EFFECTIVE USE OF IN-LINE INSPECTION TECHNOLOGIES

TO SUPPORT PIPELINE INTEGRITY MANAGEMENT

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Abstract

Chevron North Sea Limited (CNSL) operates more than 25 pipelines across three operated assets in the UK North Sea: Alba, Captain and Erskine.

Processes adopted by CNSL for effective management of pipeline integrity and reliability include a combination of online data collection, fluids sampling, corrosion risk assessment, remnant life modelling, and physical inspection techniques for the measurement of pipeline condition.

This paper discusses the input that in-line inspection (ILI) can have into an overall pipeline integrity management strategy. The following key points will be discussed:

- The importance of combining knowledge relating to active corrosion mechanisms together with an understanding of the capabilities and limitations of available in-line inspection technology.
- How ILI results can be used to review the effectiveness of corrosion management strategies and support remaining life assessment.
- How to select an appropriate re-inspection interval.

Three case studies will be used to provide a practical insight into how this is achieved within CNSL.

Overview of CNSL's UK Operations and Strategy for Managing Asset Integrity

CNSL operates more than 25 pipelines across three operated assets in the UK North Sea, Alba, Captain and Erskine, with pipelines service life of up to 20 years. The pipelines are required to transport:

- Produced hydrocarbon fluids
- Gas import/export
- Injection water for enhanced hydrocarbon recovery
- Chemicals/hydraulic fluids for flow assurance, asset integrity and subsea equipment controls

Processes adopted by CNSL for effective management of pipeline integrity and reliability follow the UK HSE recommended practice, HSG65, supported by the general principles of both the Energy Institute for corrosion management in Oil and Gas production processing and DNV RP F116, Integrity Management of Subsea Pipelines.

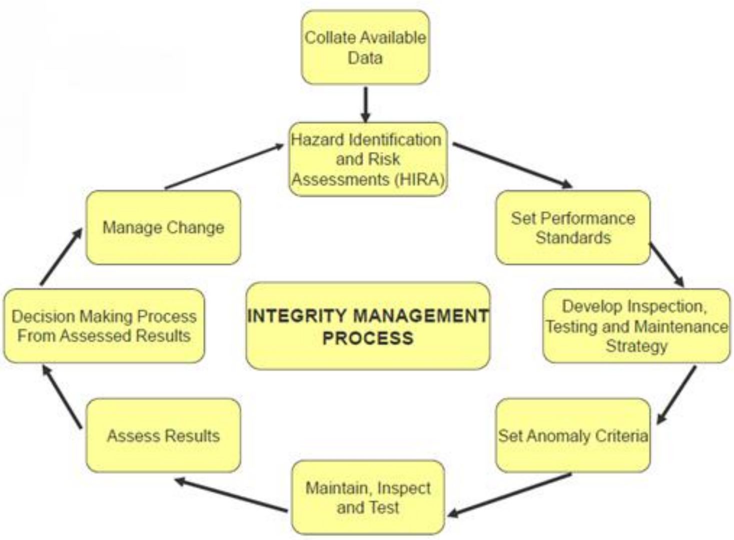

Figure 1: CNSL's Integrity Management Process

As part of the overall integrity management strategy, CNSL adopts a range of tools including:

- Online data collection and monitoring
    - Corrosion probes
    - Temperature & Pressure
    - Flow rate
    - Transient conditions
- Fluids sampling
    - Composition (CO_2, H_2S, O_2, Cl & organic acids)
    - Water cut %
    - Bacterial counts
- External inspection techniques
- Intelligent pigging & subsea UT wall thickness assessment
- Remaining life modelling

This paper focusses on the role that intelligent pigging plays in the overall integrity management strategy and the interaction between pigging and the other management tools used by CNSL.

The Role of Intelligent Pigging within CNSL's Integrity Management Strategy

When performed correctly, intelligent pigging, especially in-line inspection (ILI) enables the integrity status of a pipeline to be confirmed and provides an indication of the effectiveness of the corrosion management strategy. To help ensure that the inspection delivers the required results, it is important that the entire inspection campaign be supported by a team of engineers that can provide the following:

- A thorough understanding of the pipeline history and its required future use.
- An understanding of the corrosion threats facing the pipeline and the likely corrosion mechanisms that will need to be accurately detected and sized by the ILI tool.
- Knowledge of the capabilities and limitations of available ILI technologies.
- Sound integrity engineering knowledge to be able to combine knowledge of the pipeline and its associated corrosion threats with the results of the inspection in order to investigate the safe remaining life of the pipeline.

