary as the IMP programs are established and pipeline companies utilize combinations of Method 1 and 2 to delineate HCA areas. This number of *Miles of HCA Pipe* will gradually increase over time as additional development occurs close to pipelines.

HCA Miles Inspected will vary each year as pipelines are scheduled to be inspected. The regulations require that 50% of the pipe within HCA areas be inspected under the baseline IMP program by the end of 2007 and the remaining 50% be accomplished by the end of 2012.

Number of Immediate Repairs in HCAs will vary by year based on the number of miles of HCA pipeline inspected and the condition of the pipelines being inspected. Immediate repairs address issues that the pipeline companies (e.g. regulations) believe need quick action to prevent a future leak or incident. Based on the IMP regulatory criteria, the pipeline sections with the highest risk should be inspected in the first half of the baseline period (2003-2007 years), so it would be expected that the *number of immediate repairs per mile of HCA inspected*[13] will go down in the second half of the baseline period (2008-2013). After the baseline inspections are complete (2013), it is expected that the number of *number of immediate repairs per mile of HCA inspected* repairs will decline precipitously.

Number of Scheduled Repairs in HCAs will vary year to year based on the number of miles of HCA pipe inspected and the condition of the pipelines inspected. Scheduled repairs address issues that the pipeline companies (e.g. regulations) believe need a programmed action to prevent a future leak or incident. Based on the IMP regulatory criteria, the pipeline sections with the highest risk should be inspected in the first half of the baseline period (2003-2007 years) so it would be expected that the *number of scheduled repairs per mile of HCA inspected*[14] will go down in the second half of the baseline period (2008-2013). After the baseline inspections are complete, it is expected that the *number of scheduled repairs per mile of HCA inspected* will decrease, but a *number of scheduled repairs per mile of HCA inspected* should continue to exist if the inspection frequency is correctly designed.

Number of Leaks in HCAs should decrease over time. From past industry trends, many of the reportable leaks[15] (rather than reportable incidents) that occurred on transmission pipeline system were corrosion related, therefore an integrity program that utilizes these types of integrity tools will remove time dependent defects like corrosion. The *Number of Leaks in HCAs* is composed of two components: pipelines that have been inspected under the baseline IMP program and pipelines that have not yet been inspected under the baseline IMP program. If the

[13] Number of Immediate Repairs in HCAs / HCA miles Inspected; See Table 7
[14] Number of Scheduled Repairs in HCAs / HCA miles Inspected; See Table 7
[15] PHMSA F 7100.2-1 Annual Report for Gas Transmission and Gathering Systems

IMP program is designed correctly, one indicator is that there should be a minimal amount of leaks on pipe sections that have been through the baseline IMP inspection and are scheduled for the next reassessment. As the baseline IMP program progresses, there are fewer and fewer pipeline sections that have not been inspected. Therefore during the IMP baseline period, there should be a decline in leaks in HCA areas and the reduction should be proportional to the inspection progress achieved in the IMP baseline program.

Number of Incident in HCAs should decrease slightly over time and stabilize at the end of the baseline period. The number of reportable incidents[16] that are caused by time dependent defects for all transmission lines is 25% of the total, and is the primary focus of the IMP inspections. Therefore, at maximum, the most reportable incidents that can be affected by this IMP inspection program are the number of time dependent incidents in HCA areas. As with leaks, there are two components: pipelines that have been inspected under the IMP baseline program and pipelines that have not yet been inspected under the IMP baseline program. As the IMP baseline program progresses, there are fewer and fewer pipeline sections that have not been inspected under the IMP baseline program. If the IMP program is designed correctly, one indicator is that there should be a minimal amount of reportable incidents due to time dependent causes on pipe sections that have been through the baseline IMP inspection and are scheduled for the next reassessment.

PHMSA data for the IMP program does not provide the ability to drill down into the details of integrity assessment by tool type, nor does it provide information regarding integrity assessment results outside of HCAs.

[16] PHMSA F 7100.2 Incident Report for Gas Transmission and Gathering Systems

IMP Results for Select INGAA Member Companies

INGAA member companies are presently pooling their information on both required PHMSA reportable information and other supplemental integrity information that is required to be collected but not submitted. INGAA has compiled some of this information and the results are depicted on Table 4. This statistically significant sample[17] of integrity information reflects approximately 2/3 of INGAA's membership and does allow the ability to drill down into the details of integrity assessment by tool type.

Table 4
2004 – 2006 IMP Activities

METRIC	**2004**	**2005**	**2006**
Total Miles of Gas Transmission Piping Reporting	122,881	107,952	116,757
Gas Capacity Reductions Due Solely to IMP Activities – MMCF	16	7	10.5
Interstate High Consequence (HCA) Miles	4,403	4344	5,574
Intrastate HCA Miles	2,594	1,180	1,004
Number of Miles Inspected by ILI		5,029	6,183
Number of Miles Inspected by Hydrostatic Test		224	206
Number of Miles Inspected by Direct Assessment		331	152
Non-HCA Miles Inspected	5456	5,128	5,733
HCA Miles Inspected	820	457	810
Number of Repairs Made in Non-HCA Miles of Pipe	537	501	1041
Number of Repairs Made in HCAs	74	85	93
Pipe Replaced in Non-HCAs – (Feet)	10,000	15,391	25,294
Pipe Replaced in HCAs – (Feet)	0	1,297	3,498

Based on this sample data the following conclusions can be made about the interstate natural gas transmission pipeline system:

The number of repairs per mile in areas not covered by the pipeline integrity rule is approximately the same as the areas within high consequence areas.

Table 5 indicates the total number of repairs made per mile of High Consequence Areas (HCA) or non-HCA inspected during the year as indicated by the reporting companies. For the three year period, there was an average of 1.3 repairs made for every 10 miles of HCA inspected.

[17] Note: 438 miles of pre IMP In-line Inspection (ILI) were counted as baseline miles in 2005 and are not included in the table

Table 5
Total Number of Repairs per Mile Inspected

YEAR	HCA	NON-HCA
2004	0.09	0.10
2005	0.19	0.10
2006	0.12	0.18

The predominant choice of inspection tool for interstate natural gas pipelines is ILI

Table 6 lists the total miles inspected by inspection method for the last two years for the reporting companies. As a result of the IMP inspections, 55,480 feet of pipeline were replaced (~10 miles) over the 3 year period.

