Baker

Department of Transportation
Research and Special Programs Administration
Office of Pipeline Safety

Duckworth Pipeline Integrity Services, Inc.

TTO Number 7

Integrity Management Program
Delivery Order DTRS56-02-D-70036

Inspection Guidelines for Timely Response to Geometry Defects

This report is intended to serve as a technical resource for OPS and State pipeline safety inspectors evaluating operators' integrity management (IM) programs. Inspectors consider information from a number of sources in determining the adequacy of each IM program. Development of this report was funded via a Congressional appropriation specifically designated for implementation of IM oversight. This and other similar reports are separate and distinct from the work products associated with and funded via OPS's R&D Program.

FINAL REPORT

Submitted by:
Michael Baker Jr., Inc.

July 2004

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ChallengeUs.

List of Acronyms

The following abbreviations, acronyms and symbols are used in this report.

§, §§	Section, Sections
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
Baker	Michael Baker Jr., Inc.
CalPig1	First-generation caliper tool
CalPig2	Second-generation caliper tool
CalPig3	Third-generation caliper tool
CalPig4	Fourth-generation caliper tool
CFR	Code of Federal Regulations
DA	Direct assessment
FAQs	Frequently ask questions
HCA	High consequence area
HiRes	High resolution
ILI	In-line inspection
MFL	Magnetic flux leakage
MT	Magnetic-particle testing
NACE	NACE International (formerly National Association of Corrosion Engineers)
NDE	Nondestructive examination
NPS	Nominal pipe size
OD	Outer diameter
OPS	Office of Pipeline Safety
PT	Penetrant testing
QA/QC	Quality assurance/quality control
SCC	Stress-corrosion cracking
SMYS	Specified minimum yield strength
TFI	Transverse-field inspection
TTO	Technical Task Order
UT	Ultrasonic testing

Executive Summary

This report discusses a study undertaken at the request of the Office of Pipeline Safety (OPS) by Michael Baker Jr., Inc. (Baker). During the first round of OPS hazardous liquid integrity management program audits, questions arose regarding the timeliness of the response of pipeline operators to geometry defects revealed by an integrity assessment, typically in-line inspection (ILI) and subsequent excavation for examination.

Geometry defects are normally caused by outside forces and often result in an immediate failure. Geometry defects that do not fail immediately may pose a potential threat to the integrity of a pipeline in the future. The magnitude of the future threat depends upon the type of damage to the pipeline (plain dents, mechanical damage, etc.), the operating conditions of the pipeline and the environmental conditions surrounding the pipeline. ILI using a combination of a geometry (caliper) tool and a wall loss tool, typically employing either magnetic-flux leakage (MFL) or ultrasonic (UT) technology, is an approved method for integrity assessment of pipelines that may contain geometry defects.

The central issue of this report is clarification of the schedule for the process for determining if a geometry condition revealed by an integrity assessment presents a potential threat to pipeline integrity. The necessity for the clarification of the schedule arises because the precise meaning of "promptly" in the phrase, "An operator must promptly, but no later than 180 days after (conducting) an integrity assessment…", in §§ 192.933(b) and 195.452(h)(2) is subject to multiple interpretations. Furthermore, the compilation of frequently ask questions (FAQs) on the Office of Pipeline Safety website "Implementing Integrity Management for Hazardous Liquid Operators" includes the statements, "The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed…That will be…when the last in-line inspection tool run of a scheduled series of tool runs is performed…" in FAQ 4.13. FAQ 6.6 includes the statement, "Given the capabilities of current technology, an operator who elects to use in-line inspection will need to run two tools - a metal loss tool and a deformation device - to satisfy the baseline assessment requirements…" which implies that the 180-day period begins at the completion of field activities related to the second ILI tool run, typically by a MFL or UT tool.

In order to provide guidance on a reasonable schedule for the discovery and determination process, Baker performed the following studies:

- Review of geometry tool accuracy (Section 3)
- Review of other ILI tools' capabilities for identifying geometry anomalies (Section 4)
- Review of the impact of cracks within geometry defects (Section 5)
- Review of industry practices for geometry defect assessment, analysis and mitigation (Section 6)
- Review of pertinent regulations, industry standards and industry recommended practices (Section 7)

Under the definition of an integrity assessment performed using ILI in FAQs 4.13 and 6.6, an ILI integrity assessment provides no actionable information that a pipeline operator can use to determine that a condition presents a potential threat to the integrity of a pipeline. The central issue in this report relates to what constitutes promptness in assembly of actionable information under the requirements and limitations of the current integrity management rules (including referenced documents and FAQs). Recommendations in this report are based upon the concept that the integrity assessment process should be viewed as two distinct activities: discovery and determination. The discovery activity includes all the assessments, including the ILI run and interpretation of results, that must occur before adequate actionable information is assembled to enable or initiate the determination activity. In this concept, the discovery activity is a process that occurs over time rather than an event that occurs at a precise time. The discovery activity includes activities by both the ILI vendor and the pipeline operator, working in combination and independently.

Even though the determination activity relies upon information generated by both an ILI vendor and a pipeline operator, the determination activity is the responsibility of a pipeline operator. The determination activity typically involves multiple employees of a pipeline operator and a review cycle, so the determination activity is also more properly considered as a process than an event. In practice, the determination process may begin before the discovery process ends, especially when an attempt at determination concludes that the discovery process must assemble additional information before a proper determination relating to a specific condition can be completed.

Applying the above concept of two distinct activities, discovery of a condition could end when that potential condition has been identified to, or by, a pipeline operator. Current terminology in the integrity management rules seem to imply that the timing of the determination that a potential condition presents a threat to integrity can be assigned with greater precision than may be reality in actual practice. For example, some persons opine that a phone report from an ILI vendor to an operator based only upon a caliper tool result is adequate information to determine that a geometry condition presents a potential threat to integrity, while others would associate determination that a condition is a potential threat with excavation and examination of an indication from the ILI report. Other persons propose that intermediate events, such as receipt of a preliminary ILI report and/or a final ILI report, provide adequate information to determine that a condition presents a potential threat to integrity. According to FAQ 6.6, ILI of a pipeline for geometry defects requires integration of results from both a geometry (caliper) tool and a wall loss tool (either MFL or UT). A FAQ that requires use of two ILI tools raises questions about the enforcement of a policy that a phone report from a caliper tool provides adequate information to determine that a condition presents a potential threat to integrity. While the terms “preliminary ILI report” and “final ILI report” are used, no industry consensus on the content and quality of a preliminary ILI report was identified. Differences in opinion relating to both the quantity and quality of information that is adequate to determine that a condition presents a potential threat are exacerbated by perceptions that OPS may penalize operators for taking time to validate verbal or preliminary notification of potential conditions, rather than accepting all communication from ILI vendors as complete and accurate, and thus providing adequate information to determine that a condition presents a potential threat.

Differences in interpretation relating to what constitutes adequate information to determine that a condition presents a potential threat to integrity should not be viewed as either ill-intended or arbitrary. ILI technology and performance continue to advance, but ILI technology and tools still have real limitations, and interpretation of ILI indications to usable results requires significant skill and judgment. Consequently, an operator may perform additional examination to determine whether a reported condition actually exists, and/or evaluation to determine whether a reported condition presents a potential threat to the integrity of the pipeline. The additional examination and evaluation that a prudent operator may employ to complete the determination activity consumes both time and resources from the finite pool of resources available to the operator to respond to reported geometry conditions, as well as other types of conditions, including wall loss due to corrosion, stress-corrosion cracking (SSC), pipe seam imperfections, etc.

From the results of the studies discussed in this report, Baker prepared the following:

- Guidelines for information requirements and timing for the discovery process (Section 8)
- Guidelines for scheduling evaluation and remediation of geometry defects (Section 9)

Section 10 contains a synopsis of the study with conclusions and recommendations.

Baker presumes that clarification of the issues addressed in this report will be a priority for both operators and OPS in the next cycle of rulemaking for both the liquid and gas integrity rules. Until the issues are clarified by a future rulemaking process, Baker recommends that both pipeline operators and OPS inspectors accept, as a reasonable compromise, that an operator's receipt and acceptance of a written report from an ILI vendor will provide adequate information to determine that geometry conditions in the report that are classified as an "immediate repair condition" present a potential threat to the integrity of the pipeline. Under this proposed compromise, which could be formalized in a response to an additional FAQ in both the liquid and gas integrity websites, scheduling of "immediate repair conditions" should begin with receipt and acceptance of the written report that identifies "immediate repair conditions". An operator could reclassify conditions as appropriate when subsequent examination or evaluation of a reported immediate geometry condition during the determination activity revealed that a condition was classified incorrectly in the written ILI report. This proposed compromise could be limited to conditions classified as "immediate repair conditions" since OPS did not express concerns relating to the timeliness of operator responses to other classes of conditions.

Baker also recommends that each pipeline operator prepare for OPS review and approval the following items for incorporation into their integrity management program and manual:

- A detailed written procedure for interaction and communication with ILI vendors, specifically addressing the characteristics and requirements for the written report that will constitute adequate information about conditions identified in the written report as "immediate repair conditions" to determine that they present a potential threat to integrity.
- Detailed written specifications for purchase of applicable types of ILI services (caliper and MFL or UT), specifically addressing requirements for documenting communication of ILI results from the vendor to the operator, and the target schedule for delivery of the written report identifying "immediate repair conditions".
- A detailed written procedure for timely response to reported conditions that are classified as "immediate repair conditions" in the applicable liquid and gas integrity rule.

Baker also recommends that OPS encourage groups of pipeline operators to cooperate with ILI vendors to work toward common industry practices for the items included in the above bullet list. After interviews with four operators, Baker suggests 45 days after completion of field activities for a wall loss tool as an initial target for delivery of a written report identifying “immediate repair conditions”. Developing a consensus on the typical time required for an ILI vendor to deliver a written report identifying “immediate repair conditions” could be a high priority for industry groups. Meanwhile, OPS could manage operators that are perceived as laggard in responding to “immediate repair conditions” revealed by ILI reports by requiring adjustment of the procedures and specifications recommended in the above bullet list for inclusion in each operator’s integrity management program and manual.

OPS should observe common industry practices for communication between pipeline operators and ILI vendors that evolve over the next few years. Those common industry practices can be employed as the basis for revision of the liquid and gas integrity rules to clarify the regulatory issues relating to an appropriate schedule for timely determination if a geometry condition revealed by ILI presents a potential threat to pipeline integrity.

Baker strongly recommends revision of the current FAQ 4.13 definition of an integrity assessment during the next rulemaking cycle as one step toward resolution of the issue of “promptness”. Defining an integrity assessment, whether by hydrotest, ILI, direct assessment (DA), or other technology, as complete only when it provides adequate information for an operator to either

- identify those conditions that require repair, or
- determine that a pipeline is suitable for operation until the next scheduled inspection

would require earlier initiation of an ILI or DA process in order to meet the required assessment schedules. This proposed redefinition of the completion of an integrity assessment for purposes of compliance with inspection schedules would remove the financial incentive to delay receipt of and response to an ILI report.

1 Introduction

This report was prepared at the request of OPS and in accordance with the Baker statement of work outlined in Technical Task Order Number 7 (TTO 7) entitled *"Inspection Guidelines for Timely Response To Geometry Tool Anomalies"*.

The study consists of multiple subtasks listed in the statement of work, intended to assist OPS inspectors in determining if appropriate procedures are being implemented by pipeline operators for the analysis and mitigation of pipeline geometry defects.

The central issue of this report is clarification of the schedule for the discovery process for determining if a geometry condition presents a potential threat to pipeline integrity.

Title 49 of the Code of Federal Regulations (CFR) Part 195 Section 452(h)(2) (§ 195.452(h)(2)) states:

> Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

Title 49 CFR 192.933(b) is similar to § 195.452(h)(2):

> Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

The necessity for the clarification of the schedule arises because the precise meaning of "promptly" in §§ 192.993 (b) and 195.452(h)(2) is subject to multiple interpretations. In the OPS Notice of Final Rule "Pipeline Integrity Management in High Consequence Areas (Repair Criteria)" 49 CFR Parts 195 Docket No. RSPA-99-6355 the following clarification is noted:

> 2. Section 195.452(h)(2) refers to "discovery" of a condition. Discovery was intended to trigger timeframes for remediation action, either expressly stated in the rule or required by the operator's own schedule as specified in their integrity management plan. Several commenters objected to tying discovery to a specific point in time because of the concept of analysis of a situation occurring over a period of time rather than suddenly. The commenters mentioned that the rule requires operators to integrate information from a variety of sources in the assessment process. OPS responded with revisions so that discovery is considered to have occurred when an operator has adequate information about a condition

> to determine that it presents a potential threat to the integrity of the pipeline. However, OPS also put an upper limit on the length of the discovery process. An operator must promptly obtain the information from an assessment to ensure that remediation of a condition which could threaten a pipeline's integrity occurs soon after an integrity assessment. The discovery process will end 180 days after an integrity assessment unless an operator can demonstrate that the 180-day period is impracticable.

The compilation of FAQs on the Office of Pipeline Safety website "Implementing Integrity Management for Hazardous Liquid Operators" includes FAQs 4.13 and 6.6 that indirectly relate to the completion of an integrity assessment performed using ILI that triggers the beginning of the 180-day period.

