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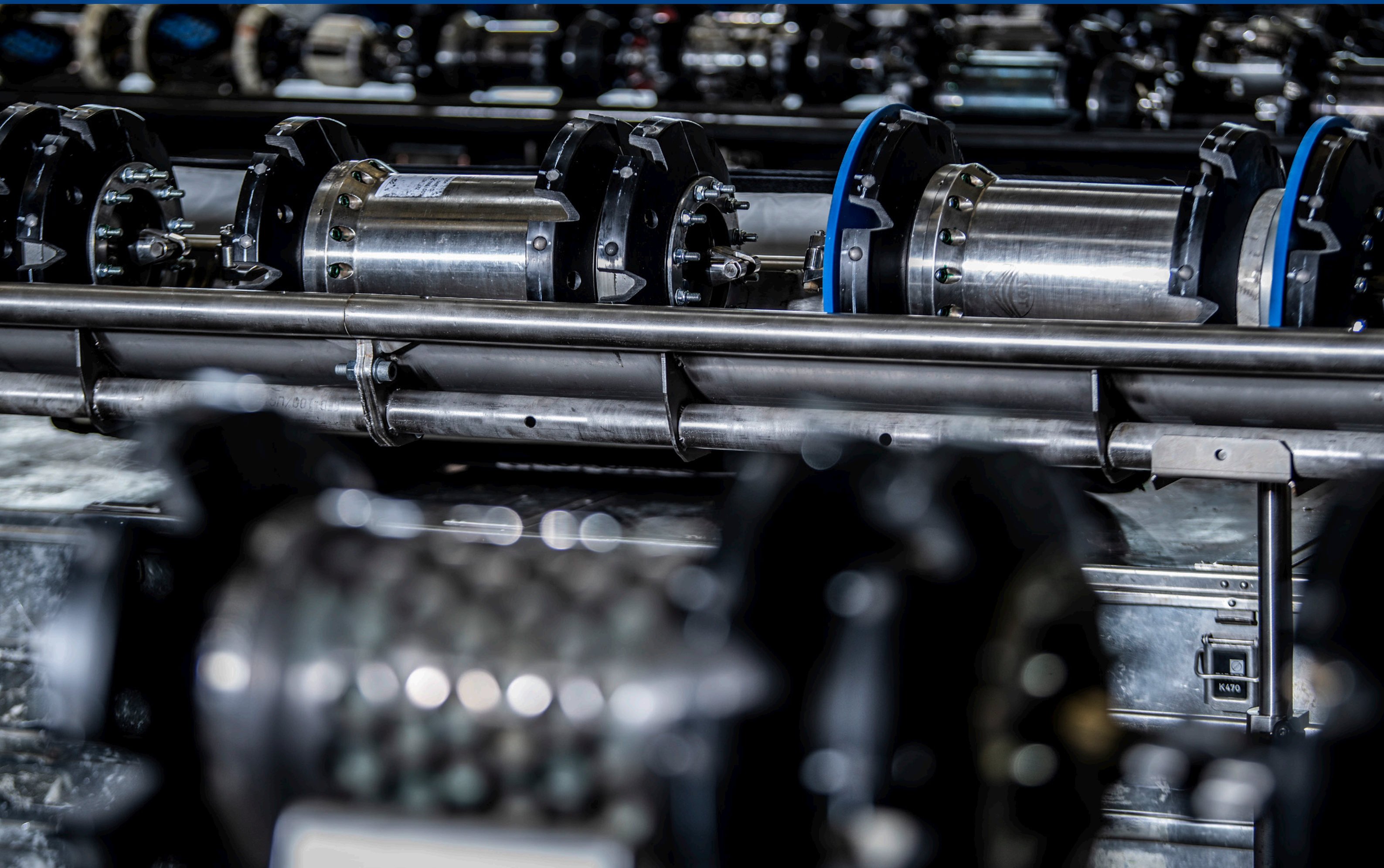
White Paper

Assessing the Accurate Topography of Complex Channeling Corrosion



White Paper

Assessing the Accurate Topography of Complex Channeling Corrosion

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Abstract

This paper presents a case study of an offshore pipeline with pitting and long axial corrosion that had been continuously inspected by Magnetic Flux Leakage (MFL) and was recently inspected with Ultrasonic Metal Loss Inspection (UMp). UMp is NDT Global's quantitative wall thickness measurement tool providing the best resolution for pitting detection and sizing. An anonymized comparison of 3 MFL inspections and the recent UMp inspection is presented. This analysis demonstrates the challenges associated with the two methods, and how UMp can be used to acquire topography that describes the complete extent of metal loss.

Further, the case study also shows a new and more customized approach to providing data that enables a better comparison of results between different ILI methods. Finally, direct measurement data enables advanced integrity methods, like DNV-RP-F101 Appendix D, which uses wall thickness and standoff data to calculate pipeline capacity and system effect considering the effects of long axial corrosion continuously spanning multiple pipe joints.

Introduction

Inline inspections (ILI) are essential components of pipeline integrity management programs. Depending on the applied inspection technology, ILI tools can detect and size a wide range of anomalies such as metal loss, crack-like anomalies, mid-wall features, and deformations. Due to the capability to provide remotely reliable and accurate data, ILI has great importance for the investigation of offshore pipelines and documentation of their current condition.