Table 6
Total Miles Inspected

INSPECTION METHOD	TOTAL MILES	PERCENT
ILI	11,212	92.4
Hydrostatic Testing	430	3.6
Direct Assessment	483	4.0
Total	12,125*	100

* Data only collected for two years (2005 & 2006).

Immediate repairs are a fraction of the total repairs conducted on interstate natural gas pipelines

Table 7, taken from PHMSA data, lists the number of repairs per miles of pipe inspected in HCAs, by repair categories, immediate and scheduled. If the inspection program frequency is designed correctly, the number of immediate defects found after the baseline inspections are complete will be close to zero, while extending the interval between inspections.

Table 7
Number of Repairs per Mile*

YEAR	2004	2005	2006
# Immediate	0.026	0.090	0.045
# Scheduled	0.150	0.150	0.099

* Data taken from PHMSA web site

The average number of *immediate repairs* in HCAs over the three years for the sampled INGAA general mileages is very low, 0.54 repairs for every 10 miles and is comparable to the PHMSA IMP data that only covers HCA mileage. The rate of scheduled repairs for the sample INGAA general mileage is 1.3 *scheduled repairs* for every 10 miles of pipe inspected and is comparable to the PHMSA IMP data that only covers HCA mileage, The PHMSA reported total repairs per HCA mile are 1.35, which is almost identical to the value of 1.3 for the Sample of INGAA companies, indicating a high degree of correlation between the sample data and the PHMSA IMP data.

The majority of defects found in the IMP program are caused by corrosion

A survey by a subset of INGAA members was conducted in early 2006 to determine the distribution of defects that were found during IMP inspections by Inline-inspection tools. These defects were classified by the major categories of static, time dependent, time independent. Those categories were further subdivided as to the particular cause. The detailed results are shown in Appendix 10.

This result needs to be combined with the corrosion growth information in Appendix 11 and the rate of reportable corrosion incidents in HCA areas to understand the overall risk to the public and how to manage the system with integrity management tools

INGAA SURVEY OF TYPES OF DEFECTS FOUND AS A RESULT OF THE INTEGRITY MANAGEMENT PROGRAM

INGAA conducted a survey[18] of its members to determine the type of defects found during the inspections utilizing inline inspection tools**.** The survey was designed to determine the distribution of anomalies categorized as scheduled and immediate for the static, time dependent and time independent threats found in HCA areas. The survey comprised of 7,025 miles of

[18] See Appendix 10

pipeline in HCA areas as submitted by INGAA members who represent 155,000 miles of transmission pipeline miles. The results covered the 2004 and 2005 time period. The predominant defect found and planned for remediation (immediate or scheduled) was external corrosion (time dependent defect). The second most common defect found and remediated was dents that appeared to be caused by original construction (static defect). Following in third place, there were some dents with mechanical damage that were found and remediated. .

The relative frequency of these defects found and remediated under the IMP program correlated with industry beliefs during the development of the original integrity management rule.

Original Construction Defects

The presence of construction defects found during the initial inspections would be expected because this would be the first time that the pipelines had been examined with inspection tools that could detect those defects. These results do raise the question of the conservativeness of the of the defect repair criteria given that these have existed in the pipeline since construction. As mentioned previously, the presences of these defects should converge to zero during the re-inspection process.

Post Construction Mechanical Defects

The identification of post construction mechanical damage defects by ILI tools does correlate with industry belief that that these tools can find mechanical damage, but it is not a good management tool for preventing excavation damage. Excavation damage incidents tend to occur at the time of the damage. This information needs to be balanced by the lack of reported delayed mechanical damage incidents on natural gas transmission pipelines.

INGAA SURVEY OF IMPLIED RATE OF EXTERNAL CORROSION DEFECTS FOUND IN IMP PROGRAM

INGAA conducted a survey[19] in 2006 of the external corrosion defects found in pipe subject to the IMP program. The survey covered almost 2,000 miles of pipe inspected in 2004 and 2005 conducted by INGAA members for the IMP program representing almost 100,000 miles of gas transmission pipelines. The intent of the survey was to determine an approximate re-inspection interval rate for pipe subject to the IMP regulations.

Information was solicited from the respondents as to the last time the pipeline had been examined for overall integrity. For almost all of the surveyed pipelines, this was at the time of construction[20]. Defect information from the baseline inspection of the IMP program was

[19] See Appendix 11
[20] Pipelines are examined when they are installed to be sure that there is no corrosion or other damage on the pipeline. Defects are repaired at time of construction

gathered for the same pipelines. The resulting combination of this information depicts the approximate time that it takes for initial scheduled or immediate conditions to appear on these pipe segments. Overwhelmingly, the period of time for scheduled or immediate defects to appear on a pipeline segment exceeded the present IMP re-inspection interval by at least three times. A fully functioning and unconstrained IMP program will remediate all scheduled and immediate defects and permit the next inspection interval to be based on expected corrosion rates.

Timing of External Corrosion Re-inspection on Pipeline Segments Subject to the IMP program

Based on the INGAA survey, it appears that the re-inspection interval (7 years) mandated by the IMP program is extremely conservative. While the majority of the gas transmission pipeline in the ground does not appear to be corroding at all, even with a sufficient safety factor, the present IMP re-inspection requirements appear to be at least twice as conservative as necessary.

BENEFITS OF PIPELINE INTEGRITY PLANS UTILIZING THESE INSPECTION TECHNIQUES

In September of 2006 the Government Accounting Office (GAO) published a report[21] on the effectiveness on the present baseline IMP assessments and made recommendations to Congress for the design of the congressionally mandated reassessment process. Listed below is an excerpt of their conclusions

> Periodic reassessments of gas transmission pipelines are useful because safety threats can change. However, the 7-year requirement appears to be conservative because (1) most operators found few major problems during baseline assessments, and (2) serious pipeline incidents involving corrosion are rare, among other reasons. Through December 2005 (latest data available), 76 percent of the operators (182 of 241) that had begun baseline assessments reported to PHMSA that their pipelines required only minor repairs. These results are encouraging because operators are required to assess their riskiest segments first. Since operators are also required to repair these problems, the overall safety and condition of their pipelines should be enhanced before reassessments begin. In addition, PHMSA data suggest that serious gas transmission pipeline problems due to corrosion are rare. For example, there have been no deaths or injuries as a result of incidents due to corrosion since 2001. Of the 52 operators contacted that have calculated reassessment intervals, the large majority (20 of 23) told GAO that based on conditions identified during baseline assessments, they could safely reassess their pipelines for corrosion, every 10, 15, or 20 years—as industry consensus standards prescribe unless pipeline conditions warrant an earlier assessment.

