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The Third Edition of API Standard 1163, In-line Inspection Systems Qualification: Are You Doing Enough?

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Introduction

The Pipeline and Hazardous Materials Safety Administration (PHMSA) added sections 49 CFR 195.191 and 192.493, In-line inspection (ILI) of pipelines, into the Federal Pipeline Safety Regulations in 2017 and 2020, respectively [1]. PHMSA has also incorporated the second edition (April 2013) of the API standard 1163, In-line Inspection Systems Qualification, by reference in §195.3 and §192.7, and in September 2021 the third edition of API Std 1163 was published. What is new? What is important?

Over the last 20 years in the United States, there have been 7,500 pipeline reportable incidents with almost 80 million gallons of hazardous liquids spilled. According to Accident Reports (PHMSA Form F7000), from 2010 to 2020 more than 30% of the pipelines involved in spilled incidents had at least one in-line inspection (ILI) that collected data at the point of the accident. This brings into question the effectiveness of ILI and what we do with its results or lack thereof.

On the morning of April 7, 2000, the Piney Point Oil Pipeline system experienced a pipe failure at the Chalk Point Generating Station in the state of Maryland, 35 miles southeast of Washington DC. The release was not discovered or addressed by the contract operating company until late afternoon. Approximately 140,400 gallons of fuel oil were released into the surrounding wetlands and Swanson Creek and, subsequently, the Patuxent River (see **Figure 1**).

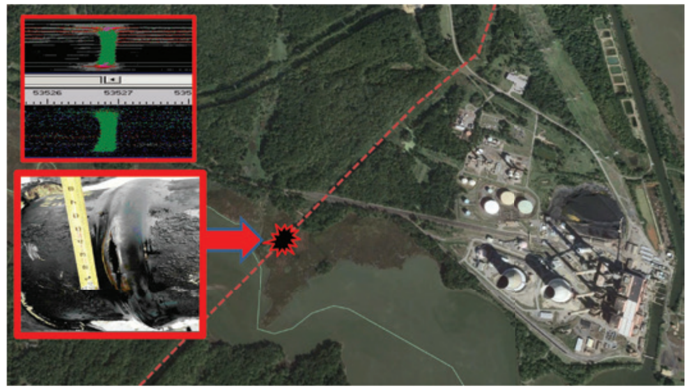

Figure 1. Location of the 2000 failure from buckle misinterpreted as tee piece near Chalk Point, Maryland.

The accident cost approximately $71 million for the environmental response and clean-up operations in 2000! The National Transportation Safety Board (NTSB) concluded that the ILI vendor interpretation of the compression wave ultrasonic tool data contained a significant inaccuracy for the feature at odometer station 53526.55 [2]. This feature was found after the accident to be a buckle. However, it was inaccurately interpreted by the ILI vendor's analyst as a T-piece in 1997. The buckle failed and resulted in the leak on April 7, 2000. Had the pipeline operator been notified that the feature was a buckle or at least an unknown, they may have attempted to excavate and investigate the feature. Therefore, the NTSB concluded that because the ILI vendor incorrectly interpreted the results of its metal loss ultrasonic tool data for the pipeline feature at odometer station 53526.55 (see insert in **Figure 1**), the pipeline operator was not alerted to the need for additional evaluation of the pipe at the location where it subsequently ruptured.

Five years later, the first edition of API Standard 1163, In-line Inspection Systems Qualification, was published in August 2005 [3]. This standard serves as an umbrella document to be used with and complement companion standards (see **Figure 2**). NACE SP0102-2010 Standard Practice, "In-Line Inspections of Pipelines," and ANSI/ASNT ILI-PQ, "In-Line Inspection Personnel Qualification and Certification," all have been developed providing service providers and pipeline operators rigorous processes, which will consistently qualify the equipment, people, processes, and software utilized in the in-line inspection industry.

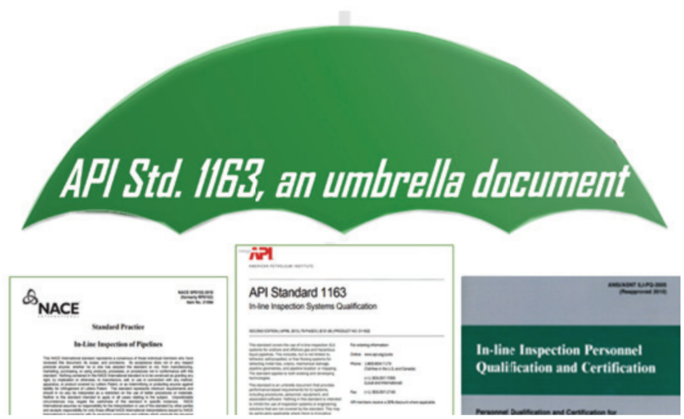

Figure 2. API Standard 1163 to be used with and complement companion standards.

The pipeline industry is operating more safely and efficiently than ever thanks in part to higher in-line inspection data quality. While ILI data quality and accuracy clearly show substantial advancements in recent years, there are still opportunities for improvement. Events such as the rupture and release in Marshall, Michigan on July 25, 2010, and in Santa Barbara, California (**Figure 3**) on May 19, 2015, involved inconsistencies in the data reported by the ILI vendor and did not meet the published accuracy of the ILI tools, evidencing a continued need for innovation to verify and validate the quality of ILI data at all stages.