The two most commonly used ILI technologies are Magnetic Flux Leakage (MFL) and Ultrasonic Metal Loss Inspection (UMp). While both tools can identify metal loss in the wall of a pipeline, they operate based on very different physical principles, which ultimately defines their performance specification. This difference in physical principles means that the appropriate application of the tool is particularly important. Not every tool is going to work for every type of corrosion. Here, we consider the type of corrosion of our sample pipeline and explore the differences between 3 MFL inspection data sets and one UMp inspection data set. We will explore the operational principles of both technologies used in these inspections.

Beyond selecting the correct tool for the job, analyzing, and reporting the data is crucial to make the most out of what the tools record. Here we compare the reporting techniques of the MFL versus UMp inspections and highlight that UMp enables better insight into the nature of the corrosion by delivering accurate corrosion topology.

Finally, the corrosion topology captured by UMp enables the use of the standard DNV-RP-F101 Appendix D, which calculates the pipeline pressure capacity of offshore pipelines with long axial channeling corrosion. This method requires River Bottom Profiles (RBPs) and accounts for the "system effect," where the capacity of a pipeline can be reduced beyond the pressure capacity of the worst joint due to long axial corrosion extending across many pipe joints.

Inline Inspection of Offshore Pipelines

Challenges

Performing ILI in offshore pipelines has its own challenges compared to onshore pipelines. Considering the structure of the pipeline, offshore pipelines typically have a higher wall thickness, flexible risers, special fixtures, thick outer casing, and Corrosion Resistant Alloys (CRA) prepared walls. Considering operation, offshore pipelines are often high pressure, operating under a significant temperature differential, and transporting corrosive media.

The structural and operational parameters of offshore pipelines shape the type of anomalies that can develop. Anomalies in offshore pipelines are often found to be complex internal corrosion. The corrosion is internal due to the challenging operating conditions and the protective outer casing that prevents external corrosion. Many crude oil and water injection pipelines are affected by internal corrosion along the six o'clock position (also called channeling corrosion, long axial corrosion, or bottom-line corrosion), that can extend over contiguous sections (Figure 1), in the worst case several kilometers in length. This corrosion usually begins as single pitting features that can develop into pitting chains and further into distinct channeling.

The shape of channeling corrosion anomalies can vary from a smooth and uniform reduction in wall thickness along the six o'clock position (as is typical e.g., for a combined corrosion/erosion process) to corrosion features with an irregular and complex shaped geometry where depth varies significantly along the distance.

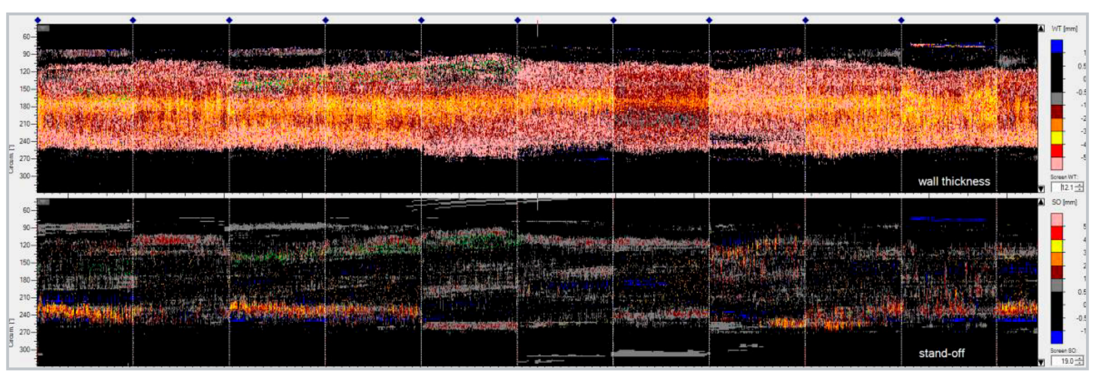

Figure 1 – Top: Wall thickness C-Scan showing a section of coherent channeling corrosion across 10 pipe joints (~410ft. / 125m). Bottom: Stand-off C-Scan showing deeper areas of metal loss within the wall affected by the broad channeling corrosion. The color scale indicates deviation from nominal wall thickness and nominal stand-off respectively.

Identifying and sizing, as well as assessing the significance of such complex corrosion, is not straightforward. The tool used to collect data that enables these tasks must be carefully selected, with an understanding of what the tool is capable of detecting. Such an understanding comes from the principles of how the tool works.

MFL Benefits and Drawbacks

MFL tools for wall thickness measurement use magnets to induce a magnetic field in the pipe wall. In the sound wall, the magnetic flux does not change. Where there is metal loss present, the magnetic flux leaks outside or inside the pipe wall. The change in the magnetic flux is compared to the sound wall magnetic flux. The relative change in the magnetic flux can be correlated to a volume loss, which means that measurements are relative. Through calibration, testing, and further analysis of signal patterns, the volume loss can be calibrated to feature dimensions (API 1160).