As the GAO is concluding in this report, the integrity management programs that utilize these inspection techniques have been successful and are assuring pipeline companies, regulators and the public that the nation's natural gas transmission pipelines are being safely managed. The key question is how to move forward and use these tools effectively and efficiently.

[21] GAO-06-945 "Risk –Based Standards Should Allow Pipeline Operators to Better Tailor Reassessments to Pipeline Threats"; Sept. 2006 ; http://www.gao.gov/new.items/d06945.pdf

APPENDIX 1

2002 to 2006 Onshore Gas Transmission Reportable Incident Data

Cause	2002	2003	2004	2005	2006	Total
External Corrosion	14	10	11	12	11	58
Internal Corrosion	0	5	2	3	6	16
Earth Movement	1	1	1	5	2	10
Lightning	0	2	0	0	1	3
Heavy Rains/Floods	3	0	2	13	0	18
Temperature	0	0	0	1	0	1
High Winds	1	0	0	3	0	4
Operator Excavation Damage	1	2	2	2	4	11
Third Party Excavation Damage	9	13	20	14	16	72
Fire/Explosion as Primary Cause	0	1	3	1	0	5
Car, Truck or other Vehicle	4	5	6	5	8	28
Rupture of Previously Damaged Pipe	0	0	0	1	1	2
Vandalism	0	0	0	1	1	2
Body of Pipe	2	3	4	3	3	15
Component	4	0	2	2	2	10
Joint	2	3	0	1	4	10
Butt	0	4	1	3	7	15
Fillet	1	0	2	0	0	3
Pipe Seam	4	6	2	0	2	14
Malfunction of Control/Relief Equipment	1	3	9	8	5	26
Threads Stripped, Broken Pipe Coupling	1	3	1	2	3	10
Ruptured or leaking Seal/Pump Packing	0	0	0	1	2	3
Incorrect Operations	0	4	0	2	4	10
Miscellaneous	4	8	8	12	8	40
Unknown	2	6	3	6	11	28
	54	79	79	101	101	414
Adjusted to 2002 gas price at $2.50	0	16	18	38	37	109
Would porbably not have been reported	54	63	61	63	64	305
Fatality	1	1	0	0	3	5
Injury	5	7	2	5	4	23

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APPENDIX 2

API 1163
IN-LINE INSPECTION SYSTEMS QUALIFICATION STANDARD

PURPOSE

This standard enables service providers and pipeline operators to provide rigorous processes that will consistently qualify the equipment, people, processes and software utilized in the in-line inspection industry. The standard incorporates by reference both NACE RP0102 Standard Recommended Practice In-Line Inspection of Pipelines and ASNT ILI-PQ-2005 In-Line Inspection Personnel Qualification and Certification.

DESCRIPTION

Performance of an in-line inspection of a segment of a pipeline is a joint effort of the pipeline operator and a service provider. The standard delineates operator and service provider responsibilities that must be completed prior to, during, and after the completion of an in-line inspection.

The standard has an extensive list of definitions, many derived from other standards. Figure 1, attached, provides the process and significant definitions utilized for an in-line inspection, which the industry (including the Regulator) are urged to adopt.

The standard, with NACE RP0102, provides guidance for selecting the appropriate in-line inspection system. In-line inspection goals, objectives, and required accuracies must be defined and the physical and operational characteristics and constraints of the pipeline segment(s) must be considered. The inspection requirements and the in-line inspection system capabilities must be aligned.

The in-line inspection systems are required to have performance specifications which are statistically validated. The performance specification defines the capabilities of the in-line inspection system to detect, locate, identify, and size anomalies and characteristics in terms of the following parameters:

- The type of anomaly or characteristic covered by the performance specification.
- Detection thresholds and probabilities of detection.
- Probabilities of proper identification.
- Sizing or characterization accuracies.
- Linear (distance) and orientation measurement accuracies.
- Limitations.

The inspection system is required to be operationally validated prior to performing the inspection, during, and after the inspection is completed. The validation includes the inspection system, mechanical and electronic systems, and above ground markers.

The standard describes the process that shall be used to verify that the reported inspection results have been met and are consistent with the performance specification for the pipeline being inspected. The verification process includes:

- A process validation
- A comparison with historic data (if available) for the pipeline being inspected, and/or
- A comparison with historic data or large scale test data from the inspection system being used.

Field verification measurements may be required.

The standard also describes reporting requirements and quality management systems requirements.

Qualification of the in-line inspection systems operators and data analysts is covered in the ASNT ILI PQ standard, which is a requirement of API 1163.

NACE RP0102 describes predominantly pipeline operator requirements for performing an in-line inspection and is also incorporated into API 1163 by reference.

PRESENT INDUSTRY PRACTICE

A survey was recently conducted that indicates that more than 60% of the respondents are presently including API 1163 in their in-line inspection requests for bid documents. Another 20% of the respondents are considering utilization of API 1163. The service providers who are members of the In-Line Inspection Association all say they can and do meet the requirements of API 1163.

The standard was first published in August of 2005. It is too early to determine the effects of the utilization of the standard. Anecdotal evidence indicates that the effects are positive, but as of yet, not quantifiable.