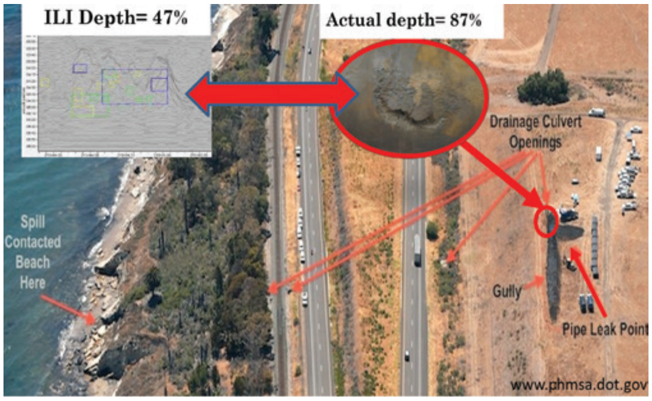

Figure 3. Rupture and release in a pipeline in Santa Barbara, California, on May 19, 2015.

Verification and validation are independent activities that are used together to confirm that an ILI service meets requirements and performance specifications, and that it fulfills its intended purpose. ILI tool verification is an internal process and is intended to check that the ILI service meets a set of design specifications, complies with regulations, and meets contractual requirements.

Validation is an external process intended to ensure the ILI results meet the needs of the pipeline operator. In general, a set of actionable anomalies are excavated, and their field measurements are compared with the tool estimation. The results comparison is used for establishing evidence that the ILI service accomplishes its intended requirements.

What's New in the Third Edition of API Standard 1163?

One of the main differences between the third edition and previous ones is the recommendation to consult the Canadian Energy Pipeline Association (CEPA) Metal Loss Inline Inspection Tool Validation Guidance Document, First Edition (January 2016). Many of CEPA's recommendations are included in several sections of the API Std 1163, Third Edition.

Performance Specification

The third edition of API Std 1163 highlights that it may not be possible to fully support all items in a performance specification by statistically valid methods. For example, detection and sizing near welds or other features is influenced by geometric and other weld characteristics, and it is not possible to statistically evaluate all permutations. In this case, the ILI service provider shall identify which parts of the performance specification are based on statistically valid methods and which are not, unless otherwise agreed to by the operator.

Inspection Goals and Objectives

The second edition of API Std 1163 was brief on the goals and objectives of the ILI. It simply indicated that the objectives shall be defined by the operator in alignment with the integrity management programs of API 1160 and ASME B31.8S. The third edition lists the following examples:

- Obtain acceptable inspection coverage and data quality for an integrity-targeted threat
- Identify, classify, and size integrity-targeted threat(s) with adequate ILI performance for the selected inspection system(s)
- Obtain comparable inspection results for historical and trending integrity analysis
- Verify the quality management system implementation to ensure that ILI services meet the inspection's goals and expectations

This is important as there is not a "best" ILI tool; there is, however, a most effective ILI tool for the particular pipeline operating conditions and the goal and objective of the ILI. The selection of the ILI tool must consider operating parameters and the type of threats and accuracy that the operator is looking for.

Prior to Inspection: Project Requirements

The second edition of API Std 1163 was brief on the project requirements. Project requirements ensure that the ILI system and operating conditions are consistent with those required to achieve the performance specifications and the requirements mentioned in NACE SP0102. The third edition is specific about data collection and analysis requirements. Prior to the actual inspection, the operator and ILI service provider should agree on items such as:

- Detection threshold for anomalies not included in the specification, or if requirements are different from the specification
- Reporting threshold for anomalies not included in the specification, or if requirements are different from the specification
- Algorithms to be used (manual or automatic filtering of reported anomalies, clustering rules, burst pressure calculation methods, etc.)
- Qualification needs for analysis personnel (i.e., Level 1, 2, or 3)
- Number of signals to be manually verified in the data
- Requirements for comparison to previous ILI results

Prior to the inspection, the pipeline geometry and planned pipeline operating conditions shall be reviewed to ensure that they are consistent with the information previously provided and that the ILI technology aligns with the pipeline condition. The following items should be reviewed:

- Historical performance of the inspection system should be reviewed by the operator to ensure that an appropriate tool has been selected considering the expected defect type(s) on the pipeline.
- The operator should share any relevant data with the ILI service provider related to design, operation, or previous inspections that will lead to a first run success.
- The ILI vendor has the responsibility to work closely with the operator to minimize the likelihood of damage to the pipeline or the inspection system.
  - The ILI vendor must confirm:
  - That the ILI system is consistent with the one used to define the required performance specifications
  - That essential variables (diameter, wall thickness, product,

pressure, etc) are within their acceptable ranges.
- That a qualified crew, per ASNT ILI-PQ, is available to support running the ILI system.