> **4.13 For purposes of meeting deadlines for completing baseline assessment, is the date of the assessment considered to be the day when the tool run is complete, when the preliminary data is received, or when the evaluation of the in-line inspection results is complete?**
>
> The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed, not including repair activities. That will be when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed…
>
> **6.6 If an operator elects to use in-line inspection for satisfying its baseline assessment requirements, must a metal loss "smart" pig and a deformation tool both be run? If so, must these both be run at the same time, or can these runs be made at significantly different times?**
>
> Given the capabilities of current technology, an operator who elects to use in-line inspection will need to run two tools - a metal loss tool and a deformation device - to satisfy the baseline assessment requirements of 195.452 (c) (1)…

According to the responses in FAQs 4.13 and 6.6, an integrity assessment performed using a hydrostatic test provides an operator actionable information (i.e., the tested segment either passes or requires repair), but the completion of field activities relating to an ILI inspection provides no actionable information. While the responses in FAQs 4.13 and 6.6 may have been expedient from an enforcement perspective, the technical justification for the distinction between completion of a hydrostatic test and completion of field activities related to ILI may not be apparent to the public who inhabit a high-consequence area (HCA). More specifically, a pipeline subjected to a hydrostatic test is presumed to have sufficient integrity until the next scheduled integrity assessment, but completion of field activities related to an ILI may reveal no actionable integrity-related information for several months. The fact that an ILI run can satisfy a regulatory milestone, but may provide no actionable integrity-related information contributes to the situation that led to this report.

In order to determine that if a geometry defect poses a potential threat to the integrity of a pipeline, an operator must execute a discovery process that includes the following steps:

- Identify geometry defects using appropriate assessment methods and tools.
- Integrate assessment results with all other pertinent data.

- Validate assessment results through excavations.
- Perform appropriate measurements, tests and inspections of excavated defects and adjust reports as needed.
- Compare defect measurements and characteristics to the criteria listed in the OPS regulations or other criteria where allowable.

Development of internal inspection guidelines requires study of the accuracy of ILI tools. Proper assessment methods and tools are required to identify geometry defects. ILI is a cost-effective and descriptive method for identifying and characterizing geometry defects prior to excavation for direct examination. The ILI tools most commonly used are geometry (caliper) tools. However, metal loss tools, such as MFL and UT tools, have also proven effective for identifying the location of geometry defects, though the sizing of geometry defects by metal loss tools is typically not precise. These issues comprise the initial scope item and are reviewed in Sections 3, geometry tools, and Section 4, other ILI tools.

The study scope also requires a study of the impact of cracks in non-critical deformations discussed in Section 5. A study of pipeline operators' practices and policies for geometry defect assessment, analysis and mitigation is reviewed in Section 6. A review of industry standards and recommended practices prepared and published by NACE International (NACE), American Society of Mechanical Engineers (ASME) and American Petroleum Institute (API) is discussed in Section 7.

Section 8 and 9 contain guidelines based on the studies and reviews conducted. Section 8 has specific information and timing guidelines specific to the discovery-determination process, while Section 9 contains guidelines for potential use by both operators and inspectors in relation to requirements for scheduling and associated documentation. Section 10 concludes this report with a brief summary and further recommendations.

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2 Background

Defects resulting from the deformation of pipeline geometry can have a significant impact on pipeline integrity. Geometry defects can take the form of dents, ovality or buckles, and can be caused by mechanical damage, rock impingement, upheaval or subsidence. Geometry defects that do not fail instantaneously, can lead to a delayed and possibly catastrophic failure. Approximately 20 percent of defects caused by mechanical damage do not fail instantaneously. Defects that do not fail immediately are the focus of this report.

Detection of geometry defects is accomplished primarily using geometry (or caliper) tools with assistance from MFL and UT ILI tools. Most geometry tools can locate and size geometry defects, allowing operators to determine "immediate repair conditions" that are defined solely by dent depth. Geometry tools will not determine if external conditions, such as mechanical damage or corrosion, are present within a dent. Consequently, determining if an external condition, such as mechanical damage or corrosion, is present requires running an MFL or UT tool, and possibly direct examination. Running MFL or UT tools and integrating the results with results from a geometry tool is necessary to assess the potential threat posed by some geometry defects; whereas running a geometry tool alone may not constitute a complete integrity assessment for geometry defects.

OPS has conducted initial integrity management inspections for the large (Category I) liquid pipeline operators. OPS inspectors observed that some pipeline operators were delaying the evaluation of geometry tool survey results until the MFL survey results could be integrated in an effort to improve anomaly characterizations. While integration of data from multiple ILI tools does add value to the discovery process, the time required for interpreting MFL and UT tool results extends the discovery process for geometry defects. In addition, some pipeline operators were reportedly adding apparently arbitrary periods (up to 30 working days, or six weeks) after receipt of the ILI reports before taking action to investigate indications. § 195.452 states that discovery of a condition "occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline". Furthermore, the regulations state that an operator must "promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable." OPS is concerned that practices of some operators may not meet the intent of the rule for prompt and timely discovery of defects, but OPS has not yet developed detailed guidelines regarding the schedule for the process of obtaining adequate information to determine that a condition presents a potential threat to integrity of a pipeline.

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3 Geometry Tool Accuracy

3.1 Subtask 01 - Scope

This section addresses Subtask 01 of the Work Scope that states:

"Evaluate the accuracy of the most widely used geometry tools. The tools' accuracies will be evaluated in terms of the probability of detecting an anomaly, sizing an anomaly and locating an anomaly (relative location and o'clock position). Runtime controlling or limiting parameters will be considered. This study will assist in determining what information is required to make discovery and when discovery is made for geometry anomalies."

3.2 Evolution of Geometry Tool ILI Technology

The caliper tools currently available for ILI are the result of a multi-generation evolutionary process that has been driven by changing needs of the pipeline industry and the development of basic technology that can be used in electro-mechanical devices. The first geometry tools were pipeline cleaning or dewatering pigs equipped with gauging plates that were run in a pipeline to determine whether deformation had occurred during construction of a new pipeline segment. The effectiveness of gauging plates was always questionable unless, of course, there was no damage at all to the gauging plates. The greatest drawback to gauging plates was that even if the degree of deformation was assumed to be accurate, the gauging plate provided no record of either the o'clock position or the linear location of indicated deformation.

3.2.1 First Generation Caliper Tools

One of the leading pig manufacturers developed a mechanical device that had a multiple finger array protruding under a conical shaped polyurethane cup (Figure 3-1). The linkage was designed to record the maximum movement of any one of the fingers at any instant in time on a single-channel strip chart contained within the body of the pig. Additionally, this device had an odometer attached to the pig so that the deformation could be linked to a linear location.

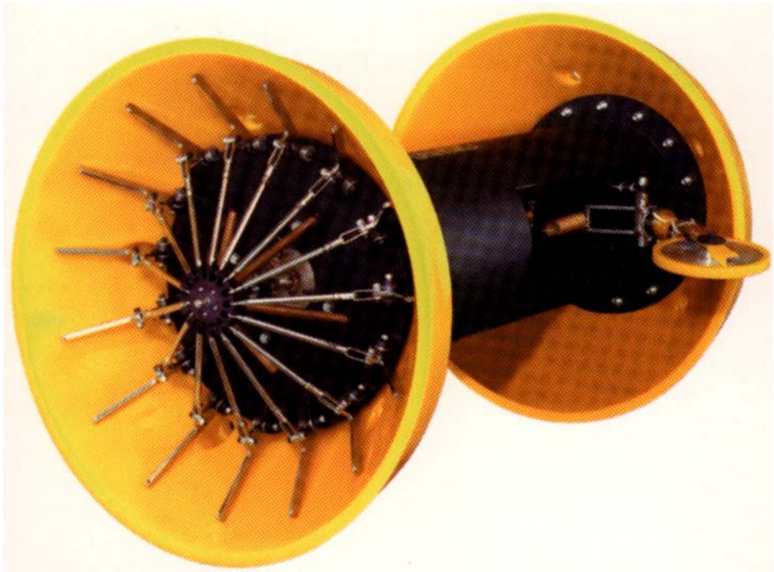

Figure 3-1 Photograph of a first-generation caliper pig illustrating an array of 15 fingers inside a conical cup.

The single-channel strip chart provided no information about which finger detected the deformation, or the o'clock position of the deformation. The linear resolution of the mechanical recording device, as low as 500 feet of pipe per 1 inch of strip chart, was limited, which resulted in significant location errors, but the maximum deformation recorded was reasonably accurate for such a simple device. This device was developed for, and used exclusively for validation of contractor performance (as related to construction-induced deformation) during construction of new pipeline facilities. For convenience of reference in this report, this single-channel caliper device will be referred to as the "first generation caliper pig" (CalPig1). Later, CalPig1 devices were used effectively to confirm that a pipeline section was free of deformation that might prohibit passage of the large and heavy MFL devices being used to find and evaluate metal loss such as corrosion.

3.2.2 Second Generation Caliper Tools

Upon demand from the pipeline industry, the application of CalPig1 was expanded to include detection and evaluation of deformation in operating pipelines. Rather than inspecting for massive deformation in new pipeline segments on a macro basis, the capabilities of CalPig1 were stretched to include structural integrity management by inspecting for deformation. The effectiveness of CalPig1 for integrity management was questionable because CalPig1:

- did not identify the o'clock position of deformation,
- did not record the deformation profile in the transverse direction at all,
- had extremely limited resolution of the deformation profile in the longitudinal direction, and
- had insufficient linear resolution to locate deformation with precision.

Consequently, a second-generation tool evolved using the same concept with multiple fingers in an array under a conical-shaped cup but wherein the travel of each finger was monitored for movement independently and the data from each finger was recorded digitally. These technical enhancements improved resolution dramatically. For convenience in reference in this report, the initial versions of a multi-channel caliper tool will be referred to as the "second generation caliper pig" (CalPig2).

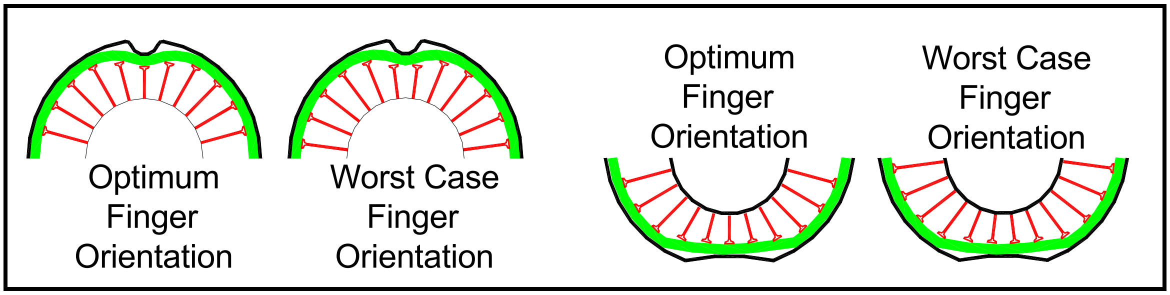

Figure 3-2 Schematic illustrating the function of a second-generation caliper tool with the conical cup (green) between the fingers and the pipe surface for two types of dents and in two orientations.

Figure 3-2 illustrates how the CalPig2 data can be affected by the conical cup (green) between the tips of the caliper fingers and the pipe wall. The conical cup was not sufficiently flexible to conform to the pipe surface at sites with deformation. The cup was likely to contact the deepest deformation, but tended to produce an averaging effect when it bridged the areas surrounding the deformation. The orientation of the caliper fingers with respect to the deepest deformation also has an affect upon the recorded depth. In the positions identified as optimum finger orientation, a finger passes directly over the deepest deformation and that depth is recorded. In the positions identified as worst-case finger orientation, the mid-point between two adjacent fingers passes directly over the deepest deformation. Each of the two fingers records a depth that can be slightly less than the deepest deformation.

3.2.3 Third Generation Caliper Tools

A variation of CalPig2 concept evolved that provided a slightly improved circumferential resolution. The conical-shaped cup was removed so that the caliper fingers contacted the pipe surface, which eliminated the averaging affect of the conical cup (Figure 3-3). For convenience in reference in this report, this caliper without the conical-shaped cup will be referred to as the "third generation caliper pig" (CalPig3).

CalPig2 and CalPig3 devices have a nominal finger spacing of approximately 2.5 to 3.5 inches at the internal pipe surface. Installing the same number of caliper fingers as the nominal pipe diameter in inches (24 fingers on a caliper tool for 24 inches OD pipe, etc.) results in a spacing between caliper fingers of approximately pi or 3.142 inches, because the circumference of a circle is pi times its diameter ($c = \pi D$).