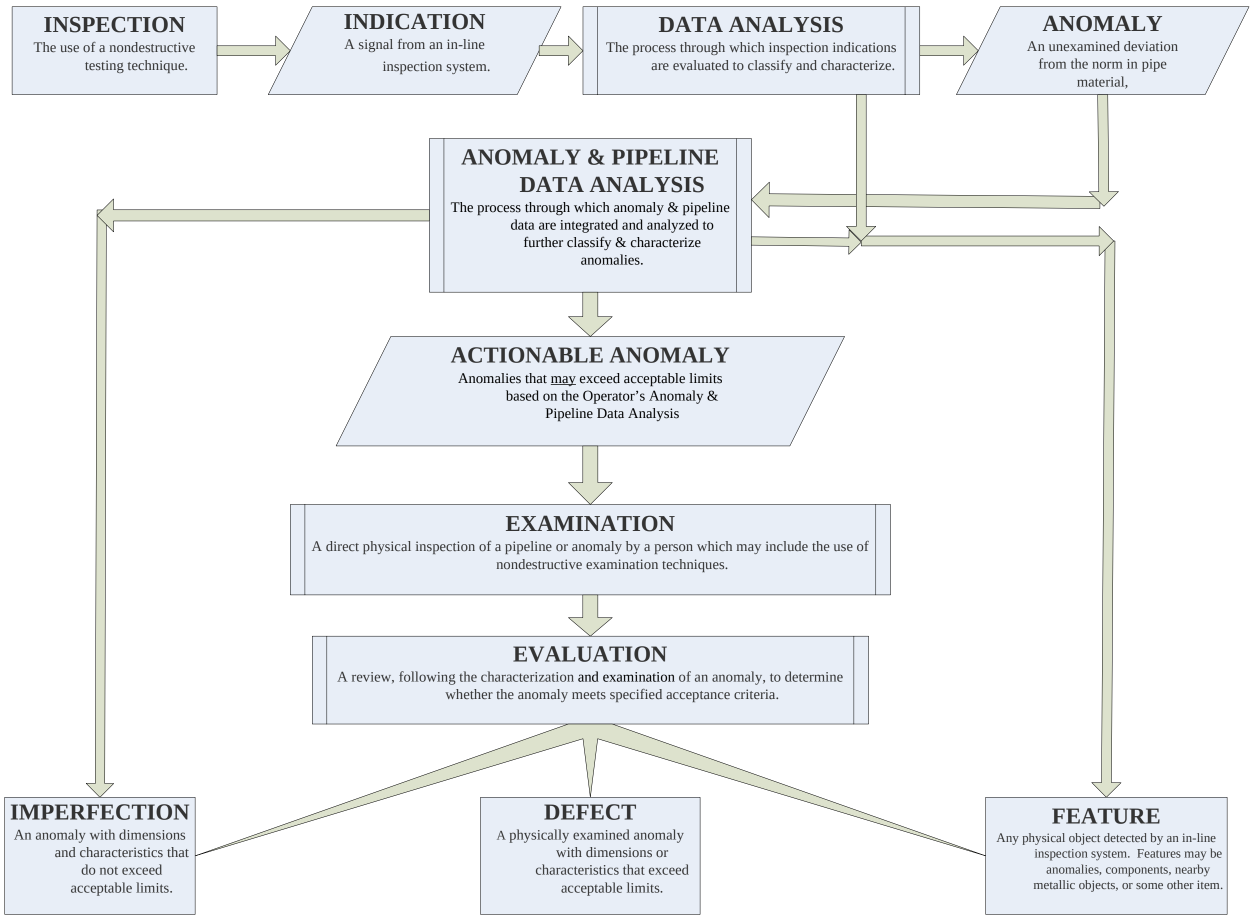

Figure 2 (API 1163)

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APPENDIX 3

ASNT ILI-PQ
IN-LINE INSPECTION PERSONNEL QUALIFICATION & CERTIFICATION

PURPOSE

This standard was developed by the American Society for Nondestructive Testing to establish minimum requirements for the qualification and certification of in-line inspection personnel whose jobs require specific knowledge of the technical principles of ILI technologies, operations, regulatory requirements, and industry standards as applicable to pipeline systems. The standard is incorporated by reference into API 1163. Thus, invoking API 1163 as part of an inspection contract, this standard is also a requirement of that contract.

The standard addresses the qualification and certification of two types of ILI personnel; tool operators and data analysts.

DESCRIPTION

This standard uses the same format as other ASNT nondestructive testing qualification standards, such as radiography and ultrasonics. Tool operators and data analysts can be qualified at 3 levels, I, II or III, the higher the level, the more tasks they are qualified to perform.

Companies employing tool operators and data analysts are responsible for the qualification of their personnel in accordance with the standard. Employers must establish a written practice for the control and administration of ILI personnel training, examination and certification.

The specific tasks that the 3 levels of personnel may perform are delineated in the standard. As an example, only a level II or level III tool operator may oversee tool launches, runs and receiving. Only a level II or III data analyst may organize and report tool results.

The standard defines the education, training and experience required for each of the 3 levels of qualification for the following technologies:

- Geometry
- Axial Magnetic Flux
- Transverse Magnetic Flux
- Ultrasonic Compression Wave
- Ultrasonic Shear Wave
- Electro Magnetic Acoustic Technology (EMAT)
- Mapping

Tables 2A &2B below, taken from the standard, show the Axial MFL tables as an example.

A written, electronic, oral and/or practical examination is administered, in accordance with the employers' written practice, to assess the qualification of personnel. Certification is provided upon successful completion of the qualification requirements including, education, training, experience and examination. Periodically, as defined in the employer's written practice, the technical performance of certified ILI personnel shall be evaluated and documented.

The standard, as in all ANSI approved standards, must be reviewed periodically and may be revised. As new technologies arise, it is intended to add these to the list of technologies requiring ASNT qualified personnel. An up and coming technology that should be considered is guided wave inspection.

Axial Magnetic Flux Technology

Table 2A - ILI Tool Operator

Level	Experience (Months)	Training (Hours)	Education (Formal)
Level I	6	80	*
Level II	18	160	*
Level III	30	320	**

Table 2B - ILI Data Analyst

Level	Experience (Months)	Training (Hours)	Education (Formal)
Level I	6	80	*
Level II	24	160	*
Level III	36	500	**

* High school graduate or equivalent
** Completion with a passing grade of at least 2 years of engineering or science study at a university, college or technical school.

APPENDIX 4

NACE STANDARD RP0102
STANDARD RECOMMENDED PRACTICE
IN-LINE INSPECTION of PIPELEINES

PURPOSE

This standard recommended practice outlines a process of related activities that a pipeline operator can use to plan, organize and execute an ILI project. Guidelines pertaining to data management and data analysis are included. The standard is intended for use by individuals and teams planning, implementing and managing ILI programs.