Prior to the inspection, the first run success criteria must be defined. First-run success shall be tracked by the ILI service provider by tool technology. It may be necessary for the operator and their service providers to collaborate on a feasibility study prior to performing an assessment. This feasibility study should include a review of the pipe design, product, pressure, flow rate, operating conditions, and other factors against the ILI technology desired for assessment.

Prior to mobilizing to the site for the inspection, the service provider and operator should meet to ensure that there are no areas of concern. The following items should be reviewed:

- Tool design is compatible with the pipeline current configuration
- Bend radii and configuration (e.g., back-to-back) are compatible with the tool setup
- Launcher/receiver length and geometry appropriate for the tool
- Planned battery life vs the duration of the inspection
- Timing of any planned shutdowns (or potential for extension) during the assessment
- Bore restrictions or difficult transitions are identified
- Previous issues with ILI are identified
- Planned flow rate and tool speed during an inspection are appropriate
- Planned survey media is acceptable for product type, temperature, pressure, cleanliness, etc.
- Safety considerations for personnel, property, and environment, including the ILI tool
- Logistics at the launcher and receiver are well understood, and any site requirements and communication plans are mapped out
- There are no concerns by any party on a successful assessment that have not been addressed to the greatest extent practical
- Launching and receiving procedures should be agreed to ahead of mobilizing the tool to the site. These procedures should then be reviewed on-site as part of the pre-job safety meeting.

Post-Inspection Requirements

In addition to the mechanical and functional checks mentioned in the 2013 edition, the latest edition gives some examples of ILI field data check content.

- Confirmation that the tool was on when pulled from the receiver
- Speed check
- Tool condition:
  - Debris amount and type
  - Wear on cups, sensors, cabling, etc.
  - Mechanical elements
  - Sensor damage
- Confirmation that the tool collected the appropriate amount of data.

ILI Data Quality Assurance and Data Analysis

The third edition requires that the data from the ILI be rigorously checked and analysed, with the following tasks identified:

- ILI Tool Data Checks
  - Tool speed (e.g., speed excursions, stall conditions)
  - Temperature
  - Tool rotation and speed of rotation
  - Sampling rate
  - Sampling (triggering) method (time versus distance)
  - Aboveground markers (AGM) placement success (e.g., effect on anomaly location accuracy)
  - Unplanned tool stoppage/stuck (e.g., operational, restrictions, tool functional)
  - Determine if the presence of debris hindered the performance of sensors
  - Number of damaged sensors and their proximity to other damaged sensors
  - Total percent sensor coverage
- ILI Data Completeness
- ILI Data Quality
  - Lift-off areas
  - Areas of degraded data
  - Signal quality locations
  - Echo loss locations (poor ultrasonic reading)
  - Inadequate magnetization levels
  - Incorrect pipeline and joint lengths (odometer problems)
  - Speed excursions
  - Excessive debris
- ILI Data Analysis Checks
  - Sensor response within expected range(s)
  - Data analysis processes executed as per defined procedures
  - Data analysis to be conducted by persons with agreed qualification
  - Automated detection and sizing parameters to be used
  - Manual intervention by data analysts to be conducted
  - Burst pressure calculation methodology to be applied
  - Correct pipeline parameters (pipe diameter, wall thickness, manufacturer, and grade) to be used
  - If blind tests were planned, anomalies detected and sized
- Assessment considerations for incomplete and/or degraded data. When a tool run is less than 100 % complete or affected by degraded data, the following parameters may be evaluated:
  - Where are the locations and extent of missing or degraded data?
  - Is it in an area of high consequence?

- Are multiple sensors affected?
- Are the sensors adjacent?
- Is there enough sensor overlap?
- What is the largest anomaly that could be missed?
- How does this affect the service providers' POI and POD, both locally and overall?
- Does the tool have proper rotation?
- What historical data are present about the locations of degraded data?
- Can the inspection results be improved with a rerun?
- Operational impacts associated with the tool run?
- What is the root cause of the failure or degraded data?
- Implications or operational complications resulting from a rerun?
- Can the missing or degraded data be compensated for?
- Echo loss of ultrasonic signals on pipe (after sensor redundancy).
- Is the missing or degraded data material to the acceptance of the run?

• Post-Inspection Process Quality Assurance
  - Verification assumes that a successful inspection is a consequence of the right tool selection and planning, execution, and analysis of the inspection data.

• Root Cause Analysis (RCA) for Failed Runs
  - In the event of a failed survey, the operator may request that an RCA be completed. This could be requested due to lack of data completeness, poor data quality, stuck ILI tool, mechanical failure, etc. Five-why's, fault tree analysis, and other investigative methodologies can be helpful in getting to the true root cause and not just a superficial root cause.

System Results Validation

Validation is the process that compares the data collected and reported by the ILI tool against some independent reference data to ensure the ILI tool meets its performance specification. Depending on the available data and the results of the ILI inspection, the validation procedure may consist of different comparisons. In all cases, the validation must include a comparison of the reported pipeline (non-defect) features such as girth welds and wall thickness changes to as-built records (or similar records). If there are actionable anomalies, then they must be excavated and compared to the ILI results. In addition, previous excavation data can be another reliable source to validate the ILI run. External features that have been recoated can be used to validate both magnetic flux leakage (MFL) and ultrasonic (UT) inspections and external features under a steel repair sleeve can be used to validate UT inspection only. Finally, if there was a previous ILI run, then the reported metal-loss anomalies must be compared to the previous inspection.

