ANSI Technical Report No. ANSI-GPTC-Z380-TR-1
November 18, 2001 (Withdrawn 3/30/12)

AGA Catalogue Number X69806

Review of Integrity Management For Natural Gas Transmission Pipelines

An ANSI Technical Report by the
ASC GPTC Z380, an ANSI Accredited Developer

ASC GPTC Z380 Secretatriat

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II. Forward

The Gas Piping Technology Committee (GPTC) was established as the Gas Piping Standards Committee (GPSC) in 1970 as an American Society of Mechanical Engineers (ASME) committee. It was formed by the ASME to maintain an active role in the pipeline safety activities in the United States after the adoption of the Minimum Federal Safety Standards, 49 CFR Part 192. The GPSC changed its name to GPTC in 1982 and its affiliation from the ASME to the American Gas Association (AGA) in 1990. It became an American National Standards Institute (ANSI) accredited committee (ASC GPTC Z380) in 1992. GPTC is renowned for its publication, *Guide for Gas Transmission and Distribution Piping Systems (ANSI/GPTC Z380.1)*, which provides valuable guidance to gas operators in complying with the pipeline safety regulations in the United States (49CFR Parts 191 and 192). The GPTC also plays an important role in proposing improvements to pipeline safety regulations through petitions to the Research and Special Programs Administration (RSPA) of the Department of Transportation (DOT) for rule changes to Parts 191 or 192. The development of technical reports is another vehicle that the GPTC uses to address and promote pipeline safety.

The GPTC consists of members with technical expertise in research, design, construction, testing, operations, and maintenance of natural gas gathering, transmission, and distribution systems. The membership of this consensus-based committee is balanced between gas distribution operators, transmission companies, manufacturers, and general interest personnel including federal and state regulators. As an independent and consensus-based committee, the GPTC requires that published technical materials be written with the purpose or intent of advancing pipeline safety, not the views or positions of any particular organization that may sponsor participation of any of its members.

This report presents an approach for managing the integrity of steel natural gas transmission pipelines. It represents an accumulation of ideas and practices employed by operators in the natural gas industry regarding testing, repairing, and validating the integrity necessary to ensure safe and reliable natural gas pipeline systems. The report provides a general reference for developing or modifying integrity management plans. It is recognized that there may be other techniques existing or being developed to monitor threats to pipeline integrity and to confirm integrity that are not addressed in this report. It is also recognized that other approaches used by operators may result in plans that appear different from the examples described in this report.

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III. INTRODUCTION

Integrity management is an integral part of an operator's mission to provide safe and reliable delivery of natural gas through its pipeline systems. Integrity management is a process of identifying, assessing, evaluating, and mitigating threats to the integrity of a pipeline system. Integrity management planning begins during the pipeline development stage, which includes consideration of route selection, material selection, and design of the pipeline system. It is an integrated process and should not be viewed as a set of independent activities. Integrity management is an evolving process providing for the long-term integrity of a pipeline system. Integrity management considerations encompass new and existing technologies and methods, along with the changing conditions under which a pipeline operates. Whether the pipeline is engaged in the gathering, transmission, or storage of natural gas, the operator uses integrity management practices to maintain its serviceability. Mitigating actions for protecting a pipeline against factors affecting its integrity may be common to many pipelines; however, each type of operation: gathering, transmission, and storage presents unique integrity challenges to the operator. The focus of this report is to describe actions that operators consider in managing the integrity of transmission pipelines.

This report describes methods that can be used to define an integrity level for a pipeline. Ideally, segment information for the pipeline is established and recorded at the time of initial design and construction. However, in some cases pipeline parameters may be established after the facilities have been placed in service.

This report describes a framework that is useful in a written integrity management plan (IMP):

- Identification of integrity concerns and threats.
- Collection, integration, and evaluation of data.
- Identification and evaluation of risk.
- Establishment of integrity programs and mitigation techniques.
- Assessment of plan effectiveness for continuing improvement.

It is recognized that there may be other techniques that exist or are being developed to monitor threats to pipeline integrity and to confirm integrity issues that are not addressed in this report. It is also recognized that other approaches used by operators may result in plans that appear different from the one described here. This document is intended to provide examples that may be considered in developing a comprehensive pipeline IMP.

A. Integrity Management Plan

An IMP is a written, systematic approach used to maintain the integrity of pipeline facilities at levels that provide safety and reliability. It helps operators to comprehensively evaluate an entire range of threats to pipeline integrity by integrating and analyzing available information about their pipelines. Although operators employ integrity management principles, not all of them take these actions within the framework of a formal written plan. A written plan provides a road map for the assessment, integration and analysis of data, and courses of action available in maintaining pipeline integrity. The data analyzed include information from existing sources such as:

- Inspections, surveys, and test results.
- Documentation of maintenance performed.
- Records of leaks and failures.
- Encroachment records.
- Records of excavation damage.

Available pipeline integrity information and assessment of relative risk can be considered to systematically define the actions needed to address pipeline integrity concerns.

B. Purpose of Integrity Management Plan

The purpose of an IMP is to maintain a safe and reliable pipeline system by monitoring and acting upon threats to pipeline safety in a systematic fashion. The plan provides for an initial pipeline integrity assessment and periodic confirmation of the pipeline's integrity through inspection, testing, and assessment of historical data. When an operator maintains the integrity of its pipeline system, it can provide reliable service for an indefinite number of years.

There are a number of reasons why maintaining the integrity of a pipeline is important to the operator. These include:

1. Protecting the public and employees. Where pipelines and people are in close proximity to each other, or where population development encroaches on areas where pipelines exist, maintaining pipeline integrity is important to reduce the probability of incidents that could affect the safety of the public and employees.

2. Protecting the environment. Although natural gas generally does not adversely affect the environment, ignition of leaking natural gas could produce adverse consequences.

3. Preventing interruption of service. Transmission pipelines are installed for the purpose of transporting natural gas from production areas to areas of consumption. The public relies on these pipelines to provide a reliable source of fuel. Effective integrity management reduces the unacceptable disruptions of service.

4. Reducing liabilities. It is in the operator's best interest to ensure that compromises in pipeline integrity do not result in failure of the pipeline. The loss in public trust, the loss of revenues, and the potential liability associated with the consequences of failure are detrimental to the operator's business.

5. Protecting and preserving investment. Operators spend billions of dollars to construct, operate, and maintain the pipeline systems used to transport natural gas for consumption by the public. Operators follow industry standards that are based on good engineering principles in designing, testing, operating, and maintaining these pipeline systems. Maintenance of pipeline integrity will permit safe and reliable operation of pipeline systems for many years. Many pipeline systems in this country are over 50 years old and continue to operate safely. Continuous integrity management will provide safe and reliable gas supply to the public at a reasonable cost.

C. How Regulations Foster Integrity Management

It is no coincidence that pipelines have safely transported gas for so many years. Many of the pipelines in this country were designed, constructed, and operated under the American Society of Mechanical Engineers (ASME) B31.8 Code well before the promulgation of Federal Regulations, 49 CFR Part 192. The ASME B31.8 Code is a recognized integrity standard. Code provisions in this document include the key elements of an IMP. The B31.8 Code is the source document for the current 49 CFR 192. Since the adoption of 49 CFR Part 192 as the Federal Regulation in 1970, the Office of Pipeline Safety (OPS) has promulgated numerous additional requirements that deal with integrity issues (particularly in the areas of damage prevention and corrosion control.) The GPTC Guide contains accepted practices for complying with these regulations and is useful in establishing integrity management programs. Some states have requirements in addition to the Minimum Federal Safety Standards.

IMPs incorporate these established minimum standards for pipeline safety which require additional measures in areas of higher population density, areas subject to abnormal loading, and areas of harsher operating environments. The integrity of a newly installed pipeline is confirmed through the testing requirements of the regulations. Once in service, the regulations require monitoring to assess the impact that changing conditions may have on maintaining acceptable safety levels established by the regulations. Monitoring is required more frequently in areas with the highest potential consequence (e.g., in Class 3 and Class 4 location areas and at highway and railroad crossings). Threats to pipeline integrity are addressed on both a segment-by-segment basis and a system-wide basis. Segment issues are addressed by regulations that deal with specific issues such as: corrosion, material defects, and damage caused by excavation, natural hazards, and other outside forces. Systemic issues are identified as a result of the integration and analysis of the data developed by addressing the issues identified on a segment-by-segment basis. A failure investigation on a pipeline segment may also suggest a systemic problem. When the integrity of a pipeline is adversely affected, the regulations require replacement, repair, monitoring, or lowering the operating pressure of the pipeline.

Regulations require operators to monitor for conditions that may affect the integrity of the pipeline and to take remedial action whenever analysis indicates the need for corrective measures. Some of the threats to pipeline integrity that are monitored include:

- Excavation Damage. Excavation damage is the most common cause of pipeline "incidents" as defined by §191.3. Subpart L of 49 CFR Part 192 prescribes minimum requirements for the safe operation of pipeline facilities including provisions for preventing excavation damage to pipelines. The natural gas industry has focused considerable effort toward preventing excavation damage to pipelines. The industry through Common Ground, a study of one-call systems and damage prevention best practices, identified and validated best practices for preventing damage to underground facilities associated with excavation activities. Section 192.705 requires pipeline monitoring for excavation and construction activities affecting or possibly affecting integrity. Sections 192.614 and 192.616 require activities aimed toward preventing excavation damage through participation in damage prevention programs incorporating one-call systems, educating existing and potential excavators, and educating the public regarding the threat to pipeline safety from improper excavations. Section 192.614 also includes requirements for the operator to communicate the location of its pipeline(s) to excavators intending to excavate in the vicinity of the pipeline facilities. Significant progress toward reducing excavation damage has been accomplished through one-call systems and damage prevention legislation enacted by states with cooperation among pipeline operators and underground contractors.

- Corrosion. Corrosion is the second most common cause of pipeline incidents and the most common cause of leaks in gas pipeline systems. Operators are required to comply with Subpart I of Part 192 that prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion. Operating and maintaining the pipelines in accordance with these regulations will reduce the chance of corrosion-related leaks and incidents along with the accompanying consequences. Sections 192.459, 192.465, 192.473, 192.475, 192.477, and 192.481 all address monitoring activities related to conditions that could lead to external or internal corrosion. Sections 192.705 and 192.706 require pipeline patrols and leakage surveys monitoring for evidence of a release of natural gas from the pipeline resulting from corrosion or other damage affecting pipeline integrity.

- Material Imperfections and Other Damage. Whenever the pipe is exposed, §192.459 requires examination of pipe for evidence of external corrosion. As part of this inspection an operator may find other conditions affecting the pipeline integrity. Aboveground facilities are also patrolled or inspected for evidence of conditions that may be detrimental to pipeline integrity under §§192.481 and 192.705. Subparts L and M of Part 192 provide requirements regarding detection and repair of leaks and cracks in pipelines.

- Environmental Hazards. Landslides, erosion, flooding, earthquakes, and other environmental hazards pose a threat to pipeline integrity. When patrolling in accordance with §192.705, the operator looks for evidence that these conditions may have affected or could potentially affect the integrity of the pipeline.

Once a pipeline integrity concern is suspected or confirmed, the operator evaluates the degree to which integrity was affected and takes remedial measures. If corrosion is the cause, §192.485 is used as the basis for evaluating the impact on the integrity, and §§192.483 and 192.485 describe remedial measures. For other causes, §§192.703 and 192.713 are used as the basis for evaluating the impact on the integrity. §§192.703, 192.711, 192.713, 192.715, 192.717, and 192.719 describe actions to be taken to restore pipeline integrity.

In addition to monitoring for segment integrity issues, the operator may identify systemic issues in meeting the requirements of §192.613, Continuing Surveillance, and §192.617, Failure Investigation.

- Continuing Surveillance. Section 192.613 comes from Section 850.5 of the 1968 edition of the B31.8 Code. As described in the B31.8 Code, continuing surveillance is to be used by the operator "as a means of maintaining the integrity of its pipeline system." It is an integration and analysis of historical records of inspections, maintenance, patrols, surveys and tests conducted to detect whether unusual operating and maintenance conditions exist on the pipeline system that may not be evident through any individual inspection, maintenance, patrol, survey or test. To facilitate the analysis to detect these conditions, the regulation requires the integration of inspection, maintenance, patrol, survey and testing information regarding each segment of the pipeline system. The operator performs these analyses across the pipeline system to determine if there are any unusual operating and maintenance conditions and if they are isolated to specific segments or are systemic.