As the MFL measurement is relative, the orientation of the magnetic field can affect the measurement. Axial MFL is where the magnetic field is established in the axial direction. Axial MFL cannot reliably detect, and size axially aligned metal loss. Circumferential MFL is where the magnetic field is established in the circumferential direction, and therefore cannot reliably detect and size metal loss oriented circumferentially. In the case presented here, axial MFL was used in all 3 runs. As one of the concerns for this pipeline was long axial channeling corrosion, axial MFL may not have been the ideal tool for the inspection. Circumferential MFL may have been better able to differentiate and size the channeling corrosion causing wall thickness variations around the circumference of the pipe. In the axial direction at a set circumferential position, there is no wall thickness variation. Therefore, axial MFL tools are not well suited to detect long axially oriented anomalies and cannot reliably size them.

Further, calibration of these tools to produce feature dimensions depends on knowledge of the local wall thickness, and in the case of the pipeline studied in this paper, the channeling corrosion was so severe that the wall thickness of a significant circumferential portion of the pipe was reduced. This affects the sizing algorithm.

The benefits of MFL are that the technology is less sensitive to residual dirt (compared to UMp which requires a clean pipeline, especially to accurately size pits), and the technology can perform well in a pipeline with a rough internal surface.

For the 3 MFL vendors compared here, the performance specification for pitting is very similar; the minimum width of a pitting, in the body of the pipe, measured with 90 % Probability of Detection (POD) is roughly the wall thickness; in this case, about 6.0 mm (Anonymous MFL Vendor Performance Specification).

UMp Benefits and Drawbacks

UMp tools for wall thickness measurement are equipped with piezo-electric transducers that emit sound waves oriented parallel to the pipe wall. The transducers operate in the pulse-echo mode. The distance between the sensor and the internal pipe wall (stand-off) is calculated from the time-of-flight of the signal reflected from the internal pipe wall, considering the speed of sound of the medium. The (remaining) pipe wall thickness is calculated from the time-of-flight difference of signals reflected from the internal and external pipe wall, considering the speed of sound of the pipe steel. The principle of UMp is illustrated in Figure 2.

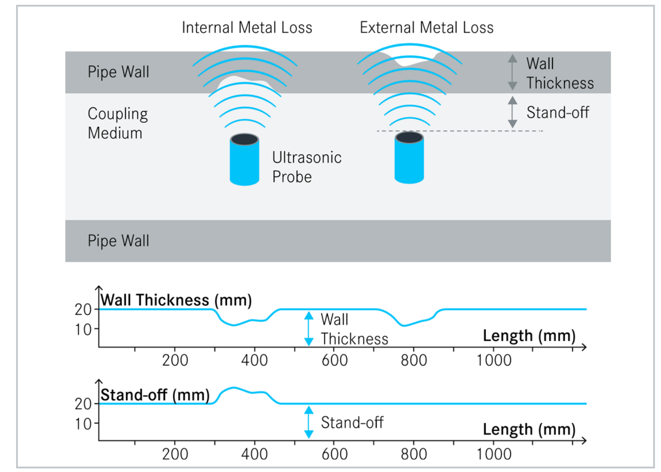

Figure 1 – Principle of ultrasonic wall thickness measurement .

UMp differs from MFL in that it is a direct measurement of the wall thickness. This means that the dimensions of the features are known. However, there is a limit to the diameter of pit that can be measured. The UMp tool used in this case can measure a minimum internal pit diameter of 0.20 in (5.0 mm), with a minimum depth of 0.03 in (0.80 mm) (UMp/UMp+ Performance Specification). Additionally, to measure the depth of pits, the pipeline must be clean. Depending on the medium, getting the pipeline as clean as necessary may be a challenge. Finally, these complex UMp features must be sized by an experienced analyst.

Channeling corrosion can be reliably detected and sized by means of ultrasonic wall thickness inspection tools. Apart from the basic anomaly dimensions (total length and width, peak depth, minimum remaining wall thickness), ultrasonic ILI data accurately displays the contour of the metal loss feature (Figure 4).

In the case presented here, the results of 3 axial MFL tools are compared to a UMp tool, and it is clear the MFL tools struggle to accurately size features relative to the UMp tool. Other generations of MFL tools (Transverse Field Inspection (TFI), spiral MFL) were developed for the detection of axial corrosion. However, their depth sizing capabilities are still limited in comparison to UMp tools, and they are not able to accurately reproduce the depth profile as the following case study shows.

Case Study - Complex Channeling Corrosion in an Offshore Pipeline

Analysis Procedure

In 2022 NDT Global performed an expedited ILI inspection of an offshore pipeline due to a leak. The Integrity Management Program (IMP) for this pipeline considered inspection intervals solely with axial MFL. Since the UMp focuses on the affected area and not exclusively single spots, the standard analysis approach for such prominent bottom-line corrosion is to capture the affected area joint-wise and search for the deepest point. However, in this case, the pipeline operator also requested a dedicated reporting of all pitting with a depth of > 10 %. To provide a complete picture of the entire pipeline condition in a useful scope, a compromise was found, in which the following was reported

- all features outside of the channeling area with depth ≥ 10%
- each channeling-affected pipe joints with depth ≥ 10%
- all pittings with a depth ≥ 50%

The benefits of this strategy are twofold. First, boxing the pittings within the channeling enables the customer to compare relevant previous inspection results with the current data set and enables NDT Global to use the correlated MFL results for their own investigations. Second, the boxing of the complete channeling areas per pipe joint allows detailed statements about the complete situation in the pipeline and an accurate integrity assessment based on appropriate calculation methods.