An operator may decide to run an untested technology in a pipeline from time to time, but that run should not be used to assess a threat on the pipeline without adequate validation, otherwise, the consequences can be severe, as we can see from the following incident.

Figure 4. 34-inch diameter steel pipeline ruptured in Cohasset, Minnesota, on July 4, 2002.

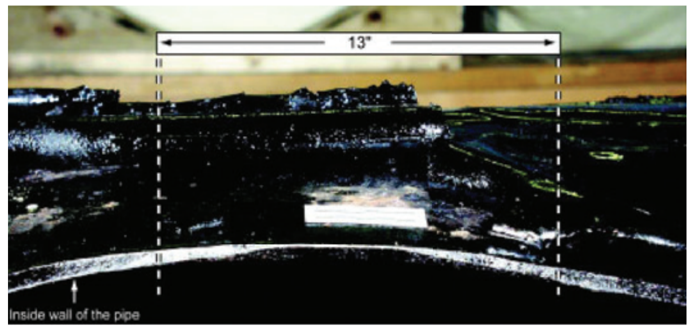

Figure 5. 13-inch-long crack, showing penetration nearly through the pipe wall in the center.

On July 4, 2002, a 34-inch diameter steel pipeline ruptured in a marsh west of Cohasset, Minnesota (see **Figure 4**). Approximately 6,000 barrels (252,000 gallons) of crude oil were released from the pipeline. The NTSB determined that the probable cause was inadequate loading of the pipe for transportation that allowed a fatigue crack to initiate along the seam of the longitudinal weld during transit. After the pipe was installed, the fatigue crack grew with pressure cycle stresses until the crack reached a critical size and the pipe ruptured [10].

Examination of the rupture revealed a pre-existing fatigue region at the centre of the rupture. The fatigue region was 13 inches long adjacent to the inside surface of the pipe, with fatigue cracking initiated at multiple locations along the inside surface at the toe of the longitudinal weld bead. Along approximately 2.5 inches in the central region, the fatigue crack almost penetrated the pipe wall. At its maximum depth, the fatigue crack penetrated through 0.270 inch of the 0.297-inch measured wall thickness (see **Figure 5**). The operator chose a relatively new ILI crack detection technology, elastic wave, in lieu of hydrostatic pressure testing. The elastic wave in-line inspection conducted before the accident recorded an indication at the point where the pipe eventually failed; however, interpretations of the recorded data found that the indication did not meet the feature selection criteria to identify it as a crack [10].

API Std 1163 presents three validation levels:

Level 1

For pipelines with low risk, it uses comparisons between ILI runs. Level 1 is based mostly on process verification checks alone (verification is the process whereby the operator checks that all procedures in the planning, preparation, acquisition, and analysis of an ILI dataset were conducted in such a manner as to produce high-quality inspection results). The third edition indicates that Level 1 (for pipelines with minimal risk only with no significant anomalies) should use comparisons between ILI runs (same line or other lines) or use prior excavation results.

Level 2

For pipelines with a higher risk, you may opt to reject the survey if the published tool specifications did not meet the actual tool specifications calculated after the run. Level 2 allows the operator to test whether the inspection performance specification was NOT met. The operator can reject the inspection if the tool performance is worse than the specification. However, an operator cannot state with confidence that the ILI tool performance was within specification. Here are the steps for Level 2 validation:

- Perform field verification measurements
- Evaluate POD and POI
- Evaluate sizing accuracy (probability of sizing)
- Estimate the number of measurements within the specifications
- Determine confidence bounds on actual certainty
- Compare confidence bounds on actual certainty with stated certainty

Level 3

For pipelines with a higher risk, Level 3 uses extensive statistical validation measurements to calculate the actual tool performance! In Annex C, the third edition provides steps to estimate the as-run ILI tool performance from field verification data. Two methods are presented: the statistical tolerance intervals and the Bayesian inference. A Level 3 validation may be necessary when:

- A new ILI technology is being evaluated
- An ILI run does not meet the published performance specifications per Level 1 or Level 2 validation.

Evaluation of Inspection System Results (Estimate POD and POI)

In the 2013 edition of API 1163, the probability of detection (POD) and the probability of identification (POI) were briefly defined as:

POD = (# times detected / total # of anomalies x 100) per anomaly / feature type and size

POI = (# times correctly identified / total # of detected anomalies x 100) per feature type

Determining the POD, (the probability of a feature being detected by an ILI tool) and the POI (the probability that the type of an anomaly or other feature, once detected, will be correctly classified (e.g., as crack-like, crack-field, etc.) is critical as we can see from the following incident.

On the afternoon of Sunday, July 25, 2010, a segment of a 30-inch diameter pipeline ruptured in a wetland in Marshall, Michigan. The NTSB concluded that the ILI vendor's analysis of the 2005 in-line inspection data for the segment that ruptured mischaracterized crack-field for crack-like defects (a "crack-like" characterization was indicative of a single linear crack whereas a "crack-field" characterization implied that the feature was made up of a cluster of small cracks typically associated with SCC, see **Figure 6**). This resulted in the operator evaluating them as if they were a single crack and not a crack-field defect [7].