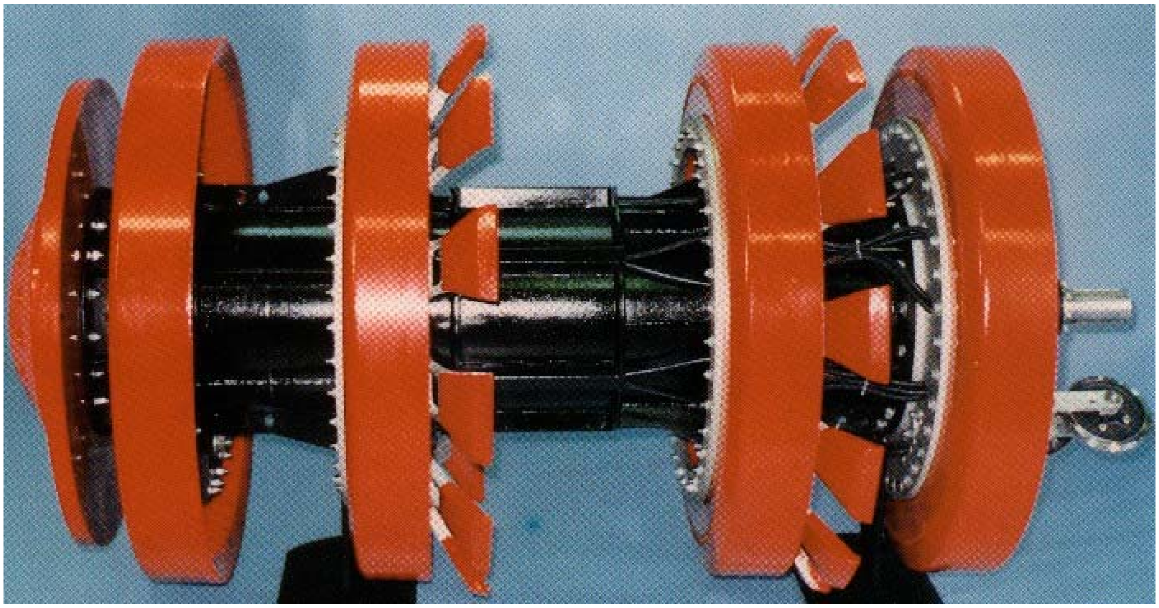

Figure 3-3 Photograph of a third-generation caliper tool with two staggered rows of paddles with a radius tip that conforms to the inside surface of the pipeline.

Some CalPig3 tools are equipped with caliper fingers in the form of paddles with a radius-tip conforming to the inside surface of the pipe while other CalPig3 tools are equipped with narrow caliper fingers with an open gap between the fingers. The difference in the shape of finger tips can cause a significant difference in response to dents.

Figure 3-4 illustrates the response of the radius-tipped paddles for both an impact dent on top and a rock dent on the bottom. The radius-tip paddles respond essentially the same, irrespective of the orientation of the paddles to the maximum depth of the deformation. Figure 3-4 illustrates that the radius-tipped paddles provide essentially full circumference coverage of the pipe surface and the maximum depth of deformation is evaluated properly for both types of deformation.

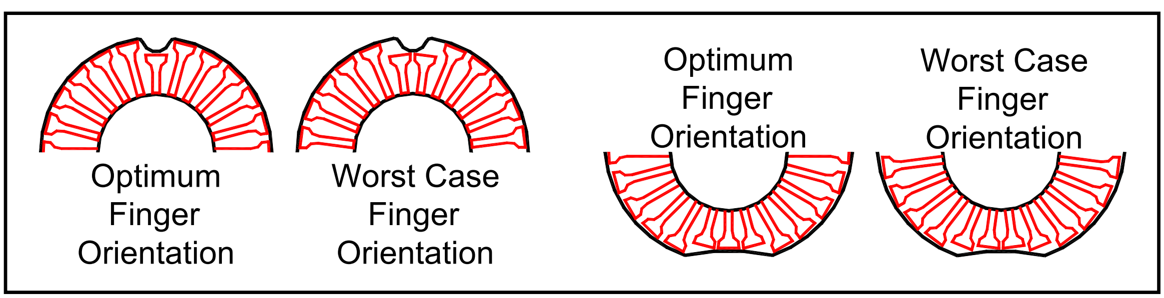

Figure 3-4 Schematic illustrating the function of a third-generation caliper tool equipped with radius-tipped paddles for two types of dents and in two orientations.

Figure 3-5 illustrates the response of narrow fingers with an open gap between the fingers for the same deformations illustrated in Figure 3-4. Comparison of Figure 3-4 with Figure 3-5 reveals that the narrow-finger design provides significantly less coverage of the full circumference of the pipe. Furthermore, the depth of deformation may be underreported by the narrow-finger design, depending on the shape of the dent and orientation of the fingers with respect to the deformation. For the small, abrupt, impact dent on the top of the pipe, the reported depth will likely be accurate when the finger passes directly over the deepest deformation. On the other hand, the depth of the same small, abrupt, impact dent may be significantly underreported if two of the narrow fingers straddle the dent so that the midpoint between two adjacent fingers passes directly over the deepest deformation.

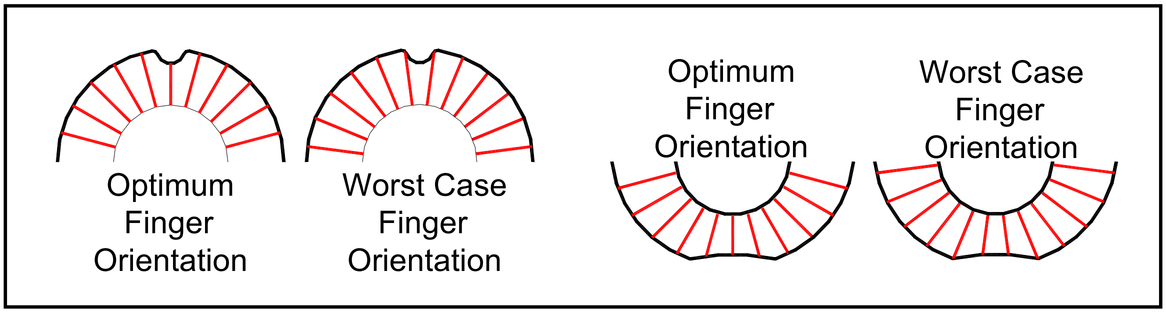

Figure 3-5 Schematic illustrating the function of a third-generation caliper tool equipped with narrow fingers for two types of dents and in two orientation.

Orientation of the narrow finger design with respect to the deformation is less significant for the large and smooth rock dent on the bottom of the pipe. When the approximately 3-inches spacing between the narrow fingers is relatively small compared to the circumferential extent of a large dent, the recorded depth may be approximately equivalent to the maximum depth.

Industry experience indicates that a relatively small, but abrupt dent on a pipeline is more damaging to integrity than a relatively large dent of equivalent depth. Unfortunately, the narrow finger design with 2.5 to 3.5 inches spacing may be less reliable for detecting the more damaging dent.

3.2.4 Fourth Generation Caliper Tools

In order to improve circumferential resolution of the small, abrupt, impact dents, ILI vendors increased the number of fingers in the array. This resulted in a compromise on finger width while still attaining full circumference coverage. For convenience of reference in this report, caliper tool with finger spacing less than 1.5 inches will be described as the "fourth generation caliper pig" (CalPig4). Figure 3-6 illustrates that utilizing 0.75-inch wide fingers on the tightest spacing mechanically possible, provides good resolution of both small impact dents and large rock dents.

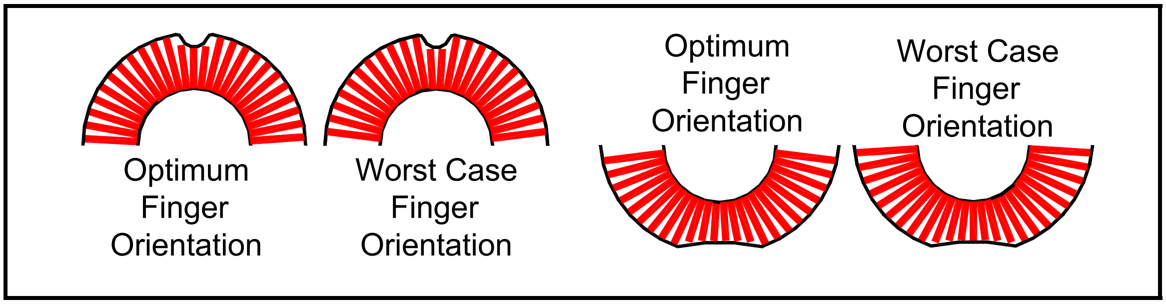

Figure 3-6 Schematic illustrating the function of a fourth-generation caliper tool equipped with closely spaced fingers of approximately 0.75 inch width for two types of dents and in two orientation.

3.3 Accuracy of Caliper Tools

The accuracy of caliper tools can be described by comparison of the reported depth of dents from the ILI results to actual dent depths measured after excavation and direct examination. The schematics and discussion of CalPig2 and CalPig3 tools reveals the sources of scatter when reported depths are plotted against actual depths. CalPig4 technology offers the best available accuracy in reported depth. Industry experience reveals that the reported depth from CalPig2 and CalPig3 runs will typically be ± 25 percent of the measured depth. However, the reported depths from CalPig4 runs will typically be within ± 0.1 inch of the measured depth.

The minimum dent depth that can be detected reliably is also an indicator of caliper tool accuracy. Industry experience indicates that CalPig4 tools are likely to detect locations of deformation that are at least 0.1-inch deep. Industry experience also indicates that CalPig2 or CalPig3 tools may miss dent depths approaching 2 percent of the pipe diameter, depending on the size and configuration of the deformation. Current regulations do not require repair of plain dents with depth less than 2 percent. Reportedly, relatively deep impact dents on the top of a pipeline may re-round to a depth less than 2 percent of diameter when the force is removed from the indenter.

ILI vendors generally represent that caliper tools can determine the circumferential position of deformation within ±1 o'clock (± 30 degrees of angular position) of the actual position. Reportedly, the reported positions are typically within 30 degrees of the actual position of the deformation.

3.4 Linear Resolution

Linear resolution of caliper tool results is significant for characterizing the shape of the deformation as well as determining the location of the deformation. The longitudinal resolution of all of these digital tools (CalPig2, CalPig3 and CalPig4) is a function of the data sample rate. If the sample rate is a function of time rather than travel distance, then resolution can be seriously affected by variations in velocity as the pig traverses the pipeline. In liquid pipelines, travel speed is more constant than travel speed in natural gas or other compressible fluid pipelines. Even when the sample rate is a function of the distance traveled (triggered off the odometer), control of travel speed is still a concern due to the possibility of odometer slippage during periods of rapid acceleration or deceleration. Linear sampling at intervals of 0.25 inch and less along a pipeline can be characterized as high linear resolution while sampling at intervals greater than 1 inch along a pipeline can be characterized a low linear resolution. Data sample rates between 0.25 and 1.0 inch can be characterized as intermediate liner resolution.

With the advent of digital data accumulation and the modern concepts utilized by most ILI vendors in their odometers and other marker systems, locational issues are less of a problem than they were formerly. All of the CalPig2, CalPig3 or CalPig4 systems should be able to locate the closest girth weld within ± 0.3 percent of the distance measured from a reference marker. Once the closest girth weld is located, the ILI results should locate a point of interest within ± 0.1 percent of the distance measured from a reference girth weld. Thus, with a marker spacing of 1 mile, the maximum distance measured to a specific reference girth weld would be 2,640 feet so that the reference girth weld could be located within ± 7.92 feet (2,640 feet x 0.003 = 7.92 feet). Assuming 40 feet pipe joints, the farthest distance from a point of interest to a reference girth weld would be 20 feet. The point of interest could be located within ± 0.24 inch (20 feet x 12 inches / foot x 0.001 = 0.24 inch).

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4 Capabilities of Other ILI Tools for Identifying Geometry Anomalies

4.1 Subtask 02 – Scope

This section addresses Subtask 02 of the Work Scope that states:

"Evaluate other ILI tools for their capabilities of identifying and characterizing geometry anomalies. Magnetic Flux Leakage (MFL) and Ultrasonic Testing (UT) tools will be evaluated to determine how they can enhance the detection and description of geometry anomalies. This study will assist in determining what information is required to make discovery and when discovery is made for geometry anomalies."

4.2 Detection of Deformation with MFL or UT Tools

MFL and UT tools have only limited capacity to detect and size deformation defects. The performance of the various tool categories for evaluating deformation is described below. In summary, the metal loss ILI devices can be used to confirm the presence and orientation of significant deformation but they cannot be reliably used to evaluate deformation size or depth.

4.2.1 Conventional MFL Tools

Conventional MFL tools will detect some forms of deformation, primarily due to shoe bounce, but are not considered reliable for detection of ovality or smooth rock dents. Conventional MFL tools will usually detect abrupt impact dents, but cannot provide a reliable indication of dent size or depth. Conventional MFL tools are useful in establishing deformation orientation for those dents detected.

4.2.2 High Resolution MFL Tools

High-resolution (HiRes) MFL tools will perform very much the same as conventional MFL tools in the presence of deformation. The detection is more reliable and differentiation from other types of defects is better, but high-resolution MFL tools still cannot provide useful information relating to dent size or depth. Like conventional MFL tools, high-resolution MFL tools can be useful for establishing deformation orientation for those dents that are detected.

4.2.3 TFI MFL Tools

The transverse-field inspection (TFI) MFL tools are more sensitive for detection of deformation than other MFL tools because of the greater length of the sensors in contact with the pipe. TFI tools will detect smaller dents than either of the other types of MFL tools, but TFI tools are not as reliable as a caliper tools for detection of deformation. TFI tools can be useful in establishing deformation orientation for those dents detected.

4.2.4 Compression Wave Ultrasonic Tools

Compression wave UT tools are very sensitive for the detection of deformation and the display is very definitive, especially in "C-Scan" mode. The definitive display shows "No Return Signal" at points of abrupt deformation and at some of the more prominent points of ovality and rock dents.

The areal extent of deformation indicated by these tools is reasonably accurate but cannot be relied upon for finite measurement of the extent. In no event can the signal be evaluated for dent depth. These UT tools can be relied upon to indicate orientation of the deformation detected.

4.2.5 Shear Wave Ultrasonic Tools

The performance of shear wave ultrasonic tools for detection of deformation is similar to the performance of the compression wave UT devices. Shear wave UT tools offer significantly more channels of information but the additional information does not improve reliability for evaluating the severity of deformation. Shear wave UT tools can be useful in establishing deformation orientation for those dents detected.