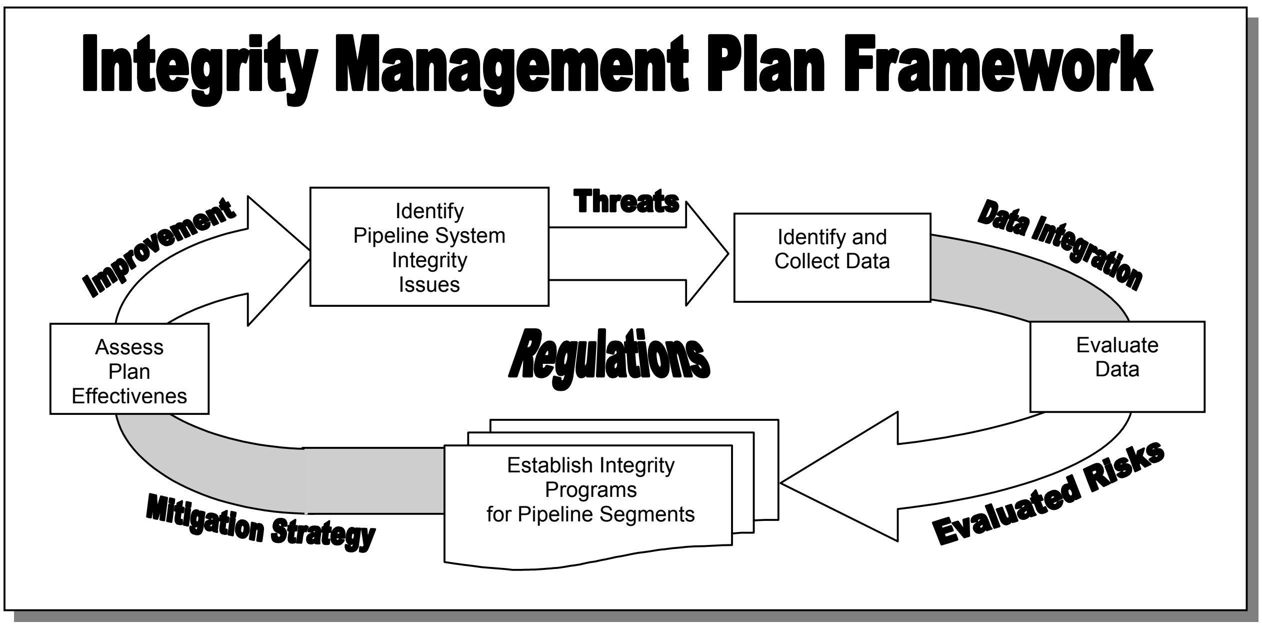
  Immediate hazards are addressed promptly. Where no immediate hazard exists, the regulation requires that the operator initiate a program to recondition or phase out segments that are found to be in unsatisfactory condition. If neither is possible, the maximum allowable operating pressure is reduced to a safe level.

- Investigation of Failures. Section 192.617 requires the operator to have procedures for analyzing accidents and failures for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence. Like the analyses conducted under continuing surveillance, the failure analysis can identify if the problem is isolated to a specific site or if the problem is systemic. If the problem is not an isolated occurrence, the operator takes action to address similarly situated pipelines where conditions similar to those at the accident site or failure location are likely to exist.

IV. OVERVIEW

This section presents an overview of how operators of natural gas transmission pipelines develop integrity management plans. A general framework for a pipeline integrity management plan (IMP) is shown in Figure 1.

Figure 1 - Framework for an Integrity Management Plan



The framework for an IMP often consists of a process of the following items, with pipeline safety regulations as a centerpiece:

- Identify pipeline system integrity issues leading to an understanding of the threats.
- Identify and collect data[1] leading to data integration.
- Evaluate data leading to an understanding of risks.
- Establishment of integrity programs leading to specific mitigation strategies.
- Assess plan effectiveness leading to improvements of the IMP.

The items in this framework are summarized below and described in detail in the following sections.

[1] Throughout this report the terms data and information will be used interchangeably to describe all information used in managing pipeline integrity ranging from operator personnel knowledge of the pipeline system to electronic databases.

A. Identify Pipeline System Integrity Issues

There are many variables that operators examine when establishing an IMP. Operators review their systems and identify the integrity issues that must be considered within their IMP. These issues are examined considering the possible threats to each segment of the pipeline system.

B. Threats

The identification of threats to a pipeline and the management of those threats are integral parts of an IMP. The types of threats to a pipeline are numerous and the mechanics of failure can vary. Therefore, significant threats to particular pipeline segments and the risk they impose are considered in determining an overall approach to integrity management. Knowledge of the pipeline system; threats to the system; the tools that protect against, inspect for, and monitor those threats; and mitigation measures are necessary to develop an IMP addressing diverse and dynamic sets of threats and failure modes.

C. Identify and Collect Data

The identification, collection, and verification of data supporting the IMP are crucial. This includes gathering of available data, making efforts to define and gather additional data necessary to support the operator's risk assessment process, validating data, and taking steps necessary for data integration. Integrity data can be readily captured for new facilities. For existing pipelines this data may not be readily available. The IMP defines the process required to identify the methods to obtain required data to support the operator's risk assessment.

D. Data Integration

Integration of data is one of the keys to the implementation of an effective integrity management program. The data collected is assembled to provide a complete picture of the pipeline system, with special emphasis on key indicators selected by the operator. While the concept of data integration is simple, the implementation can be difficult.

E. Evaluate Data

Data and information are reviewed and analyzed to identify and assess risks. Quantitative analysis or qualitative review or both are used to identify factors that influence risk to pipeline integrity. The approach to assessing risks tends to be unique to the operator and to the operating environment of the individual pipeline segments. As more data and information become available, operators update their analysis. As results from the analysis become available, operators gain a greater understanding of the factors influencing pipeline integrity. This can lead to refinement of the risk assessment approach.

F. Evaluated Risks

Risk is an inherent part of life and is associated with industrial activities as well as nature. While the overall risk of an operating pipeline can be managed, changed, or possibly reduced, it cannot be reduced to zero. The process or result of changing risks of one source or type can affect risks of another source or type. Risk is generally defined as the product of the likelihood of an event and the consequence of that event. Each of these events results in the loss of pipeline integrity. Understanding risk factors is an important part of an IMP, because it is used to identify mitigation strategies. The total risk for a particular pipeline segment is the summation of the risks from the various threats to that segment.

G. Establish Integrity Programs for Pipeline Segments

Pipeline segment integrity programs are developed within the IMP framework. At this stage, operators identify the threats to which a specific pipeline segment is exposed. Approaches used by operators for assessing and prioritizing a pipeline segment for the development of a mitigation strategy covers the spectrum from the use of operational knowledge through use of probabilistic based models. Regardless of the approach used for assessing and prioritizing segment integrity concerns, the operator's local knowledge, skill, and judgement play an important role in establishing pipe segment integrity programs.

H. Mitigation Strategy

After establishing integrity programs for pipeline segments, operators develop a mitigation strategy. This involves examining individual pipeline segments within the broader scope of system-wide integrity. Mitigation is the action of reducing a pipeline's integrity-related concerns by addressing factors affecting either the likelihood of failure or the consequence expected from a loss of pipeline integrity. Mitigation actions generally fall into one of the following four categories: monitoring, inspection, remediation, or education. Selecting the appropriate mitigation action(s) is based on effective use of resources for improving a pipeline's integrity. Mitigation may also lead to improvements in the way a pipeline is designed, constructed, tested, and operated.

A combination of mitigation actions may be employed along a segment of pipeline to ensure or improve its integrity. These actions may require immediate implementation or may be scheduled over a short- or long-term.

The final result is a comprehensive strategy of specific mitigation actions that reduce integrity concerns for the natural gas transmission pipeline.

I. Assess Plan Effectiveness

The effectiveness of an IMP is assessed by collecting performance information and conducting audits to evaluate the success of integrity assessment methods, pipeline repair activities, and other prevention and mitigation activities. The techniques employed to collect performance information may include internal benchmarking, external benchmarking, integrity management process audits, and feedback from operating personnel. One or more of these techniques can be employed to assess the effectiveness of systems, processes, and results that support integrity management decisions.

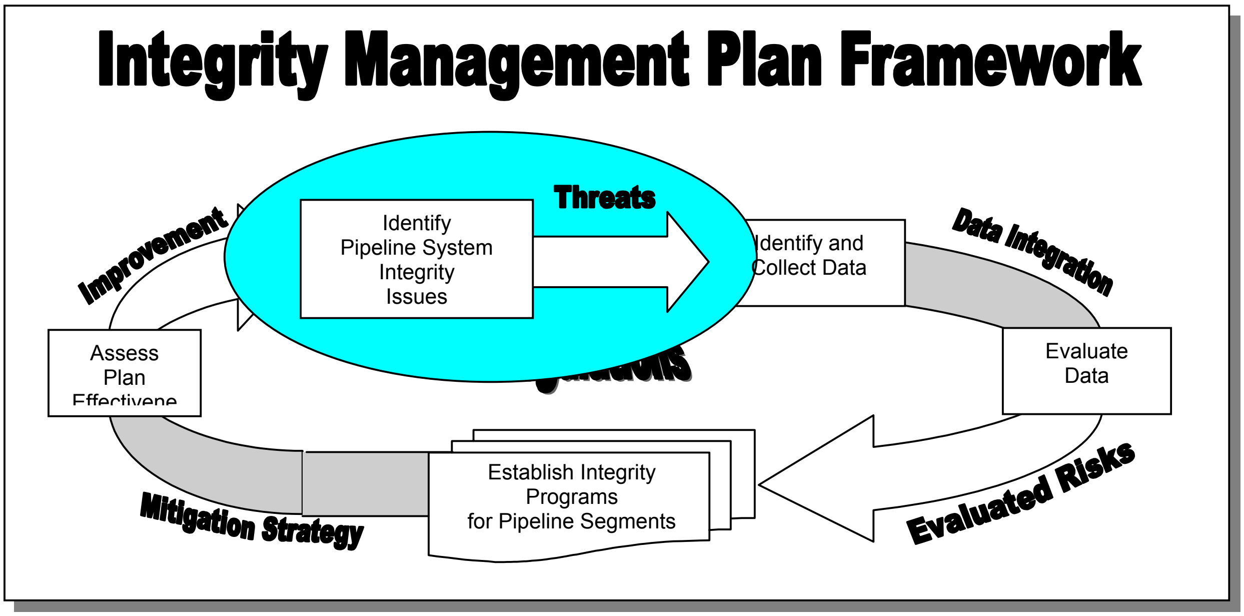
J. Improvement

Pipeline systems and the environment in which they operate are dynamic. IMPs are adapted to meet the changes to the pipeline system, its environment, new technology, and the industry challenges. The performance measurement and audit results along with operating personnel feedback are essential to the continuous improvement of the plan.

V. ISSUES AND THREATS TO PIPELINE INTEGRITY

Figure 2 highlights Integrity Management Plan (IMP) activities described in this section.

Figure 2 – Issues and Threats to Pipeline Integrity



A. Identify Pipeline System Integrity Issues

No two transmission systems are identical. Transmission systems vary in length[2], operating pressure, diameter of pipe, mechanical properties of pipe, operating environments, and other characteristics. Integrity concerns vary from one location to the next and from one section of pipe to the next. Not every section of pipe is exposed to the same risks. Therefore operators generally review integrity concerns on a segment-by-segment basis.

Typically an operator conducts reviews to identify integrity concerns using company personnel with local knowledge and technical expertise about the specific pipeline segment. Considerations that may affect both the likelihood of a pipeline integrity failure and the expected consequence from the loss of pipeline integrity are identified. Conditions that might increase the likelihood of pipeline failure are referred to as threats.

B. Threats

The demands on the pipeline system and threats to pipeline integrity are constantly changing. The identification of threats to a pipeline and the management of those threats are integral parts of the IMP. The types of threats to a pipeline are numerous and the mechanics of failure may be time dependent, static, or random[3]. Table 1 contains a representative list of threats to pipeline integrity.