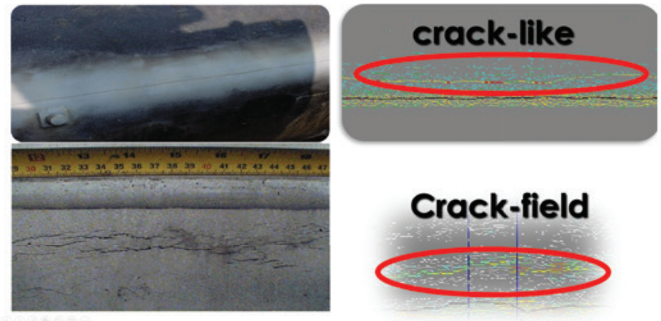

Figure 6. Crack-field and crack-like defects and corresponding ultrasonic crack detection ILI signals.

The 2013 edition, in Annex A, provides a sample format for performance specification (shown in part in **Figure 7**).

In the third edition, POD is defined as follow:

POD (reported anomalies)= True Positives (within specifications) / (True Positives (within Specifications) + False Negatives (within specificiations))

True positive (within specifications) is an anomaly that has been reported by the ILI and found in the field with field dimensions greater than or equal to the detection thresholds (or the reporting specification agreed upon by the operator and the service provider).

True positive (outside specifications) is an anomaly that has been reported by the ILI and found in the field with one or more field dimensions less than the detection threshold(s).

Some additional definitions have been included to supplement the ILI performance evaluation, such as the probability of reporting (POR) and the probability of false reporting (POFR).

POR is the probability that an anomaly is detected, identified/classified, and reported with both the correct anomaly type (e.g., cracks found in the field that were reported as cracks by the ILI) and the correct severity as defined by the operator (e.g., "anomaly of interest": axial crack with a depth > 40% of the nominal wall thickness to be considered as severe, or actionable).

POFR is the probability of reporting an actionable false positive, which is the probability that an imperfection is incorrectly reported as an anomaly with a severity and/or morphology that would be defined as actionable in consideration of size, burst pressure, and/or type:

POFR=(#FC(# of incorrectly reported noninjurious anomalies deemed actionable)/(#TC (# of reported anomalies deemed actionable))

An actionable false positive will require significant, yet unnecessary effort to mitigate, while false-positive imperfections will simply be revisited in the next ILI.

In **Figures 9** and **10**, "Other" means a different type of anomaly. For instance, an operator may have different ILI response

Feature	Yes POI> 90%	No POI< 50%	Maybe 50%<=POI< =90%
Int./ext./mid wall discrimination	✓		
Additional metal / material:			
– debris, magnetic	✓		
– debris, nonmagnetic	✓		
– touching metal to metal		X	
– Other			✓
Anode			✓*

Feature	Yes POI> 90%	No POI< 50%	Maybe 50%<=POI< =90%
– mill anomaly non-metallic -- Inclusion	✓		
– mill anomaly cluster	✓		
– ovality	✓		
– ripple/wrinkle	✓		
– SCC		X	
– spalling	✓		
– spiral weld crack		X	

Figure 7. Features and Probability of Identification (based on 2013 edition).

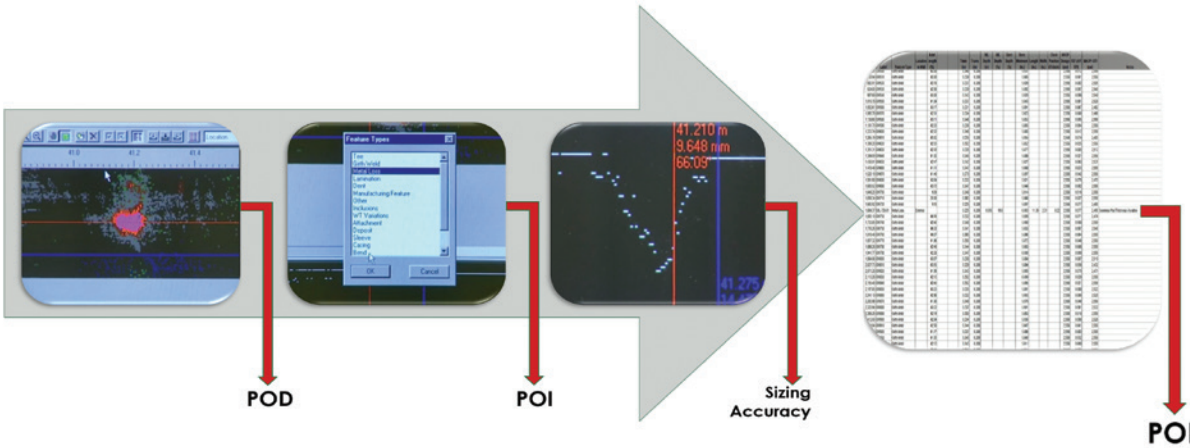

Figure 8. Relationship of POD, POI, and Sizing Accuracy with POR.