The role of intelligent pigging is discussed further in the following case studies which highlight the importance of pre-inspection and post-inspection activities and how inspection data can be used for remaining pipeline life assessment.

Pre-Inspection Technology Selection:

The initial case study considers the selection of appropriate ILI technology prior to carrying out the inspection. Inspection technology is a critical aspect within the overall inspection process. For the purpose of corrosion detection and sizing, the two most commonly used technologies are magnetic flux leakage (MFL) and ultrasonic (UT). Both technologies are widely used by the industry and have the ability to reliably and accurately detect and size most forms of corrosion damage and other defect features in rigid walled steel pipelines. However, each has limitations relating to specific corrosion mechanisms and pipeline operating conditions; it is important that these are understood in order to select the correct technology and minimise the likelihood of receiving poor quality / incomplete ILI data.

To demonstrate the importance of ILI tool selection, the inspection history of the 12" Alba water injection pipeline is discussed below. ILI inspections of the pipeline had been carried out on two occasions (in 2006 and 2009) using axial MFL technology (the most commonly used technology in the industry). Both inspections had been completed by the same ILI vendor and both reported internal corrosion features throughout the length of the pipeline. The corrosion was predominantly located within the bottom half the pipeline but the distribution was irregular with concentrations of small diameter pitting reported at the 3 o'clock, 6 o'clock and 9 o'clock positions. A detailed analysis of the 2006 and 2009 inspection data, combined with a review of historical pipeline operating conditions had concluded that erosion-corrosion was the most likely mechanism, based on the following:

- The irregular distribution of the internal corrosion was atypical of the distribution of most known internal corrosion mechanisms.

- Corrosion had been reported throughout the length of pipe joints, but an increased number of features were reported close to pipeline girth welds.
- An assessment of the significance of the internal corrosion features had concluded that the pipeline was fit-for-service based on maximum allowable operating conditions but a detailed comparison of the 2006 and 2009 MFL data (including signal-based comparison) indicated that the corrosion was active.
- Based on the flow rate of the pipeline and the knowledge that O_2 levels had not always been controlled within the target level of 5 ppb.

Erosion-Corrosion is one of the main mechanisms in water injection pipelines which can be caused by the inherent velocity of the product combined with oxygen corrosion. The ingress of oxygen results in the formation of a range of different corrosion products on the surface. Weakly adherent corrosion products are more likely to form in the presence of higher oxygen concentration and can be more easily removed from the wall by local flow characteristics compared to strongly adherent corrosion products formed in the absence of oxygen. Once loose corrosion products are removed, bare steel is available for further corrosion governed by the local oxygen gradient. Corrosion debris flowing in the bottom of the pipe is also available to enhance local corrosion rates and erosion at the bottom of the pipe.

Erosion-corrosion often results in a smooth channel centred at the 6 o'clock position. Figure 2 shows a section of the Strathspey water injection pipeline which had been operated under similar conditions to the 12" Alba pipeline.

Figure 2: Groove Corrosion on the Strathspey Water Injection Pipeline

As previously stated the inspections for the 12" Alba water injection line were carried out using MFL technology and the distribution of corrosion reported was irregular and not typical of channelling corrosion. MFL technology relies on irregularities within the pipe surface causing disturbances to the applied magnetic flux; the more abrupt the irregularity, the larger the disturbance to the flux. Furthermore, axially oriented MFL tools are more sensitive to irregularities which are oriented in the circumferential plane. As a result, axial MFL tools are relatively insensitive to smooth channelling corrosion and tend only to report features where there is a change in profile. Changes in profile often occur at girth welds (where the weld metal is sometimes more resistant to erosion-corrosion) or at the edges of the channel.

Due to the concern that the MFL tools may have failed to accurately size any channelling corrosion, the 12" water injection pipeline was re-inspected in 2010 using both MFL and UT technologies. MFL was used to allow a direct comparison against the previous inspections and UT was used to detect and size channelling corrosion.

