Overcoming missing or incomplete pipeline data in ageing assets: ILI and NDE techniques combine to provide traceable, verifiable, and complete records

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PIPELINES CONSTRUCTED IN the last 10 to 20 years should have traceable, verifiable, and complete records. As such, pipeline operators should possess comprehensive records, including hydrostatic test reports, maximum allowable operating pressure validation, and mill-test reports, for specific lots of pipe. But what about older pipeline segments, or segments that have been through acquisitions? Often, these historical, detailed records are misplaced, lost, or simply never transferred with the sale of an asset. A solution to this need—overcoming missing or incomplete pipeline data—is Pipe Identification, which incorporates advanced inline inspection and non-destructive examination technologies to recreate important pipe-material records, close documentation gaps, and provide information that will ensure the appropriate level of risk is applied to specific pipe joints or segments.

PIPELINES CONSTRUCTED IN the last 10 to 20 years should have traceable, verifiable, and complete records. As such, operators should possess comprehensive records, including hydrostatic test reports, maximum allowable operating pressure (MAOP) validation, and mill-test reports (MTR) for specific lots of pipe.

But what about pipeline segments that are decades old? Or assets that were once managed by one operator, sold to another, and then, potentially, sold again?

Often, these historical, detailed records are misplaced, lost, or simply never transferred with the sale of the asset. Such records are critical in supporting current operating pressures, and they ensure that the pipeline operator is aware of the pipe type in a given segment, allowing them to apply the appropriate level of risk.

A combination of advanced inline inspection (ILI) and non-destructive evaluation (NDE) techniques, known as Pipe Identification, can help overcome these missing and incomplete records.

Through more advanced ILI tools, such as a multiple dataset (MDS) platform—including deformation, high field axial magnetic flux leakage (MFL), helical MFL, and low field MFL—operators are, first, able to identify characteristics specific to the pipe material itself:

- Base material magnetic characteristics (using various magnetic fields): Impacts from both the manufacturing and milling process
- Pipe type: Seamless or seamed pipe
- Seam characteristics: Differentiate seams formed through diverse welding processes.

By using the Pipe Joint Classification (PJC) process, these key characteristics — and others, including bore, joint lengths, etc. — are used to group each pipe joint into like-bins. The PJC process results are then complimented by a variety of NDE techniques used to identify the physical material properties and chemical composition of the pipe. The result is an output similar to the original MTR and pipe grade identification.

By combining the pipe joint classification process with an NDE technique known as Positive Material Identification (PMI), a subset of joints from within the same bin can then be used to establish the material properties for the entire bin. This complete process, combining advanced ILI and NDE techniques, is known as Pipe Identification.

Pipe Identification allows operators to: recreate important pipe material records; close documentation gaps; and ensure the appropriate level of risk is applied to a specific pipe joint(s). All of which are critical to an overall integrity assessment program for ageing pipeline assets.

Integrity verification

In the Pipeline Safety Act (PSA) of 2011, PSA Section 23(a) 60139(a) and (b) – Verification of Records and Reporting – requires United States pipeline operators to identify pipe segments for which they do not have records to substantiate MAOP for all gas transmission steel pipe (Class 3, 4 and all HCAs). Furthermore, PSA §23(a) 60139(d) – Testing Regulations – requires conducting tests to confirm the material strength of previously untested gas transmission steel pipelines in high consequence areas (HCAs) and operating at a pressure greater than 30 percent specified minimum yield strength (SMYS) that were not previously pressure tested. These tests can include pressure testing or alternative equivalent means such as inline inspection programs [1].

On Jan. 10, 2011, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued Advisory Bulletin ADB-11-01; Establishing MAOP or Maximum Operating Pressure (MOP) Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation. A follow-up ADB was released May 7, 2012, ADB-2012-06, specifically addressing records verification for both natural gas and hazardous liquids pipeline operators. ADB-2012-06 states that operators:

- Must assure that the records are reliable when calculating MAOP / MOP
- These records shall be traceable, verifiable, and complete
- Verifiable records are those in which information is confirmed by complimentary, but separate, documentation
- The Operator may need to conduct other activities such as in-situ examination, measuring yield strength … and non-destructive testing or otherwise verify the characteristics of the pipeline to support a MAOP or MOP determination [2].

The result of the Advisory Bulletin is pending Integrity Verification Process (IVP) regulation. Objectives of IVP are for pipeline operators to focus on pipe that may be most susceptible to lack of sufficient records upon which current operator parameters are based. This includes hydrostatic test records to confirm MAOP, hydrostatic integrity test, pipe type records (seamless, Electronic Resistance Welded (ERW), Electronic Fusion Welded (EFW), etc.), as well as pipe grade. Pipelines most relevant for IVP are ageing assets, or those deemed "vintage" and installed prior to 1970.