4.3 Detection of Metal Loss with MFL or UT Tools

Quantative information about the accuracy of ILI tools for detection and sizing of wall loss is limited. Evaluating ILI detection and sizing accuracy in buried pipelines requires excavation and direct examination, which is costly. Extrapolating ILI detection and sizing accuracy determined in a test loop to cross-country pipelines has practical limitations. Above ground pipelines offer access for direct examination employing manual NDE without excavation, but the extent of above-ground pipelines that have been subjected to ILI is limited.

One report (Williamson, 1993) summarized a 5-year program of recurring MFL inspections of NPS 16 and 24 multiphase pipelines at Prudhoe Bay, where the above-ground pipelines provide relatively convenient access for radiographic and ultrasonic testing to confirm ILI reports. These pipelines had experienced internal corrosion caused by the transported fluids and external corrosion caused by collection of water under the external insulation, especially under the field applied insulation covering girth welds. A significant number of known corrosion features had been identified by manual NDE prior to ILI. Although the pipelines were in multiphase service, all ILI was performed with temporary launchers and receivers and gas pressure due to the absence of permanent launchers and receivers.

Observations from that report included that 50.5 percent of identified corrosion features were categorized in the correct wall-loss category, but 39.5 percent of the identified corrosion features were categorized in one or more categories more severe than actual while 10.0 percent of the corrosion features were underestimated. Other observations based on MFL inspection of NPS 16 and 24 pipelines at Prudhoe Bay included that MFL results missed 77 percent of the known corrosion damage in girth welds, 46 percent of the known damage in bends and 82 percent of the known damage at girth welds in bends.

Another report (Williamson, 1994) summarized ILI of three additional above-ground pipelines at Prudhoe Bay employing a UT tool. One observation from analysis of the UT results was that a significant portion of the reported indications were significantly less severe than reported. The report explained that relatively shallow internal corrosion pits were confused with relatively severe external corrosion.

While ILI technology has improved since these references were prepared, detection and sizing of metal loss using MFL and UT tools can be a technical challenge in a typical pipeline segment. Detection of wall loss in deformation clearly presents a greater challenge.

4.4 Detection of Metal Loss in Deformation

In ovality, the metal loss might take the form of mill defects, corrosion, or cracking. All of the MFL and UT tools should perform reasonably well in detecting metal loss (within their capability in straight pipe) in areas of relatively smooth ovality. At or near the extremities of the long axis where the radius of curvature is smallest, the sensors will not conform properly to the pipe surface and the minimum detection level can be seriously impacted. In any event, the severity of metal loss cannot be ascertained accurately in the presence of large degrees of ovality. Thus any metal loss detected by a metal loss tool, coincident with ovality as determined by one of the deformation tools should be excavated and remediated as required by regulation.

The same types of metal loss found in ovality are found in rock dents. Rock dents are more abrupt than ovality and the probability of one of the metal loss tools being able to perform well within these discontinuities is relatively low. In the smoothest of rock dents, it is possible to get a metal loss signal but it should not be relied upon for evaluation of the metal loss. As rock dents become deeper, they become more and more abrupt and the probability of metal loss detection becomes less and less. In these situations, evaluation of any metal loss signal received is not practical. The UT devices perform even worse than the MFL devices in these situations because of loss of the return signal.

In the most injurious of all deformation categories, impact dents, all of the forms of metal loss may exist along with the addition of gouging and surface hardening as a result of the impact. These stress concentrators found coincident with abrupt impact induced deformation represents a common cause of catastrophic pipeline failure. To make matters worse, it is extremely rare to detect metal loss of any kind within this serious discontinuity due to the abruptness of the deformation causing sensor lift-off and a gross deterioration in the sensitivity to metal loss.

In summary, the more abrupt the deformation, the more serious the defect, and the more probable that metal loss is coexisting. The more abrupt the deformation, the more probable that metal loss will not be detected by metal loss devices. In no event can any of the metal loss ILI devices be <u>reliably</u> used to determine the presence of metal loss in deformation. Further, they cannot be used at all to evaluate the severity of metal loss in impact dents.

4.5 Detection of Deformation Coincident with Welds:

None of the caliper devices can reliably identify the location of a longitudinal seam in line pipe. Therefore, in order to determine whether a deformation condition is coincident with a longitudinal seam or not, one must correlate the deformation data to another data set that can identify the location of the longitudinal seam. Location of longitudinal seams, and especially smoothly trimmed ERW seams, is a challenge with either conventional or HiRes MFL tools, as well as with the compression wave UT tools. The TFI MFL and shear wave UT tools do a good job of locating the weld seam and are also sensitive to deformation (detection only). Consequently, TFI MFL and shear wave UT tools can identify deformation coincident with a longitudinal seam without integrating results from a caliper tool.

Traditionally, longitudinal seams were typically located in the upper one third of a pipeline, but that practice has been modified by some operators. Operators should determine the typical location of longitudinal seams in each segment scheduled for ILI and share that information with ILI vendors. If ILI results do not positively identify the location of a longitudinal seam in a joint with deformation, excavation of the deformation for direct examination would seem prudent.

All of the deformation ILI devices currently in use are capable of locating each girth weld as well as the deformation as previously described and therefore, deformation coincident with a girth weld can be identified without correlation to another data set.

5 Impact of Cracks Within Geometry Defects

5.1 Subtask 03 - Scope

This section addresses Subtask 03 of the Work Scope that states:

"Review all available information on the impact of cracks within geometry defects (dents) on pipeline integrity. This study will examine the relationships between cracks, dents and re-rounding."

5.2 Types of Geometry Defects

A "dent" is a permanent deformation of the circular cross section of a pipeline without a corresponding change in wall thickness. This report will focus upon the three types of deformation illustrated in Figure 5-1.

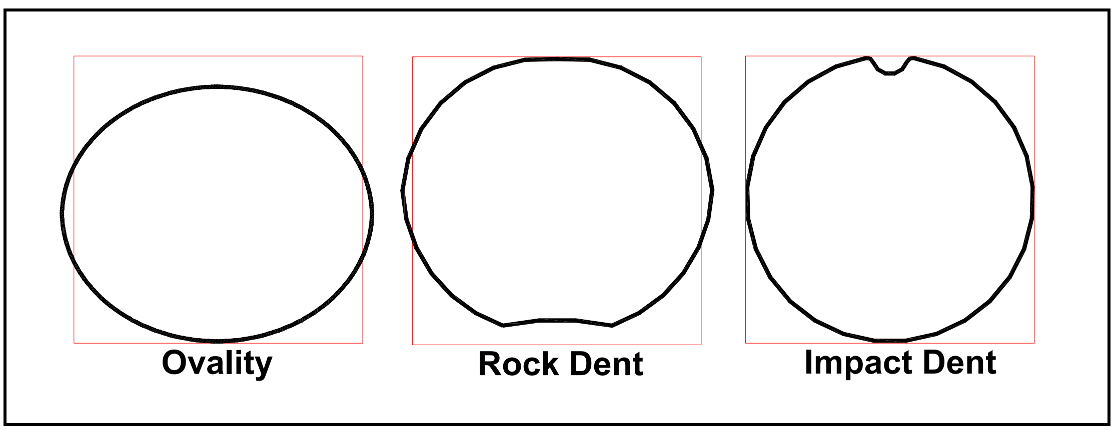

Figure 5-1 Schematic illustrating the three types of deformation that are the primary focus of this report.

5.2.1 Ovality

The most common general form of deformation, ovality, is typically non-injurious and is found in most pipelines inspected. Ovality typically occurs in larger diameter, thinner wall thickness pipelines due to the weight of the product in the pipeline, the weight of the overburden, and the weight of the pipe itself. Another form of ovality occurs at field bends and it too is non-injurious except in the more-extreme cases. With certain types of the older external coating systems, even moderate levels of ovality can cause disbonding of the external coating, which can result in a contact of the external surface with a potentially corrosive environment. Ovality can be very injurious in extreme cases when the radius of curvature at the extremities of the large diameter (horizontal axis as shown in Figure 5-1) becomes quite small so as to exceed the elastic limit. In these rare instances, buckling occurs and may be followed by pipeline failure.

5.2.2 Rock Dents

Another general form of deformation commonly found in pipelines is smooth dents or mashes (rock dents). These are usually the result of foreign objects such as a skid or a large rock left in the ditch bottom during original construction (thus they are commonly referred to as "rock dents"). Sometimes bottom side dents occur over time as the pipeline settles with the soil while a portion cannot settle due to the presence of a large rock below the ditch bottom. Quite often some ovality will also be induced as is shown in Figure 5-1. Regardless, a very large percentage of these rock dents are smooth in nature due to a rather uniform distribution of stresses and are almost always at or near the bottom of the pipe. Sometimes, however, these can be much more localized, contain stress concentrators, and in the more serious variations, can buckle and fail in service. In special circumstances, thermal cycles can exacerbate the condition and cause additional stresses at the point of denting, which also can be a point of restraint as compared to the surrounding pipe. As in the case of extreme ovality, disbonding of the external coating may occur resulting in contact of the external surface with a potentially corrosive environment. In addition, the presence of a large rock can cause shielding and negatively impact the effectiveness of impressed current cathodic protection systems. Another of the more injurious circumstances that can occur with smooth rock dents is when the restraint (rock, skid, etc.) is removed and the dent pops out. If left unrestrained, the pipe can begin to flex under cyclic loading much like a diaphragm in a pump. This effect is commonly referred to as "re-rounding" and multiple pipeline failures have been attributed to re-rounding.

5.2.3 Impact Dents

Another general form of deformation is caused by mechanical impact inflicted by some form of heavy excavating equipment. Thus, these "impact" dents are almost always found in the top half of the pipe. Impact dents are usually very abrupt in configuration, especially when compared to the smooth ovality and rock dents described above. Often the pipe fails when struck by these robust excavating devices but sometimes they are merely damaged to an extent that there is a good probability that they will fail later under cyclic stress. A time related failure could occur at these impact dents for two reasons. The first is that re-rounding occurs as is described previously and the second and more probable occurrence is due to a gouge being cut into the pipe by the force of impact in addition to the dent, providing a point of additional stress concentration resulting in failure.

5.3 Consequences of Geometry Defects

Dents in pipelines are a common result of third-party damage or backfill loads over hard spots beneath the pipe. While dents are common, failures from dents alone (i.e., dents without mechanical damage such as scratches and gouges that reduce the wall thickness, otherwise known as "plain" dents) are relatively uncommon. Dents with mechanical damage are typically caused by third-party damage and result in immediate failure approximately 80 percent of the time (Rosenfeld, 2001). In the remaining 20 percent of third-party damage incidents, damage is not sufficiently severe to cause immediate failure, but if the damage is not repaired, failure may occur later due to an increase in the internal pressure, corrosion of the damaged material, or pressure-cycle fatigue. Pressure-cycle fatigue is caused by the dent cyclically rebounding or "re-rounding" under internal pressure fluctuations

Plain dents, particularly dents located on the bottom of a pipeline, or "bottom-side" dents, are generally not an immediate threat to pipeline integrity. Plain dents can, however, create a longer-term issue due to the development of ancillary problems (e.g., coating damage, shielding from cathodic protection, corrosion, SCC, hydrogen cracking, or punctures due to continued settlement). In some cases, plain dents can also be subject to pressure-cycle fatigue.

Dents that are prevented from re-rounding under the effects of internal pressure by the soil surrounding them, such as dents caused by rocks in the ditch are considered "restrained" or "constrained". Unrestrained" or "unconstrained" dents are those that are not prevented from re-rounding under the effects of internal pressure by the soil surrounding them. Pressure-cycle fatigue of dents is most common in "unrestrained" or "unconstrained" dents. In cases where there are closely spaced restrained dents, the saddle-shaped area between the dents is actually unrestrained and thus may be susceptible to pressure-cycle fatigue even if the dents themselves are restrained (Rosenfeld, 2002).

Regardless of the cause of the dent, if the restraining force is removed, such as when a rock dent is exposed and the rock removed, the dent is then unrestrained and subject to possible fatigue.

Pressure-cycle fatigue of dents is more likely to occur in liquid lines, as compared to gas lines, due to the more cyclical operating pressure spectrum.

5.3.1 Plain Dents

Plain dents are typically formed by rock impingement from original construction due to improper ditch padding or subsequent movement of the pipeline relative to a local hard spot in the surrounding soil. Plain dents are typically on the bottom of the pipe and are most often restrained from re-rounding by a persistent force impinging on the dent. Impingement of a force from a local hard spot prevents re-round of the pipeline, thus reducing flexing of the dent and the likelihood of fatigue crack formation. However, liquid pipelines have experienced cyclic fatigue of dents formed by rock impingement after the rock was removed, thus allowing the dent to flex (Rosenfeld, 2002a). In addition, fatigue cracks have been found in the "saddle" formed between two closely spaced rock dents.

If a rock is sharp enough, it may lead to a puncture of the pipe material. Rock impingement can cause coating damage or shielding from cathodic protection that may lead to corrosion, SCC or hydrogen cracking. Most failures that have occurred from rock dents fail as leaks rather than ruptures.

Research has shown that for pipelines with a diameter–to-wall thickness ratio (D/t) of 68 or greater, which are pressurized to 72 percent of specified minimum yield strength (SMYS), any dent detected deeper than 5 percent of the outside diameter is most likely a constrained (i.e., rock) dent or a buckle.