Field	ILI: Actionable Category 1 Anomaly	ILI: Actionable Other Category Anomaly	ILI: Nonactionable Category 1 Anomaly	ILI: Nonactionable Other Category Anomaly	Field Totals
Actionable Category 1 Anomaly	Correct Identification and Severity (A)	Incorrect Identification (B)	Incorrect Severity (C)	Incorrect Identification and Severity (D)	A+B+C+D

Figure 9. Expanded Identification Table.

Field	ILI: Actionable Category 1 Anomaly	ILI: Actionable Other Category Anomaly	ILI: Nonactionable Category 1 Anomaly	ILI: Nonactionable Other Category Anomaly	Field Totals
Actionable Category 1 Anomaly	Correct Identification and Severity (A)	Incorrect Identification (B)	Incorrect Severity (C)	Incorrect Identification and Severity (D)	A+B+C+D
Actionable Other Category Anomaly	Incorrect Identification (E)	Correct Identification and Severity (F)	Incorrect Identification and Severity (G)	Incorrect Severity (H)	E+F+G+H
Nonactionable Category 1 Anomaly	Incorrect Severity (I)	Incorrect Identification and Severity (J)	Correct Identification and Severity (K)	Incorrect Identification (L)	I+J+K+L
Nonactionable Other Category Anomaly	Incorrect Identification and Severity (M)	Incorrect Severity (N)	Incorrect Identification (O)	Correct Identification and Severity (P)	M+N+O+P
ILI Totals	A+E+I+M	B+F+J+N	C+G+K+O	D+H+L+P	

Figure 10. Detail of Anomaly Category 1.

criteria for single axial crack-like anomalies or colonies of crack-like anomalies such as the operator of the 2010 Marshalls incident. In this case, an incorrect identification may lead an operator to make a different decision based on the classification alone, even if other characteristics are not changed. For an actionable anomaly category 1, we have:

For Category 1 anomalies, we have:

$$POI = (A+C) / (A+B+C+D)$$

$$POR = (A) / (A+B+C+D)$$

$$POFR = (B+C+D) / (A+B+C+D)$$

Evaluation of Inspection System Results (Estimate Sizing Accuracy)

A unity plot is a simple way to compare one set of ILI results to previous ILI results or to field verification results (see **Figure 11**). A unity plot should be prepared to compare the field-measured dimensions to the ILI-reported dimensions to assess sizing accuracies. False negatives and false positives are not used to estimate the sizing accuracy. They are used only to calculate POD (using false negatives), and the POFR (using false positives).

It is important to remember that over-called anomalies are not within specifications. This is one of PHMSA's identified contributory causes of the 2015 rupture in Santa Barbara, California:

"[the operator] incorrectly added the over-called anomalies in the close-out reports. The close-out reports should have only reported the anomalies that were within the reported accuracy of the ILI tool. The reported tool accuracy is +/- 10 %, 80 % of the time. Adding the overcalled anomalies outside of the tool accuracy skews the data [8]."

Evaluation of Inspection System Results (Burst Pressure Estimation)

For feature assessment of cracking and metal loss anomalies,

Feature ID	Odometer (ft)	Nominal Thicknes s (in.)	ILI depth (%)	ILI Depth (in.)	ILI Length (in)	ILI Width (in)	Deepest Point Orientatio	ILI Notes	Δ_i	Field depth [%]	Field depth [in.]	Field Length (in)	Field Width (in)	Deepest Point Orientation	Field Notes
		0.250	20%	0.050	6.0				-5%	25%	0.063	6.9			
		0.250	15%	0.038	7.8				10%	5%	0.013	8.8			
		0.250	25%	0.063	8.0				15%	10%	0.025	8.9			
		0.250	30%	0.075	2.0				15%	15%	0.038	1.5			
		0.250	37%	0.093	6.0				13%	24%	0.060	10.0			
		0.250	15%	0.038	5.0				10%	5%	0.013	6.5			
		0.250	15%	0.038	9.0				10%	5%	0.013	7.0			
		0.250	20%	0.050	6.0				10%	10%	0.025	6.5			

Estimate of the systematic bias of the error in ILI	$\bar{x}$= 4.8%	Sample size required	13
Estimate of the random component of the error in ILI	s= 8.5%	Actual Sample size	13
Standard error to compute estimate confidence interval	se= 2.4%	Population Size	13