Results

General Results

For correlation purposes, the operator provided 3 MFL reports from the last 3 years. Each run was carried out by a different vendor. A change of the inspection technology from MFL to UMp was necessary to clarify the cause of a leak that could not be explained by all previous ILI results. An overview of the greatest variances between the different vendors is shown in Table 1. For the complete pipeline, the depth of each feature over the length of the pipeline is shown in Figure 3.

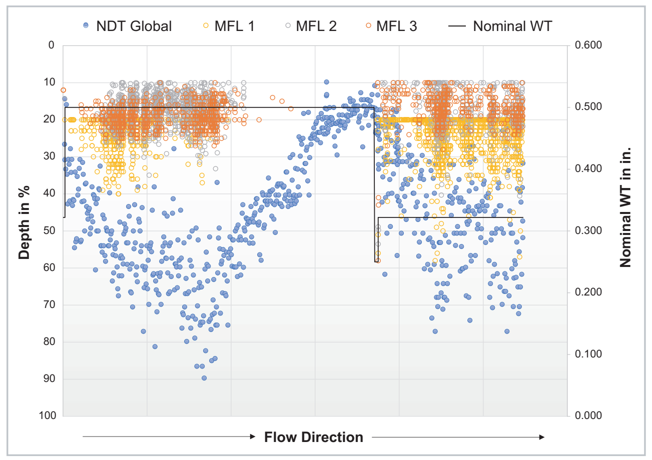

Figure 3 – Depth distribution of features according to the different vendors

	UMp (2022)	MFL Vendor 1 (2019)	MFL Vendor 2 (2020)	MFL Vendor 3 (2021)
Minimum Depth in %	10	20	10	10
Maximum Depth in %	90	58	54	58
Average Depth in %	56	22	18 (15)	18 (15)
Variance Depth in %	46	19	22 (18)	14 (18)
Standard Deviation Depth in %	6.8	4.3	4.6 (4.3)	3.8 (4.3)
Number of Features	2947[1]	3324	1571 (5611)[2]	1188 (7120)
Number of Features ≥ 50%	2802	7	2	1 (9)

Table 1 - Result Overview of different MFL vendors and UMp

[1] *Here, only single pittings are counted to provide a relevant comparison.*

[2] *Numbers in parentheses show the total feature numbers in the provided lists. Numbers not in parentheses display all features which could be used for correlation.*

In Figure 3, only the UMp channeling boxes, which reflect the deepest point, are plotted for ease of visualization.

Both Table 1 as well as Figure 3 reveal significant differences in the results between the UMp and MFL measurements, but also significant differences among the MFL vendors.

All ILI vendors were able to cover the dominant areas of channeling corrosion but in varying degrees of quantity and quality. MFL 2 and MFL 3 provide almost the same results with depths that are much shallower than the UMp measurement, whereas MFL 1 takes a middle position between all results. The most obvious fact is, that none of the MFL results matches the deepest UMp results, confirmed by the pipeline operator and its own investigations with Non-Destructive Examination (NDE).

All MFL results show that the different wall thicknesses and the magnetization of the tool have a clear impact on the data recording. This is clear when considering the nominal wall thickness in Figure 3. For the section of the pipeline with a nominal wall thickness of 0.500 in/12.7 mm, the MFL vendors significantly undercall the feature depths. In the section of the pipeline with a nominal wall thickness of 0.325 in, the discrepancy is less significant. This difference could be due to the effects of different magnetization levels within the different wall thicknesses. Further, within the 0.500 in/12.7 mm section, the UMp data shows a steady increase in feature depth with distance.

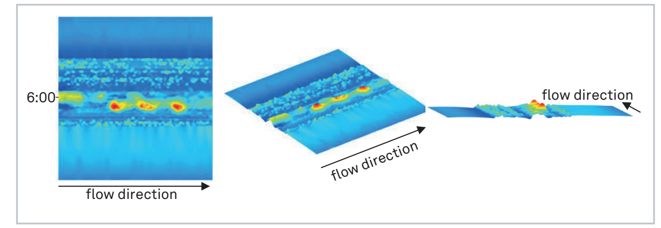

Figure 4 – Three views of the measured stand-off of a section of the offshore pipeline to demonstrate the internal channeling corrosion topography collected with UMp technology. The colors are proportional to the value of the stand-off.

None of the MFL data captures this gradient, possibly due to the circumferential extent of the channeling corrosion reducing the wall thickness and obscuring the MFL measurement.

Besides the reporting of the correct depths and reliable information about the remaining wall thickness, the direct and precise measurement with UMp means it is also possible to create an exact topography of the bottom-line corrosion and to recognize differences within certain areas. For example, in Figure 4 the shape of the internal corrosion is clearly visible. There are 3 distinct bands of channeling across the circumferential direction. There is a band along the 6 o'clock position that has large, deep pits visible. The bands on either side of this central band have many smaller, shallower pits. This is consistent with the concept of pitting chains that form together to generate the channeling. In this case, the channeling bands take up about 50 % of the inner circumference of the pipe. Additionally, this topography is useful for advanced integrity investigations.

