WHEN BOTH SHALL MEET: MANAGING INTEGRITY FOR H_2 AND CO_2 CONVERSION

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Abstract

The advancing global energy transition faces many challenges when it comes to ensuring a sustainable, reliable and affordable energy supply. An emphasis on decarbonizing the existing infrastructure will lead to greater penetration of greener fuels, such as hydrogen, ultimately produced from renewable energy. This paper will review the challenges associated with transporting these green fuels through pipelines, and outline an Integrity Framework approach as part of the decarbonization value chain.

Many operators are currently in the initial stages of investigating possibilities to build dedicated hydrogen pipelines or convert existing natural gas pipelines to hydrogen. With its innovative inspection technologies, supported by world class Integrity Engineering, ROSEN is well on its way supporting the industry with these challenges. This will be highlighted by a use case containing multiple ROSEN inspections performed in 100% hydrogen under operational conditions.

In parallel with the need for hydrogen pipelines, there is a re-emergence for the requirement to transport CO_2. This time, the requirement is related to (blue) hydrogen production as a clean energy source. The transportation of carbon dioxide (CO_2) within carbon steel pipelines for the purposes of carbon capture, usage and storage (CCUS) has been a topic of interest for a number of years, but it is fair to say that it has not taken off to the extent anticipated ten years ago. This paper reviews the re-emergence of the requirement for CO_2 transportation in carbon steel pipelines and looks at the related integrity challenges associated with CO_2 in a hydrogen production environment. We will identify threats related to downhole pipework for CO_2 storage, transportation of CO_2 and hydrogen as input for a holistic Integrity Framework.

Introduction

There is currently a strong push for global governments to tackle climate change and to drive the transition to a low-carbon economy. This is gaining focus with the upcoming COP26 Glasgow climate change summit and world governments have already started to react. Currently 14 countries (mainly European but also including Japan, South Korea, Canada and New Zealand) have legally binding net zero emissions targets, a further three are bringing forward legislation and 43 (including China and the US) have brought forward policy documents with targets. In almost all the rest of the world the concept of net zero is under discussion and targets are being debated[1]. If these targets are to be met an energy revolution is required, which will of necessity lead to the increased use of green fuels (such as hydrogen) and a significant increase in CCUS.

For both economic and practical reasons this energy revolution is likely to be driven within the existing energy sector. Existing infrastructure, and existing technologies, offer a real opportunity to decarbonize quickly, efficiently and economically. This has been recognized by, among others, the

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[1](https://eciu.net/netzerotracker, accessed 19/10/21

European Hydrogen Backbone which envisages a network of almost 40,000 km of hydrogen pipelines by 2040, of which 69% (c. 27,000 km) will be repurposed existing lines.

Figure 1 – Proposed European Hydrogen Backbone in 2040

At least in the short term, the majority of this hydrogen is likely to be manufactured by steam methane reforming (SMR) with the addition of some carbon capture, utilization and storage (CCUS).