An extract of the 2006, 2009 and 2010 MFL data and the 2010 UT data is shown in Figure 3.

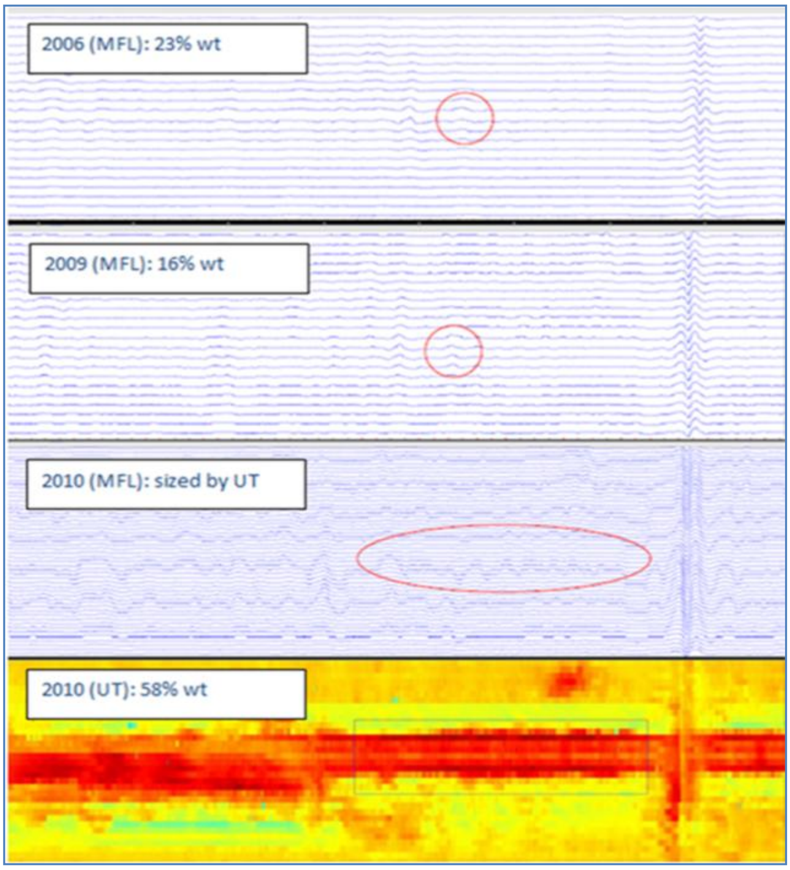

Figure 3: Repeat MFL and UT Signal Data for 12" Alba WI Pipeline

This shows that although a feature was detected and sized by the MFL inspections, the feature was reported with a small length and width. The 2010 UT data clearly shows the channelling corrosion that was confirmed to be present in the pipeline. It can also be seen that the MFL inspections had significantly under-estimated the depth of the channelling.

This case study highlights the following key learning points:

- Irregular corrosion distributions reported within ILI data may be a function of the detection capabilities of the tool and not a true representation of the actual distribution. In particular, a concentration of metal loss features reported by an MFL tool at the bottom of the pipeline and concentrated at girth welds *may* indicate a channelling corrosion risk.
- A pre-inspection corrosion risk assessment should be performed to identify the potential corrosion mechanisms that may be present within the pipeline prior to the selection of an appropriate ILI technology.
- Lessons learnt from other pipelines should be communicated effectively (for example using the findings of the Strathspey water injection pipeline investigations to highlight the possibility of channelling corrosion within the Alba pipeline).

Subsequent inspections on other pipelines within the network highlighted that in the absence of UT data, high resolution calliper data can provide an indication of whether channelling corrosion is present although the accuracy of depth sizing would be limited.

Post -Inspection Integrity Evaluation:

Typically, post-ILI evaluation will involve the following key activities:

1. Data verification and review of ILI findings to determine the likely cause of any reported corrosion
2. Assessment of the significance of the reported features at the required operating conditions
3. Estimation of corrosion growth rate
4. Modelling of future corrosion growth to determine a suitable re-inspection interval and investigate remaining pipeline life
5. Develop / modify the corrosion management plan to minimise further corrosion activity and extend the safe life of the pipeline

Methodologies for performing fitness-for-service assessment and estimating corrosion growth rates (either through corrosion modelling or comparison of repeat ILI data) have been well researched and documented. Therefore, the remaining case studies in this paper focus on two main aspects of post-ILI evaluation: data verification and corrosion diagnosis based on ILI results and using the ILI data to investigate the remaining life of the pipeline and review of the corrosion management strategy.