Similar research concluded that plain, unconstrained dents that have survived a hydrostatic test to 90 percent of SMYS or more are likely to re-round to depths of less than 2 percent. The research further indicated that these dents, both in the body of the pipe as well as those located on sound welds, would not cause a failure within the useful life of a pipeline (Alexander, 1997). However, if these hydrostatic test conditions are not met (i.e., testing to 90 percent of SMYS), unconstrained dents with depths greater than 2 percent may remain in the pipe and could be susceptible to pressure-cycle fatigue cracking.

In natural gas pipelines, plain dents, both restrained and unrestrained, are usually not considered a potential threat unless high-localized strains are present. However, since hazardous liquid pipelines tend to experience more aggressive pressure cycles than natural gas pipelines, pressure-cycle fatigue of unrestrained, plain dents in liquids pipelines may ultimately lead to a failure. In addition, corrosion may occur as the result of coating damage associated with a dent.

5.3.2 Mechanical Damage

Mechanical damage caused by the impact from excavating equipment is a significant cause of pipeline failures. Mechanical damage typically causes indentation, but the dent may re-round after the external force is removed. Mechanical damage caused by excavating equipment may occur as gouges, scrapes or crushed metal, and are often within a dent.

Mechanical damage can cause significant metallurgical damage to the microstructure of the metal at the location of impact. Metallurgical damage includes the plastic flow, and even melting, that can occur due to the heat generated by the energy transferred to the pipe surface as the result of mechanical damage. The metal's microstructure may be crushed and cold-worked below the surface of a gouge. Metallurgical damage may lead to a reduction in the ductility and toughness of the metal (Rosenfeld, 2002a). Excavating tools that strike a pipeline and then slide along the surface may fuse to the pipe surface and then quickly shear the bond due to the sliding force. Repeated fusing and shearing may cause a series of surface cracks behind the point of contact that are perpendicular to the sliding direction. Re-rounding of dents with associated mechanical damage can lead to crack formation at the root of the gouge where the cold work occurred.

5.3.3 Pressure-Cycle Fatigue Cracking

As mentioned above, a restrained dent is one that is constrained by some physical means and cannot rebound back to its original contour. Unrestrained dents, such as that caused by a blunt impact, will typically rebound nearly completely due to the internal pressure of the pipeline once the impacting force is removed.

The primary concern with unrestrained plain dents is pressure-cycle fatigue. Pressure-cycle fatigue is a result of high local bending stresses associated with the dent flexing as the result of operating pressure cycles (i.e. as the internal pressure increases the dent tends to flatten, also known as re-rounding, and as the pressure decreases the dent tends to resume its initial shape). Much research has been completed on demonstrating or predicting the pressure-fatigue characteristics of dents (Rosenfeld, 2001).

The fatigue performance of dents is affected by several factors. For unrestrained dents, fatigue life has been shown to:

- decrease with increasing initial depth (Alexander, 1997),
- decrease with increasing pressure cycle range (Alexander, 1997),
- increase with mean pressure level,
- decrease with increasing initial local strain (Kiefner, 1999),
- decrease with increasing dent width-to-depth ratio (Rosenfeld, 1997),
- decrease with increasing pipe D/t (Fowler, 1993), and
- decrease with increasing SMYS (Fowler, 1993).

The last factor in the bullet list is due to the fact that a dent in low-SMYS material is more likely to re-round plastically to a shallower residual depth than would a similar dent in a high-SMYS material, and thus undergo smaller elastic fluctuations from pressure cycles, leading to a longer life compared to the deeper residual depth (Rosenfeld, 2001)[1].

Tests have shown that plain dents having residual depths of 2 percent or less of the pipe diameter exhibited fatigue lives between 10^5 and 10^6 cycles of pressure producing hoop stress levels between 36 and 72 percent of SMYS (Rosenfeld, 2001). Due to the low number of pressure cycles typically experienced by gas pipelines, 10^5 and 10^6 pressure cycles are likely equivalent to an indefinite life for most gas pipelines. However, as some liquids pipelines operate with pressure spectra that have a frequency and magnitude several orders of magnitude greater than most gas pipelines, pressure-cycle fatigue of dents may be a concern for certain liquid pipelines.

Given the same depth and shape, restrained dents typically have a fatigue life at least an order of magnitude greater than unrestrained dents. In one series of tests, restrained dents up to 18 percent of the pipeline diameter survived hundreds of thousands of pressure cycles between 36 and 72 percent of SMYS without failure (Alexander, 1997). Based on these results, there is a reason to believe that excavating rock dents should be avoided, even though doing so will facilitate addressing long-term corrosion control and monitoring issues mentioned earlier.

An important exception, and likely only applicable to liquids pipelines, is if there are two closely spaced (less than or equal to one pipe diameter) restrained dents with a flattened or saddle-shaped area between them. This flattened area may be susceptible to pressure-cycle fatigue since it can be effectively unrestrained and thus flexes in response to pressure cycles. In this situation, further investigation is warranted, and if confirmed in the field, the best response would be to install a full-encirclement sleeve around the feature.

5.4 Conclusions

Cracks are one of the leading causes for delayed failure of geometry defects, primarily dents, in pipelines. Cracks are more likely to form as a result of pressure-cycle fatigue associated with mechanical damage than as a result of rock impingement. Pressure-cycle fatigue cracks are often not visible to the unaided eye and therefore, whenever a geometry defect is exposed, appropriate forms of nondestructive examination (e.g., liquid penetrant inspection (PT), magnetic particle inspection

1 This concept is based on theoretical considerations that may be outweighed by other important advantages associated with higher-strength pipe, such as improved toughness. It is not intended to suggest that low-strength pipe is categorically superior to high-strength pipe in resisting mechanical damage.

(MT), etc.) must be employed to ensure the integrity of the pipeline. Proper mitigative measures must be taken when cracks are found to be associated with a geometry defect. In the case of cracks resulting from pressure-cycle fatigue, there are two mitigative options; installation of a full-encirclement welded steel sleeve, or pipe replacement.

6 Industry Practices for Geometry Defect Assessment, Analysis and Mitigation

6.1 Subtask 04 – Scope

This section addresses Subtask 04 of the Work Scope that states:

"Interview a cross-section of pipeline operators to determine the variance in operator practices for finding, analyzing and mitigating geometry defects. The purpose of this study is to determine if there are day-to-day operating circumstances that should be considered in setting inspection guidelines. These circumstances could be tool re-runs, shortage of tools or accessibility issues. Any considerations that could impact the timeliness of defect mitigation will be listed in the inspection guidelines."

6.2 Introduction

Based on OPS recommendations, Baker conducted interviews with the integrity management departments of four pipeline operators. These companies operate predominantly hazardous liquid pipeline systems consisting of several thousand miles. Each operator has completed a "quick hit" inspection of their integrity management programs by OPS inspectors. These four companies are designated as Company A, B, C and D for convenience of reference in this report and to preserve their privacy.

6.3 Operator Interviews

The operator interviews were conducted to collect information relating to industry programs for the assessment, analysis and mitigation of geometry defects. The operators were very cooperative in supplying information regarding their procedures and policies. Results from the interviews are summarized in Table 6-1, and additional details are discussed in the following sections:

Table 6-1 Summary of Interviews

Question	Company			
	A	B	C	D
Does operator use a combination of caliper and MFL tools to assess geometry conditions?	Yes	Yes	-	Yes
What is typical time lapse in weeks between geometry and MFL tools?	2	2	-	2
Has operator experienced problems with tool availability?	No	No	No	No
Does operator use deformation/caliper tools?	Yes	Yes	Yes	Yes
Does operator use high-resolution MFL tools?	Yes	Yes	Yes	Yes
Does the company calculate localized strains for geometry conditions?	No	Yes	No	No
Does operator have internal standard for tool performance and accuracy of data?	Yes	Yes	Yes	Yes
Is report accuracy analyzed by comparison with data collected at excavation sites?	Yes	Yes	Yes	Yes
Has operator experienced problems with data interpretation?	Yes	Yes	-	-
Does operator rely upon preliminary report for determination in certain situations?	No	Yes	Yes	Yes
Does operator rely primarily upon final report with integrated results for determination?	Yes	Yes	Yes	Yes
Has the operator experienced integrity problems due to bottom-side dents?	No	No	No	No
Does operator rely upon ILI tools to detect cracks in dents?	No	No	No	No
Does operator perform MT examination of dents for cracks?	Yes	Some	Yes	Yes

6.3.1 Company A

Company A uses both a caliper and an MFL tool to assess geometry defects. They typically run the Enduro caliper pig followed by the CPIG high resolution MFL. The MFL tool is scheduled to be run within two weeks of the caliper tool. Company A has not encountered any problems with the availability of these tools, but they do recommend adequate advanced planning. They have an internal standard for ILI tool performance and accuracy of data. The tool accuracy is analyzed through the examination of the data collected at excavation sites. They are very confident in the accuracy of these tools, and have frequently found that discrepancies are usually the result of data interpretation. Data interpreted incorrectly is subsequently corrected.

The procedure for the discovery process at Company A includes collection of adequate information regarding the condition before determining that the condition presents a potential threat to the integrity of the pipeline. At Company A, the discovery process continues until the final report for either tool has been reviewed and the condition is determined to be a potential threat. The only exception is detailed in the next paragraph. The potential threat to the pipeline is determined by using the criteria in § 195.452 (h)(4). Company A does not assess the severity of geometry defects by calculation of localized strains.

After the caliper tool run, Company A receives a preliminary report. This company does not consider the preliminary report sufficient for determination unless the pipeline diameter-to-wall thickness ratio is greater than 60 and there is a dent greater than 6 percent on the top of the pipeline. (They report to have encountered enough problems with the accuracy of the preliminary reports that they prefer to wait for the final report before taking action.) Company A continues the discovery process until the final report is received and it is determined that a condition that presents a potential threat exists. The immediate, 60-day and 180-day conditions are identified, and investigation and mitigation begins on the immediate conditions. The MFL tool is run following the caliper tool. When the final report from the MFL tool is available, it is integrated with the caliper tool final report to obtain a more complete indication of the conditions. Once again, the immediate, 60-day and 180-day conditions are identified, and investigation and mitigation begins on the immediate conditions. If there are any delays in getting the final results from the MFL tool, the mitigation schedule from the caliper tool continues as planned.

Company A follows the regulations with regards to investigation and mitigation of bottom side dents. Bottom side dents that are less than 6 percent in depth are listed as an “other concern” and are monitored. Company A has not experienced integrity problems with bottom side dents and do not consider them a serious threat to their pipeline system. Company A does not run ILI tools to identify cracks in dents as they do not have sufficient confidence in these tools’ detection capabilities to justify using ILI tools for this purpose. They do perform MT on every dent that is investigated. In the majority of the dents that have been investigated, they have not experienced cracking in the dent.

6.3.2 Company B

Company B uses both a caliper and an MFL tool to assess geometry defects. They use a variety of tool vendors, but the TDW and Enduro caliper tools are used most frequently. They occasionally run the Tuboscope high-resolution caliper tool and perform strain calculations from the data. They follow the caliper runs with PII, Rosen or Tuboscope high-resolution MFL tools, and occasionally they use the PII ultrasonic tool. The MFL or UT tool is scheduled to be run as soon as two weeks following the caliper run. Company B has not experienced problems with tool availability. They have an internal standard for the tool’s performance and accuracy of data. The tool accuracy is analyzed through the examination of the data collected at excavation sites. They are very confident in the accuracy of these tools, but have frequently found that discrepancies are usually the result of data interpretation errors. Data interpreted incorrectly is subsequently corrected.

Company B continues the discovery process until there is adequate information regarding the condition to determine that the condition presents a potential threat to the integrity of the pipeline. Depending upon the specific situation, a determination may be reached at stages of discovery, but all determinations are made within the 180-day timeframe. The earliest determination is for dents greater larger than 6 percent in depth (an immediate condition). If the preliminary report indicates that there are dents with depths exceeding 6 percent, confirmation digs are performed. The determination is reached if direct examination verifies the preliminary report. For dents that are less than 6 percent in depth, determination is reached when the final report is evaluated and a potential threat is believed to exist. The final report is one report with both the caliper tool and MFL or UT information integrated. The immediate, 60-day and 180-day conditions are identified, and investigation and mitigation begins on the immediate conditions.

The potential threat to the pipeline is determined by using the criteria in § 195.452(h)(4). This company investigates all dents greater than 2 percent in depth. Company B does assess the severity of geometry defects by calculation of localized strains when appropriate.

Company B follows the regulations with regards to investigation and mitigation of bottom side dents. They have not experienced integrity problems with bottom side dents, but they do consider such dents to be a potential integrity issue. They consider bottom side dents to be a lower priority integrity issue. This company does not run ILI tools to identify cracks in dents. They do not have enough confidence in these tools' detection capabilities to justify using them. They perform MT, and UT to detect cracks in dents. They do not inspect every dent for cracks, although they are moving in that direction. They currently inspect dents for cracks based on their experience and judgment.

6.3.3 Company C

Company C uses a caliper tool, or a combination gauging pig and MFL tool, to assess geometry defects. They use the Magpie high resolution MFL, Magpie deformation tool and the TDW caliper tool. Company C has smaller diameter pipelines with a heavier wall thickness than Companies A, B and D which are less prone to denting than pipeline with a greater diameter-to-wall thickness ratio. They have had an extensive ILI program, and maintain a large historical documentation program.