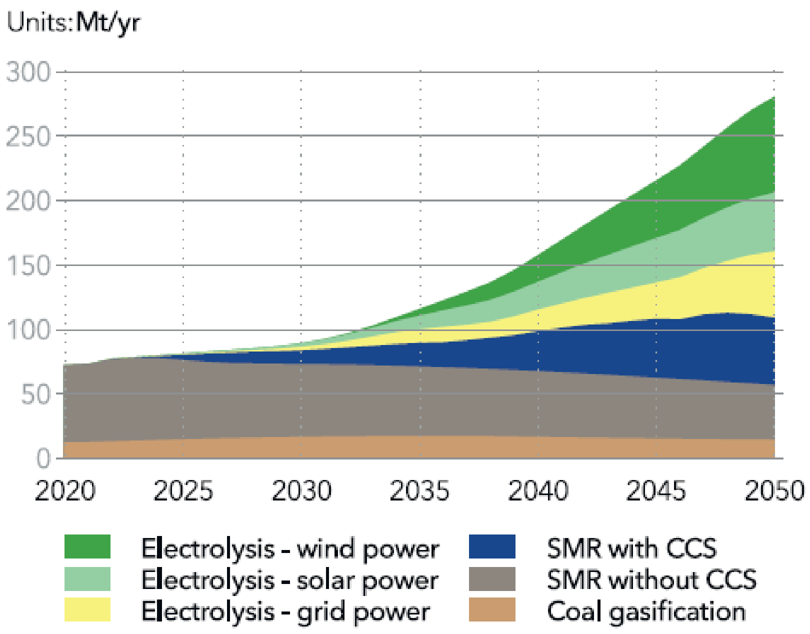

Figure 2 – World Hydrogen Production by Source

As with hydrogen transportation, for reasons of economics and practicality the majority of this CCUS is currently planned to use existing infrastructure (pipelines and underground or undersea storage in depleted hydrocarbon fields).

This emphasis on the re-use of existing infrastructure, while obviously attractive, places heavy demands on inspection and integrity engineering in order to ensure that assets are fit for a purpose for which they were not originally designed. This paper will give an overview of some of the challenges involved and explore potential inspection, engineering and pigging solutions.

Integrity Challenges and Gaps for H_2 and CO_2

The transportation of hydrogen and CO_2 by pipelines introduces key integrity challenges to be addressed for long-term safe operations. The key major points of interest are the same as any pipeline integrity management system:

- Pipeline condition – *What are the time-dependent threats? Which type of defects should I tackle? Where? How severe?*
- Integrity Remaining Life – *How safe is my pipeline operations? How long?*
- Consequences – *What are the consequences of loss of containment?*
- Management – *Can I safely manage pipeline operations?*

Nonetheless, there are key integrity management differences between the different modes of transportation. These differences derive from the specific physicochemical behavior of the fluid, and its interaction with the pipeline materials. For example, internal corrosion is generally not a concern for hydrogen service, while it is a key consideration for CO_2 (and hydrocarbon) infrastructures. On the other end of the spectrum, crack management is (broadly speaking) an even more critical topic [1] of focus for hydrogen pipelines than for other services.

These threats are best managed and understood in the context of an integrity framework, an example of the application of a hydrogen integrity framework is included in [1].

While CO_2 and hydrogen pipelines could be purpose-built [2][3][4] to address the range of applicable integrity concerns, it is very likely that a major proportion of the future transmission network will revolve around the integration of existing Natural Gas (NG) or other hydrocarbon infrastructures. Hydrogen and CO_2 pipeline design codes[2] tend to be more constraining or restrictive than that for hydrocarbons. For example, typical hydrogen standards will limit the use of steels up to API 5L X52 (L360) to tackle hydrogen embrittlement issues, while over 45%[3] of the European NG system is designed with higher steel grades (see Figure 3).