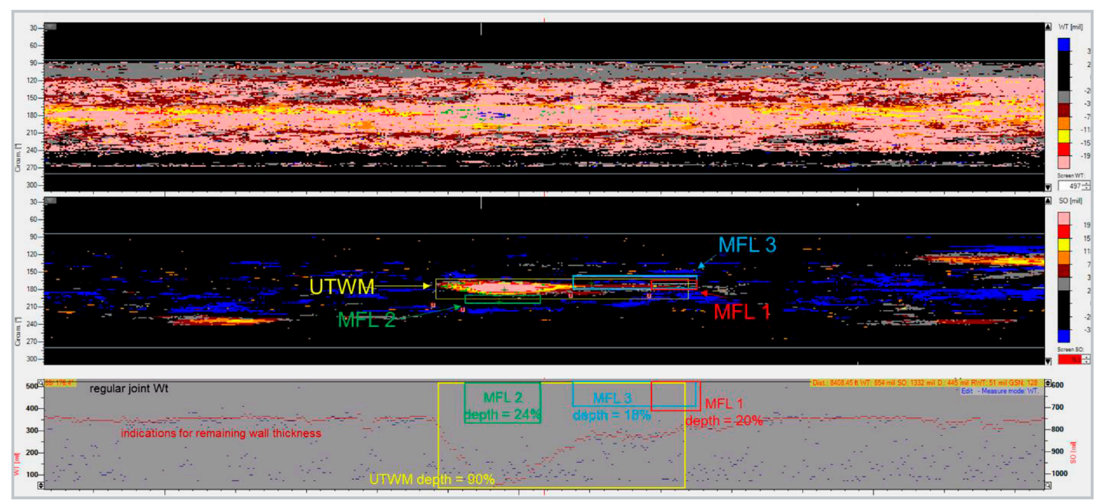

Figure 5 – Top: Wall thickness C-Scan for a section of the joint (~1.5 ft. / 0.5 m) containing the deepest point.
Middle: Corresponding stand-off C-Scan.
Bottom: Corresponding B-Scan showing the wall thickness through the deepest point. The colored boxes indicate the depth and approximate axial location and depth of the MFL and UMp boxes. Due to slight differences in the odometers for each run, the exact axial position can be neglected.

Deepest Point in the Pipeline

A closer view of the deepest metal loss in the pipeline shows the discrepancies between the UMp and MFL measurements in detail.

While not all corrosion spots were consistently identified by vendors along the length of the pipeline, the deepest point was detected by all vendors. But while the UMp measurement delivered a depth of 90 % with indications of a possible leakage for that point, the MFL results delivered significantly lower depths, around 20 %, as the projections in Figures 5 and 6 show. The blue, red, and green boxes in the bottom

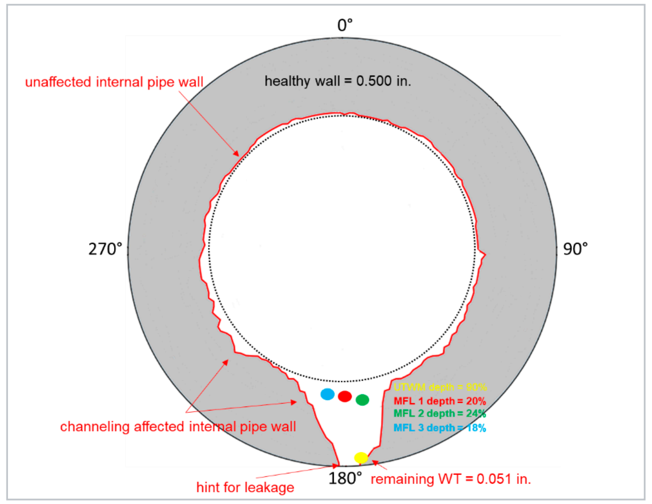

Figure 6 – Depths measured by different tools, shown at the deepest point in a cross-section, constructed from UMp data.

third of Figure 5 show MFL detection is only focused on the metal loss due to the channeling corrosion. Examining the figure, the depth of the boxes is close to the local wall thickness, marked in red. The total height of the area represents the nominal wall thickness. The real gap between reference wall thickness and remaining wall thickness caused by the local metal loss within the channeling is not considered. The axial cross-section of the pipe in Figure 6 illustrates the circumferential extent of the channeling corrosion and gives a reference for the size of the deeper metal loss within the channeling. It appears the channeling obscured the axial MFL measurement.

Reporting Single Pitting v Affected Area

Even if pipeline operators know that each ILI technology has its own pros and cons, the expectation is often to consider UMp as a complement to confirm existing MFL results. Of course, this is possible in most cases, but it is not the primary task of UMp.

Due to the direct measurement of the wall thickness for each shot, the focus of the technology, and its most important benefit, is to visualize the topography of the affected areas. Instead of an incoherent detection of the single pittings, the complete area is now visible (Figure 7). Examining the boxes in Figure 7 shows clearly that MFL boxes only capture single pits, the boxes have a shallower depth than the UMp boxes, and UMp captures not only the pits but also the extensive channeling. This enables the depth or remaining wall thickness profiles required for Level 2 assessment methods like RSTRENG Effective Area or DNV-RP-F101 Complex Shape and Appendix D for long axial corrosion.