Table 1: A LIST OF THREATS TO PIPELINE INTEGRITY

Threats	Comments
Defective girth weld	Some examples include: • Lack of penetration. • Lack of fusion. • Porosity. • Welds with lower yield strength than the pipe. • Arc burn outside of the heat affected zone. • Low toughness welds (e.g., early arc or oxyacetylene welds). • Inadequate transition of wall thickness • Unusual joint designs (e.g., bell and spigot joints joined by fillet welds)
Defective pipe	Some examples include: • Blisters (raised spots on the surface of the pipe that result from the expansion of gas in cavities in the wall of the pipe). • Ovality (oval or egg shaped pipe). • Laminations (internal metal separation creating layers parallel to the pipe surface). • Inclusions (impurities within the pipe wall). • Burnt pipe (a sporadic lap-welded pipe problem that occurs when the edges of the skelp are heated too high and austenite grain-boundary sulfides form, making the pipe brittle and susceptible to cracks). • Hard spots (high hardness areas in the pipe caused by localized quenching during hot rolling of the skelp).
Earth movement	Landslides, earthquakes, or mining (e.g., long wall) may remove lateral support from the pipeline, buckle the pipeline, or collapse the pipeline. Earth movement may also expose the pipeline to greater threats, such as excavation damage or increased overburden stresses.

[2]Some transmission systems have less than a mile of pipe and others have tens of thousands of miles of pipe.
[3] See Hartford Steam Boiler Inspection and Insurance Company Report

Table 1: A LIST OF THREATS TO PIPELINE INTEGRITY	
Threats	**Comments**
Equipment malfunction	This may occur due to poor equipment selection, poor design, improper installation, poor manufacturing, insufficient or improper maintenance, or improper operation.
Erosion	This may result from heavy rain or floods that erode support from around the pipeline, expose the pipeline to damage by outside force, or isolate portions of the system from the operator's control.
Excavation damage	This may result from activities of outside contractors, farmers, landowners, public works, other utilities, or the operator. Excavation damage can result from routine open-trench excavation, the use of augers, directional drilling, or other earth moving activities. Some types of excavation damage to the pipeline include dents, dents with stress concentrators, and gouges. Damage may also impact associated facilitiessuch as pipeline coating, cathodic protection systems, and pipeline markers.
External and internal corrosion	This is metal loss caused by electrochemical, galvanic, microbiological, or other attacks on the pipe due to external or internal conditions affecting the pipe.
Hydrogen induced cracking (HIC)	This is caused when abnormally high cathodic protection potentials create free hydrogen that can accelerate crack propagation to failure. Also, hydrogen introduced during the welding process and cooling period may cause HIC.
Hydrogen induced damage	This is a form of degradation of metals caused by exposure to environments (liquid or gas) which cause absorption of hydrogen into the material. Some examples include: • Formation of internal cracks, blisters, or voids in steels. • Embrittlement (i.e., loss of ductility).
Pipe seam defect	Some examples include: • Selective seam corrosion, also known as preferential seam corrosion, is corrosion across or adjacent to longitudinal seams (most prevalent in ERW pipe.) • Fatigue cracking from improper loading of rail cars for shipment. • Low quality seams associated with early manufacturing processes, including flash welded seams and very early ERW processes (e.g., pre-1970 ERW pipe). • Incomplete fusion (a lack of complete coalescence of portions of the metal in a weld joint). • Hook cracks (upturned fiber imperfections caused by imperfections at the edge of the skelp).

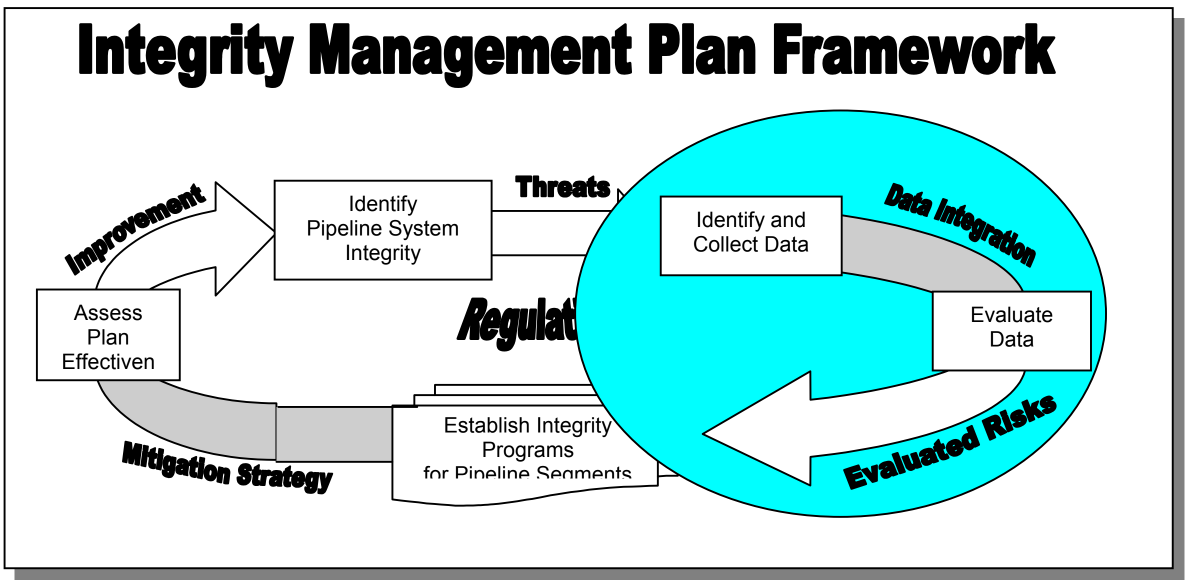
Table 1: A LIST OF THREATS TO PIPELINE INTEGRITY	
Stress corrosion cracking (SCC)	Brittle cracking of a metal resulting from the combined effects from localized corrosion and tensile stress. SCC requires three elements to occur: a susceptible microstructure, a conducive environment, and a tensile stress. Where these conditions exist, small cracks may lengthen, deepen, and form colonies of cracks. Cracks may grow to sizes that threaten the pipeline. SCC is associated with high or low pH environments.
Vandalism	This may occur when a person(s) purposely causes damage to the pipeline. Examples are numerous and may range from graffiti to physical damage of the pipeline.

Once the threats to the system are identified, data is collected to evaluate the threats.

VI. COLLECTION AND INTEGRATION OF DATA

Good data is essential to an integrity management plan (IMP). The integration of collected data into useable information provides the foundation for integrity management decisions. Historical trending, data integration, and system-wide analysis provide the details of where and what to look for in order to address pipeline integrity issues. In the past, data was often managed by individual corrosion, metallurgical, construction, and other departments. As a result, individual departments managed data based on their area of expertise. Pipeline integrity management promotes system-wide coordination and integration among departments from project design through construction and continuing with day-to-day operations to ensure threats are addressed. Figure 3 highlights IMP activities described in this section.

Figure 3 – Collection and Integration of Data



A. Identify and Collect Data

The existing data about a pipeline system needs to be collected and analyzed. The amount and type of data vary among operators and pipeline systems. For newer pipeline systems, operating history, construction, material, and installation data is readily available. For older pipeline segments, similar data may not be initially available. During the preliminary assessment process, the need for additional basic data (e.g., wall thickness or pipe grade) or additional testing and inspection data may be identified. If many pipeline segments require additional data, the operator prioritizes the pipeline segments for data gathering.

Current pipeline regulations require operators to perform many tests and inspections. A listing of the tests, inspections, and records is given in the GPTC Guide for Transmission and Distribution Systems (ANSI Z380.1) – Guide Material Appendix G-192-17. In addition to this data, operators also collect other data that can be useful in assessing the integrity of their system.

Some of the data needed to perform an assessment are listed in Tables 2 through 8. All the listed data may not be needed for any given pipeline system. Data gathered for one segment may assist in analyzing and prioritizing similar pipeline segments.

Table 2: MATERIAL INFORMATION

Type Of Data	Comments And Factors To Consider
Date of manufacture	Problems may be linked to the vintage of pipe, e.g., pre-1970 ERW pipe.
Manufacturer	Historical problems may be linked to various manufacturers.
Pipe diameter	Used to determine stress levels and area affected by a rupture.
Pipe grade	Used to determine operating stress levels.
Pipe properties (mill test report)	Physical and chemical properties of the steel, pipe toughness, yield strength, and tensile properties are factors to consider.
Pipe wall thickness	Used to determine operating stress levels.
Type of coating	Some coatings are more prone to disbondment or stress corrosion cracking.
Type of seam	Problems may be linked to pipe manufacturing process. For example, low frequency electric resistance welded (ERW) pipe may be prone to selective seam corrosion.

Table 3: CONSTRUCTION AND INSTALLATION DATA

Type Of Data	Comments And Factors To Consider
Depth of cover	Greater cover decreases the likelihood of damage by excavation or erosion.
Field coating and repair methods	Some coatings have proven to be preferable to others. For example, some tape applications may result in problems associated with shielding from cathodic protection. Weather conditions at the time of installation may be an issue in some cases.
Hydrostatic tests	The initial hydrostatic test is designed to find material and construction defects. Older pipelines may not have been tested or were tested at low

Table 3: CONSTRUCTION AND INSTALLATION DATA	
Type Of Data	**Comments And Factors To Consider**
	defects. Older pipelines may not have been tested or were tested at low stress levels.
In-Line Inspection (ILI) data following construction	The initial ILI data can be compared to subsequent ILI data to determine changes and potential problems.
Installation date	Work practices and procedures have a tendency to be similar for given periods of time.
Method of bending	Wrinkle bends, for example, may have created problems associated with stress concentrators.
Name of contractor	Work practices and procedures by a particular contractor may be similar from project to project.
Soil and type of backfill	Rocks may have caused pipe or coating damage. Cathodic protection requirements and Stress Corrosion Cracking may also be linked to type of soil and backfill.
Welding inspection	The percentage of welds nondestructively tested and the percentage of welds rejected may be a factor in evaluating pipeline integrity.
Welding procedures	Weld defects and problems may be related to welding procedures.

Table 4: CORROSION CONTROL HISTORY	
Type Of Data	**Comments And Factors To Consider**
Bacteria sampling	Certain types of bacteria are known to contribute to the corrosion process.
Date installed	For pipelines installed prior to 1971, the cathodic protection system may not have been installed until several years after the pipeline installation.
Interference problems	Pipeline integrity can be affected by interference from: • Cathodic Protection (CP) systems on other facilities. • Direct current (DC) and voltage from trains, mining equipment, and other sources. • Alternating current (AC) and voltages from electric transmission systems.
Internal corrosion monitoring	Results of monitoring are useful in determining the risks associated with internal corrosion.
Level and changes in cathodic protection readings	High voltage readings may indicate coating damage, and low voltage readings may indicate inadequate protection. Unexplained changes in readings may indicate a problem. Increasing current requirements may

Table 4: CORROSION CONTROL HISTORY	
Type Of Data	**Comments And Factors To Consider**
readings	indicate problems with the coating or CP system.
Type of cathodic protection	The type of CP system may influence the type of assessment tools. For example, conducting a close-interval survey (CIS) using instant-off data is not feasible where numerous sacrificial anodes are attached directly to the pipeline.

Table 5: OPERATING DATA	
Type Of Data	**Comments And Factors To Consider**
Gas composition	The presence of oxygen, hydrogen sulfide, or high levels of carbon dioxide could influence internal corrosion rates. Rich gas may influence crack propagation.
Operating pressure history	Determines stress levels. Pressure cycling could contribute to fatigue and to susceptibility to stress corrosion cracking (SCC).
Operating temperature	High operating temperatures may damage pipeline coatings. Pipe with low fracture toughness may become brittle at low temperatures. Temperature could also influence pipeline liquid and hydrate formation. Elevated temperatures may influence susceptibility to SCC.
Pipeline liquids	Liquids in the line will increase the likelihood of internal corrosion and erosion. Attention is given to monitoring and maintaining gas quality, running cleaning pigs, eliminating dead ends, and maintaining or removing drips.
Throughput and contract requirements.	Loss of throughput and the inability to meet requirements are possible consequences of failure.

Table 6: LEAK AND FAILURE DATA	
Type Of Data	**Comments And Factors To Consider**
Failure data	Pipeline segments that have high failure rates should receive a higher priority than segments with low failure rates, if the consequences of the failure are equal. If the conditions leading to the failure are known, the operator can look for similar conditions in other pipeline segments, and assign higher priority to those pipeline segments.
Leak data	Pipeline segments that have high leak rates should receive a higher priority than segments with low leak rates, if the consequences of the leak are equal. Determination of the cause of leaks (e.g., material defect, coating damage, shielding, bacteria, excavation damage) is a key factor in assessing

Table 6: LEAK AND FAILURE DATA	
Type Of Data	**Comments And Factors To Consider**
	the integrity of the pipeline segment and taking proper corrective action.
Repair methods	The type of repair methods used may affect the risk assessment of a segment, especially if temporary repairs were made.