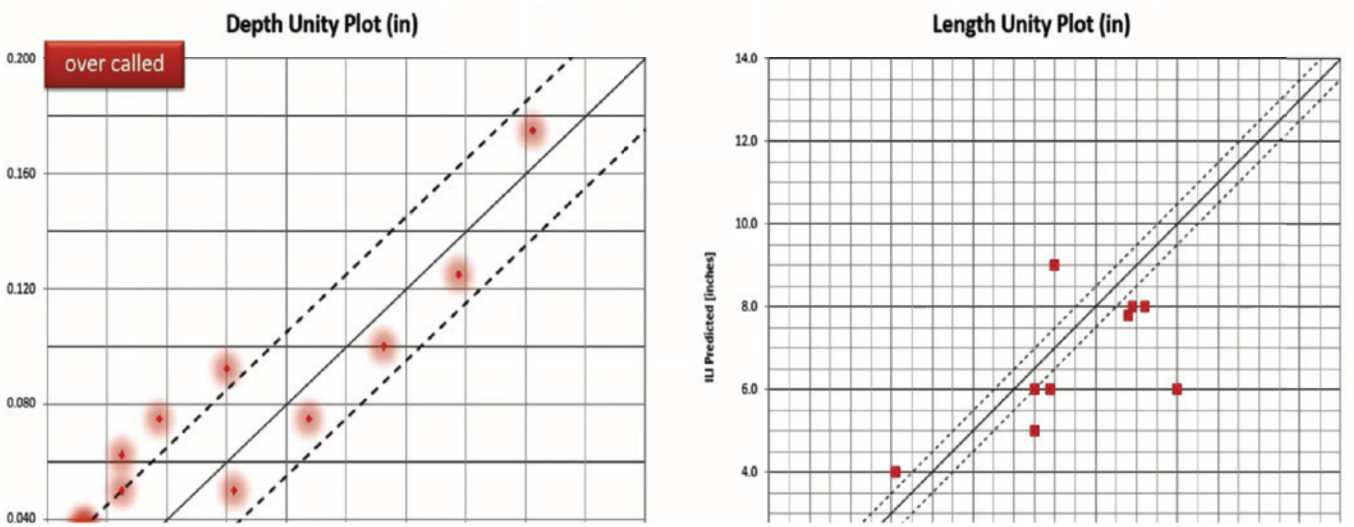

Figure 11. Unity Plot Example.

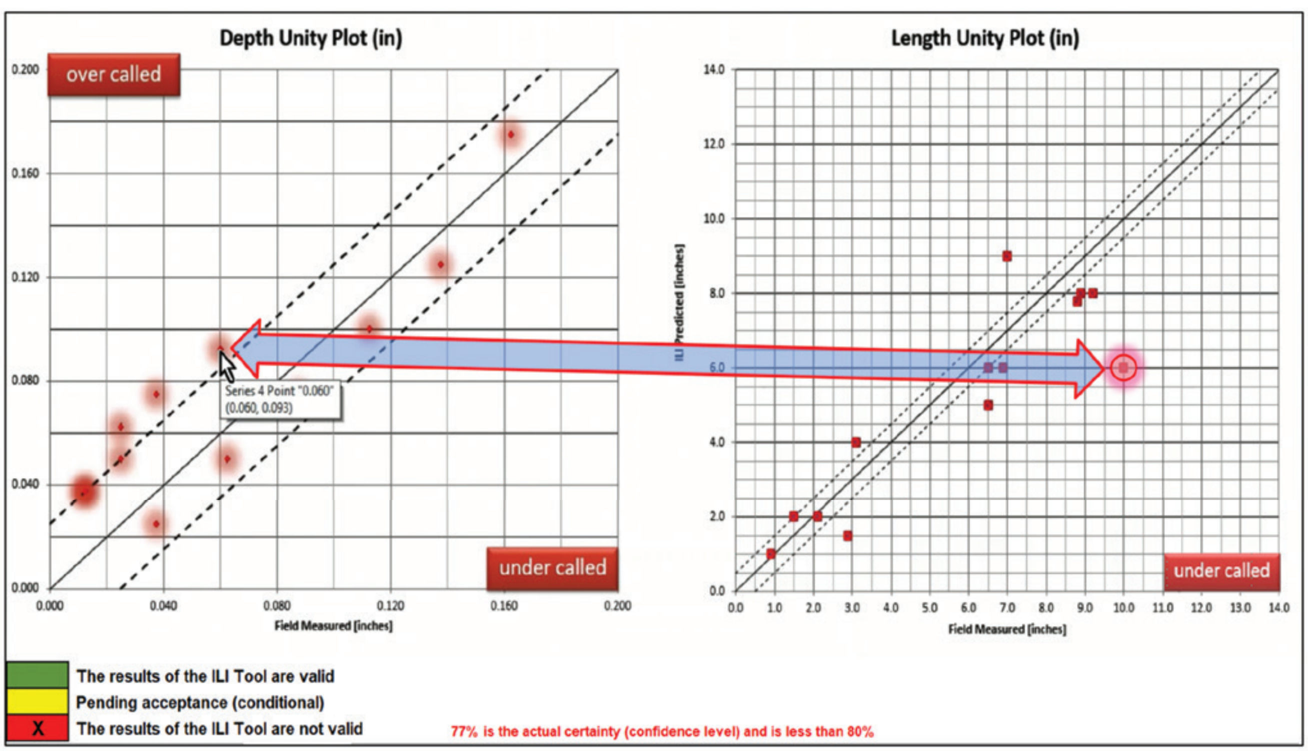

Figure 12. Unity Plot, one anomaly over-called in depth is under-called in length.

consideration should be given to the estimation of predicted burst pressure calculated from both ILI and field NDE measurements. The calculation takes into consideration feature depth, length, (see **Figure 12**) and the interaction with similar anomalies, to determine the ILI system's overall ability to estimate the severity of an anomaly from the rupture failure mode standpoint. Burst pressure estimation from ILI and field measurements allows for an efficient and effective evaluation of the ILI system's performance in measuring feature profiles and the combined effect of depth and length for cracking or metal-loss features.