In addition to ensuring that traceable, verifiable and complete records are available for vintage pipeline segments, these segments may also experience potential integrity threats specific to the manufacturing processes of the time. In the paper written and presented by John Kiefner at the ASME Engineering Technology Conference on Energy in 2002, Dealing with Low–Frequency –Welded ERW Pipe and Flash–Welded Pipe With Respect to HCA-Related Integrity Assessments, Dr. Kiefner discussed cold welds, stitching, hook cracks, and grooving corrosion in the bond-line (also known as selective seam weld or preferential corrosion) being associated with vintage pipe and the related manufacturing processes [3].

Ageing assets

According to PHMSA, 59 percent of U.S. gas transmission pipelines were installed prior to 1970 [1]. For the install base of hazardous liquids, pre-1970 pipelines represent 50 percent of total onshore assets [4].

Ageing assets is not just a U.S. phenomenon. Regions outside of the United States face similar circumstances relative to pipeline installation prior to 1970. For example, based on CONservation of Clean Air and Water in Europe (CONCAWE) data, 47 percent of the assets they cover were installed prior to 1970 [5]. And, while it does not explicitly contain specific data on percentage of pipelines installed prior to 1970, the European Gas Pipeline Incident Data Group's (EGIG) ninth report published in February 2015 does address the influence of the age of pipelines on their failure frequencies [6].

The multiple dataset (MDS) ILI system

Multiple Datasets (MDS) incorporates various ILI technologies onto a single inspection vehicle. This approach allows fusion with various datasets for comprehensive detection and characterization of potential integrity threats. Highlighted below are the technologies included on the MDS platform, along with the applications of each. An image of the MDS inspection device can be found in Figure 1.

- *High Resolution Deformation* (DEF) is a measurement of the changes of the inner pipeline bore. In addition to the detection of standard pipeline features – such as valves, tees, bends –

  DEF is designed to detect dents, ovalities, expansions, and weld misalignments. DEF is also sensitive to the rolling and forming process during pipe milling and manufacturing.

- *Low Field Axial Magnetic Flux Leakage* (LFM) identifies changes in the steel microstructure due to mechanical working and/or heating/cooling. LFM detects dent re-rounding, which can raise the severity of a dent and lead to cracking; hard spots, a localized hardening of the steel due to rapid cooling; and sensitivity to chemical and metallurgical properties of the steel itself.

- *High Field Axial Magnetic Flux Leakage* (MFL) detects volumetric metal loss, mill anomalies, extra metal, and is less sensitive to local pipe material differences.

- *Helical/Spiral Magnetic Flux Leakage* (SMFL) provides inspection of longitudinal pipe axis, including weld seams, and detection of other longitudinally oriented anomalies, whether in the seam or pipe body (axially extended metal loss, gouging, hook cracks, lack of fusion, selective seam weld corrosion). High field MFL, applied in the helical direction, also allows detection of longitudinal aspects of material changes and long seam characteristics.

- *Internal/External* (IDOD) is designed to detect metal loss on the internal diameter (ID). It is also sensitive to ID surface permeability changes in the radial direction.

- *XYZ Mapping* (XYZ) provides high resolution mapping that, when tied to above-ground coordinates, provides pipeline routing, enhances dig programs, and contributes information to perform bending strain analysis.

In addition to comprehensive assessment of a pipeline asset, ageing or otherwise, data obtained by the MDS platform can be used to group pipe joints by their characteristics. As described above, each individual technology on the inspection vehicle plays an important role in identifying specific features of a pipe joint. These features may pertain to raw material, manufacturing process and construction. Accurately identifying like pipe joints is the first step in the creation of material records for a pipeline segment where they do not exist.

The role of pipe manufacturing

Raw material, or skelp/ingots, will have elements identifying a resulting joint with the original steel before it is formed into pipe joints. Pipe manufacturing further impacts the mechanical properties of constructed pipe joints. For seamed pipe, raw material goes through a rolling or forming process, welding, seam trimming, cooling, quenching and sizing. Seamless pipe does not contain a longitudinal weld seam, as the name implies, and is manufactured by taking a billet, or solid cylinder, of molten steel and piercing with a steel mandrel.

Each of those manufacturing processes create fingerprints that may be tied to a given manufacturer, mill run, or type of pipe. Fingerprints can be identified through use of the MDS platform, and grouped into associated bins based on their characteristics. The process is known as Pipe Joint Classification.