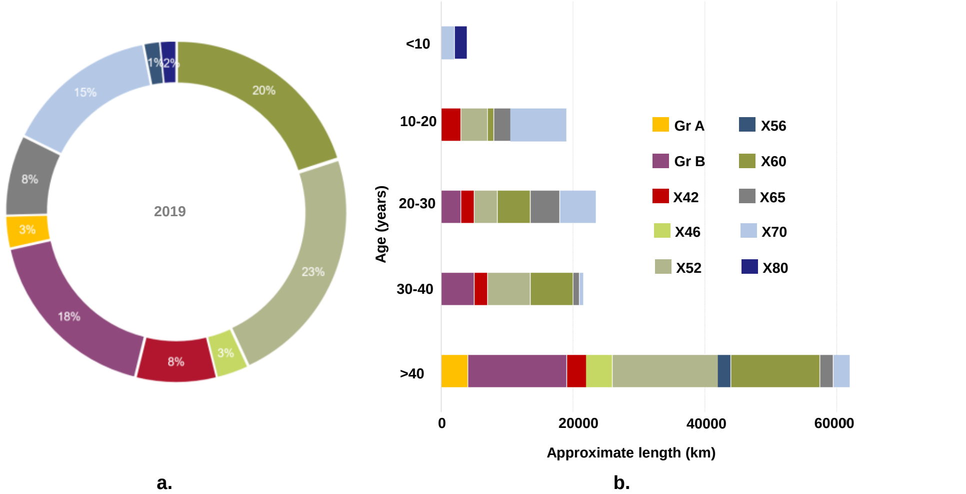

Figure 3 – Steel Grades[3] in NG Transmission Lines in Europe (a) 2019 Distribution; (b) Versus Age [1]

Similarly, the design of CO_2 pipelines entails minimum toughness requirements in order to withstand ductile fracture propagation in the case of loss of containment, particularly if the CO_2 is transported as a dense phase; otherwise crack arrestors should be considered. This implies pipeline duty holders have a clear understanding (i) that fractures will be ductile rather than brittle (Drop Weight Tear Test [DWTT]), (ii) of fracture toughnesses across pipeline lengths. There is unfortunately no mandatory requirement to DWTT test pipes supplied to base API 5L/ISO 3183 requirements or for routine fracture toughness testing in linepipe production. While the offshore sector might have the required data in more contemporary projects *("let's do every test we can think of on this very expensive project just in case the data might be useful")*, there is no guarantee the vintage lines will meet current industry criteria due to the evolvement of steelmaking and manufacturing practices.

It is therefore unreasonable to expect that pipelines designed specifically for hydrocarbon service can be directly converted to hydrogen or CO_2 service without due diligence. The following sections provide a high level summary of some key integrity challenges to consider for the repurpose of existing facilities to hydrogen [1][5][6] and CO_2 transportation [7][8][9] respectively.

Hydrogen Service

The fundamental feature, which drives much of the integrity concerns and challenges in gaseous hydrogen pipelines, is the absorption of atomic hydrogen within the steel microstructure. It is generally acknowledged that such interactions lead to a major degradation of steel ductility and fracture toughness, and to the development (initiation) or acceleration (crack growth) of certain time-dependent cracking mechanisms (e.g. fatigue, SCC), which are symptomatic of hydrogen

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[2] There are no recognized international standards dealing specifically with CO_2 pipelines, although DNV produced a recommended practice in 2010, which has been superseded by another DNVGL recommended practice in 2014.

[3] The grade only refers to the Specified Minimum Yield Strength (SMYS), the Actual Yield Strength (AYS) could be higher. It is common for material nominally supplied as X52 to have an actual strength, which would meet X60 or even X65 requirements. Thus the percentages of pipelines designed with grades above X52 can be actually much greater than 45%.

embrittlement. Nonetheless, the quantification of such influences remains uncertain, and there is a large scatter in the data [1][6].

A key reason for this is that the magnitude of interaction of hydrogen and steel is determined by the specific nature of the steel microstructures and chemistries [1][10][11], *not just* the grade. This important facet puts a *great emphasis* in the understanding of materials 'DNA' and on testing. These aspects are at the core of conversion and integrity management strategies. As discussed further elsewhere [1][6], crack detection technologies such as Electro-Magnetic Acoustic Transducer (EMAT) and materials properties in-line inspection (ILI) such as ROSEN's RoMat PGS and DMG services are likely to be integral to the inspection and conversion of hydrogen pipelines.

CO_2 Service

In many respects, the management of time-dependent threats in CO_2 pipelines is fundamentally an extension on the knowledge and the experience gained through the traditional oil and gas industry. The main key difference is that in "traditional" gas production CO_2 is mainly an unwanted by-product or impurity, while for CCUS CO_2 will be the primary fluid being transported, and hence will likely be at a higher partial pressure (which will broadly speaking mean a greater corrosion risk) and may have its own inherent impurities. Nonetheless, internal time-dependent threats will remain negligible as long as no free (separated) liquid water is present in the pipeline [7][8]. Note that this means that inspection of a CO_2 line with ultrasonic technologies, which generally rely on a water couple, can be challenging.