Conclusions

The third edition of API Std 1163 presents verification and validation processes and includes multiple activities to ensure an ILI service meets requirements and the results meet the needs of the pipeline operator. These processes are performed throughout the inspection sequence from ILI tool selection to validating results, ensuring each step is properly executed and information is captured. Following the requirement and recommendation of the third edition of API Std 1163 will improve the effectiveness of ILI and what we do with its results.

Even if historic information on the pipeline being inspected is not available, you can verify the reported ILI results through comparisons with prior data using the same type of ILI tool, but on other pipelines supplemented with data from large-scale tests. The reported results can be considered verified by comparisons with the results from prior validated inspections on other pipelines, provided the prior data reported similar anomaly types and characteristics, and that the previous inspection variables match those used in the current inspection.

The Level 2 validation approach provides estimates of POD/POI, and an upper and lower bound on actual certainty (the second edition of API Std 1163 included these steps in C.3 and C.4). Examining both upper and lower confidence bounds allows a pipeline operator to understand the ILI performance. Level 2 validation does not usually confirm with statistical confidence that the inspection met its performance specification. However, it evaluates whether there is statistical evidence the inspection did not meet its performance specification.

A Level 3 validation is meant to incorporate statistical methods that provide a more accurate estimate of the POD, POI, and actual sizing accuracy. A Level 3 analysis estimates the actual ILI performance as indicated by the available field verification measurements. Level 3 uses statistics to estimate the distribution of ILI errors, and conservatively account for the effects of working with a finite sample drawn from the population of ILI measurements.

PHMSA included section §195.591, In-Line Inspection (ILI) of Pipelines, in the Federal Pipeline Safety Regulations in 2017 and added a new rule in §192.493, In-Line Inspection of Pipelines in the Gas Regulations (Mega Rule) on July 1, 2020. This means that when conducting an in-line inspection of pipelines, each operator must comply with the requirements and recommendations of three documents incorporated by reference in §195.3 and §192.7.

The latest edition of API Std 1163 will facilitate the validation of ILI results. In addition, the standard will help you to generate quantitative comparisons to determine if critical anomalies have been classified and characterized using an appropriate level of conservatism. In this way, the final verified and validated ILI results can be correlated with previous inspections, other surveys, cathodic protection data, and any existing construction, coating, soil, and relevant operating history of the pipe to obtain valuable and truthful information on the life of your asset.

Are you doing enough? Some operators would say that they trust the tool vendor's analyst to identify and classify all actionable anomalies. While this would be the perfect scenario, it is not the one that usually plays out. It may be ideal to think that the ILI operators and analysts are very good, but it is probably a mistake to bet the safety and integrity of your pipeline system on that assumption. To gain confidence that you have done your due diligence, you must have a process in place to verify and validate ILI surveys. After all, managing the integrity of a pipeline is not really about what you found and responded to using ILI results; the true integrity of the pipe is based on how confident you are about the features that remain in the pipe that you decided not to respond to. Verification and validation of the ILI data using the third edition of the API Std 1163 will save you headaches as well as money! ■

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Bernardo Cuervo is a Pipeline Integrity Consultant with over 30 years of experience in the pipeline integrity industry. Cuervo has authored and presented numerous papers on the topics of in-line inspection (ILI) and pipeline integrity management. He leads the ILI discipline within the Corrosion and Material Group at EN Engineering. In this role, Bernardo is responsible for all ILI projects from feasibility, tool selection, data quality, ILI verification and validation, run comparisons, advanced data analysis, signal-to-signal comparisons in A-MFL, C-MFL, EMAT, and Ultrasonic data sets to fitness for service assessment. Cuervo graduated as a Civil Engineer, co-chairs the Corrosion Control Course at the University of Oklahoma, and is a PHMSA associate instructor for the Safety Evaluation of ILI Pigging Programs. He is also a Pipeline Integrity Voting Group member for API Std 1163 In-line Inspection Systems Qualification and API RP 1176 Assessment and Management of Cracking in Pipelines committees.

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Mark has over 25 years of experience in integrity and risk management for both onshore and offshore assets, including pipelines (upstream, midstream, and downstream), pipeline facilities, subsea equipment, and subsea production systems. Mark has successfully directed, developed, grown, and managed teams with multidisciplinary skills to meet each client's needs. Mark has developed onshore pipeline integrity management plans for transmission pipeline operators in accordance with the Pipeline Safety Regulations. Mark has led risk-based inspection workshops to identify credible threats to assets (e.g., pipeline, subsea production system, SURF) and developed mitigations to eliminate and/or manage the threat. Typically, for that threat that cannot be designed out, the mitigation takes the form of an inspection, maintenance & repair plan that compliments and complies with the integrity management program requirements. With his acquired knowledge and thorough understanding of numerous potential failure modes, Mark develops optimized inspection and maintenance programs, identifying key performance indicators, to help the operator ensure a healthy operating system.