Pipe joint classification (PJC)

When using multiple datasets (MDS), the shared characteristics of pipe, from the same manufacturer, can be identified and used to assign each joint into associated groups or bins; referred to moving forward as Pipe Joint Classification (PJC). The two main categories from which characteristics can be observed include raw material (i.e., skelp/ingots, billets) and the pipe joint fabrication process itself.

Raw material may contain artifact patterns in the circumferential and axial direction. Other aspects of raw material include material thickness and magnetic permeability – including magnetic saturation, magnetic property variations, and the resulting magnetic fingerprint.

Pipe joint fabrication itself, the finished product, will contain a wider range of variables for classification based on the process used. Elements include length, wall thickness, bore, internal surface, magnetization level, and axially and/or circumferentially oriented fabrication artifacts (such as from rolling/forming). For seamed pipe, the type of seam will vary as well. For example, welding could have been performed by Electronic Fusion Welding (EFW), Electronic Resistance Welding (ERW), Double Submerged Arc Welding (DSAW), Single Submerged Arc Welding (SSAW), and Lap Welding. Each of these welding processes can create distinct signatures detectable by the various ILI technologies.

Still other attributes associated with pipe joint fabrication include the longitudinal seams themselves, such as trim, magnetic response, seam deformation height, and resulting can upset and/or profile. For seamless pipe, artifacts include clockwise and counterclockwise orientation of the resulting pattern from the mandrel, and frequency of the striations left as a result of manufacture.

While the elements of PJC described here refer to grouping all pipe joints, the process also applies to the identification of "rogue" pipe joints, joints that may have been replaced at some point during the pipeline's life, though not accurately documented when repairs or other modifications were made.

PJC in practice

As pointed out above, the various datasets from the MDS platform allow specific attributes from every pipe joint to be gleaned from each dataset. This information is used to group or bin every joint based on their like characteristics. As the MDS tool travels through the pipeline, deformation, high field axial MFL, internal/external sensors, helical and low field MFL record specific information unique to each technology. Deformation records information on bore, seam trim, can offset. Axial MFL detects magnetization levels and circumferential characteristics. Internal/external records information about the internal surface. Helical MFL records details about the long seam, as well as any other axially oriented characteristics. And low field identifies microstructure changes in the steel as a result of raw material and/or the manufacturing process.

Figure 2 is a screenshot of MDS datasets side-by-side for three pipe joints. The data is from a single inspection, aligned based on the odometer on the MDS platform, and analyzed in the same software. Each dataset is scrutinized for specific attributes, both qualitative and quantitative, and used to align every pipe joint in a given pipeline to a specific group or bin. Figure 3 represents the summation of PJC on a given pipeline segment.

Positive material identification

According to the PHMSA Gas Transmission 49 Code of Federal Regulations (CFR) Part 192 Draft IVP Chart from Sept. 10, 2013, "Detail of Material Documentation Process Step 11" states that if there is missing or inadequate material documentation, an operator must "implement a program to test pipe samples to establish material properties. The program must be based on long term statistical sampling and utilize in-situ NDE, cutouts and destructive tests, destructive tests of pipe cutout for other reasons (such as repairs and relocations), use of conservative assumptions for evaluation of defects and repair criteria, etc." [7].

Positive Material Identification (PMI) is an in-ditch, NDE process to establish mechanical properties and chemical composition in-situ, requiring no line shut downs, and resulting in pipe grade determination. The PMI test method can be used on ageing or unknown carbon steel line pipe in the oil and gas industries to determine material grade as defined by the American Petroleum Institute (API) 5L Specification. This process can identify both yield and tensile strengths, along with chemical properties and carbon equivalence. Accuracies have been developed through extensive testing, with verification proven via third-party laboratory testing. The process utilizes standard NDE methodologies, along with material property assessment (MPA) and optical emission spectrometry (OES) technologies. Figure 4 shows in-field application of MPA.

The proven PMI process began development soon after the initial Advisory Bulletin, ADB-11-01, was published Jan. 10, 2011. The ADB-11-01 discussed further enhancement of safety efforts, and implementation of the National Transportation Safety Board's (NTSB) Jan. 3, 2011 recommendation to PHMSA concerning establishing MAOP and MOP using record evidence and integrity management; threat and risk identification; risk assessment; risk information collection, accuracy and integration; and identification and implementation of preventive and mitigative measures. Based on ADB-11-01, to ensure company records accurately reflect the pipeline's physical and operational characteristics, "operators must review and scrutinize pipeline infrastructure documents and records, including but not limited to, all as-built drawings, alignment sheets, specifications, and all design, construction, inspection, testing, material manufacturer, operational maintenance data, and other related records. These records should be traceable, verifiable, and complete to meet 192.619 and 195.302. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP using this method. If such a document and records search, review, and verification cannot be satisfactorily completed, the operator may need to conduct other activities such as in-situ examination, pressure testing, and non-destructive testing or otherwise verify the characteristics of the pipeline when identifying and assessing threats or risks" [8].