DESCRIPTION

This standard is applicable to carbon steel pipeline systems used to transport natural gas, hazardous materials including anhydrous ammonia, carbon dioxide, water (including brine), and liquefied petroleum gases. The standard is primarily applicable to “free swimming” ILI tools. Tethered or remotely controlled inspection devices are not specifically excluded.

The standard describes a process for selecting the proper tool(s) to meet the goals and objectives of the inspection. Table 1 of the standard lists 7 different types of ILI tools and more than 15 types of anomalies that may be found in pipelines and which tools are best to find which anomalies.

Section 4 of the standard describes some requirements for tool launching and receiving facilities. It also describes mechanical pipeline features that may cause difficulties for an ILI tool such as, back to back bends, valves, unbarred tees, chill rings. Careful review of the system and proper responses to the tool providers’ questionnaire usually resolve such issues before a run is made. Pipeline cleanliness and speed control issues are also addressed.

Section 5 on ILI logistics provides the Operator a guide for the process to successfully contract for and manage an ILI inspection, including post testing issues such as data acceptance and post-run operational reports.

Section 6 addresses the timing, scheduling, manpower requirements, environmental considerations and tool tracking during the inspection.

Design considerations for new construction are provided in section 7 for making pipeline systems ILI tool compatible.

Section 8 describes data analysis and verification methods such as the use of pipeline features and benchmarks and surface chaining for determining where to dig for affected joints.

Appendix A of the standard has a very useful and complete Pipeline Inspection Questionnaire. The information provided in the filled out questionnaire can be used to fully characterize the segments to be inspected for the service provider so that appropriate tools are chosen that will operate correctly in the pipeline.

APPENDIX 5

NACE RP0502
PIPELINE EXTERNAL CORROSION
DIRECT ASSESSMENT METHODOLOGY

PURPOSE

This recommended practice provides guidelines to ensure the pipeline external corrosion protection systems are working correctly and any deficiencies are corrected in a timely fashion. The integrity of the pipeline for the threat of external corrosion is best maintained by ensuring that the cathodic protection system is working correctly to provide corrosion protection were ever the anti-corrosion coatings are no longer providing the first line of protection.

DESCRIPTION

This recommended practice applies to all parts of a pipeline or pipeline facility including line pipe, pump station piping, terminal piping, compressor station piping, metering station piping, delivery station piping, regulator station piping, appurtenances connected to line pipe, appurtenances connected to facility piping, fabricated assemblies, valves, tees, elbows, reducers, flanges and any other buried pipeline equipment or appurtenances.

This recommended practice does not apply to pumping units, compressor units, breakout tanks, pressure vessels, control piping, sample piping, instrument piping/tubing, or any component or piping system for which other codes specify pressure testing requirements (i.e. ASME Boiler and Pressure Vessel Code, piping systems covered by building codes, etc).

This document provides the methodology to conduct external corrosion direct assessment (ECDA):

- Preassessment – gathering data and deciding which two complementary inspection methods can best be used to assess the cathodic protection performance in the different pipeline regions. These regions are the start and finish locations where ECDA is feasible
- Indirect Inspection – conducting two or more complementary indirect electrical and other inspections from above ground, such as Close Interval Surveys (CIS), Direct Current Voltage Gradient (CDVG), to determine the protection performance of the coating and cathodic protection system. Pre-established threshold levels of both inspections are used to determine if these are indications of protection deficiencies and how to prioritize the severity of the indication locations for excavation based on magnitude and historical observation. The excavation sites are prioritized into immediate and scheduled locations.

- Direct Assessment - excavation of those immediate and scheduled indication sites to measure the actual depth and length extent of external corrosion and collect coating damage, environmental data to help improve the prediction of immediate and severe excavations. Corrosion on the pipeline is assessed and any necessary mitigation or repair is finished before the pipe is recoated and reburied.
- Post Assessment – the methodology requires a validation excavation to confirm the process and also the corrosion found in the excavation is used to determine the interval to the next integrity assessment. B31.8S requires that all the indications be investigated to reach the maximum interval of ten or more years, other wise a five year interval is the maximum.

The standard requires continuous improvement with changes to be made to previous steps to improve analyses and prediction. The standard contains a strenuous records requirement to document observations and the decisions made. The appendix provides detailed guidance for the different above ground inspection methods. The methods in the body of the revised standard including the appendix will refer to the new NACE standards:

- RP0104-2004 The Use of Coupons for Cathodic Protection Monitoring Applications
- RP0497-2004 Field Corrosion Evaluation Using Metallic Test Specimens

APPENDIX 6

NACE RP0206
INTERNAL CORROSION DIRECT ASSESSMENT METHODOLOGY FOR PIPELINES CARRYING NORMALLY DRY NATURAL GAS (DG-ICDA)

PURPOSE

This recommended practice provides guidelines to ensure that normally dry pipelines are properly managed for internal corrosion. Corrosion requires that condensed moisture/electrolyte have persisted for some total duration, even for microbiologically influenced corrosion (MIC). Unfortunately operational decisions made upstream and therefore not controllable, can introduce water from operational consequences such as infrequent short term flooding or upsets. The ICDA standard evaluates locations downstream from each potential water introduction site. It looks for those places where water or other electrolyte first accumulates, allowing inferences to be made concerning the integrity of the remaining downstream length of pipe. Probable sites where water may remain trapped or persist over time are determined by integrating a simple flow modeling analysis and the rate of change in the elevation of the pipeline. Probable sites are those that exceed the critical angle down stream from each introduction site. If corrosion is not found for two sites past the last location of internal corrosion then the rest of the pipeline is considered free from internal corrosion (until the next water introduction site is reached). Corrosion sites which are upstream from where the last spot corrosion was detected are prioritized for investigation, prevention, and or mitigation sometimes including the immediate site at a lower elevation upstream from the water introduction sites.

DESCRIPTION

This recommended practice applies to transmission pipeline facilities including line pipe, terminal piping, metering station piping, delivery station piping, regulator station piping, appurtenances connected to line pipe, appurtenances connected to facility piping, fabricated assemblies, valves, tees, elbows, reducers, flanges and any other pipeline equipment or appurtenances.