Table 7: EXCAVATION ACTIVITIES	
Type Of Data	**Comments And Factors To Consider**
Class location information	The class location and proximity of the public to the pipeline will affect the consequences of failure.
One-call activity	A high volume of one-call activity may affect the risk assessment.
One-call system	The effectiveness of the one-call system may affect the relative risk from excavation damage.
Right-of- way encroachments	Encroachment activity often involves excavation or crossing pipeline facilities with heavy equipment. The level and nature of construction activity may affect the risk assessment.

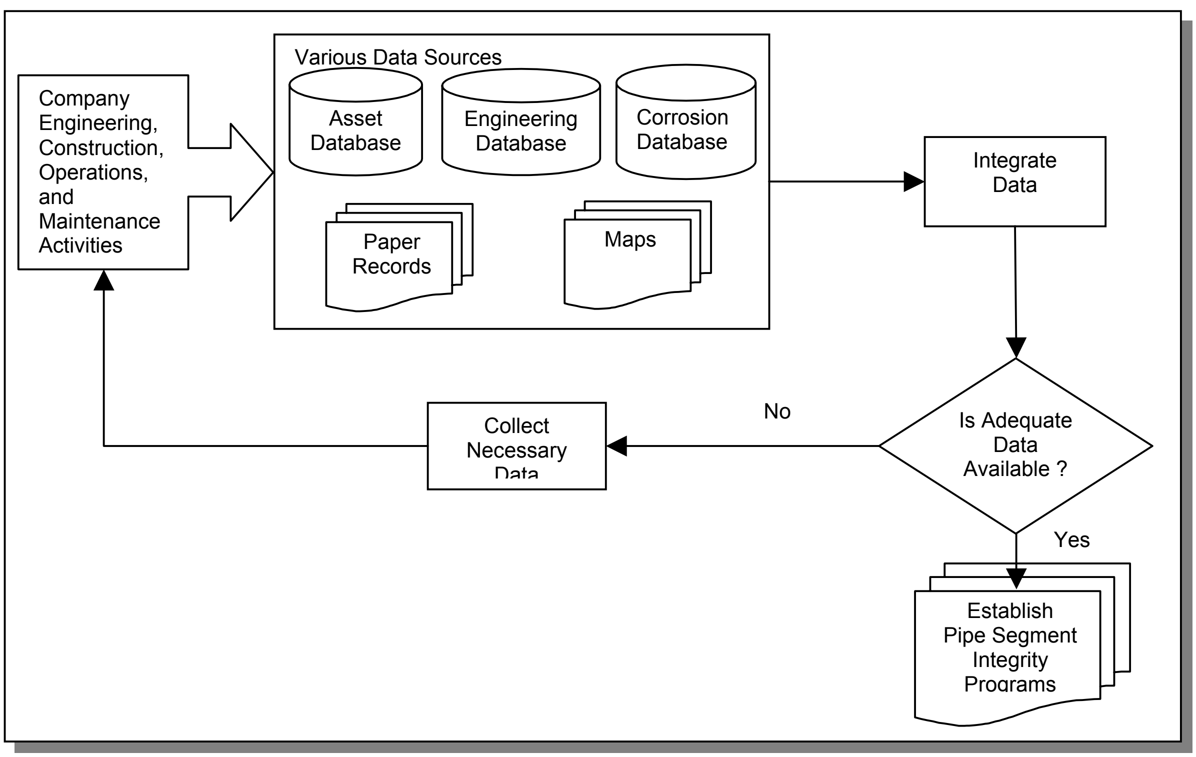
Table 8: PRIOR ASSESSMENT DATA	
Type Of Data	**Comments And Factors To Consider**
Bellhole inspection	Provides location specific data.
In-line inspection	Provides information related to the pipe condition.
Post-installation hydrostatic test	At the time of the test, critical flaws should have been eliminated, but the test could cause sub-critical flaws to grow. Analysis of failures during the test can provide assessment data for the tested segment and similar segments.
Supplemental electrical survey	Tools such as Close-Interval Survey (CIS) and Direct Current Voltage Gradient (DCVG) survey can be used to assess coating integrity.

Data from external sources can also be useful in implementing an IMP. External sources include reports and findings from government agencies, research agencies, manufacturers, other operators, and industry consortiums. These groups provide information on failures, standards, and industry trends.

B. Data Integration

Integration of data provides the information needed to develop and implement an effective integrity management program. Data integration refers to the merging of data and information in a manner or format enabling the operator to evaluate the components of the system as a whole. Data and information come from various sources throughout the organization (see Figure 4). Sources of data and information take many forms, e.g., paper records, spreadsheets, corporate databases, departmental databases, and external sources. While the concept of data integration is simple, its implementation can be difficult. For example, one step in data integration involves developing a common reference system to allow data and information from various sources to be associated with the same location on the pipeline. Advances in computerized data and information management systems may allow for a greater degree of integration to aid in the evaluation of a pipeline system. Data integration is an important part of the IMP because it results in useable information that can lead to better overall analysis of risk.

Figure 4 - Data Integration Flow Chart



1. *Data Integration Example*

The advantages of data integration can be illustrated using the following hypothetical example. During the installation of a housing development, a piece of excavating equipment hits and gouges a transmission pipeline. The damage is not reported to the pipeline operator. The pipeline does not fail but now contains a stress concentrator that could lead to future failure. Sometime after the damage, the pipeline operator conducts a close-interval survey (CIS). In the vicinity of the housing development, a slight decrease in the pipe-to-soil potential is noted, although cathodic protection criteria are still being met. A year later, the operator runs a magnetic flux leakage (MFL) inspection tool. The inspection tool identifies a minor anomaly on the top of the pipeline in the area of the housing development. The operator may now have several pieces of data concerning the pipeline through the housing development. This data could include:

- Record of line location in response to a one-call.
- Record of a facility patrol indicating activity along the rights-of-way.
- Close-interval survey showing a minor anomaly.
- An internal inspection tool survey indicating a minor anomaly.

Each of these items individually may not indicate a serious threat to the pipeline. However, when the data is integrated, by linking to the same point in the pipeline, there is an indication that the pipeline may have been damaged and the integrity of the pipeline may have been compromised.

2. *Barriers to Overcome in Data Integration*

The integration required to link all the data to the same point is not an easy task. Some of the barriers to overcome in data integration include the following:

- Data may be stored in various locations. Storage locations may include operating facilities (e.g., compressor stations or meter and regulator facilities), local field offices, regional or support offices, headquarters, or offices of third party contractors.

- Data may be stored in various formats. Existing data may be in the form of maps, drawings, paper forms, charts, and various electronic databases.

- Data may use different reference points. Data collected for the same point on the pipeline could be referenced using any of the following methods: Engineering or survey station, milepost, Global Positioning System (GPS) coordinates, surface reference, or odometer reading.

- Data may be incomplete or missing. Additional data may have to be collected. If additional data cannot initially be collected, an alternate assessment tool may be needed.

3. *Data Management System*

A data management system can be used to overcome the barriers to data integration. The size and type of data management system needed depends on the amount of data to be analyzed and the operator requirements. Data management systems can take various forms and can be developed in-house or purchased from a vendor.

An effective data management system needs to be able to accept data from various locations and sources. For a small operator with a simple pipeline system, a paper data management system may be adequate. For operators with complex pipeline systems, a computer network system may be useful. Since information from maps and drawings may be needed, a geographical information system (GIS) can be an integral part of the data management system.

A key step in managing data involves correlating data to a common reference system. This allows data from various sources to be associated with the same point on the pipeline. The varying degree of accuracy or precision of the data from various sources also is considered. Table 9 lists some of the reference systems in use and some of the accuracy issues that need to be considered.

Table 9: REFERENCE SYSTEMS FOR DESCRIBING LOCATION ON A PIPELINE

Reference System	Example	Accuracy And Precision Concerns
Engineering or survey station	190+08	Station data can be accurate and precise at the time the pipeline was constructed. Data collected using station references are generally made relative to a visible feature such as a valve set or road crossing. The accuracy of the data depends on the tools used to measure the distance (e.g., survey equipment, tape measure, counting paces, or measuring wheel).
GPS coordinate	N 40^{O}16.7”, W 76^{O} 27.9"	The accuracy range of GPS data can range from inches to several hundred feet depending on the type of equipment, the terrain, and other conditions at the time of measurement.
Milepost	3.6 miles	The concerns are similar to engineering station data.
Odometer reading	1756.7 feet	Data from in-line inspection tools are generally measured by an odometer attached to a wheel on the inspection tool. The accuracy of the odometer can be affected by the condition of the wheel, debris in the pipeline, terrain changes, pipeline

Table 9: REFERENCE SYSTEMS FOR DESCRIBING LOCATION ON A PIPELINE		
Reference System	**Example**	**Accuracy And Precision Concerns**
		features, and pigging speeds.
Surface reference	300 feet north of Smith Road	The accuracy of the data depends on the tools used to measure the distance (e.g., survey equipment, tape measure, counting paces, or measuring wheel), and the distance from the reference point and the nature of the reference point. The accuracy also depends on the precision of the reference point. For example, the 300 feet north of a road may represent a measurement from the centerline, edge of the blacktop, or the shoulder of the road. Furthermore, the location or width of the road may have been changed since it was mapped.

When comparing data from different sources, possible location errors must be reconciled. For example, anomalies indicated by a close-interval survey are generally located by an engineering station reference system. Anomalies indicated by an in-line inspection tool survey are generally located by an odometer reference system. It may be necessary to tie these anomalies to a common reference system. Tying the results of these two surveys to a common reference point may identify areas where both surveys indicate a single pipeline integrity concern.

New technologies continue to improve the accuracy with which an operator may locate a particular point on the pipeline system.

C. Evaluate Data

After data for a system or a particular pipeline segment has been integrated, it is reviewed and analyzed. This evaluation is typically done by a team of personnel with a range of knowledge related to the pipeline system and with a variety of technical expertise. The team determines if the data is comprehensive enough to perform a valid risk evaluation. The team may determine the need for additional data to enable risk evaluation.

In the data integration example described earlier in this report, the results from the in-line inspection would likely have alerted operator personnel to the possibility of metal loss on the top portion of the pipe. The operator may then review close-interval survey results to further investigate this possibility. Additionally, the operator researches other information related to activity at that location on the pipeline.

The team required to evaluate this particular data might include:

- Operating personnel that were involved with the patrols and locate requests in the vicinity of the housing development where the excavation damage is suspected. Aerial patrol reports may include information related to the housing development. A class location study may have been done related to this new construction activity. Local operating personnel have knowledge related to this type of activity, and they have ready access to related documentation.

- Operating personnel involved in corrosion control work who will be able to provide input related to the results of the close-interval survey on this pipeline segment. In this particular example, the decrease in pipe-to-soil potential becomes an important piece of information for evaluating data and for subsequent decision making.

- Operating personnel involved in the analysis of data from in-line inspection (ILI). In this particular example, the MFL in-line inspection data has shown metal loss in the top portion of the pipe at a location.

In this example, initial evaluation of the integrated data indicates the possibility of excavation damage. The operator may conduct a bellhole inspection to evaluate for possible damage. Results of the bellhole inspection would be included in the data evaluation process for this pipeline segment.

D. Evaluated Risks

In addition to the data evaluation process, an operator typically conducts periodic reviews of specific pipeline segment risk factors using company personnel with local knowledge and technical expertise. This may also be done on specific pipeline segments that have been identified as candidates for risk evaluation or on the pipeline system in its entirety, depending on the approach the operator chooses. Several approaches are described in the Case Studies in the Appendix of this report.

These reviews identify considerations that may affect the likelihood of a pipe integrity failure and the consequence that would be expected from the loss of pipe integrity. Some considerations are shown in Tables 10 and 11.