PMI is more than utilization of one or two technologies. Obtaining accurate material and chemical results non-destructively, and precise correlation to pipe grade, requires a comprehensive process. PMI was developed through the course of years, proven over multitudes of laboratory and blind tests. Critical development milestones include:

- Q1 to Q3 2011: Research and analysis of available material properties equipment
- Q3 2011: Selection of advanced material properties equipment
- Q4 2011: Technology validation
- Q1 2012 to Q4 2012: Algorithm testing and modifications
- Q1 2013: Internal validation of material less than 60Ksi; process development
- Q2 2013: External validation of material less than 60Ksi; process improvement
- Q1 2014: Development of initial PMI specification; Rev. A
- Q3 2014: Internal validation of high strength material (60-70Ksi)
- Q4 2014: External validation of high strength material (60-70Ksi)
- Q1 2015: Development of updated PMI specification to include up to 70Ksi; Rev. B

PMI is also proven to be completely non-destructive. Indentions from the indenter are removed and the area is Magnetic Particle inspected to ensure integrity of the pipe surface. The burn locations from the OES measurements have been thoroughly tested by a third party laboratory, through examination of the polished and etched cross sections, and revealed an observed maximum depth of penetration at the heat affected zone of the burn location of only 0.0013 inches. It was also confirmed that away from the burn area, the microstructure appears normal for a carbon or alloy steel material [9].

Pipe identification (PI)

Pipe Identification (PI) combines PJC to group pipe joints based on their characteristics with PMI to identify material properties where they do not exist. The end result is the alignment of PMI to PJC to close records gaps for segments of pipe or an entire pipeline. This process also identifies "rogue" joints where records are not up to date; i.e., joints of pipe that may have been used as replacement, but records do not reflect this type of pipe.

PJC + PMI = PI

PMI by itself will create material properties for a given joint of pipe. With PJC, joints of pipe are identified with a given group, of which a subset can then be assessed by PMI to apply to a given bin. PMI, applied to a subset of joints within each bin, would then apply to the complete bin.

Conclusion

As with all things or beings, as soon as creation occurs a state of entropy begins. With age comes forgetfulness, misplacing items, and performing activities because they have always been done a certain way. Pipelines are not immune. Documentation can be misplaced, or simply not transferred during acquisition of pipeline assets. Manufacturing and construction practices for vintage pipe, while at the time were best available, as they have aged have been found to contain specific integrity threats. Understanding the pipe in the ground, whether seamless, ERW, EFW, DSAW, etc., and ensuring material properties are known is critical to any integrity management program.

Leveraging state-of-the-art ILI systems such as MDS allows for comprehensive inspection of a given asset, as well as information needed to group pipe joints by their specific manufacturing, magnetic, wall thickness, internal surface, seam type, seamless, and other characteristics. Pipe Joint Classification is a process developed to create bins of pipe joints, and identify "rogue" joints that may be undocumented.

Through several years of development and testing, Positive Material Identification is a proven non-destructive method of determining material and chemical composition, which correlates to API 5L grade. Time spent developing this solution specifically for the pipeline industry made it clear that simply applying an indenter technology or other singular technology is insufficient to determine pipe grade. A prescriptive, controlled process is needed to obtain accurate and repeatable results. PMI displaces destructive methods to determine pipe properties by cutting out a coupon and sending it to an off-site laboratory.

Pipe Identification combines the latest ILI and NDE platforms and processes to create a non-destructive solution for the creation of pipe records. The pending Integrity Verification Process regulation in the United States will require an understanding of what pipe is in the ground, which is critical to any integrity management program for MAOP validation, anomaly safe pressure calculations, threat mitigation, safety and protection of the environment. For similar reasons, those regions without such pending regulation will certainly benefit from closing any records gaps that may exist. Digging up each joint of pipe in a pipeline system to recreate records is not economically, environmentally, or from a time perspective, feasible. With approximately 50 percent of pipe currently in the ground constructed prior to 1970, generating records via non-destructive means will be a crucial part of compliance, and overall improvement in a pipeline integrity management program.