An effective mitigation of internal time-dependent threats is to keep the water content below saturation levels or its solubility limits in the CO_2 stream. However, this could be a first challenge by itself, and the complexity is largely associated with the source and the purity of the CO_2. If the CO_2 comes from natural sources, which is the case in most current transportation applications (e.g. in United States), the carbon dioxide is relatively pure and this implies that defining a water specification for such product is not too complex a problem. This is a benefit that may not be offered for CO_2 originating from process plants, in which case the nature and concentrations of impurities present need to be captured in the water solubility equation. In the specific case of the SMR process, concentrations of carbon monoxide (CO) and hydrogen sulphide (H_2S) should be considered; some references [12] suggest that for example H_2S could lower the solubility of water in CO_2. Fundamentally, for "blue" hydrogen it is likely that the stream composition (including water content) specification will be SMR system-specific.

Despite all the precautions taken at the process design stage to guarantee acceptable water contents in CO_2, upset conditions in the CO_2 dehydration process and water breakouts are still a possibility in complex pipeline systems, especially over decades of operating life. The resulting risk of internal time-degradation mechanisms such as CO_2/H_2S corrosion, sour cracking or SCC resulting from the $CO_2/CO/H_2O$ system from such excursions should not be excluded.

As discussed previously, a key point of focus for the conversion of hydrocarbon lines into CO_2 service is to address potential issues of ductile fracture propagations under loss of containment scenarios, particularly if the CO_2 is intended to be operated in the dense phase (likely to be required, or at least desired, for economic reasons). Certain industry approaches recommend a minimum average Charpy toughness of 250 J to manage this problem. However, there remains some debate whether such high-level values are required. Anyhow, and as pointed above, this implies the pipeline duty holder will have a reliable understanding of fracture toughness. Such information will not be widely available, and targeted sampling/testing could be required. If not practical, alternatives will be required, for example the installation of crack arrestors at strategic locations or the transport of CO_2 as a gaseous state.

If lines are to be converted to CO_2 it is therefore necessary to understand the materials, as well as the presence of time dependent threats such as metal loss corrosion or cracking, implying a role for such ILI technologies as ILI, EMAT and RoMat PGS.

Storage Challenges

One of the implications of the energy transition is the requirement for storage, which will inevitably involve the greater use of downhole pipework. This will hold true both with respect to hydrogen and salt cavern storage, and the injection of CO_2 as part of CCUS schemes. In contrast to hydrogen and CO_2 pipelines, the storage cavern itself poses relatively few challenges [13] from an integrity point of view; however, the situation is different for the associated (metallic) pipework. This pipework is subject to all the threats outlined above, any of which can result in leakage if not identified and mitigated against in time. Due to the nature of downhole pipework, this leaking product can travel long distances underground before eventually seeping to the surface meaning that the only immediate indication of a leak is a drop in pressure. This pressure drop may not be easily detectable, especially in the case of a gas such as hydrogen, leading to potentially serious safety implications. To take one extreme case, a former LPG storage well was re-opened for natural gas storage. During the re-opening of the well the casing was damaged. This created a leak that almost a decade later would form several brine and natural gas geysers, some of which ignited, causing the deaths of two people and a major inner-city fire. The necessity of inspecting this downhole pipework is therefore apparent, but there are also challenges.

Inspection Track Record

There are obvious challenges associated with the inspection of both hydrogen and CO_2 pipelines and storage, some of which have been outlined in previous PPSA webinars.[4] Despite these challenges, ROSEN have successfully inspected gaseous hydrogen and dense phase CO_2 pipelines and storage facilities in the past. Details of this track record are included below.