Company C employs a combination assessment method, which relies on a gauging pig, a tool with a deformable metal disk that is slightly smaller in diameter than the inner pipe diameter. The concept of the combination method is that if there are any dents of significant depth (6 percent or larger) the gauging plate will be deformed. This method relies on the MFL tool to identify and locate possible dents, which the MFL tool does with great accuracy. This combination method works well for an operator that has good historical information on their system. When the combination method is used, the operator has the option to excavate all dent indications or run a caliper tool to size the dents, which is an economic decision. An operator that has not experienced a history of significant mechanical damage can save money using this method.

Company C has not experienced problems with tool availability. They have an internal standard for the tool's performance and accuracy of data. The tool accuracy is analyzed through the examination of the data collected at excavation sites. This company will excavate several points from every segment that is inspected. The number of excavations depends upon how confident they are in the consistency of the data.

Company C continues the discovery process until there is adequate information regarding the condition to determine that the condition presents a potential threat to the integrity of the pipeline. After a caliper run, Company C receives a phone call from the tool vendor if any immediate conditions exist. Company C will begin excavation of the immediate conditions based on preliminary reports without waiting for the final report. In any case, Company C will make a determination within 180 days. The potential threat to the pipeline is determined by using the criteria set forth in § 195.452 (h)(4). Company C does not assess the severity of geometry defects by calculation of localized strains.

For the combined assessment method, a gauging pig is run, and the gauging plate is analyzed and accepted or rejected. If the tool is rejected, the gauging pig is repaired and re-run, or a caliper tool is run and they proceed to the MFL tool. If the tool is accepted, an MFL tool is run. The results from the MFL tool are examined to determine the number and location of geometry defects. A decision is then made to either excavate all reported possible dents, or run a caliper tool to characterize the dents. If all dents are excavated, determination is reached after examination of each dent.

Company C has not experienced integrity problems with bottom side dents and do not consider such dents a serious threat to their pipeline system. This company does not run ILI tools to identify cracks in dents. They perform either MT or PT at every dent to determine if cracks exist in the dent.

6.3.4 Company D

Company D uses both a caliper and an MFL tool to assess geometry defects. They typically run the Enduro caliper pig followed by the BJ high resolution MFL or occasionally the CPIG high resolution MFL. Company D has not experienced problems with tool availability. They have an internal standard for the tool's performance and accuracy of data. Tool accuracy is analyzed through the examination of the data collected at excavation sites. This company has an extensive statistical evaluation of tool accuracy that has been verified by excavation.

Company D continues the discovery process until there is adequate information regarding the condition to determine that the condition presents a potential threat to the integrity of the pipeline. Company D reaches a determination when they have reviewed both the preliminary and final reports, performed their internal data integration, and determined that a condition presents a potential threat to the integrity of the pipeline. The ILI vendor will call with immediate conditions resulting from the caliper tool run, and Company D will act upon those. This operator states that for immediate conditions, a determination is reached within five working days of receiving the ILI vendor reports. For 60-day and 180 day conditions, a determination is reached within one month of receiving the vendor report, and when possible, within 180 days of the ILI run. Company D documents all reasoning for the discovery process exceeding 180 days. This operator typically runs the caliper tool and MFL tool within two weeks of each other. Both reports are received from the vendor in an integrated form. The potential threat to the pipeline is determined by using the criteria set forth in § 195.452 (h)(4). Company D does not assess the severity of geometry defects by calculation of localized strains.

Company D follows the regulations with regard to investigation and mitigation of bottom side dents. They have not experienced integrity problems with bottom side dents and do not consider such dents a serious threat to their pipeline system. This company does not run ILI tools to identify cracks in dents. Company D performs MT at every dent to determine if cracks exist in the dent. In some situations, the pipe is painted white to give more contrast to the black magnetic particles, which increases sensitivity of the examination.

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7 Pertinent Regulations, Industry Standards and Industry Recommended Practices

7.1 Subtask 05 - Scope

This section addresses Subtask 05 of the Work Scope that states:

"Review all relevant regulations, industry standards and industry recommended practices. The guidelines will be revised to make certain they have similar language and intent as the regulations, standards and recommended practices."

7.2 Introduction

The following regulations, industry standards and recommended practices were reviewed for this report:

- Title 49 CFR 192 *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards*
- Title 49 CFR 195 *Transportation of Hazardous Liquids by Pipeline*
- ASME B31.4-1994 *Transportation Systems for Hydrocarbon, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols* (1992 Edition with ASME B31.4a-1994 Addenda).
- ASME B31.4-1998 *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquid*s (1998)
- ASME B31.4-2002 *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquid*s (2002)
- ASME B31.8-1995 *Gas Transmission and Distribution Piping Systems* (1995)
- ASME B31.8-1999 *Gas Transmission and Distribution Piping Systems* (1999).
- ASME B31.8-2003 *Gas Transmission and Distribution Piping Systems* (2003)
- ASME B31.8S-2001 *Managing System Integrity of Gas Pipelines*
- API Publication 1156 *Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines* (1997)
- API Standard 1160 *Managing System Integrity for Hazardous Liquids Pipelines* (2001)
- NACE RP0102 *In-Line Inspection of Pipelines* (2002)

7.3 Title 49 CFR 192 and 195

Both Title 49 CFR 192 and 195 use essentially identical language to define "Discovery" and give detailed criteria for determining what defects must be repaired and the acceptable timeframe for making these repairs by categorizing defects by severity. The definitions of immediate conditions and the associated timing for repairs are somewhat different, however the general concepts are similar.

Title 49 CFR 192.933 states:

> (a) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to

demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary reduction in operating pressure using ASME/ANSI B31G (ibr, *see* § 192.7) or AGA Pipeline Research Committee Project PR–3–805 ("RSTRENG"; ibr, *see* § 192.7) or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (*See* appendix A to this part 192 for information on availability of incorporation by reference information). A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (ibr, see § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with § 192.949 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(d) *Special requirements for scheduling remediation.*—(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

Title 49 CFR 195.452 (h) contains the following:

(4) *Special requirements for scheduling remediation.*

(i) *Immediate repair conditions.* An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4 (incorporated by reference, see § 195.3). An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss greater than 80% of nominal wall regardless of dimensions.

(B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in § 195.3.

(C) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

(D) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.

(E) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(ii) *60-day conditions.* Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition.

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3% of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(B) A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

(iii) *180-day conditions.* Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:

(A) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(C) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(D) A calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991)) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in § 195.3.

(E) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(G) A potential crack indication that when excavated is determined to be a crack.

(H) Corrosion of or along a longitudinal seam weld.

(I) A gouge or groove greater than 12.5% of nominal wall.

(iv) *Other conditions.* In addition to the conditions listed in paragraphs (h)(4)(i) through (iii) of this section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

Specific methods for finding and evaluating defects are not mandated, however, Appendix C of Title 49 CFR 195 does offer limited guidance on ILI tool selection. In the end, however, it is still incumbent on the operator to identify injurious defects on his system.

7.4 ASME B31.4

When this report was written, ASME B31.4 (1992 Edition with ASME B31.4a-1994 Addenda) was incorporated by reference in § 195.3. The rulemaking to become effective July 14, 2004, revised § 195.3 to incorporate the 1998 edition. Paragraph 451.6 of both these editions of ASME B31.4 is entitled Pipeline Repairs. The General section, paragraph 451.6.1, specifies that repairs should be "covered" by a maintenance plan but does not specify the contents nor essential components of the plan. Paragraph 451.6.2 "Disposition of Defects" defines dents that should be removed or repaired as:

a. Dents which affect the pipe curvature at the pipe seam or at any girth weld

b. Dents containing a scratch, gouge, or groove;

c. Dents exceeding a depth of ¼ in. (6 mm) in pipe NPS 4 and smaller, or 6% of the nominal pipe diameter in sizes greater than NPS 4;

ASME B31.4 (2002 Edition) added a fourth condition requiring repair or removal of dents.

d. Dents containing external corrosion where the remaining wall thickness is less than 87.5% of that required for design

Revising the reference to ASME B31.4 in § 195.3 in a future rulemaking to a current edition that contains the fourth condition would have no practical effect since § 195.452 (h) identifies a dent with any indication of metal loss as a repair condition.

ASME B31.4 contains additional requirements for local corrosion, pitting, allowable repair procedures and methods. However, the requirements in § 195.452 (h) are more specific than, and supercede the ASME B31.4 requirements.

7.5 ASME B31.8

When this report was written, ASME B31.8 (1995 Edition) was incorporated by reference in § 192 Appendix A and in § 195.3. The rulemaking to become effective July 14, 2004 did not revise the referenced edition of ASME B31.8. Section 841.2 of this and subsequent editions of ASME B31.8 is entitled "Installation of Steel Pipelines and Mains" and Section 841.243 is entitled "Dents":

> All dents that affect the curvature of the pipe at the longitudinal weld or any circumferential weld shall be removed. All dents that exceed a maximum depth of ¼ in. in pipe NPS 12 and smaller, or 2% of the nominal pipe diameter in all pipe greater than NPS 12 shall not be permitted in pipelines or mains intended to operate at 40% or more of the specified minimum yield strength.

The requirements generally parallel those of ASME B31.4, but the NPS for a ¼ in. deep dent is increased from 4 to 12. Paragraph 841.243 limits all dents to a maximum depth of only 2 percent of the nominal diameter, but Paragraph 841 is in Chapter IV entitled Design, Installation, and

Testing, which implies that Paragraph 841.243 applies only during new construction to manage contractor performance.

Chapter V Operating and Maintenance Procedures contains Paragraph 851 Pipeline Maintenance. The following requirements for Paragraph 851.4 would apply for managing pipeline integrity.

> …Smooth dents in existing pipelines do not require repair unless they
>
> a. contain a stress concentrator, such as a scratch, gouge, groove, or arc burn;
>
> b. affect the curvature of the pipe at the longitudinal weld or a circumferential weld; or
>
> c. exceed a maximum depth of 6% of nominal pipe diameter.

The requirements in §§ 192.933 and 195.452 (h) are more specific than, and supercede the ASME B31.8 requirements.

7.6 ASME B31.8S

ASME B31.8S, Section 7.2.3 "Metal Loss and Caliper Tools for Third Party Damage and Mechanical Damage" states:

> Indications requiring a scheduled response would include any indication on a pipeline operating at or above 30% SMYS (Specified Minimum Yield Strength) of a plain dent that exceeds 6% of the nominal pipe diameter, mechanical damage with or without concurrent visible indentation of the pipe, dents with cracks, dents that affect ductile girth or seam welds if the depth is in excess of 2% of the nominal pipe diameter, and dents of any depth that affect non-ductile welds. (For additional information see ASME B31.8, para. 851.4.)

7.7 API 1156

API 1156, and its addendum, presents results from numerous experimental and finite element analyses to determine the effects of smooth dents and rock dents on the integrity of liquid petroleum pipelines. The report provides conclusions related to potential significance of dents detected by ILI both in terms of severity and location, as well as information on dent behavior and the potential failure mechanisms.

From an operators point of view, the most useful piece of information in this report is probably Appendix C of the Addendum, which contains a field guide for the assessment of dents and buckles that includes methods for prioritizing these anomalies based on ILI results and assessment techniques based on excavation and examination.

7.8 API 1160

API Standard 1160, contains information about dents in Appendix A "Anomaly Types, Cause, and Concerns." Section 9.6 "Strategy for Responding to Anomalies Identified by In-Line Inspections" states:

> An operator shall take action to address pipeline integrity concerns identified during the evaluation of in-line inspection data. If a condition exists on the pipeline that

> presents an "immediate concern…", the operator shall initiate mitigative actions within five days in order to continue to operate the affected part of the system. Mitigation action is based on regulatory requirements, company guidelines, and assessment of risk.
>
> When a pipeline is inspected by an in-line inspection tool, the final results of the inspection should be provided to the operator within six months. However, certain types of potential defects should be brought to the operator's attention through a preliminary report…

The descriptions of what constitute an "immediate concern" are slightly different than the "Immediate" conditions in the CFR provisions, however there are close parallels in most cases. Once an "immediate concern" is identified, Section 9.6 states:

> Mitigative action…shall be based on in-line inspection data analysis without excavation verification. Temporary mitigative action(s) shall be initiated as soon as possible; within five days of receipt of the preliminary in-line inspection report and shall remain in place until the anomaly can be excavated and assessed. Permanent mitigative action such as repairs, if required, should be accomplished within thirty days of receipt of the preliminary in-line inspection report.

7.9 NACE RP0102

The first edition of NACE RP0102 was published in 2002. It is a comprehensive industry standard for the planning, organization and execution of an ILI project. Various aspects regarding the reliability and detection capability of ILI tools and the operational issues that that should be considered when selecting an appropriate ILI tool are discussed. The standard also discusses considerations that should be evaluated to determine if the tool is compatible with the pipeline system and the operating environment.

Planning and scheduling an ILI run, from scheduling to reduce customer impact to benchmarking and tracking of the pig, are discussed. The intent is for the operator to be adequately prepared in order to maintain the proper operating parameters for the running of the tool.

Finally, the standard briefly discusses ILI data analysis and management.

In general, this standard provides guidelines to assist an operator in establishing and managing an ILI inspection program. It does not, however, present any specific information on anomaly characterization, nor does it address any aspects of mitigation or repair of defects detected.

8 Guidelines for the Information Required for the Discovery Process and When Determination is Prudent

8.1 Subtask 06 - Scope

This section addresses Subtask 06 of the Work Scope that states:

"Using the information collected, Baker will write guidelines to determine what information is required to make discovery and when discovery is made as defined in 49 CFR 195.452 (h). These guidelines will list any inspections and tests that are needed."