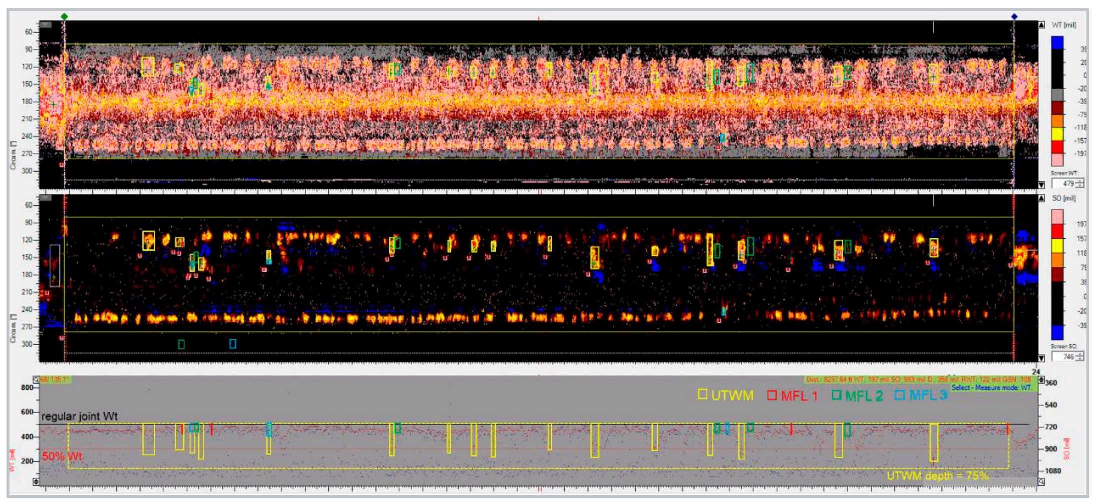

Figure 5 – Top: Wall thickness C-Scan for an entire joint (~40ft. / 12m). Middle: Corresponding stand-off C-Scan. Bottom: Corresponding B-Scan showing the wall thickness through the deepest point. The colored boxes indicate the approximate axial location and depth of the MFL and UMp boxes. Due to slight differences in the odometers for each run, the exact axial position can be neglected.

Application of DNV-RP-F101

Appendix D: Assessment of Long Axial Internal Corrosion Defects

As discussed in the previous section, ILI reporting of long axial channeling corrosion is typically given as individual boxes (in the case of MFL) and joint-length boxes described by the deepest point of the entire joint (in the case of UMp). Performing integrity assessments with just this type of list information (Level 1 methods) does not sufficiently capture the complexity of the metal loss. Therefore, Level 2 assessment methods should be used to calculate safe operating pressure. However, even Level 2 methods may not be sufficient in the case of axial channeling corrosion that covers a significant axial extent of the pipeline.

Conventional methods determine the safe operating pressure from the pressure capacity of the worst anomaly. However, if kilometers of pipe are operating at reduced pressure capacity, the pipeline could be in worse condition than one with a single joint at a significantly reduced pressure capacity. DNV-RP-F101 Appendix D describes an assessment method tailored for pipelines affected by long axial corrosion that accounts for the number of pipe joints operating at reduced capacity. The method used to do this uses the Probability of Failure (PoF) concept, where the pressure capacity of a single joint is correlated to a probability of failure, and then the probability of failure of multiple joints can be mathematically combined, and then correlated back to a pressure capacity that represents the multiple joints. Using this method requires UMp data due to the fact that river-bottom profiles are needed.

The method provides guidance on how to calculate the pipeline pressure capacity, corrosion growth rates, and the pipeline pressure capacity at a future point in time. The next sections demonstrate these three pieces of the DNV-RP-F101 Appendix D procedure for a different offshore crude oil pipeline that was affected by severe channeling corrosion with growth rates up to 1 mm/year. The design pressure of this pipeline is 245 bar, and the Maximum Allowable Operating Pressure (MAOP) is 150 bar.

> **Conventional methods determine the safe operating pressure from the pressure capacity of the worst anomaly.**

Example: Calculate the Pipeline Pressure Capacity

The basis for calculating the pipeline pressure capacity is the Complex Shaped Defect method of DNV-RP-F101 Part A. This calculation provides the pressure capacity of each individual joint. Then this pressure capacity is converted to a PoF. Just relying on the worst pressure capacity value for a single joint is not sufficiently conservative because for pipelines with long axial channeling corrosion, the PoF associated with the whole pipeline system (PoF system) might be higher than the PoF of the worst pipe joint (which is called the “system effect”).

According to DNV-RP-F101 Appendix D, the maximum safe working pressure of a pipeline with long axial corrosion is determined as follows:

1. River-bottom profiles are calculated for all selected pipe joints based on filtered wall thickness data, which is obtained from a UMp measurement.
2. The safe working pressure Psafe is calculated for all selected pipe joints using the complex shape method of DNV-RP-F101 Part A. Psafe values are determined for profile subsections of approximately 1.5 m length (depending on pipeline diameter and wall thickness).
3. Every Psafe value is converted to the associated PoF based on the considered assessment pressure.
4. PoF system is calculated from the individual PoF values of all pipe sections using statistical methods.
5. PoF system is compared to the target PoF of the pipeline safety class and a pressure adjustment factor is calculated. The safe working pressure of the pipeline is then given by the considered assessment pressure times and the calculated pressure adjustment factor.