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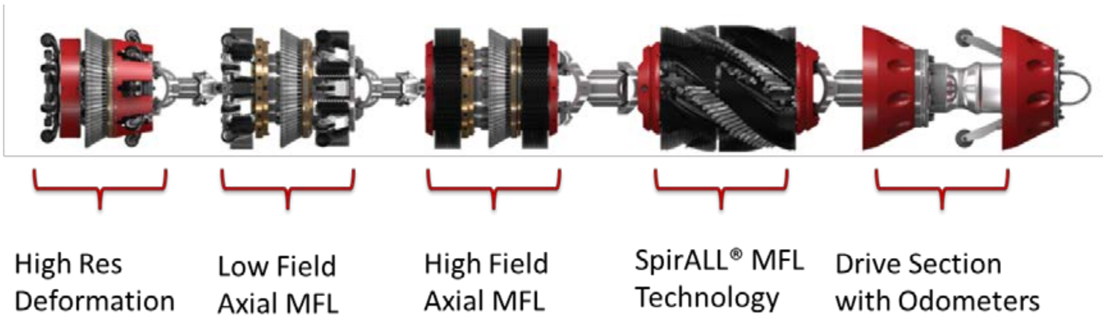

Fig.1. MDS platform.

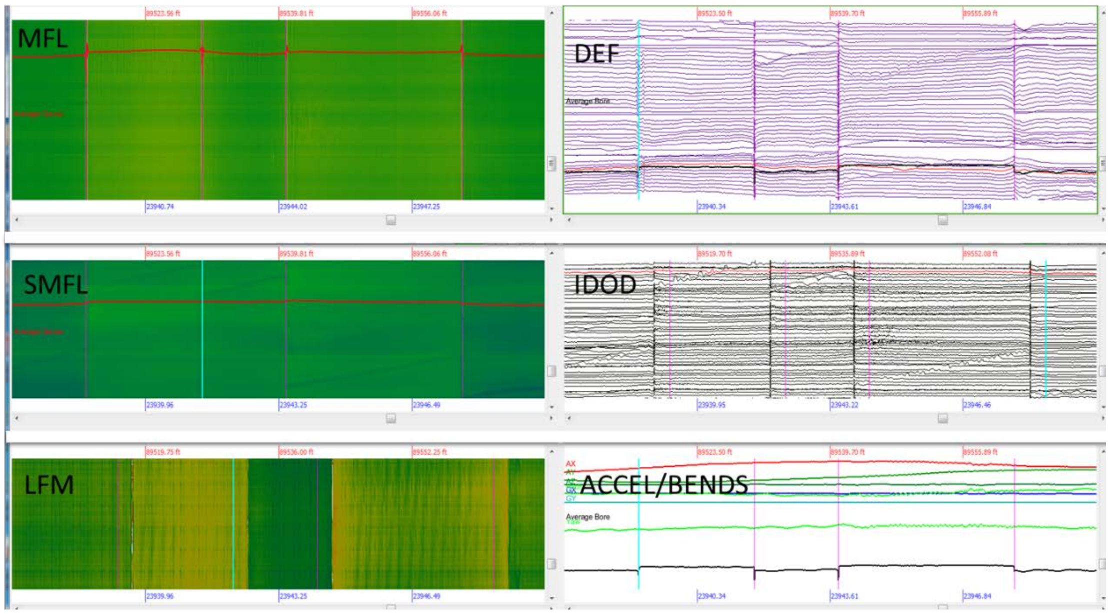

Fig.2. Several joints visible in each dataset on the MDS platform revealing specific characteristics. Data on left top to bottom: high field axial MFL, helical/spiral MFL, low field MFL. Data on right from top to bottom: deformation, internal/external, accelerometers and gyroscopes.

Pipe Type	Total Length (ft)
Pipe Type Property Change 1A	339,029.11
Pipe Type Property Change 1B	188,514.92
Pipe Type Property Change 1C	1,104.61
Pipe Type Property Change 1D	1,457.75
Pipe Type Property Change 1E	26.18
Pipe Type Property Change 2A	130,077.67
Pipe Type Property Change 2B	20,865.10
Pipe Type Property Change 2C	178.25
Pipe Type Property Change 2D	51.37
Pipe Type Property Change 3A	736.26
Pipe Type Property Change 3B	104.93
Pipe Type Property Change 3C	164.40
Pipe Type Property Change 3D	55.05
Pipe Type Property Change 3E	2,024.07
Pipe Type Property Change 3F	66.20
Pipe Type Property Change 3G	74.63
Pipe Type Property Change 4A	33.96
Pipe Type Property Change 5A	189.49

Fig.3.Pipe joint classification report.

Fig.4. Material property assessment.