Case Study – Hydrogen Pipeline – 19 km long, 10" (254 mm) diameter [14]

This pipeline was originally installed in 1996 and set up for the transport of hydrogen. At the time, the only way to inspect hydrogen pipelines was by utilizing water as the propellant which was costly and time consuming. In 2015, the operator approached ROSEN for a method to safely inspect the line using a combination of geometry and magnetic flux leakage (MFL) technologies, and requested whether the inspection could be performed in hydrogen. Following a detailed study, it was concluded that this was possible and could be done safely. Initially the tool was set up in accordance with the European Union's ATEX directives, which included providing a flameproof enclosure for the components, having a pressurized enclosure for the electronics and utilizing intrinsic safety with voltage-restricted electrical circuits. The tool was also set up with non-standard cups (different hardness) to lower the risk of static electricity, resist decomposition and allow for proper resistance to uneven wear. The magnet circuits were also protected to avoid the possibility of hydrogen damaging the magnets themselves. Finally, the flow conditions were assessed. For a standard tool set-up a minimum pressure of 435 psi is typically requested, however this was not considered feasible for the hydrogen pipeline, instead a pressure of ~270 psi and a flow rate of 11 MMscfd was required. In order to reduce excessive velocity from pressure build-up in installations while still providing enough seal to propel the tool through the line, various bypass holes and notches were applied to the design (see Figure 4).

[4] https://ppsa-online.com/webinar-video, accessed 19/10/21

Figure 4 – ATEX Compliant MFL ILI Tool

Once these adjustments had been made to the tool, the line was initially inspected in January 2017. The resulting data showed 100% sensor coverage for both geometry and MFL, and magnetization levels, although some velocity spikes were noticed in installation areas the overall data quality was acceptable for evaluation. The tool was inspected after extraction and there was no evidence of any damage to tool or components, with the cups showing minimum wear (see

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Figure 5 – Tool on Arrival at Receiver

Following this success, the operator returned to ROSEN for re-inspection in 2019. This time, a pressure was 340 psi was able to be provided while maintaining the same flow rate. Due to the previous success the same tool configuration was used again, and once again the cups showed minimum wear and the tool was generally in good condition. This time round however, some damage was noted to the combination tool which was determined to be due to impact with the door of the receiver trap, primarily due to the higher than usual velocity of the pig. Due to this damage it was not possible to establish an electronic connection with the tool on-site; however, data was recovered without difficulty at ROSEN's workshop. During data review a few velocity spikes in installation areas were again noted. However, the increased pressure allowed for an overall reduced speed and a more stable inspection. Once again the data showed 100% sensor coverage for both MFL and geometry, and was acceptable for evaluation.

CO_2 Inspections

As noted previously, CO_2 could be a challenging and aggressive environment to the pipeline integrity, when operational upsets are considered in the asset life cycle. The ILI inspection of CO_2 pipelines is therefore important from an integrity management point of view. However, the deployment of ILIs in CO_2 pipelines also comes with its own operational challenges [15]; a sample of the key challenges is summarized in Table 1.

Table 1 – Key challenges for running ILIs in supercritical CO_2 lines

Challenge	Components affected	Reason	Management
Chemical degradation and explosive decompression	Non-metallic materials Multiple components within ILI tool e.g. cables, sensors, seals	Interaction with dense CO_2 Explosive decompression at end of ILI run	Control of decompression rate and material selection
High wear	Tool cups and discs	Dry environments	Material used can be adapted or different design solutions can be used, examples include the use of support wheels, wear reinforced cups and brushes.
Damage of electronic components	Tool electronic components	Build-up of an electrostatic charge on the tool due to the movement of the ILI tool cups along the pipe wall in dry environment This leads to high voltages being generated between the tool and the pipeline, which inevitably results in a discharge Depends on the position and intensity of this discharge	Development of conductive PU to prevent the build-up of extreme potential differences and the use of protective shielding for any particularly delicate electronic components

It is important to note some of these challenges are not unique to CO_2 pipelines and have been addressed for other applications e.g. inspection in dry gas environments (wear of cups and discs). Neither are they insurmountable. They require appropriate and thorough material selection and engineering design according to the pipeline specific design and operational conditions. Examples where ROSEN have conducted ILI in supercritical CO_2 pipelines are captured in Table 2.