This recommended practice does not apply to pumping units, compressor units, breakout tanks, pressure vessels, control piping, sample piping, instrument piping/tubing, or any component or piping system for which other codes specify pressure testing requirements (i.e. ASME Boiler and Pressure Vessel Code, piping systems covered by building codes, etc).

The NACE document provides the methodology to conduct dry gas internal corrosion direct assessment (DG-ICDA):

- Preassessment – gathering data and deciding if the data is sufficient to be able to conduct DG-ICDA. Dry Gas must be above its dew point and be free of condensed liquid. Each possible water introduction site sets the beginning location for each pipeline DG-ICDA region where DG-ICDA is feasible. Bidirectional flow must be treated as two separate assessments.
- Indirect Inspection – The operator is required to conduct flow modeling to determine the critical angle for water transport where forward motion is prevented by gravity and surface tension. The operator must then determine the inclination profile of the pipeline and integrate with the flow modeling to locate potential sites and then prioritize them for detailed examination.
- Detailed Examination - The operator is required to excavate sites by priority and measure the actual depth and length extent of internal corrosion by X-ray, or other suitable non destructive technique. The internal corrosion inspection process proceeds downstream until no corrosion is found in two successive sites. Corrosion is present if the wall loss exceeds 10% based on the wall thickness. Once the operator has determined that two sites in succession down stream of the last location with corrosion are corrosion free, then the remaining pipeline downstream is free of internal corrosion. While the excavation is open the operator may elect to install monitoring systems to track the effectiveness of future prevention and mitigation programs.
- Post Assessment – the methodology requires a validation excavation at one site downstream of the last excavation site where the inclination angle exceeds the critical angle to confirm the process. The operator must establish the effectiveness of DG-ICDA and measure change after each assessment. If extensive corrosion or corrosion at the top of the pipe is found, then the assumption of normally dry gas must be re-examined. The corrosion found in these excavations is used to estimate the interval to the next integrity assessment.

The standard requires continuous improvement with changes to be made to previous steps to improve analyses and prediction. The standard contains a strenuous records requirement to document observations and the decisions made. The appendix provides detailed guidance on the integration of the elevation profile and the critical angle calculation to determine excavation sites.

The Dry Gas ICDA standard should be read in conjunction with the recently revised internal corrosion control standard:

- NACE SP0106-2006 Control of Internal Corrosion in Steel Pipelines and Piping Systems

APPENDIX 7

NACE RP0204
STESS CORROSION CRACKING (SCC)
DIRECT ASSESSMENT METHODOLOGY

PURPOSE

This recommended practice provides guidelines to locate places along the pipeline that have a higher potential of harboring SCC. The integrity of the pipeline for the threat of stress corrosion cracking is assured by following the recommendations in ASME B31.8S A3 and the NACE SCCDA standard.

DESCRIPTION

This standard recommended practice applies to all parts of a buried pipeline or pipeline facility including line pipe, pump station piping, terminal piping, compressor station piping, metering station piping, delivery station piping, regulator station piping, appurtenances connected to line pipe, appurtenances connected to facility piping, fabricated assemblies, valves, tees, elbows, reducers, flanges and any other pipeline equipment or appurtenances. SCC has been found on the higher stressed pipelines and not observed on fittings or class 3 and 4 pipe.

This recommended practice does not apply to pumping units, compressor units, breakout tanks, pressure vessels, control piping, sample piping, instrument piping/tubing, or any component or piping system for which other codes specify pressure testing requirements (i.e. ASME Boiler and Pressure Vessel Code, piping systems covered by building codes, etc).

SCCDA is a formal process to assess a pipe segment for the presence of SCC primarily by examining with MPI selected joints of pipe within that segment after systematically gathering and analyzing data for pipe having similar operational characteristics and residing in a similar physical environment. The SCCDA process provides guidance for operators to select appropriate sites to conduct excavations for the purposes of conducting SCC integrity assessment. Detailed guidance for this process is provided in NACE RP0204-2004 “Stress Corrosion Cracking Direct Assessment (SCCDA) Methodology”.

This document provides the methodology to conduct external corrosion direct assessment (SCCDA):

- Preassessment – gathering data and deciding which pipeline segments would be likely SCC candidate regions. These regions begin and end those locations where SCCDA is likely. Limited industry experience has indicated successful use of in-line inspection for SCC. It is the responsibility of the operator to develop appropriate assessment plans when ILI is used for SCC or used as historical information.

- Indirect Inspection – Close interval testing and coating condition surveys have been helpful in determining where the pipe may be periodically shielded by deteriorated coating and soil conditions. During the course of routine pipeline maintenance activities, areas susceptible to SCC that exhibit disbonded coating shall have coating removed and the surface inspected for SCC using magnetic particle inspection (MPI) with a documented inspection procedure. This information along with an evaluation of the pipeline history of prior SCC, the presence of tape, asphalt or coal tar coatings and relevant information from prior ILI inspections (such as deformations, dents, strains, and or coating adhesion) are integrated to determine the likelihood of SCC being present. Both ASME B31.8S A3 and NACE 0205 are currently being revised to improve the list of data elements used to help determine the likelihood of SCC being present. For example, all corrosion coating systems other than plant applied or field applied FBE or liquid epoxy when abrasive surface preparation was used during coating application may become susceptible to SCC. The excavation sites are then prioritized into immediate and scheduled dig locations.
- Direct Assessment- The operator is required to excavate those immediate and scheduled indication sites, clean the pipe, measure the actual extent of SCC, and collect environmental data to help improve the prediction ability when choosing future immediate and severe excavations. The length of an SCC excavation will be addressed in the operator's plan. The pipeline is assessed to determine the severity of SCC indications. The response is based on a failure pressure and an interval wherein the pipe remains safe. A new table of responses is followed when making the necessary mitigation or repair before the pipe is recoated and reburied. These responses require an additional investigation or inspection, a temporary pressure reduction, and/or a timely pressure (hydro) test.
- Post Assessment – the methodology requires a validation excavation to confirm the process. The range of SCC damage found in all the excavations is used to determine the interval to the next integrity assessment. B31.8S is being revised to bring the language into line with the most recent R&D findings.