ILI Data Verification & Corrosion Diagnosis

Prior to performing detailed assessment of ILI data it is first necessary to investigate the quality of the data and determine whether the inspection has performed within its stated specifications.

ILI data can be verified either directly or indirectly. For onshore pipelines it is typical to select a sample of features (often the most severe) and to excavate the pipeline to allow the features to be sized using a range of external non-destructive techniques. The results of these direct examinations can then be compared with the ILI results to investigate whether the inspection has performed within specifications. API 1163 provides an outline approach for performing direct verification of ILI data.

For subsea pipelines the costs involved prohibit regular direct examination of subsea sections and therefore such investigations are typically limited to situations where the ILI data suggests that the integrity of the pipeline is compromised or the safe remaining life is short. Direct examinations of offshore pipelines can however be performed in accessible locations such as the topside piping and risers. However, the corrosion in these areas is often not representative of the corrosion in the subsea section and therefore care should be taken when using the results of such examinations to draw conclusions about features reported subsea.

In the absence of direct examination of the pipeline, indirect verification of ILI data can be used to investigate the reliability of the ILI data prior to using it to support critical decisions relating to the pipeline’s fitness for continued service and its remaining life. Indirect verification can take the form of the following:

- A review of the factors that can negatively affect the quality and completeness of the ILI data. These include run speed and acceleration, sensor malfunction / data loss, magnetisation (for MFL tools) and echo loss (for UT tools).
- A sense-check to compare the sizes and distribution of features reported by the ILI with what was predicted by the corrosion risk assessment. For example, are the depths of reported features consistent with corrosion modelling results? Is the distribution of features consistent with that which would be expected from the likely corrosion mechanism?
- Comparison of the results against previous ILI results or manufacturing records.

Once ILI data has been verified, a review of the corrosion features reported by ILI can support corrosion diagnosis activities to understand more fully the corrosion mechanisms active within the pipeline system. Most causes of internal corrosion can be diagnosed by reviewing characteristics of the reported features such as their shape, proximity to girth welds, association with low points in the pipeline profile and orientation around the circumference of the pipeline. A detailed review of ILI data can also be used to support the management of external corrosion on offshore pipelines.

Due to the effectiveness of corrosion protection coatings and cathodic protection systems, external corrosion on offshore pipelines is typically confined to topside piping and risers. Within these areas, locations at high risk of corrosion damage include splash zones and coating interfaces. Therefore, diagnosing the cause of external corrosion in these areas is dependent on accurately aligning ILI data with riser drawings which indicate the location of riser clamps, coating interfaces and the splash zone. Accurate alignment can be limited by the reliability of the ILI distance measurement, which can be negatively affected by odometer wheel slippage in vertical riser sections and by the accuracy of the riser drawings. To illustrate some of these challenges, a recent case study is discussed below.

During a recent general visual inspection (GVI) of the 16” Captain Oil Export riser, an area immediately above the neoprene splash zone coating was found to be corroded (Figure 4). A work order was consequently executed to repair the area, whereupon all corrosion products were removed, and the area was blast coated and painted before a sealant was applied to prevent future water ingress. Although photographs were provided of the repair itself, it was not clear whether the neoprene had been stripped back to repair any corrosion damage below the neoprene coating during the repair operation.

Figure 4: External Corrosion Area above Neoprene Splash Zone Coating

After the GVI survey, the pipeline was inspected using magnetic flux leakage technology (MFL), which reported a circumferential area of external corrosion on the riser near the splash zone (although the precise location of the corrosion could not be accurately determined from the ILI data alone with respect to the position of the top of the external