Table 10: FACTORS AFFECTING LIKELIHOOD	
• Age and Results of In-Line Inspection • Age of Pipeline Facilities • Amount and Nature of Excavation Activities • Coating Condition • Coating Type • Damage Prevention Efforts • Depth of Cover • Design Characteristics • Effectiveness of One-Call Programs • External Stress Levels • Gas Quality • Ground Movement • Leak/Failure History – Corrosion – Excavation Damage – Material Failures – Ruptures • Location • Maintenance History	• Number of Defects • Operating Characteristics – Operating Hoop Stress – Pressure Cycling • Pipe Diameter • Pipeline Construction Techniques • Pipeline's Proximity to Hazard • Presence of Liquids • Public Awareness • Soil Type • Stress Corrosion Cracking Leaks • System Configuration • Type of Defects • Type of Repair • Type of Seam • Wall Thickness • Weld Joint Design • Weld Quality

Table 11: FACTORS AFFECTING CONSEQUENCE	
• Access/Use of Rights-of-Way • Depth of Cover • Disruption to Commerce • Environmental (National Parks, Forests, Wet Lands, Navigable Waterways) • Location of Pipe in relation to People and Property • Looping	• Loss of Natural Gas • Loss of Throughput • Maximum Operating Pressure • Pipe Diameter • Population Density/Structures • Service Interruption • Width of Rights-of-Way

1. Defining the Affected Area for Consequence Evaluation

There are a number of published models available that an operator can use to estimate the geographical area that would be affected by a failure on a particular pipeline segment. The consequences of a loss of pressure containment for a particular pipeline segment are a function of the area affected by the event and the value that the operator places on the anticipated damage or loss resulting from the event. The area affected is generally a function of the pipe diameter and the pressure in the pipe at the time of the event. The area affected increases as the pipe diameter or pressure increases. Among the published models are the following:

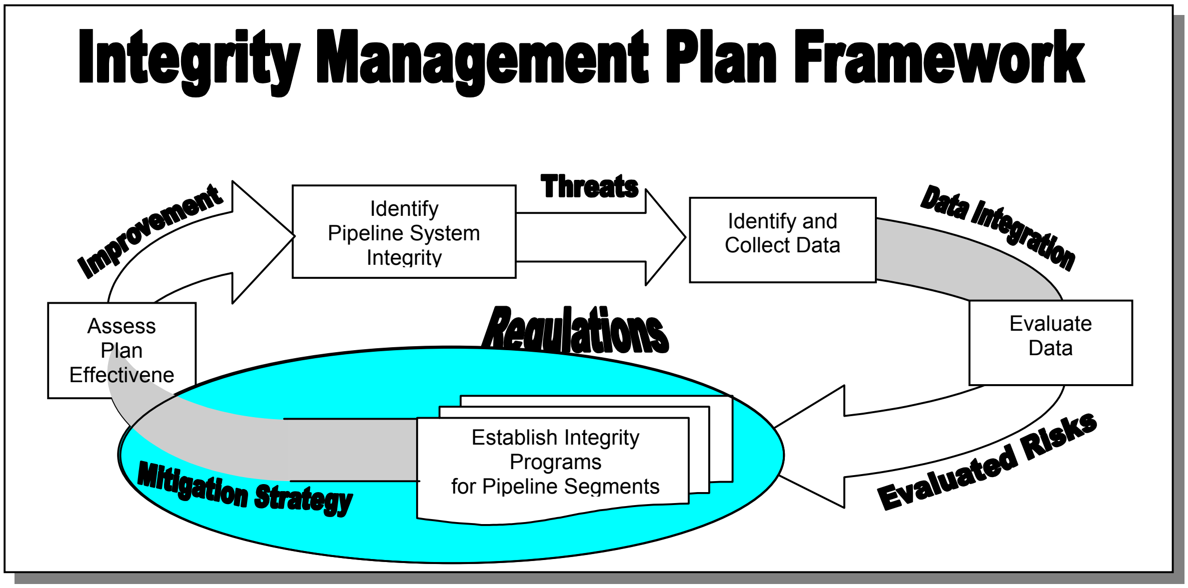
- Bilo, M. and Kinsman, P.R. 1997. "Thermal Radiation Criteria Used in Pipeline Risk Assessment." Pipes & Pipelines International, November-December, pp.17-25.
- Gas Research Institute Technical Report GRI-00/0189. "A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines."
- Standards Australia. Guide to Pipeline Risk Assessment in Accordance with AS 2885.1.

The above models do not account for factors that may decrease the affected area, such as depth of the pipeline, soil type (e.g., sandy vs. rock), natural barriers (e.g., foliage, terrain, and hills), and man-made barriers (e.g., buildings). The models also assume certain pipeline rupture geometries. Operators recognize that the models have a tendency to yield conservative (larger) estimations of the affected areas.

VII. ESTABLISH INTEGRITY PROGRAMS FOR PIPELINE SEGMENTS AND MITIGATION STRATEGY

Figure 5 highlights Integrity Management Plan (IMP) activities described in this section.

Figure 5 - Establish Integrity Programs for Pipeline Segments and Mitigation Strategy



A. Establish Integrity Program for Pipeline Segment

After evaluating risks, operators turn their efforts to developing specific pipeline segment integrity programs. Three key elements are integrity concern assessment, mitigation selection, and continuing assessment.

1. *Integrity Concern Assessment and Prioritization*

The methods used by operators of transmission pipelines to assess data and prioritize pipeline segment integrity concerns cover the spectrum from the collection of operational knowledge through the use of probabilistic models. These methods are typically developed using in-house personnel. However, outside firms and, more recently, commercially available software, are used to supplement in-house assessment and prioritization efforts. The approach employed to develop an assessment and prioritization method involves a combination of subjective assessment, engineering knowledge, statistical analysis, and mathematical modeling. The effectiveness of the prioritization model is not necessarily a function of the number of risk factors used. The effectiveness of the model is confirmed by data from field observations.

One consideration in the risk assessment process is how to define pipeline segments. An operator may choose to end one segment and begin another whenever there is a change in operating hoop stress, age of pipe, class location, or some other characteristic that is deemed significant. An operator may choose to define a segment based upon the practicality of hydrostatic testing the segment or running an in-line inspection (ILI). As an example of the latter, an operator may choose to define pipeline segments from compressor station to compressor station.

a. Index Model

Two types of models used for prioritization are the index model and probabilistic model. The index model involves identifying critical factors and ranking the relative importance of these factors. The relative importance of each factor is quantified by giving it a weighted value. These weightings are based upon general operator experience and industry data including historical failure data, near misses, and the general knowledge base of the pipeline personnel. The higher the weighting, the more important the factor is in determining the risk of leaks and ruptures on the pipeline. An example of how weighting is used to define a risk score is illustrated by the basic index method equation below.

$$Total\ \ Risk\ Score = \sum_{i=1}^{n} (w_i \times Likelihood_i) \times \sum_{j=1}^{m} (w_j \times Consequences_j)$$

In this equation the total risk score associated with a particular pipeline segment is the summation of the measures assigned to each factor times the weighting (*w*) assigned to each factor.

An operator may choose to use a checklist, a very simple index model, or a very complex model with intricate algorithms. The basic index method above falls in between this range of complexity. The simple model may use a relatively few number of parameters that are rated qualitatively, such as being of high, medium, or low concern. An operator may, on the other hand, choose to develop an index model that uses an algorithm for estimating the relative risk of the various pipeline segments and then assigns some measure to each parameter. Soil type, for example, may be assigned a value of 1 to 3. An operator may choose a more complex equation for a risk assessment algorithm. Class location might be squared, for example, to represent the consequence related to population density. Tables 10 and 11 include some factors that may be considered related to likelihood and consequence of failure.

An index model provides a relative score for each segment, not an absolute measure of risk. The index allows comparison of a pipeline segment against other segments ranked using the same tool. If one segment scored 100 and a second scored 200, the operator can conclude that the second segment has greater risk but cannot conclude that the risk of the second segment is twice the risk of the first

b. Probabilistic Model

Another type of prioritization model is based on the probabilistic method. In this approach a quantitative analysis is performed on individual processes that could affect pipeline integrity. Some examples of processes modeled in risk analysis are pipe manufacturing, leak detection systems, equipment staging, regular maintenance scheduling, and isolation valve placement.

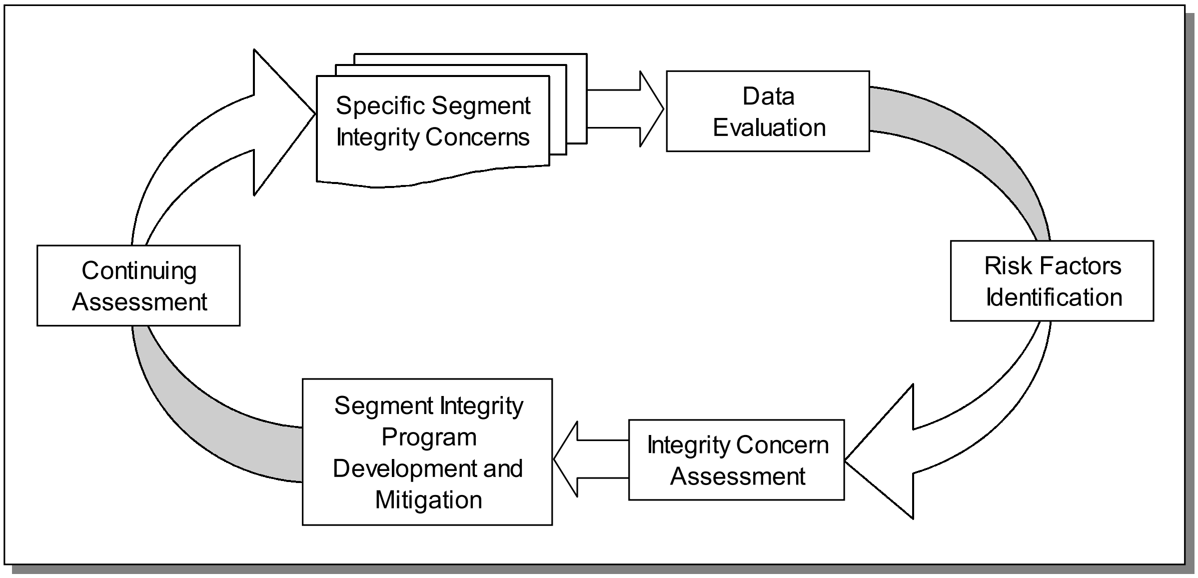
First, failure modes or threats relating to each process are identified. Then the consequences of each hazard and the probability or likelihood of it occurring are estimated. Next the probability is multiplied by the consequence, resulting in a quantifiable value of risk for a particular threat. When this is done properly, the system can be used to perform "what if" scenarios to determine how risk can be decreased and to identify segments of higher risk.

The advantages of the probabilistic method are that (1) the results are quantifiable (may be expressed in monetary terms), (2) the model provides prioritization in terms of an absolute measure of risk, and (3) the operator can evaluate the risk impact of different mitigation scenarios. This method also offers the advantage of benchmarking quantitative pipeline risk values against historical failure rates. The disadvantages are that (1) it takes a large amount of data to determine probabilities of each failure mode for each individual pipeline segment, (2) data must be collected over a lengthy period of time, and (3) a large and flexible computer system is required.

Regardless of the approach, prioritization methods are not precise models of integrity. Models are developed as tools to assist in assessing segment integrity concerns and are used in conjunction with the operator's local knowledge, skill, and judgement in assessing integrity concerns.

B. Mitigation Strategy

Figure 6: Mitigation Strategy



Once the operator has assessed the integrity concerns for the pipeline segments and has prioritized the segments according to perceived risk, a mitigation program is determined for each pipeline segment. The goal is to match mitigation techniques to pipeline segments in such a way that a company optimizes available resources to enhance system-wide pipeline integrity. This can be done by matching the mitigation tools and techniques to the needs of and threats to the individual pipeline segments. No one tool or approach is appropriate for all applications.

Mitigation techniques include four categories:

1. Monitoring. Examples of this are more frequent patrols, leak surveys, and pipe-to-soil potential surveys.
2. Inspection and investigation. An operator may decide that more information is needed for a particular pipeline segment. Examples of this are close-interval surveys, bellhole examinations, radiographic examination, ultrasonic examination, pressure testing, geometry pigs, and in-line inspection (corrosion detection or metal loss pigs).
3. Remediation. Examples of this are recoating (reconditioning), additional cathodic protection, anomaly repair, pipe replacement, line lowering, change in alignment, reduction in operating pressure, and erosion control measures.

4. Education. Examples of this are notices sent to landowners along the pipeline's rights-of-way, public education efforts, damage prevention programs, and coordination efforts with public officials.