The standard requires continuous improvement with changes to be made to previous steps to improve analyses and prediction. The standard contains a strenuous records requirement to document observations and the decisions made. The appendix provides detailed guidance for the different above ground inspection methods. The methods in the body of the revised standard including the appendix will refer to the new standards:

- API 1110 Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids or Carbon Dioxide
- NACE RP0104-2004 The Use of Coupons for Cathodic Protection Monitoring Applications
- NACE RP0502 Pipeline External Corrosion Direct Assessment methodology
- NACE SP0206 Internal Corrosion Direct Assessment Methodology for Pipelines Normally Carrying Dry Natural Gas

APPENDIX 8

API RP 1110
PRESSURE TESTING OF STEEL PIPELINES FOR THE TRANSPORTATION OF GAS, PETROLEUM GAS, HAZARDOUS LIQUIDS, HIGHLY VOLATILE LIQUIDS OR CARBON DIOXIDE

This standard has been approved but not published as of the date of this report. It is intended that the standard will be incorporated into ASME B31.8S as the "how-to" practice for conducting pressure tests for integrity management purposes.

PURPOSE

This recommended practice provides guidelines for pressure testing steel pipelines for the transportation of gas, petroleum gas, hazardous liquids, highly volatile liquids or carbon dioxide. The recommended practice provides guidance so that:

- Pipeline Operators can select a pressure test suitable for the conditions under which the test will be conducted. This includes, but is not limited to, pipeline material characteristics, pipeline operating conditions, and various types of anomalies or other risk factors that may be present.
- Pressure tests are planned in order to meet the overall objectives of the pressure test.
- Site-specific procedures are developed and followed during all phases of the pressure testing process.
- Pressure tests consider both personnel safety and environmental impacts.
- Pressure tests are implemented by qualified personnel.
- Pressure tests are conducted in order to meet stated acceptance criteria.
- Pressure test records are developed, completed and retained for the useful life of the facility.

DESCRIPTION

This recommended practice applies to all parts of a pipeline or pipeline facility including line pipe, pump station piping, terminal piping, compressor station piping, metering station piping, delivery station piping, regulator station piping, appurtenances connected to line pipe, appurtenances connected to facility piping, fabricated assemblies, valves, tees, elbows, reducers, flanges and any other pipeline equipment or appurtenances.

This recommended practice does not apply to pumping units, compressor units, breakout tanks, pressure vessels, control piping, sample piping, instrument piping/tubing, or any component or piping system for which other codes specify pressure testing requirements (i.e. ASME Boiler and Pressure Vessel Code, piping systems covered by building codes, etc).

This document provides guidelines for:

- Planning a pressure test
- Developing a site-specific procedure for a pressure test
- Conducting a pressure test
- Documenting the results of a pressure test

This recommended practice does not address piping systems that are pressure tested with natural gas, nitrogen, or air as the test medium.

APPENDIX 9

GUIDED WAVE ULTRASONIC TESTING (NOT YET A STANDARD PRACTICE)

The inspection technique has been accepted by PHMSA to inspect pipelines in difficult to assess areas providing all 18 points are addressed to their satisfaction. To date only three pipeline operators have been approved to use GWUT in limited situations. This inspection technique needs to find a sponsoring standard development organization to minimize future adjustments to gain industry acceptance and regulatory approval.

PURPOSE

A recommended practice is needed to provide standard guidelines to inspect pipelines for wall loss in difficult to assess areas such as ICDA potential segments, inside insulation, hold down straps, concrete wall penetrations, road and cased crossings. The GWUT inspection technique is similar to a pressure (hydro) test in that it can locate all corrosion defects that would rupture on hydro-testing but can not adequately size defects to allow a failure pressure calculation. The physics are greatly different and any comparisons to ILI are unwarranted.

The GWUT technology has proven to be a very successful inspection technique when used to inspect plant and production facilities. Pipeline adoption remains limited. Before GWUT can be used as an alternate integrity methodology to pressure testing, ILI, or Direct Assessment, there needs to be agreement on a comprehensive practice that will set out performance requirements, equipment and inspector qualifications, and standards for operations in the field. Until these coalesce in a consensus standard, the operators and PHMSA must agree on a consistent interim methodology.

The INGAA Special Permit request and supporting white paper provide a standardized approach to reach agreement and allow operators to conduct GWUT in 2007. In the meantime the industry should agree to validate the existing performance of GWUT, locate a sponsoring SDO, and initiate draft language. These tasks will move GWUT towards a real “Other Technology” alternative to the existing three integrity assessment methodologies.

DESCRIPTION

GWUT applies to all parts of a pipeline or pipeline facility that remain inaccessible to other inspection techniques that make it near impossible to conduct wall loss assessments. These include long ICDA potential segments, inside concrete walls penetrations, road and cased crossings, line pipe, pump station piping, terminal piping, compressor station piping, metering station piping, delivery station piping, regulator station piping, appurtenances connected to line pipe, appurtenances connected to facility piping, fabricated assemblies, valves, tees, elbows, reducers, flanges and any other pipeline equipment or appurtenances. The range is a function of the thickness and sound dampening of the applied coatings and the constraint of the soil or other features constraining the pipe.

GWUT is not yet an integrity assessment methodology! The PHMSA "Go-No Go" document outlines a set of 18 critical points. These points address essential tool performance, personnel skills, and operational requirements to provide an initial inspection methodology to help operators conduct their direct examination tasks for external and internal corrosion direct assessment (ECDA and ICDA).

Direct Evaluation of wall loss - The operator is required to expose or excavate next to likely corrosion sites. The pipe is cleaned to ensure good coupling of the sound between the inspection collar and the pipeline. The amplitude of the returned sound intensity and the directionality are required to assess the magnitude and extent of any unidentified reflection signals. These are all assumed to be corrosion damage. The inspection technique can not yet distinguish between internal and external corrosion damage.

The INGAA response to PHMSA's 18 points suggests a method to set ranges of detection criteria and classify these unknown indications. These classifications each come with an appropriate prevention and mitigation response. The interval until the next integrity assessment needs to be determined using both the ECDA and ICDA methodologies. There is also a shortage of qualified inspectors. Qualifications could be accelerated if the operators arranged for a set of documented corroded pipe samples that would be available for new inspector training, equipment performance validation, and periodic inspector qualification validation.

A standard is needed similar to API 1163 for ILI which includes not only the performance of the inspection tools but also requires qualification of the inspectors (ASNT ILI PQ 2005) who conduct and interpret the information plus and standard for conducting field operations (through NACE RP0102).