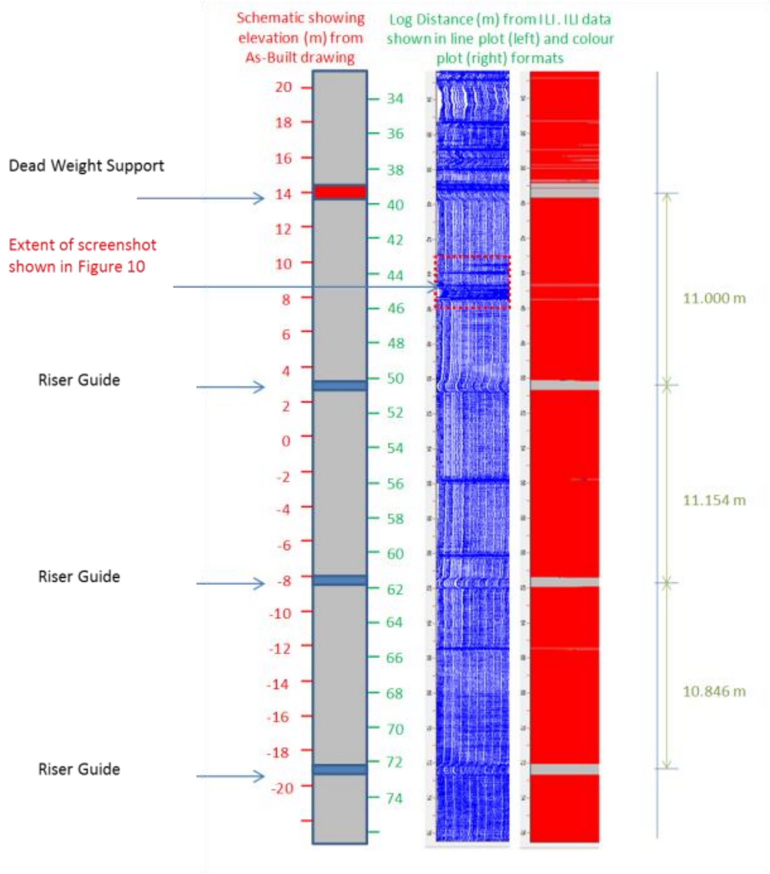

Figure 5: Correlation of ILI Data with As-Build Drawings

splash zone coating). A comparison of repeat ILI data in that area confirmed that the corrosion had grown since a previous (2008) MFL inspection.

There was uncertainty about whether the active corrosion identified by the ILI was the same corrosion that had been identified by the GVI and subsequently repaired. This led to further verification of the MFL signal data in an attempt to correlate this with the visual inspection findings. Using the dead weight support and riser guides which were visible in the MFL inspection data, the approximate elevation of the area could be estimated by cross-referencing with as-built drawings (Figure 5).

From this it was concluded that corrosion below the neoprene had been repaired if the neoprene coating interface was greater than 780 mm downstream of the closest girth weld. The position of the neoprene interface was re-evaluated to confirm that all external corrosion reported by the ILI in this area had been repaired.

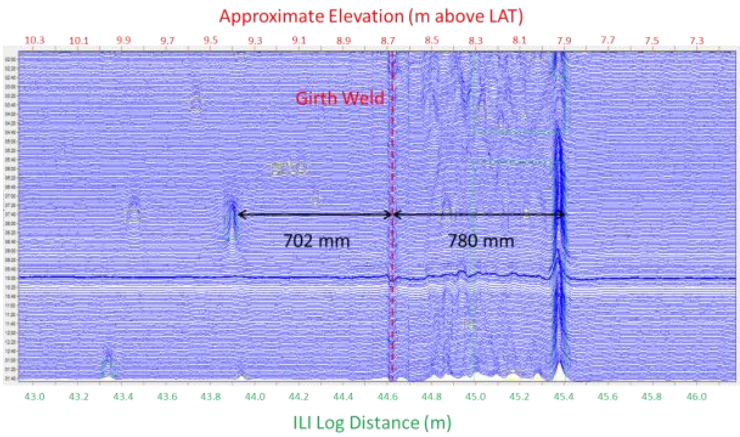

Figure 6: Locating External Corrosion on the Captain Oil Export Riser

Investigation of Pipeline Remaining Life and Appropriate Re-Inspection intervals

As the North Sea pipeline network ages, operators are increasingly having to demonstrate the continued fitness-for-purpose of their assets during remnant life / life extension studies. ILI is an effective method of quantifying the current condition of a pipeline but in order to determine its remaining life, an accurate estimation of corrosion growth rate is required. Many of CNSL's pipelines have now been inspected on multiple occasions and after each inspection, a detailed comparison of the repeat ILI data is performed in order to estimate the rate of corrosion growth between the inspections. This estimation is used to supplement the results of corrosion modelling and the information received from corrosion coupons and probes.