Table 2 – Example of ILIs conducted in supercritical CO_2 lines

Diameter	Pipeline length	Pressure	Temperature	Tool deployed	Observations post-run
24” OD	116 km	131 bar	16 degC	Geometry (Electronic Geometry PIG: EGP)	Run successful; no damage was reported. Several hours later in the workshop, the plastic and rubber parts of the tool began to show signs of bubbling. The cups and discs were not severely affected, with no bubbles being identified while the buffer showed signs of swelling and bubbling. This was attributed to the different materials used, with the buffer being softer (65 Shore hardness) than the cups and discs (85 Shore hardness), see Figure 6.
				Magnetic Flux Leakage (MFL)	Run successful; tool showed no extreme wear on the cups and the disc. There was a visible difference in appearance of a high number of cables a short time after receiving, with excessive swelling being noted, see Figure 6.
24” OD	120 km	134 bar	-	Geometry (Electronic Geometry PIG: EGP)	Similar to above
				Magnetic Flux Leakage (MFL)	Similar to above

Figure 6 – Post-run Images of EGP tool (left) and MFL Tool (right)

Storage Inspection Challenges

The most obvious challenge [13] associated with the inspection of cavern pipework is that the pipes are vertical, there is therefore a great risk of the tool dropping into the opening at the top of the cavern, situated vertically. This is a danger as, even though tools are held by a tether, pulling it back into the pipe would almost certainly do significant damage to the sensors and mechanics of the tool. Additionally, if a liquid batch was required (e.g. for ultrasonic inspection in a dry gas atmosphere) this would be disrupted.

The propulsion of the inspection tool constitutes a second challenge. Since there is no medium available to push the tool forwards, gravity is the obvious alternative. Unfortunately, with high-friction technologies such as MFL, the force of the magnets might actually be too strong to be overcome by the tool's self-weight and prevent it from moving at all. Therefore, additional measures must be taken to ensure the tool travels through the pipe as planned.

Finally, the pipe's wall thickness is a factor that must be accounted for. Cavern casings and tubes generally consist of shorter pieces of pipe that are connected either by welds or by threaded couplings. Since these connections must withstand enormous tensile stress, they tend to be thicker than the surrounding pipe.

Cavern Storage Case Study 1

The operator had a concern for small corrosion spots on dry gas pipework. The traditional solution (a single rotating UT transducer with a spread beam) provided neither the accuracy nor the coverage required to detect the corrosion, in addition to requiring a liquid couple.

KTN, a ROSEN company, therefore tailored a bespoke solution to this challenge by equipping an inspection tool with special sealing discs at the front in order for it to carry a small water batch. Additional UT transducers were installed at the tool's end, which signaled when too much water had leaked through the sealing discs. If this happened, more water could be poured from the surface to increase the batch again. This configuration was tested at KTN's home base in Bergen, Norway, with a replicated riser tower before it was put into action at the operator's premises.

For the actual inspection run, the tool was gravity fed into the casing by its own weight combined with the weight of the water batch. The measurement was performed in the downwards direction. In addition to the UT wall-thickness measurement system, the tool was equipped with a camera. Therefore, a real-time video of the environment in front of the tool was visible for the team in the control unit, as well as the UT data for the geometry and wall thickness measurements. Two odometer wheels on the tool delivered highly accurate information both on the distance travelled by the tool and the lengths of the defects detected. Additionally, the travelling distance was compared to the length of the cable that went into the stuffing box mounted on the entrance flange. Finally, the UT data was compared with the operator's pipe/weld book since it showed all girth welds clearly. This allowed exact positioning of the defects in the casing.