For the demonstration pipeline, 370 pipe joints showing significant channeling corrosion were selected for the assessment. For the worst pipe joint, a safe operating pressure of 231 bar was calculated according to the Complex Shaped Defect method of DNV-RP-F101 Part A. This is below the original pipeline design pressure of 245 bar, but significantly higher than the relevant MAOP of 150 bar. Figure 8 shows a significant variation of the Psafe values with distance. The lowest pressure values are concentrated in a short section between km 15 and km 16.

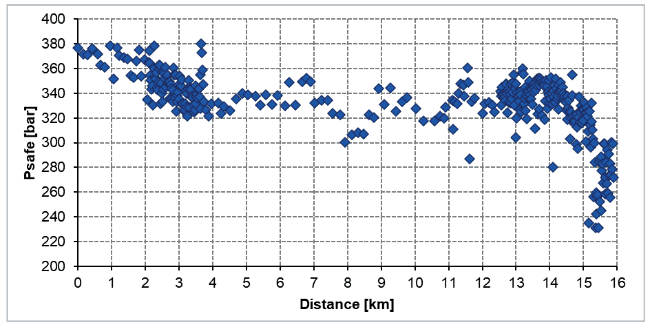

Figure 8 – Safe operating pressure of assessed pipe joints according to DNV-RP-F101 Complex Shape Part A

The histogram in Figure 9 shows the distribution of Psafe values for pipe sections of 1.5 m (4.92 ft) length.

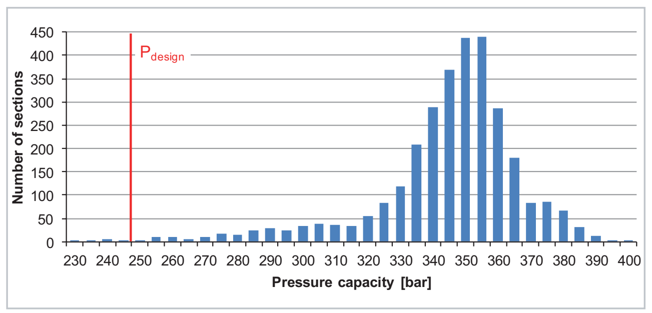

Figure 9 – Histogram of pressure capacity for 1.5 m (4.92 ft) long pipe sections

Following the Appendix D procedure and accounting for the system effect, a safe working pressure of the pipeline system of 223 bar was calculated. The pressure capacity of the pipeline system is 8 bar (4 %) below the pressure value of the worst pipe joint. In cases where more pipe joints have low Psafe values, a higher system effect, i.e., a higher reduction of the pipeline system pressure capacity compared to the worst feature, is expected.

Example: Corrosion Growth Assessment

The complexity of channeling corrosion means calculating the corrosion growth rate straight from ILI report listings is unlikely to be meaningful. The deepest points could change between the years and the extent of corrosion along the joint is not considered. DNV-RP-F101 provides guidance on determining the corrosion growth rates in a pipeline affected by long axial channeling corrosion using River Bottom Profiles (RBPs) from repeated ILIs.

From these RBPs, so-called characteristic wall thickness (CWT) profiles are calculated by averaging the wall thickness in sections of approx. 1.5 m length. Growth rates for these short pipe sections are then calculated from the change in CWT.

The procedure is shown in Figure 10. The top figure shows RBPs of 3 ILIs for one pipe joint. The resulting corrosion growth rates are shown in the bottom part of this figure. In this example, the overall growth rate was reduced from approx. 0.55 mm/year (between ILI 1 and ILI 2) to 0.20 mm/year (between ILI 2 and ILI 3). However, corrosion growth at the deepest spot of this anomaly remained constant between ILI 1, ILI 2, and ILI 3.

The corrosion growth rates for all assessed pipe joints are plotted in Figure 11. The corrosion growth behavior varies along the distance, with maximum growth rates observed between 3 and 4 km.

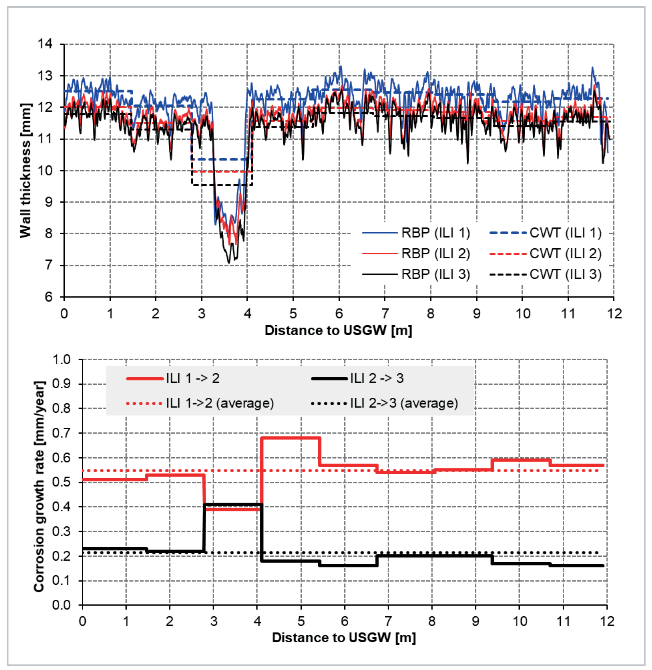

Figure 10 – Example of corrosion growth assessment by comparison of river-bottom profiles (one pipe joint). Top: river-bottom profiles and characteristic wall thickness, bottom: growth rates