8.2 Introduction

A determination that a condition represents an integrity threat is defined in the OPS regulations as occurring when "an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline". The regulation further states, "An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless an operator can demonstrate that the 180-day period is impracticable". The definition of impracticable provided by Merriam-Webster OnLine is:

> impracticable- not practicable **:** incapable of being performed or accomplished by the means employed or at command.

It seems apparent from the above definition that impracticable does not include matters of convenience or inadequate planning.

While the four operators that were interviewed for this study agreed with the regulatory definition of "discovery", each employed a different procedure for the process of determining is a condition presented a potential threat to pipeline integrity.

8.3 Guidelines for the Discovery Process

Each pipeline operator should prepare a written procedure for the discovery process that will be performed for geometry defects. The written procedure for the discovery process should include the following general characteristics:

- A description of the integrity assessments that will be performed to initiate the discovery process for geometry defects, with specific emphasis upon geometry defects that may be classified as "immediate repair conditions". The procedure should include the processes to be employed by both the ILI vendor and the operator for validation of ILI inspection results prior to the ILI vendor issuing a written report to the operator.
- A performance specification for ILI services that includes definition of indications of "immediate repair conditions" that the ILI vendor must report to the operator in writing as soon as is practical after their observation and validation. Processes and methods that the ILI vendor and operator will employ to validate indications of "immediate repair conditions" should be defined in the ILI performance specification. The performance specification for ILI services should include an expected schedule for reporting of conditions that the ILI vendor classifies as "immediate repair conditions". Reportedly, most ILI vendors can and

will deliver such reports within 45 days of the completion of a typical MFL or UT run, but this turnaround may not be attainable from all ILI vendors or for all pipeline segments.

- A description of the significant steps in the process to identify potential conditions and determine if they present a potential threat to integrity. The description should identify the various types and sources of information to be assembled and integrated with the ILI results as the basis of the determination if a condition other than "immediate repair conditions" presents a potential threat to integrity.
- A schedule for the significant steps in the discovery-determination process. This is discussed further in Section 0.
- Identity of the persons or persons responsible for executing the significant steps of the process to identify potential conditions and determine if they present a potential threat to integrity, especially the person or persons who are authorized to determine if a condition presents a potential threat to pipeline integrity.
- The protocol for documenting that the significant steps of the process were completed and when completed, especially the determination of a condition presenting a potential threat to pipeline integrity.

Each operator's procedure for the process to identify potential conditions and determine if they present a potential threat to integrity should focus upon the following objectives, which are required to make a determination that a condition presents a potential threat to the integrity of a pipeline:

- *Identification of a possible defect* - This discovery process begins with receipt of information from the integrity assessment(s). For dents, the assessment tool would be a geometry tool. For metal loss features associated with dents, the assessment tool would be a metal loss tool run (e.g. MFL, UT). Calibration of initial ILI indications through excavation and examination of selected indications is a reasonable and prudent step prior to an ILI vendor issuing a written report to an operator.

- *Verification that a defect exists* - Some operators have more confidence in the currently available ILI assessment tools than other operators. Confidence in, or the lack thereof, likely depends upon an operator's prior experiences with ILI vendors and/or a particular vendor. For example, some operators assume that if an ILI vendor reports a defect, then, in fact, that defect does exist. Other operators integrate the information from an ILI vendor with their own knowledge of the pipeline to determine if the assessment results are consistent with their anticipated condition of the pipeline before making a determination. Finally, other operators may elect to excavate at the location of one or more reported indication of a possible defect in order to perform a visual examination.

  Each of the approaches described above for verifying that a defect exists can be an acceptable and prudent practice, depending upon the specific circumstances. To expedite the response to geometry defects that an ILI vendor classifies as "immediate repair conditions", Baker recommends that operators accept a written report from an ILI vendor, which satisfies the requirements of the operator's performance specification for ILI services, as "adequate information" to determine that conditions classified as "immediate repair conditions" presents a potential threat to the integrity of a pipeline. Consequently, receipt of a written report from an ILI vendor classifying one or more indications as "immediate repair conditions" would initiate temporary remediation through pressure reduction and/or permanent remediation by repair. Of course, should excavation for examination and repair of a condition identified as an "immediate repair condition" reveal that an indication was not caused by an "immediate repair condition", the operator could immediately reclassify the indication appropriately.

- *Determining that a defect presents a potential threat to the integrity of the pipeline* – An operator may determine that a potential threat to the integrity of the pipeline exists by multiple approaches, depending upon the circumstances. The earliest prudent time for an operator to make a determination that a potential threat exists is upon receipt of the information presented in an ILI vendor's written report. If an ILI vendor's report is to be used to assess the severity of a defect, the anticipated measurement tolerances of the tool should be considered in making a determination. The most reliable practice for assessing the severity of a defect is to excavate, examine, measure and analyze the defect. Examination and measurement of the defect may require the performance of more than one inspection or test, depending the type of defect (e.g. corrosion, gouging or cracking in a dent).

Concerns about "promptness" of each operator's response to conditions classified as "immediate repair conditions" could be managed and resolved through review, and required revision when appropriate, of the written procedure and associated specifications for ILI services.

8.4 Guidelines for Time of Determination

The appropriate steps for the process of determining if a geometry condition presents a potential threat to integrity may depend upon the type of defect (e.g. plain dent, dent with corrosion, dent with gouges, dent with cracks), the operator's knowledge of the condition of the pipeline system and the operator's confidence in the assessment tools. No operator should exceed the 180 days allowed by the regulation to reach a determination that a potential threat does or does not exist, without specific proof of extenuating circumstance. A lack of proper planning, training and preparation should not be considered an extenuating circumstance. Reasons for exceeding the 180-day allowance should be in agreement with the definition of "impracticable", as used in the regulation, and not simply a matter of convenience.

None of the operators interviewed for this report have experienced problems with tool availability resulting from a shortage of assessment tools. However, these operators preformed the advanced planning necessary to assure that the preferred tools were available on the appropriate schedule. A prudent and cost-effective discovery process should include sufficient resources to permit the investigation and validation of information that indicates an immediate condition exists as soon as practicable, regardless of the source of information.

8.4.1 Liquid Pipelines

Figure 8-1 incorporates requirements from § 195.452 (h), clarifications from FAQ 4.13 and 6.6 and requirements from API Specification 1160 § 9.6 into a schematic timeline to illustrate the range of prudent responses to geometry defects in liquid pipelines identified by ILI. None of the references incorporated into Figure 8-1 define:

> …when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. (§ 195.452(h)(2)).

For the purposes of Figure 8-1 and this report, Baker suggests that an operator of a liquid pipeline has adequate information about any geometry condition classified as an "immediate repair condition" to determine that the condition presents a potential threat to integrity upon receipt and acceptance of a written report from an ILI vendor and should proceed with mitigation of that "immediate repair condition". Although API Specification 1160 is not referenced by § 195.452, § 9.6 requires temporary mitigative actions, such as a reduction in pressure, be initiated within five days of receipt of an ILI report. API Specification 1160 § 9.6 further requires that permanent mitigative actions be accomplished within 30 days of receipt of the ILI report.

The promptness of the responses of liquid pipeline operators to conditions other than "immediate repair conditions" was not identified as an issue for consideration in this report. Consequently, Figure 8-1 illustrates no constraint upon the schedule for those conditions other than the 180-day period from completion of the field work related to the final ILI run.

Because ILI tools do not reliably identify all instances of wall loss on dents, wrinkle bends and buckles, excavation and examination of geometry conditions that were not identified as "immediate repair conditions" in the ILI vendor's written report may reveal the presence of wall loss. Observation of wall loss associated with a dent may convert a condition to "immediate repair condition" that requires temporary and/or permanent mitigative actions. Such delayed identification of "immediate repair conditions" was not included in the schematic timeline in Figure 8-1.

8.4.2 Gas Pipelines

Figure 8-2 incorporates requirements from § 192.933(b), and requirements from ASME B31.8S § 7.2.3 into a schematic timeline to illustrate the range of prudent responses to geometry defects identified by ILI. For purposes of this report and Figure 8-2, concepts relating to integrity assessment of liquid pipelines using ILI that are presented in FAQs 4.13 and 6.6 were assumed to be applicable to gas pipelines. As is the case for liquid pipelines, none of these references define:

> …when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. (§ 192.933 (b)).

For the purposes of Figure 8-2 and this report, Baker suggests that an operator of a gas pipeline has adequate information about any geometry condition classified as an "immediate repair condition" to determine that the condition presents a potential threat to integrity upon receipt and acceptance of a written report from an ILI vendor to proceed with mitigation of that "immediate repair condition". § 192.993(c) *Schedule for evaluation and remediation* references § 7 of ASME B31.8S and § 7.2.3 contains the statement:

> …The operator shall examine these indications with a period not to exceed five days following determination of the condition.

The gas integrity rule has not been in place for sufficient time for evaluation of the promptness of gas pipeline operators to discovery of geometry defects that are not classified as "immediate repair conditions". Consequently, Figure 8.2 illustrates no constraint upon the schedule for those conditions other than the 180-day period from completion of the field work related to the final ILI run.

Comparison of Figure 8.1 with Figure 8.2 reveals that the current regulations for gas pipelines permit significantly longer times for mitigation of geometry defects that are not classified as "immediate repair conditions". Perhaps the perception that liquid pipelines may be exposed to more frequent pressure cycles and/or pressure cycles of greater magnitude than gas pipelines accounts for the observed differences.