Table 12 contains a list of mitigation tools and practices used in the prevention and detection of damage to a pipeline.

Table 12: PREVENTION AND DETECTION OF DAMAGE TO A PIPELINE

Mitigation tool and practice	Description
Bellhole inspection	Exposure of a pipe section for examination. Usually includes visual and other nondestructive examination (NDE) methods.
Close-interval survey (CIS)	Aboveground potential measurement at close-intervals.
Coating condition evaluation	Inspections associated with evaluating pipe coating of exposed, buried, or aboveground pipe sections.
Compliance audit	Audit conducted by operator personnel to ensure compliance with regulatory and company procedures.
Comprehensive construction procedures	Written methods and procedures to ensure high quality pipeline construction.
Comprehensive emergency procedures	Written procedures covering pipeline and facility emergency measures.
Comprehensive operations and maintenance procedures	Documented procedures for pipeline operations and remediation.
Construction inspection	Inspection effort during pipeline construction to ensure regulatory and specification compliance.
CP test points	Required measurement of CP current at fixed test points.
Damage prevention and public education programs	Primary tools for excavation damage prevention.
Design specifications	Pipeline and facility design specifications that are suitable for the intended purpose.
Direct current voltage gradient (DCVG)	Aboveground piping coating integrity assessment.

Table 12: PREVENTION AND DETECTION OF DAMAGE TO A PIPELINE	
Mitigation tool and practice	**Description**
External coupon monitoring	Installation and monitoring of buried coupons adjacent to pipe for corrosion monitoring and (IR) drop estimates.
Gas analysis	Analytic determination of natural gas composition and potentially corrosive components.
Geometry in-line inspection survey	Internal diameter inspection of pipe to detect dents, gouges, bend radius, bend orientation, fittings, pipe ovality, wrinkle bends, and clearance for in-line inspection tool.
Ground displacement survey	Use of survey methods to detect and monitor the extent of pipe deformation due to unstable soil or subsidence.
In-line inspection tool survey (baseline)	In-line inspection tool run in newly constructed pipe to establish initial as-built baseline pipe condition and to detect construction damage.
In-line inspection tool survey (in-service)	In-line inspection tool run for pipeline integrity assessment. The typical tool inspects for metal loss. However tools are being developed to detect cracks and other defects. See Table 13.
Internal coupon monitoring	Installation and monitoring of coupons inside a pipeline to detect and monitor internal corrosive conditions.
Iron analysis	Determination of iron quantities in the gas stream as indicator of internal corrosion at upstream location(s).
Leak survey	Above ground surveillance for natural gas leaks.
Manufacturer inspection	Active (QA/QC) during pipe and component manufacture to initially ensure adequate product quality.
Materials specifications	Specifications establishing the required pipe and material quality for the facility design conditions.
Microbiological corrosion monitoring	Process of determining the contribution of microbiological organisms to either external or internal corrosion.
One-call system	Centralized locations for excavation activity notification.
Operator personnel training	Formal and on-the-job training processes that produce qualified operations and maintenance personnel.
Patrol	Aerial or foot patrol of Rights-of-way, and visual inspection.

Table 12: PREVENTION AND DETECTION OF DAMAGE TO A PIPELINE	
Mitigation tool and practice	**Description**
Pre-service pressure test	Pressure test to validate initial integrity and to detect construction damage and defective materials.
Pressure retest	Test to ensure continued integrity.
Rate predictive methods	Use of corrosion rate data to predict when excessive metal loss will occur and estimate maintenance interval.
Resistivity survey	Over-the-line determination of soil resistivity to estimate corrosive potential.
Rights-of-way management	Includes pipeline markers, reviewing development near pipeline (ROW), acquisition of land, reviewing zoning changes, mowing, and clearing right of way.
Soil evaluation	Evaluation of soil samples removed from a bellhole to identify corrosive properties.
Strain monitoring	Installation and monitoring of devices to detect the extent of pipe or component deformation.
Surface nondestructive testing	Includes techniques (e.g., magnetic particle, dye penetrant, and ultrasonic testing) to assess pipe anomalies.
Surface radiography	Radiography to determine weld seam integrity, girth weld integrity, and internal corrosion pitting.
Transportation inspection	Inspection during pipe and component loading to ensure the use of proper methods to minimize transportation related damage.
Visual examination	Includes visual determinations and measurements of pipe and components.

ILI tools play an increasingly important role in many pipeline integrity programs. Selecting the right tool requires knowledge of the pipeline segment, knowledge of the threat being addressed, and knowledge of thecapabilities of the available tools. Using a metal loss pig is effective for detecting corrosion; however, the same pig has limited benefit in detecting cracks (e.g., SCC, fatigue, longitudinal seam). ILI can be used to identify dents that may have resulted from excavation. However, ILI tools cannot reliably detect gouging and cracking within dents. Sound engineering judgment is needed when establishing appropriate evaluation criteria. It is important to use the correct ILI tool to address the threats on an individual pipeline segment. See Appendix B for a table on In-line Inspection Tools that provides more details on ILI tool selection.

Mitigation actions are selected, scheduled, and planned considering the reduction of risk for particular pipeline segments and the overall reduction of risk for the entire pipeline system. Operators generally review the recommended mitigation program in an effort to balance financial, material, and manpower resources. Mitigation actions are selected with consideration for the safety of the public and the needs and constraints of producers, other transportation customers, and end-users.

The final result of these efforts is a comprehensive strategy of specific mitigation actions that reduce system integrity concerns for the natural gas transmission pipeline.

1. *Continuing Assessment*

Since the concerns affecting the integrity of the pipe segment are dynamic, the operator continues to review each pipe segment's integrity concerns, threats, risk factors, and mitigation techniques. Operators keep abreast of new developments and commercially available mitigation techniques through participation in industry associations and by other means. As additional information regarding the pipeline segments and the area around the pipe segment is received, the operator re-evaluates pipeline integrity concerns, risk factors, and the risk assessment model to determine if the mitigation actions are still appropriate. The following are examples of what an operator may consider in adjusting mitigation actions:

- Population development.
- Changes in pipeline conditions indicated by surveys, inspections, or tests.
- Leaks.
- Failures.
- Excavation damage.
- Pipeline regulatory advisories and alerts.
- Natural hazards.
- Changes in pipeline operations.
- Changes in supply and demand requirements.
- Changes in available monitoring and mitigation tools and techniques.

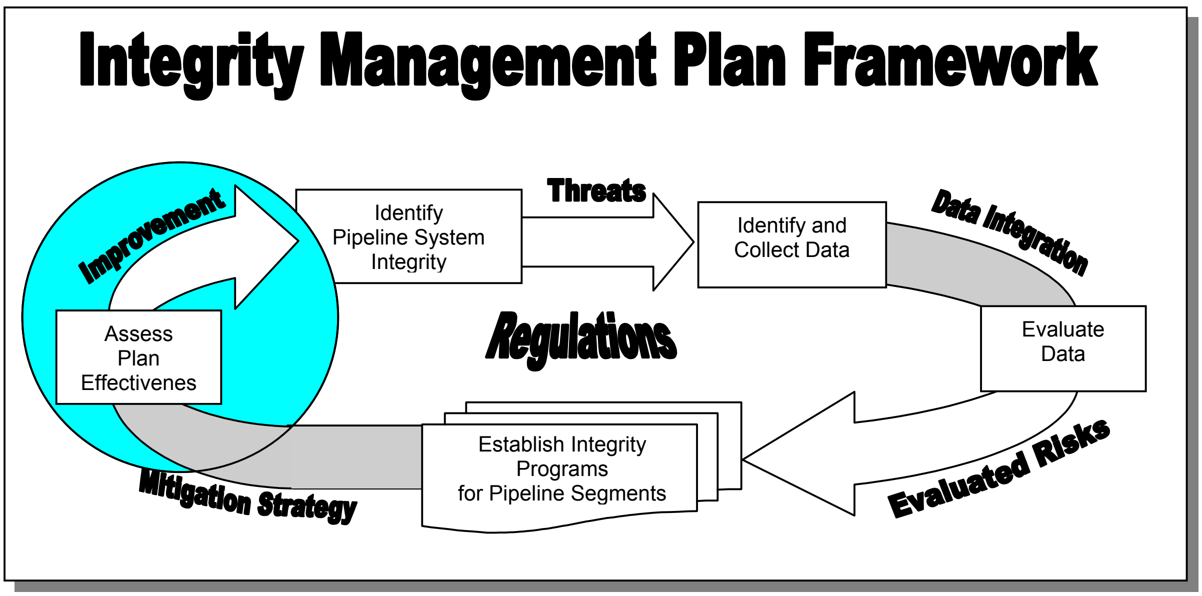
Adjustments are made to the mitigation program to account for changes in resources, new mitigation techniques, and changes in integrity concerns. This continuing assessment process serves as a necessary source of feedback for improvement to individual integrity programs and the IMP.

VIII. ASSESS PLAN EFFECTIVENESS AND IMPROVEMENT

"Measuring is the first step that leads to control
and eventually to improvement.
If you can't measure something, you can't understand it.
If you can't understand it, you can't control it.
If you can't control it, you can't improve it."
Author Unknown

Figure 7 highlights Integrity Management Plan (IMP) activities described in this section.

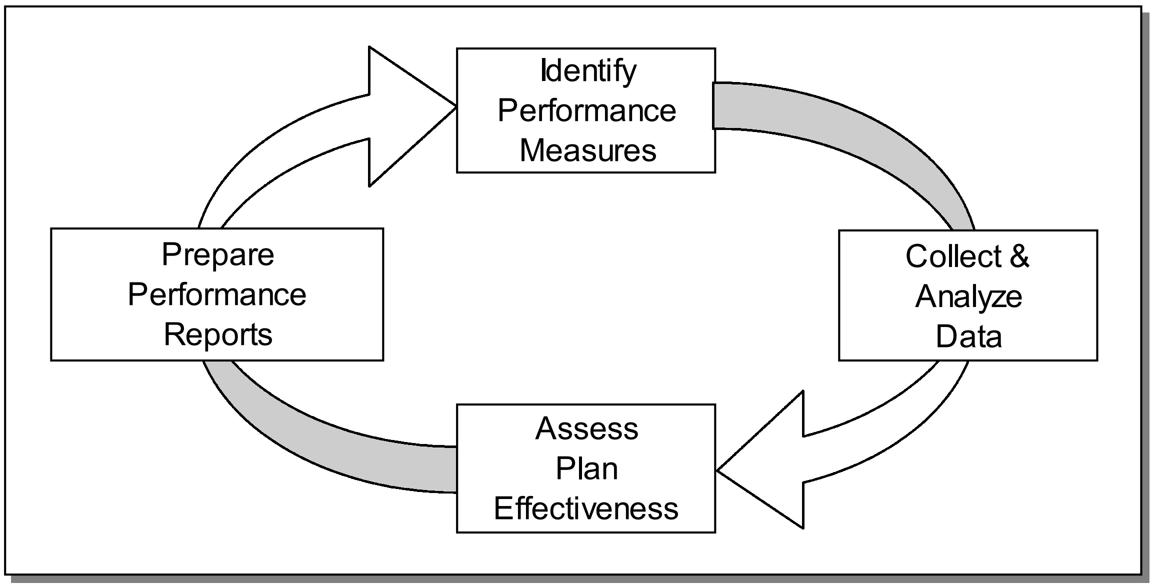
Figure 7 – Assess Plan Effectiveness and Improvement



A. Assess Plan Effectiveness

The purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, operators develop performance measures to determine IMP effectiveness. An effective IMP supports the performance of operators by focusing resources to provide for effective preventative maintenance. This is helpful not only in providing for safe, reliable operations, but also in protecting the stakeholders'[4] long-term investment in the pipeline facilities. Figure 8 is a generalized framework for assessing an IMP's effectiveness.

Figure 8 - Integrity Management Plan Effectiveness



1. *Performance Measures*

The effectiveness of an IMP is gauged by the degree to which its objectives are met. An operator selects a set of measures that determine how well its IMP performs. Some of the questions that are asked in selecting plan performance measures include:

- Is it an actual report card measuring results (e.g., reduction in anomalies) rather than just activities (e.g., leaks repaired per year)?
- Is it readily measurable (i.e., stated in terms of quality, quantity, time, or cost)?
- Does the data exist or can it be gathered in a practical manner?
- Is the data in a form such that it can be readily used as a measure of performance?
- Do any of the plan performance measures overlap any other?
- Is the measure a key indicator of the integrity management plan's effectiveness?
- Is the number of plan performance measures manageable?
- Will the measure be useful over time?