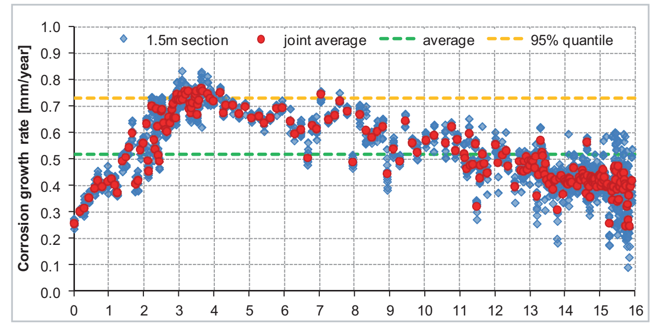

Figure 11 – Corrosion growth rates vs. pipeline distance (red dots: pipe joint average growth rates, blue dots: growth rates for 1.5 m sections)

Example: Extrapolation of the pipeline pressure capacity

After the determination of the pipeline pressure capacity at the date of the latest ILI, and after the corrosion growth assessment is performed, the future development of the pipeline-safe operating pressure can be extrapolated. This is achieved by reducing the remaining wall thickness of the RBPs according to the considered corrosion growth rates and by repeating the capacity assessment as described above. Depending on the considered corrosion growth rate, the extrapolated pipeline pressure capacity will reach the MAOP of 150 bar 3.5 to 5.5 years after the latest inspection (see Figure 12).

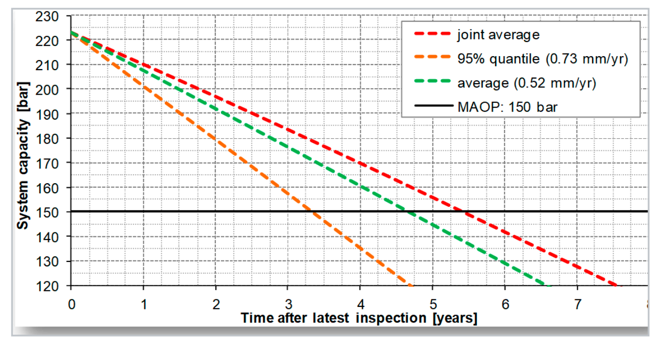

Figure 12 – Extrapolation of pipeline pressure capacity

MFL and UMp each have their own benefits and challenges.

Summary and Conclusions

ILI is key to managing offshore pipeline integrity, but it is not as simple as choosing any inspection technology. The case study presented here demonstrates a scenario where the inspection technology chosen for the IMP was not appropriate for the task. The two most common options for an operator, MFL and UMp, each have their own benefits and challenges. While MFL can be less costly and does not require extensive cleaning, the dependence on magnetic field orientation and the relative nature of the measurement means that the technology must be chosen with an understanding of the type of threat it is evaluating. UMp can provide a direct measurement regardless of the type of threat, but the cleanliness requirements may prove difficult, especially given the type of mediums offshore pipelines transport. In the case study presented here, the UMp was able to provide accurate corrosion topography where three different MFL vendors could not. The detailed corrosion morphology from UMp includes both the deepest pits, as well as the circumferential and axial extent of the long axial corrosion, enabling the application of DNV-RP-F101 Appendix D.

The second case study, which applies Appendix D to an offshore pipeline, provides a method of accounting for the pressure capacity reduction caused by long axial channeling corrosion. From an intuitive perspective, it makes sense that a pipeline with many joints operating at reduced pressure capacity may be more concerning than a pipeline with a single joint operating at an even larger reduced pressure capacity. The Appendix D method of working with PoF provides a mathematical framework to combine the reduced pressure capacity of multiple joints into one value for the system. This provides the operator with a clearer picture of the state of the pipeline, which is valuable when managing and developing IMPs.

NDT Global

Axial Cracks

Circumferential Cracks

Metal Loss

Geometry Ovalities

Mapping

Abbreviations

ILI – Inline Inspection

MFL – Magnetic Flux Leakage

RBPs – River Bottom Profiles

CRA – Corrosion Resistant Alloy

POD – Probability of Detection

NDE – Non-Destructive Examination

IMP – Integrity Management Program

MAOP – Maximum Allowable Operating Pressure

TFI – Transverse Field Inspection

PoF – Probability of Failure

Psafe – Safe Working Pressure

CWT – Characteristic Wall Thickness

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[1] API 1160 Managing System Integrity for Hazardous Liquid Pipelines (Feb 2019): American Petroleum Institute Standard.

[2] Anonymous MFL Vendor Performance Specification

[3] NDT Global Performance Specification for Detection Identification, and Sizing. EVO Series 1.0 UMp/UMp+. PS-011-en Performance Specification Metal Loss. Version 13. 2022.

[4] DNV-RP-F101 Corroded pipelines (2019): DNV Standard, Edition 2019-09 – Amended 2021

This paper was published at the 2023 Pipeline Pigging and Integrity Management conference.

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