Compared to the traditional tools used before, the KTN tool showed much improved measurement resolution. With 160 sensors for a 10" casing and parallel measurements with all sensors every 1.5 mm, the measurement grid was 5 mm by 1.5 mm. This resulted in nearly 107,000 focused scans per meter of pipe. With this configuration, KTN was able to detect pits from an internal diameter (ID) of 8 mm and general metal loss of only 0.4 mm depth, with a measuring tolerance of +/-0.4 mm. In addition, the internal geometry was mapped very accurately by using the standoff signal from the UT probes.

A first data analysis could already be done during the inspection run while the final report provided more detailed information on the casing's state of integrity; the inspection assured the operator that the pipe was in better condition than expected, and that it could be operated safely until the next scheduled inspection. The extreme measurement accuracy even allowed for shallow corrosion in the initial stages of formation to be identified. Thus, a precise calculation of the asset's remaining life time was possible.

Cavern Storage Case Study 2

Salt caverns are in many ways ideal for gas storage, being largely inert and protected from external threats. However, they do have some drawbacks, one of these is that even though salt is a solid, it behaves like an extremely viscous fluid in the long term, meaning it “flows.” Thus, cavities have a tendency to close if the caves are deep (at least 1,300 m) and the storage pressure is low. Therefore, a key concern for operators of salt storage caverns is the axial load compromising integrity of their pipe casings, specifically that of threaded couplings, which may open due to tensile stress. This issue has not yet been addressed properly with the traditional casing inspection solutions.

An operator believed that their cavern may have been closing, and was therefore concerned about the integrity of their cavern pipe. The specific request was initially to measure the opening width of its threaded couplings. Additionally, a defect indication from a caliper tool run at a later time raised further integrity concerns.

Threaded couplings are characterized by a high wall thickness. Since MFL is sensitive to wall thickness changes, this technology was selected for an inspection run. Pull-testing confirmed that MFL is indeed well-suited to accurately measure the opening width of threaded couplings.

After the measurement technology was proven, trials were performed to validate and optimize the inspection method. For the actual inspection, the MFL tool was connected to a wireline and a weight was added to ensure the tool moved down and overcome the MFL induced frictional forces. The magnetizer was set up bi-directionally and optimized so as to enable the tool’s smooth passage, even when passing welds and ID step changes. The wireline operation was performed with a technically advanced wireline truck that allowed for detailed monitoring during operations in order to identify possible obstacles and otherwise ensure the run went as planned.

Even during the inspection the benefit of MFL’s high-resolution corrosion measurement capabilities became evident: A fast track evaluation demonstrated that the defect previously detected by the caliper tool was not significant. Furthermore, the inspection indicated nothing of concern in regards to the condition of the threaded couplings. This led to the conclusion that the line was fit for purpose and avoided unnecessary additional downtime and cost.

Conclusions

The conversion of existing infrastructure to hydrogen or CO_2 service brings unique integrity management challenges. Ultimately, It is unreasonable to expect that facilities designed specifically for hydrocarbon service can be directly converted to hydrogen or CO_2 service without due diligences. Management strategies will revolve around understanding material “DNA” and testing, and the deployment of in-line inspections to address pipeline and pipework fitness-for-service.

For hydrogen lines some of the major time dependent integrity threats are associated with potential hydrogen embrittlement of the pipeline steel, and the consequent threat of cracking. ILI of hydrogen pipelines can also be challenging due to the different physical and flow characteristics of hydrogen compared to natural gas. Despite this, it can be done and ROSEN have a proven track record in successful inspection of hydrogen pipelines.

For CO_2 lines ILI is necessary to understand the materials and presence of any time dependent threats such as metal loss corrosion or cracking. ILI of dense phase CO_2 pipelines is challenging due to the nature of the fluid being transported, however again ROSEN have a proven track record in this field.

The energy transition will result in greater use of downhole pipework for hydrogen storage and CCUS purposes. This pipework can be subject to time dependent threats and therefore requires inspection, while also posing major challenges for conventional ILI. Bespoke tailored solutions are therefore required, KTN (a ROSEN company) specializes in these kind of challenging inspections and has a successful track record in downhole inspection.

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