Determining effective performance measures is not a simple task. Not all measures effectively reflect performance and some performance measures may be subjective. Operating personnel can provide important knowledge about measures that correspond to an IMP's performance.

[4] This includes pipeline owners, public, employees, and local, state, and federal agencies.

Performance measures are selected that are both reasonable indicators of the plan's effectiveness and that will remain good indicators as the plan evolves.

Plan performance measures can be categorized, although the distinction between categories is not always clear. The following is one way to distinguish these categories.

External influence measures. Some measures monitor the results of surveillance and preventive activities undertaken by the operator (e.g., near misses). These measures indicate how well an operator is implementing the various elements of the IMP.

Operational measures. Trends may indicate reduced system integrity despite preventive operational or maintenance activities (e.g., rectifier power consumption). These measures are evaluated over time to identify and understand trends.

Failure measures. Trends may indicate improvement (e.g., decrease in number of leaks, in incident cost, or in gas loss). These measures indicate progress towards the objectives of the plan. Failure measures are evaluated over time to identify and understand trends.

Performance measures can be further characterized as either lagging measures or leading measures. Lagging measures provide an indication of how a plan or program has performed. Leading measures provide an indication of how a plan or program is expected to perform. A few examples of performance measures are shown in Table 13.

Table 13: ILLUSTRATIVE INTEGRITY PLAN PERFORMANCE MEASURES

Measurement Categories	Lagging Measures	Leading Measures
External influence measures	Excavation damage per locate request.	Number of Locate Requests.
Failure measures	Incident rate per excavation.	Number of incidents of excavation in ROW without locates.
Operational measures	Significance of anomalies found from ILI.	Increased frequency or magnitude of pressure fluctuations, change in wall loss, change in cathodic protection current demand, close-interval survey data, and bellhole inspection data.

An IMP may consist of a number of integrity management programs tailored to meet the unique requirements of particular transmission segments with each program having its own specific set of performance measures. These measures may differ from those measures selected to assess and evaluate the overall IMP. Program measures tend to focus on pipe failure mode, specific threats, or other pipe specific anomalies associated with a pipeline segment.

Performance measures are indicators of effectiveness, not an absolute measure of effectiveness.

2. *Plan Effectiveness Assessment*

Operators collect performance information and periodically conduct audits to evaluate the success of their integrity assessment methods, pipeline repairs, and other prevention and mitigation activities. IMPs can be evaluated by direct and indirect techniques. Techniques used may include internal benchmarks, external benchmarks, integrity management process audits, and operating personnel feedback. One or more of these techniques are used to assess the effectiveness of systems, processes, and results that support integrity management decisions. When IMPs are probabilistically based, they can be evaluated by noting changes in integrity measures.

Comparisons of performance measures are one way to assess how integrity-related parameters for a pipeline segment in one area compare to those in other areas. This internal benchmark information is used to help identify best-practices. Operators can share information related to their IMPs with other operators. This can help both individual operators and the entire industry to validate integrity management efforts.

Internal benchmarking may compare one pipeline segment to another pipeline segment, or a portion of a pipeline to a different portion of the same pipeline (e.g., anomalies per mile on portions of the system within Class 3 locations versus other portions of the system). Consolidations within the gas transmission industry provide opportunities to compare one system with another system. The information obtained may be used to evaluate the effectiveness of specific prevention activities, mitigation techniques, or performance validation, and to identify best practices. Likewise, internal benchmarking comparisons from one geographic region to another geographic region within the same operating company, or from one business unit to another business unit, is a means of identifying areas with best-practices.

The natural gas industry has a long-standing reputation of sharing pipeline integrity related information. External benchmarking among operators has proved practical when measures are of industry-wide importance and do not result in the exchange of confidential information. When such benchmarking is possible, care is taken to ensure that benchmark information is comparable among the operators or systems. The information obtained may be used to evaluate the effectiveness of specific preventive activities and mitigation techniques, validate performance, and identify best practices. Operators also conduct periodic evaluations of their own performance in comparison with industry-wide data sources. For example, operators periodically review their performance in comparison with the database of 49 CFR Part 191 incident reports managed by the Office of Pipeline Safety.

In addition to benchmarking, operators routinely audit their IMP to assess and improve the effectiveness of the plan. These audits ensure that policies, procedures, and practices are being conducted in accordance with the IMP. These audits identify both strengths and improvement opportunities, and may be performed by internal staff or outside consultants. While the audits are based on local conditions, the following is a series of questions these audits typically answer:

- Is there a written policy and program for integrity management?
- Are there written procedures for tasks relating to integrity management?
- Are activities being performed as outlined in the program documentation?
- Is someone assigned responsibility for each subject area?
- Are the people who do the work qualified in the subject area?
- Are all required activities documented?
- Is there follow-up on action items?
- Is there a formal review of the rationale used to develop the risk criteria contained in the IMP?
- Is the appropriateness of performance measures reviewed?
- Is feedback used to evolve the IMP?

3. *Performance Reports*

IMPs are adapted to meet changes to the pipeline system, its environment, new technology, and changes to the industry. The performance measurement and audit results, along with feedback from operating personnel, are integral to the continuous improvement of the plan.

Integrity management reports are prepared periodically. These reports may address areas such as:

- IMP Statement of Purpose.
- Performance targets with specific performance criteria that identify the need for action.
- Target levels.
- Current measures.
- Variances from expectations.
- Performance projections.
- Budget initiatives affecting the IMP.
- Material issues and strategies to address variances from plan.

These reports, the results from benchmarking, and recommendations resulting from audits are distributed to individuals responsible for pipeline integrity and operations. This information forms the foundation for continuous improvement in the operator's policies, procedures, practices, and programs that underlie the IMP.

B. IMPROVEMENT

The tools used to assess plan effectiveness may reveal areas of IMP improvement. Best practices identified during benchmarking may be incorporated to improve the IMP. Improvement goals may be established as a result of benchmarking, comparisons of historical failure rates with industry rates, or other quantitative measures.

As illustrated by the IMP Framework (Figure 1), the IMP is a dynamic,cyclical process. As experience is gained by the operator, improvements can be incorporated into the plan. For example:

- Utilizing new information and refining existing data on pipeline segments enable operators to fine tune risk analysis.
- Improved monitoring tools and mitigation techniques expand the options available for addressing integrity concerns

The IMP improvement process includes eliminating IMP components that are ineffective and enhancing integrity management processes that result in a safe and reliable system.

VIII. CONCLUSION

The purpose of this technical report is to review the subject of integrity management of steel natural gas transmission pipelines. Integrity management is in the best interest of all stakeholders, especially pipeline companies, to preserve the huge investments made in our nation's natural gas transportation infrastructure. Continual management of pipeline integrity remains essential for providing energy through a safe and reliable pipeline network.

Integrity management is not a new concept. It has been fostered for many decades by the pipeline safety codes (e.g., ASME B31.8), by the Minimum Federal Safety Standards, 49 CFR Part 192, and the GPTC Guide. Technological advances over the years have provided operators with better tools to manage integrity of their pipeline systems. For example, computers and computer-based systems have enabled better integration and management of data. As advances in technologies continue, integrity management improvements will also continue to occur.

An integrity management plan (IMP) is a written, systematic approach to maintaining the integrity of pipeline facilities at levels that provide appropriate system safety and reliability. A framework for development of an IMP consists of several processes:

- Identify pipeline system integrity issues leading to an understanding of the threats.
- Identify and collect data leading to data integration.
- Evaluate data leading to an understanding of risks.
- Establish integrity programs leading to specific mitigation strategies.
- Assess plan effectiveness leading to improvements of the IMP.

An IMP is a dynamic,cyclical process that evolves as the operator gains experience. As more information is incorporated into the operator's plan, refinements can be made at any point in the process without having to reinitiate the entire process. These refinements lead to continuing improvement of the IMP over time.

IMPs are tailored to the operator's ability to use available detection, monitoring, data management, and data analysis tools. Because of differences in the systems, operating conditions, and available resources, there is not one plan that is suited for all operators. Effective plans may range from simple to more complex as described in this report. When properly written and effectively implemented, a plan, regardless of complexity, contributes to improving an operator's ability to maintain system integrity. Without a systematic approach, the risk of integrity loss increases.

As operators successfully integrate technological advances, their evolving IMP will continue to result in further improvements to system safety and reliability.

IX. LIST OF APPENDICES

A. Case Studies

B. In-Line Inspection Tools

C. Glossary

D. References

A. Case Studies

An operator may choose from a wide range of approaches in developing the Integrity Management Plan (IMP). The plan can be very simple or complex, depending on the nature of the pipeline system, management philosophy, and available resources. For purposes of illustration, this appendix presents three hypothetical approaches that demonstrate the broad spectrum of possible IMPs.

In ***Case 1***, the operator uses a simple approach to integrity management. The data, maps, and drawings are manually collected and stored. Data integration is a manual process accomplished by reviewing available information regarding the system. One manager will qualitatively evaluate risk based upon the overall knowledge of the operating personnel,and may use a simple checklist to begin to quantify risk. Input is obtained from the various operating disciplines, but the manager makes the final decision regarding the prioritization of risk. The manager selects mitigation measures after consulting with operations personnel. The number of failures or near misses per year and informal measures e.g., feedback from field personnel, are used to assess plan effectiveness.

In ***Case 2***, the operator uses a more complex approach to integrity management. The operator uses both manual and electronic data, reports, drawings, and maps. An integrity management group integrates the data at a high level (primarily using electronic data and field knowledge) and selects the higher risk pipeline segments. Then, a more formal and detailed data gathering, data integration, and risk assessment process is done on these particular segments. A qualitative risk assessment process is completed by the integrity management group using a set of simple algorithms, parameters, and weighting factors. Risks for the identified segments are calculated using a spreadsheet. Input from field and operations personnel is then used to modify or validate the final prioritized project list. Mitigation measures are selected after consulting with operations personnel and operating disciplines. Simple trending is used on performance measures e.g., occurrence of leaks, anomalies found per mile, and cost tracking to assess plan effectiveness.

In ***Case 3***, the operator uses a very complex and detailed approach to integrity management. The majority of records, drawings, reports, and maps are in electronic form and can be easily retrieved and integrated using sophisticated software packages. Data integration is done using software tools that allow both GIS views and tabular listings that can be sorted and analyzed. Risk assessment is done with software that is linked to the various databases and is performed on the entire pipeline system. The number of parameters used in the model may vary from a few, perhaps 6 to 10, to more than 100, and can be qualitative or quantitative. A risk department has been established to develop the algorithm used and to oversee the process. Mitigation measures will be selected after consulting operations personnel, vendors, and operating discipline experts. Computer-based trending will be done and operations personnel will be consulted to assess plan effectiveness.

The following table gives a comparative overview of these three approaches.

<table>
<tr><th colspan="4">Table A: CASE STUDIES</th></tr>
<tr><th></th><th>Case 1</th><th>Case 2</th><th>Case 3</th></tr>
<tr><td>Data Collection</td><td>Manually collected data from paper records and information from field personnel experience.</td><td>Combination of manual and electronic records, drawings, and maps plus information from field personnel experience. Majority of information collected and retained at field location.</td><td>Highly automated electronic data storage:
• Databases.
• GIS.
• CAD.
Data collection is decentralized. Data storage is centralized.

Automated data collection

Information from field personnel experience.</td></tr>
<tr><td>Data Integration</td><td>Review data gathered with operations personnel and consolidate information.

Examples of information reviewed:
• Construction records.
• Corrosion control records.
• Bell hole examination reports.
• Patrol reports.
• Leak history.
• Information concerning encroachments.
• Incidences of excavation on or near the rights-of-way without proper locate requests.
Primary integration tools are spreadsheets and operator knowledge of system.</td><td>A limited amount of data is utilized to filter pipe segments.

Then specific and detailed information is integrated for the remaining high-priority segments. The information integrated is similar to that listed in Case 1, except it is gathered in greater detail.