APPENDIX 10

INGAA SURVEY ON REPAIRS IN HIGH CONSEQUENCE AREAS

INGAA

Appendix 10: INGAA Survey on Repairs in High Consequence Areas

Number of Transmision Miles (2004 PHMSA Annual Report)	155,054
Number of HCA Miles (February 2006 report)	7,025
2004 HCA Miles Inspected	1488

Number of Repairs in a High Consequence Area as reported to PHMSA utilizing the Semiannual IMP Performance Reporting Form

Cause of Repairs	**First half 2004 (scheduled repairs)**	**First half 2004 (immediate repairs)**	**Second half 2004 (scheduled repairs)**	**Second half 2004 (immediate repairs)**	**2004 Scheduled Repairs per hundred miles**
Corrosion					
**External Corrosion*	2	0	20	4	1.479
**Internal Corrosion*	0	0	0	0	0.000
**SCC*	0	0	0	0	0.000
Manufacturing Defect	0	0	0	0	0.000
**Long Seam*	0	0	0	0	0.000
**Pipe Body*	0	0	0	0	0.000
Mechanical Joint Failure/Separation					
Girth Weld/Fabrication Weld	0	0	0	0	0.000
Original Construction Damage					
** Wrinkle Bend or Buckle*	0	0	0	0	0.000
** Mechanical damage*	0	0	0	0	0.000
** Girth Welds*	0	0	0	0	0.000
** Plain Dent*	1	0	6	0	0.471
** Sharp Dent*	0	0	0	1	0.000
** Plain Dent with Mechanical metal loss*	0	0	2	0	0.134
** Sharp Dent with mechanical metal loss*	0	0	0	1	0.000
** Plain Dent with corrosion*	0	0	2	5	0.134
** Sharp Dent with corrosion*	0	0	0	2	0.000
** Mechanical metal loss*	0	0	0	0	0.000
** Mechanical metal loss with corrosion*	0	0	0	0	0.000
Excavation or post construction damage					
** Plain Dent*	0	0	0	0	0.000
** Sharp Dent*	0	0	0	0	0.000
** Plain Dent with Mechanical metal loss*	0	1	0	2	0.000
** Sharp Dent with mechanical metal loss*	0	0	0	5	0.000
** Plain Dent with corrosion*	0	2	0	0	0.000
** Sharp Dent with corrosion*	0	0	0	0	0.000
** Mechanical metal loss*	0	0	0	0	0.000
** Mechanical metal loss with corrosion*	0	0	0	0	0.000
Equipment Failure					
Precautionary removal (does not fit criteria)	0	0	49	0	3.294
Total	3	3	79	20	

Appendix 10: INGAA Survey on Repairs in High Consequence Areas

Note: 2006 data currently being compiled.
Expected March 2007

2005 HCA Miles Inspected	754	**2006 HCA Miles Inspected**	87

2004 Immediate Repairs per hundred miles	First half 2005 (scheduled repairs)	First half 2005 (immediate repairs)	Second half 2005 (scheduled repairs)	Second half 2005 (immediate repairs)	2005 Scheduled Repairs per hundred miles
0.269	0	1	22	20	2.919
0.000	0	0	1	0	0.133
0.000	0	0	0	0	0.000
0.000	0	0	0	0	0.000
0.000	0	0	2	0	0.265
0.000	0	0	1	0	0.133
0.000	0	0	0	0	0.000
0.000	0	0	2	0	0.265
0.000	0	0	0	0	0.000
0.000	0	0	0	0	0.000
0.000	4	0	19	2	3.051
0.067	0	0	0	0	0.000
0.000	0	0	4	1	0.531
0.067	0	0	0	0	0.000
0.336	0	0	0	0	0.000
0.134	0	0	0	0	0.000
0.000	0	0	1	0	0.133
0.000	0	0	0	0	0.000
0.000	4	0	0	0	0.531
0.000	0	0	1	0	0.133
0.202	2	3	2	2	0.531
0.336	0	0	0	4	0.000
0.134	0	0	0	0	0.000
0.000	0	0	0	1	0.000
0.000	0	0	0	0	0.000
0.000	0	0	0	0	0.000
0.000	0	0	2	1	0.265
	10	4	57	31	

Appendix 10: INGAA Survey on Repairs in High Consequence Areas

2005 Immediate Repairs per hundred miles	Total	Cause of Repairs
		Corrosion
2.786	126.4524	**External Corrosion**
0.000	1.13267	*Internal Corrosion*
0.000	0	*SCC*
0.000	0	**Manufacturing Defect**
0.000	2.26534	*Long Seam*
0.000	1.13267	*Pipe Body*
	0	**Mechanical Joint Failure/Separation**
0.000	0	***Girth Weld/Fabrication Weld***
	0	**Original Construction Damage**
0.000	2.26534	* *Wrinkle Bend or Buckle*
0.000	0	* *Mechanical damage*
0.000	0	* *Girth Welds*
0.265	41.78725	* *Plain Dent*
0.000	1.067216	* *Sharp Dent*
0.133	7.79778	* *Plain Dent with Mechanical metal loss*
0.000	1.067216	* *Sharp Dent with mechanical metal loss*
0.000	9.470509	* *Plain Dent with corrosion*
0.000	2.134431	* *Sharp Dent with corrosion*
0.000	1.13267	* *Mechanical metal loss*
0.000	0	* *Mechanical metal loss with corrosion*
	0	**Excavation or post construction damage**
0.000	5.530679	* *Plain Dent*
0.000	1.13267	* *Sharp Dent*
0.663	16.39568	* *Plain Dent with Mechanical metal loss*
0.531	9.866757	* *Sharp Dent with mechanical metal loss*
0.000	5.134431	* *Plain Dent with corrosion*
0.133	25.13267	* *Sharp Dent with corrosion*
0.000	0	* *Mechanical metal loss*
0.000	0	* *Mechanical metal loss with corrosion*
	0	**Equipment Failure**
	0	
	0	
0.133	55.69157	***Precautionary removal (does not fit criteria)***
		Total

APPENDIX 11

INGAA SURVEY ON DEFECTS FROM TIME OF CONSTRUCTION