Comparison of ILI data can, however, only provide an indication of what rate the corrosion has been growing at, whereas the remaining life of the pipeline is determined by the future corrosion rate which is critically dependent on the effectiveness of the corrosion management strategy. It is therefore necessary to consider a range of corrosion rates which reflects the uncertainty in the corrosion growth rate predictions and the extent to which the corrosion can be controlled by mitigation. The accuracy of the corrosion rate predictions and the effectiveness of the applied mitigation are then monitored through repeat inspections.

This type of analysis can be used to quantify how effective mitigation (e.g. compliance with the corrosion inhibitor and maintenance pigging targets) can extend both the ILI interval and the safe working life of the pipeline. In this way, specific performance measures can be defined and any extension to the ILI interval be made dependent on successfully achieving those measures. Figure 7 shows an example of remnant life modelling and how to define the next re-inspection interval.

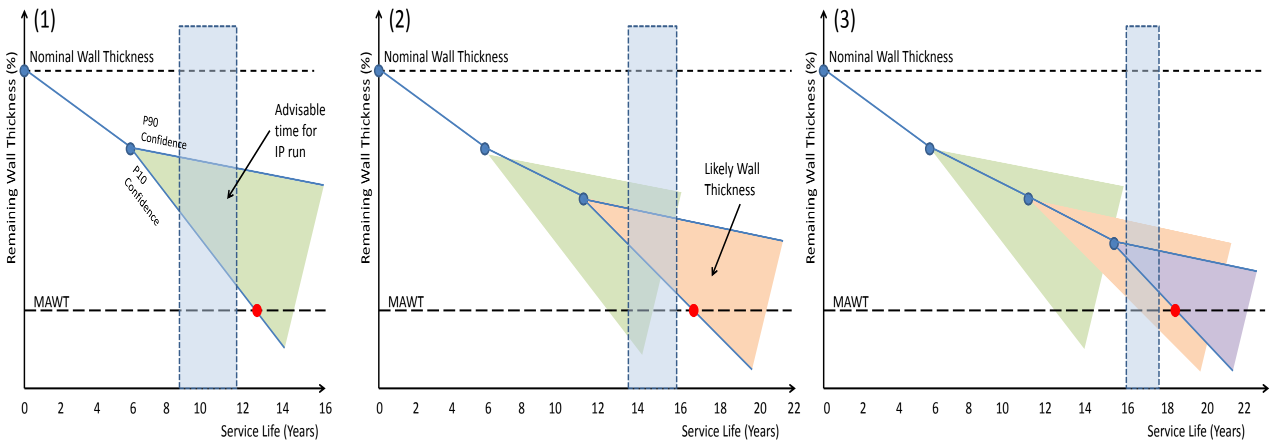

Figure 7: Use of Repeat In-Line Inspections to Investigate Suitable Inspection Intervals and Safe Remaining Pipeline Life

Summary

Extending the safe working life of a pipeline requires effective integrity management, in particular corrosion control. ILI provides a vital input to the overall integrity management of offshore pipelines by:

- Allowing the continued effectiveness of the corrosion mitigation measures to be monitored, and
- Confirming the current condition of the pipeline and supporting remnant life assessments.

The direct and indirect costs and operational impact of running inspections can be significant so it is important that the value of the inspection be maximised. This can be achieved through consideration of the following:

- Prior to the inspection, review the findings of a corrosion risk assessment to highlight the corrosion mechanisms that the pipeline is most susceptible to. Findings from previous in-line inspections of other pipelines that transport similar products and have similar operating conditions should also be considered.
- Ensure that the ILI technology selected is capable of accurately detecting and sizing the type of corrosion that is expected and that the internal pipeline conditions (e.g. cleanliness) are conducive to the technology being considered.
- The quality of the ILI data should be verified, either directly or indirectly, prior to using it within a post-ILI integrity assessment.
- If repeat ILI data is available, a detailed comparison should be conducted to determine the rate of corrosion growth between inspections. The accuracy of such comparisons will be dependent on the type(s) of ILI technology used and the method used to compare the data.