The primary integration tools are spreadsheets and the use of a specified set of risk algorithms and evaluation protocols.</td><td>A significant amount of data is integrated for all the pipeline segments using tools such as:
• Intranet.
• AM/FM/GIS.
• Databases and software used for specific operating and maintenance activities (i.e., corrosion surveys, gas quality monitoring, etc.).
• Risk management computer models.
The data integration is done primarily by the computer systems based on a specified set of risk algorithms and evaluation protocols.</td></tr>
</table>

Table A: CASE STUDIES			
	Case 1	***Case 2***	***Case 3***
Evaluated Risks	Risks and concerns are evaluated and analyzed by completing a checklist that may consider: • Corrosion history. • Leak history. • Age of pipe. • Population density. • Test history. • Wall thickness. • Grade of pipe. The primary tool is the expertise of the personnel and operator input.	For the high priority segments, in-house spreadsheets using data from stand-alone databases and manual records are created based on a specified set of risk algorithms and evaluation protocols.	Vendor and in-house developed statistical models linked to databases. Highly automated for all pipelines.
Prioritization	Manager discusses evaluated risk with field personnel. Final decision is made by a Manager.	Spreadsheet ranks risk for high priority segments. Results reviewed with operations personnel and revised as needed.	Model prioritizes and ranks all segments comprising the system. Once this is complete, operations personnel and technical experts review and revise list as needed to account for factors not included in risk model.
Mitigation	Manager determines mitigation after consulting field personnel.	Risk team recommends mitigation for identified segments after consulting field personnel.	Risk department recommends short term and long term mitigation program after consulting field personnel. This could include long-term in-line inspection and corrosion survey programs based on the prioritized risk listing.
Assess Plan Effectiveness	Review plan with management annually. Use year-to-year comparison of activities performed and results found. Trend failure information and survey results. Also use informal feedback from	Annual plan assessment is conducted by trending selected parameters, e.g., leak history, anomalies found per mile, repairs, and replacements required to maintain integrity. Results are	Formal plan assessment is done annually with periodic informal reviews by the integrity management team. The assessment captures activity and performance indicators in databases and uses computer based trending with a combination of

Table A: CASE STUDIES			
	Case 1	***Case 2***	***Case 3***
	field personnel.	communicated to management and to individuals responsible for implementing each part of the integrity management program. Separate integrity management program reports are used.	quantitative and qualitative performance measures. The performance measures compare risk assessment to actual results as well as the trending noted in Case 2. Also, comparisons are completed across districts, divisions, and within the industry. Results are communicated to management by the integrity management team and made available organization-wide.

B. In-Line Inspection Tools

Table B: IN-LINE INSPECTION TOOLS

ANOMALY TYPES	METAL LOSS TOOLS			CRACK DETECTION TOOLS			Geometry Tools (Caliper Tools)	Geography Tools (inertial navig. tools)
	Magnetic Flux Leakage (MFL)		Ultrasonic (normal beam – compression wave)	Ultrasonic (angle beam – liquid coupled)	Ultrasonic (angle beam – wheel coupled)	Circumferential MFL[14]		
	Standard Resolution	High Resolution						
METAL LOSS (CORROSION) External and Internal Corrosion	detection[1], approximate sizing,[3] no external internal discrimination	detection[2], sizing[3]	detection[2], sizing[3]	detection[2]	detection[2]	detection[2], sizing[3]	not applicable	not applicable
Narrow Axial Corrosion	no detection	limited detection[4]	no detection[4]	detection[2], sizing[3]	detection[2], sizing[3]	detection[2], sizing[3]	not applicable	not applicable
CRACKS AND CRACK-LIKE DEFECTS (axial) Stress Corrosion Cracking Fatigue Cracks Longitudinal Seam Weld Imperfections Incomplete Fusion (lack of fusion) Toe-Cracks	no detection	limited detection	no detection	detection[2], sizing[3]	detection[2,11], poor sizing[3] (sizing accuracy less than liquid coupled)	detection[2,5] limited sizing[3]	not applicable	not applicable
Circumferential Cracking	no detection	limited detection and sizing	no detection	no detection[2]	no detection[2]	limited detection	not applicable	not applicable
DENTS Plain Dents Wrinkle Bends/Buckles	detection[7]	Improved detection[7,10]	Detection,[7,10] no sizing	limited detection,[7,10] no sizing	limited detection,[7,10] no sizing	Detection,[7,10] sizing not reliable	detection and[8] sizing	detection and sizing
DENTS WITH GOUGES	not reliable detection	not reliable sizing for dents	Detection,[7] sizing not reliable	Detection,[7] sizing not reliable	Detection,[7] sizing not reliable	Detection,[7] sizing not reliable	dent detection[8] and sizing	dent detection and sizing
LAMINATIONS	no detection	limited detection	detection	detection	detection	no detection	not applicable	not applicable
INCLUSIONS	no detection	limited detection	limited detection	detection and possible sizing	detection and possible sizing	possible detection	not applicable	not applicable
PREVIOUS REPAIRS	detection only of steel sleeves, patches and marked composite reinforcement sleeves		detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches welded to pipe	detection only of steel sleeves and patches	not applicable	not applicable
MILL-RELATED ANOMALIES	detection[12]	limited detection[12]	detection[13]	detection[13]	detection[13]	detection[12]	not applicable	not applicable
OVALITIES	no detection	no detection	no detection	no detection	no detection	no detection	detection and sizing[3]	detection and sizing[3,9]

See Footnotes below:

Table B Footnotes

1. Limited by the minimum detectable metal loss.
2. Limited by the minimum detectable depth, length, and width of the defects.
3. Defined by the specified sizing accuracy of the tool.
4. If the width is smaller than the minimum detectable defect width for the tool.
5. Reduced POD for tight cracks.
6. *Intentionally left blank.*
7. Reduced reliability depending on the size and shape of the dent.
8. Depending on the configuration of the tool, also circumferential position.
9. If the tool is equipped for ovality measurement.
10. In case of detection, circumferential position is given as well.
11. Poor discrimination between inclusions and cracks with wheel coupled.
12. Identifies volumetric or metal loss.
13. Identifies volumetric, metal loss, and planar.
14. Emerging technology.

C. Glossary

Table C: GLOSSARY	
Item	**Description**
Abandoned pipeline	A pipeline that is physically separated from its source of gas and is no longer maintained under Part 192.
Abandonment	The process of abandoning a pipeline.
AM/FM	(Automated Mapping/Facilities Management) The automated mapping system portion of a Geographical Information System (GIS) designed for the processing of facility information.
Backfill	Soil used to support the pipe and fill an excavation after pipe has been installed or exposed.
Bellhole	An excavation that minimizes surface damage yet provides sufficient room for inspection or repair of buried facilities.
Benchmark (external)	A standard of measure established to compare two or more similar business functions in an effort to establish areas of improvements. External benchmarks refer to process reviews with outside companies and similar processes in different industries.
Benchmark (internal)	A standard of measure established to compare two or more similar business functions in an effort to establish areas of improvements. Internal benchmarks refer to process reviews between different departments or divisions within a company in an effort to examine company best practices.
CAD	(Computer Aided Design) Software used in the design of facilities.
CIS	(Close-interval survey) Aboveground pipe-to-soil potential measurements taken at increments of several feet along the pipeline and used to provide information on the effectiveness of the cathodic protection system.
Class location	A "class location unit" is an onshore area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Class location units are categorized as Class 1 through 4. Class 1 locations are more rural, and Class 4 locations are more urban.
CP	(Cathodic Protection) A procedure by which underground metallic pipe is protected against deterioration (rusting and pitting).
Data	Numbers, characters, images, or other records in a form which can be assessed by a human, as entered, stored, and processed in a computer, or transmitted by some digital method. Data on its own has no meaning. Only when interpreted by some kind of data processing system does it take on meaning and become

Table C: GLOSSARY	
Item	**Description**
	information.
Database	Collection of data objects stored together, in electronic form, according to a common format and made accessible by computer.
DCVG	(Direct current voltage gradient) Aboveground coating integrity assessment method that will identify areas of coating defects which could indicate potential corrosion sites.
Document	Recorded information which can be treated as a unit in a documentation process regardless of its physical form and characteristics.
DSAW Pipe	(Double submerged-arc-welded pipe) Pipe having longitudinal or spiral butt joints. The joints are produced by at least two passes, including at least one each on the inside and on the outside of the pipe.
ERW Pipe	(Electric resistance welded pipe) Pipe that has a longitudinal butt joint, wherein coalescence is produced by the application of pressure and by the heat obtained from the resistance of the pipe to the flow of an electric current in a circuit of which the pipe is a part.
Failure	A general term used to imply that a part in service has become (1) completely inoperable, (2) is still operable but is incapable of satisfactorily performing its intended function, or (3) has deteriorated to the point that it has become unreliable or unsafe for continued use.
Fracture toughness	The resistance of a material to failure from the extension of a crack.
GIS	(Geographical information system) A system of computer software, hardware, data, and personnel to help manipulate, analyze, and present information that is tied to a geographic location.
GPS	(Global positioning system) A coordinate system used to identify facility locations by determining location using GPS satellites.
HIC	(Hydrogen induced cracking) A form of hydrogen induced damage, which includes cracking of the metal.
Hydrogen- induced damage	A form of degradation of metals caused by exposure to environments (liquid or gas), which cause absorption of hydrogen into the material. Examples of hydrogen- induced damage are (1) formation of internal cracks, blisters, or voids in steels, and (2) embrittlement (i.e., loss of ductility).
Hydrostatic test	A measure of the strength of a piece of equipment (pipe) in which the item is filled with water, sealed, and subjected to pressure. Used to validate the integrity and to detect construction defects and defective materials.

Table C: GLOSSARY	
Item	**Description**
ILI	(In-line inspection) A pipeline inspection process that uses devices known in the industry as "smart pigs." These devices run inside the pipe and can detect corrosion and deformation anomalies.
Incident	An event that involves a release of gas from a pipeline and 1) a death or personal injury necessitating in-patient hospitalization, or 2) estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more, or 3) an event judged to be significant by the operator.
Information	A collection of facts from which conclusions may be drawn and knowledge acquired through study or experience or instruction.
Lamination	An internal metal separation creating layers generally parallel to the surface.
MAOP	(Maximum allowable operating pressure) The maximum pressure at which a pipeline may be operated in compliance with the gas pipeline safety regulations.
MFL	(Magnetic flux leakage) A type of in-line inspection process that induces a magnetic field in a pipe wall between 2 poles of a magnet. Sensors record changes in the magnetic flux (flow), which can be used to measure metal loss.
Mitigation	Limitation or reduction of any expected consequence for a particular event.
NDE	(Nondestructive evaluation) Inspection methods that do not damage the item being examined. These techniques include visual, radiographic, ultrasonic, magnetic particle, and dye penetrant methods.
Operator	An individual, firm, joint venture, partnership, corporation, association, state, or municipality that engages in the transportation of gas.
Pig	A device run inside a pipeline to clean or inspect the pipeline, or to batch fluids.
Pipe grade	A portion of the material specification for pipe. which includes specified minimum yield strength.
Pipeline	A transmission line along with its associated valves and fittings.
Pipeline integrity	The continuing ability of a pipeline system to safely and reliably transport gas.
Process audit	An independent examination to determine whether procedures and results comply with the integrity management plan (IMP), and whether the planned procedures are implemented effectively and are suitable to achieve objectives.
Risk	The product of the probability (likelihood) of an event and its consequence.

Table C: GLOSSARY	
Item	**Description**
Risk factors (criteria)	Terms of reference by which the significance of risk is assessed. Risk factors can include associated costs and benefits, socioeconomic and environmental aspects, the concerns of stakeholders, priorities, and other inputs into the risk assessment.
ROW	(Right-of-way) A strip of land in which pipeline, railroads, power lines, and other similar facilities are constructed.
SCC	(Stress corrosion cracking) Brittle cracking of a metal due to the result of the combined effects from localized corrosion and tensile stress.
Smart pig	See ILI.
SMYS	(Specified minimum yield strength) The yield strength specified as a minimum in the material specification.
Stress concentrator	A discontinuity in structure or change in contour that causes a local increase in stress.
Transmission pipeline	A pipeline, other than a gathering line, that (a) transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from the distribution center; (b) operates at a hoop stress of 20 percent or more of SMYS; or (c) transports gas within a storage field.
Ultrasonic	High frequency sound waves. These are used to determine wall thickness and to detect the presence of flaws within a pipe wall.
Wrinkle bend	A pipe bend produced by field bending methods resulting in abrupt contour discontinuities on the inner radius.

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Catalogue No. X69806
November 2001
www.aga.org