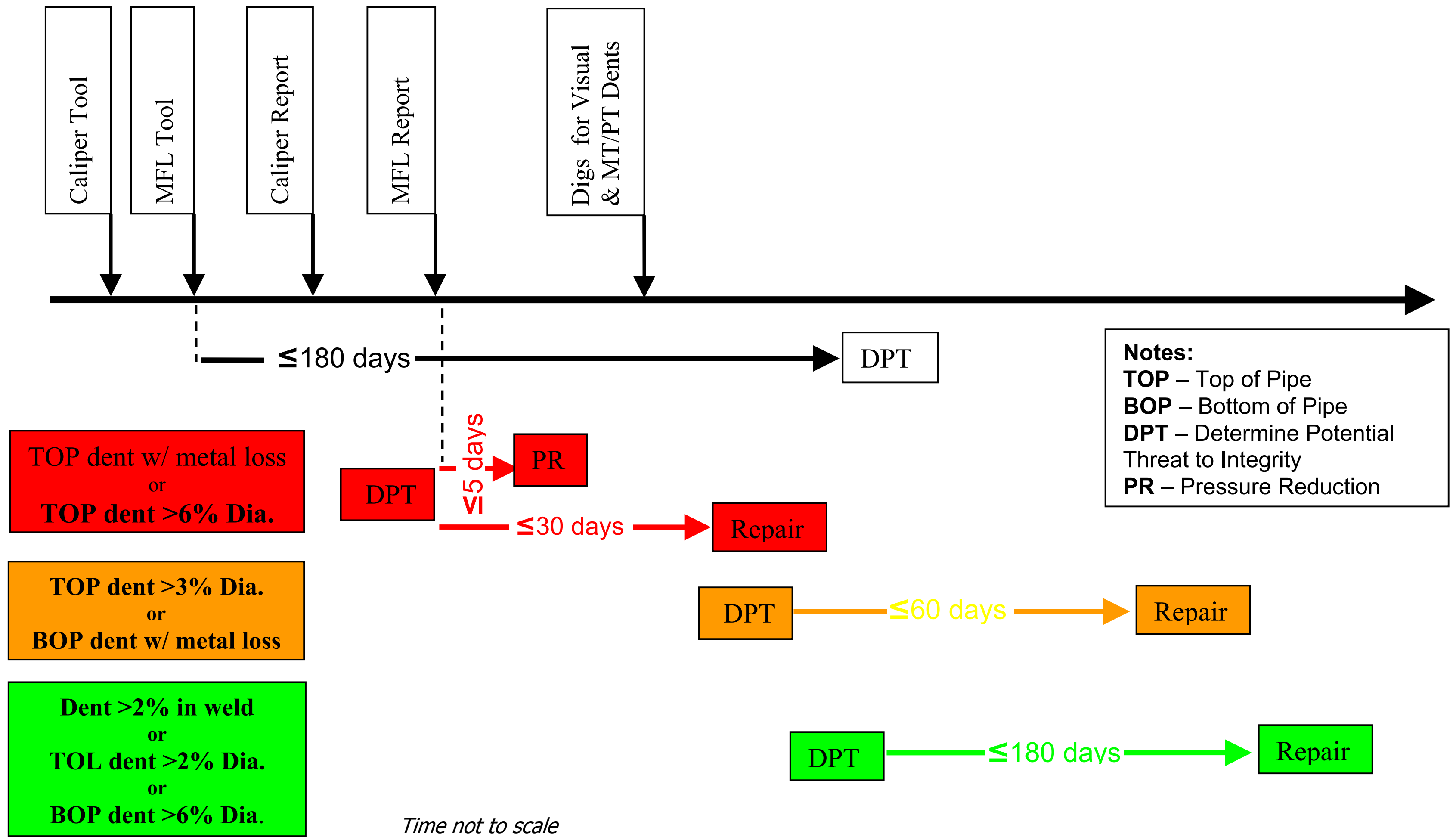

Figure 8-1 Time Line for Response to Geometry Defects – Liquid Pipelines

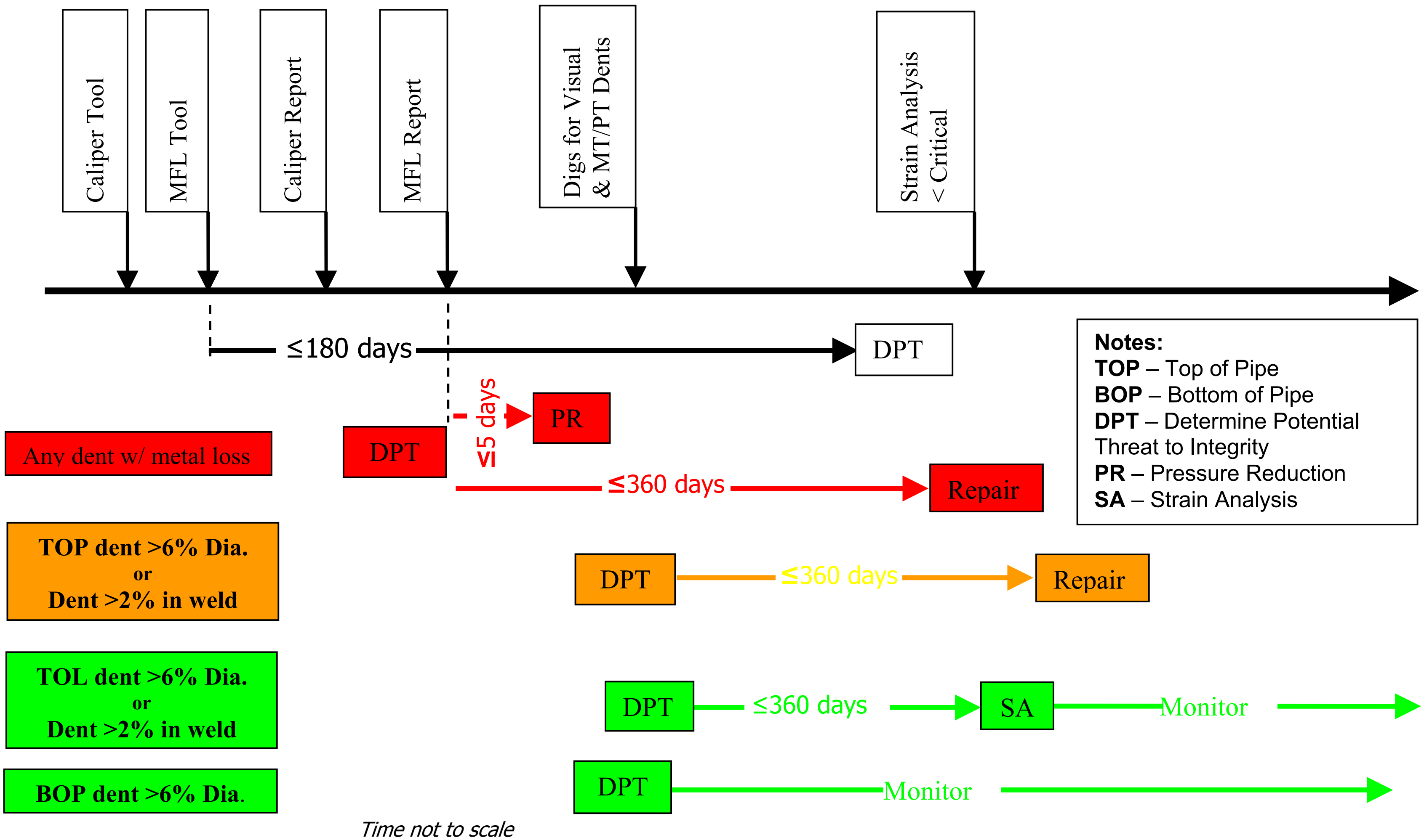

Figure 8-2 Time Line for Response to Geometry Defects – Gas Pipelines

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9 Guidelines for Scheduling Evaluation and Remediation of Geometry Defects

9.1 Subtask 07 – Scope

This section addresses Subtask 06 of the Work Scope that states:

"Using the information collected, Baker will write guidelines describing the actions required for scheduling evaluation and remediation of geometry defects."

9.2 Introduction

The scheduling of evaluation and remediation of geometry defects is detailed in §§ 195.452 and 192.933. These regulations define the evaluation and remediation timeframes for defects based on the potential impact of the defects on the integrity of the pipeline. Specifically § 195.452 (h) contains the following:

> (3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. An operator must send the notice to the address specified in paragraph (m) of this section.

The concern in this area, as communicated by OPS, deals with the timeliness of evaluation and remediation and not with the remediation methods. No concerns were communicated regarding defect repair options; therefore, this is not covered in the report.

9.3 Guidelines for Scheduling the Evaluation and Remediation of Geometry Defects

An operator should incorporate into his Integrity Management plan a procedure documenting his approach for the evaluation and remediation of geometry defects. This procedure should explicitly contain his procedure for scheduling the evaluation of defects. The operator procedure should contain the following elements, with each subsection identifying the person or operator's agent responsible for completion of the sub-section:

- Qualification of ILI – Sub-procedure to qualify vendors and ILI tools for use on their line. The qualification procedure should consider such elements as the product characteristics and throughput, pig launcher/receiver spacing, minimum bend radius and other limiting factors for tool passage, accuracy required especially for corrosion within dents based on line history, and documentation and data storage requirements
- Reporting Requirements – Sub-procedure detailing the elements to be reported during any ILI tool run. Although some details of formatting may differ by vendor, the essential data report should contain information that allows correlation with data collected by other qualified vendors. The procedure should address report ranges of defects, handling of error bands, alerts for immediate conditions, quality assurance/quality control (QA/QC) requirements, schedules for electronic and hardcopy transmittals.

- Defect Prioritization – Sub-procedure that addresses how the assembled data from the ILI vendor will be handled upon transmittal to the operator. As a minimum, the operator should demonstrate high priority given to conditions classified as "immediate repair conditions" according to §§ 192.993 and 195.452(h). Guidelines for scheduling these determinations are contained in the previous section.
- Defect Determination – Sub-procedure documenting a qualified procedure and/or vendor qualification to perform determination of a discovered condition. This should include a procedure for reconciliation of data from past ILI runs and/or excavations for direct examination. A database of anomaly defects, whether actual or suspected, and the prior actions assigned to each anomaly is recommended to expedite this referencing. Specific measurement techniques to be employed for direct examination of anomalies should be explicitly defined in order to assure differences examination crews would arrive at the same result. Qualification of alternative direct examination methods should refer to these base techniques to ensure compatible data capture and accuracy. General considerations for dent examination and determination are included below.
- Repair Prioritization – Sub-procedure documenting the use of the results of the determinations. This should contain the requirements for alerting internal and external oversight groups as to critical conditions as required. The procedure should address all repair condition requirements and require a schedule that addresses all determined conditions. Documentation requirements for conditions that were determined not to be repair requirement should also be included. If a scheduled procedure falls outside the internal guidelines, and especially if it falls outside of regulatory requirements, a reporting procedure should be fully detailed containing reasons for the delay, alternatives investigated, supervisory oversight and commitment to the new schedule.
- Performance of Repairs – Sub-procedure documenting qualified repair procedures and/or the qualification of vendors to perform repairs. The timeframes for remediation of geometry defects detailed in the OPS regulations are consistent with industry consensus standards. The regulatory timeframes are reasonable and understandable and should serve as the current guidance for the repair.
- Closure – Sub-procedure documenting final regulatory requirements, database updates, information transmittal requirements back to the ILI vendor for future runs if any.

9.4 Acceptance and Repair Criteria

The current criteria for the acceptance or repair of a dent detailed in Federal regulations are based on the depth of the dent as a percentage of the nominal pipe diameter. These criteria are consistent with the criteria in the ASME industry standards, except that ASME standards use the term "pipe outer diameter (OD)" rather than the term "nominal pipe diameter". The terms "pipe outer diameter" and "nominal pipe diameter" are essentially equivalent for outside diameters of 14 inches and greater. The outside diameters of pipe 12¾ inches and smaller are a fraction of an inch greater than the nominal pipe diameters. A dent is defined as a permanent deformation of the circular cross section of the pipe that is re-entrant to the pipe and is caused by external forces. A dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe in any direction. Denting a pipe can cause a flattening or ovality in the pipe's circular cross section.

This ovality contributes to the flexing of the dent and thus cannot be separated from the dent when measuring the maximum deflection caused by the dent (Rosenfeld, 2002b).

An alternative method to determining the severity of a dent is to calculate the circumferential and longitudinal strains induced by the dent. This evaluation method is not currently included the regulations, but should be examined further as an alternative method of determining the severity of a dent. The 2003 edition of ASME B31.8 includes recommendations for strain-based evaluation of dents.

The information characterizing deformation that can be obtained from ILI tools is becoming more accurate and more descriptive. The strains provide an indication of the sharpness of the dent. When evaluating information characterizing deformation, dent sharpness can aid in determining whether or not the dent is mechanical damage, and can assist in judging the severity of the dent without excavation (Rosenfeld, 2002a).

A current limitation for calculating dent strains is that there are no industry standards for acceptance criteria for maximum allowable strain. The ASME pipeline design code allows field bends that impart a cold strain in the pipe wall of up to 3 percent. Therefore, 3 percent strains could serve as a lower bound for a reasonable acceptance criteria. It has been observed that the likelihood of puncture in dents, and cracking in other deformations such as buckles, seems to increase where the material strain exceeds approximately 12 percent, which could be considered as the upper bound for a reasonable acceptance criteria. The ASME Task Group decided to use a strain level of 6 percent as a screening threshold for rock induced deformations for incipient metal damage (Rosenfeld, 2002a, and Rosenfeld 2002b). The 2003 edition of ASME B31.8 incorporates the recommendations of the ASME Task Group.

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10 Conclusions and Recommendations

Geometry defects that do not fail immediately upon damage caused by outside forces may pose a potential threat to the integrity of a pipeline. The severity of the threat is dependent upon the type of damage that the pipeline sustains (plain dent, mechanical damage, etc.), the operating conditions of the pipeline, and the environmental conditions surrounding the pipeline.

Integration of information from multiple sources is required to identify the location and likely severity of a geometry defect. Equally prudent operators may reach different conclusions about the amount and validation of information that is required to make the determination if a condition poses a potential threat to pipeline integrity. Determination whether a condition poses a potential threat to pipeline integrity should never exceed the 180 days allowed in the regulations without proof of extenuating circumstances. Complying with the allotted time will require that an operator properly plan integrity assessments, and will likely require assembly of historical information in advance of the integrity assessments. In order to determine that a condition does or does not pose a potential threat to pipeline integrity, the operator must:

- Identify geometry defects using appropriate assessment methods and tools;
- Integrate assessment results with all other pertinent data;
- Validate assessment results through excavations;
- Perform appropriate measurements, tests and inspections of excavated defects and adjust reports as needed;
- Compare defect measurements and characteristics to the criteria listed in the OPS regulations or other criteria where allowable.

Due to the various integrity conditions and assessment options available to pipeline operators, specifying a uniform discovery process and schedule is neither practical nor prudent. Requiring each operator to prepare a written procedure for the discovery process that specifies the following items is both practical and prudent:

- The type and quality of information that will be assembled as the basis for the discovery process.
- A performance specification for ILI vendors.
- The person or persons responsible for determining the status of conditions.
- The process for reaching determinations.
- How determinations will be documented.

Written procedures for the discovery process could include information similar to that in Sections 8 and 9 of this report. A written procedure for the discovery process should recognize that the latest acceptable time for determining the status of a condition should be when the data from the assessment tool(s) have been validated through excavation and direct examination of selected indication, and any corrections to the data have been made. In general, this should be considered a minimum threshold and it should be recognized that specific conditions exist that will accelerate this minimum.

Industry experience has been that ILI geometry assessment tools can generally provide reasonably accurate and reliable data. However, ILI tools are significantly less reliable for identification and sizing of mechanical damage, cracking and corrosion that may be associated with geometry defects. Consequently, some operators conclude that ILI tool results related to geometry defects should be analyzed and validated through the excavation of an appropriate number and sample of reported defects. After an operator concludes such a study that calibrates an ILI tool and assessment data for his line, then the operator can use ILI reported results from future runs more readily, considering the vendor's error margins and his own statistical results in determining if the indications of defects pose a potential threat to pipeline integrity.

This report recommends that the current discovery process be broken into two distinct parts: discovery and determination. Discovery would occur once a potential condition has been identified. There is then a certain period of time in which the operator must perform additional evaluation to determine whether the indication is in fact correct and if it truly constitutes a potential threat to the integrity of the pipeline. During this period, if more accurate data is acquired that indicates the condition was initially misclassified, the indication would then be placed in the appropriate category for further action, if required.

Baker recommends that both pipeline operators and OPS inspectors accept, as a reasonable compromise, that an operator's receipt and acceptance of a written report from an ILI vendor will provide adequate information to determine that geometry conditions in the report that are classified as an "immediate repair condition" present a potential threat to the integrity of the pipeline.

Further recommendations are for operators to have written procedures within their Integrity Management plan covering:

- Qualification and reporting requirements for ILI vendors
- Anomaly prioritization
- Defect determination
- Defect repair prioritization
- Performance of repairs
- Disposition documentation

The current acceptance criteria for evaluating the severity of a dent in the regulations are based primarily on the depth of the dent. However, it is recommended that OPS investigate the use of localized strains as acceptance criteria and as a screening tool to infer the severity of mechanical damage.

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