Hydrogen Blended Pipelines: a Path to Integrity Readiness and the Role of ILI Inspection

Jeff Sutherland
Baker Hughes

Pipeline Pigging and Integrity Management Conference

February 12-16, 2024

Organized by
Clarion Technical Conferences

https://doi.org/10.52202/072781-0025

https://doi.org/10.52202/072781-0025

Abstract

This paper will discuss aspects of pipeline integrity, and a perspective of threats and the damage mechanisms of pipelines, namely the presence of defects and the susceptibility (threat) for such defects to initiate and occur, through their related mechanisms.

We start with the broad premise that damage mechanisms become accelerated with the presence of hydrogen in natural gas pipelines, while acknowledging that ongoing research is very active to refine and qualify specific parameters and situations.

Also, as a premise of treating this situation of a pipeline conversion as a change of service, with some common direct steps to establish a readiness for service. A key premise is the need to establish a baseline reference for defects and integrity and failure/leakage sources, including some conventional defects that may become more prominent for integrity concerns due to their potential nature to concentrate H2. (Historically, a significant change would be a liquid to gas operation or vice versa – or a notable change in product like sour gas versus conventional gas).

And fundamentally from a conventional integrity perspective, we will describe aspects of what is the same and what is different for integrity data coming from ILI tools and achieving a state of readiness. This includes a perspective of what readiness means for ILI tools, their operation in hydrogen blended pipelines, and expectations for data reporting.

Introduction

As the globe targets reductions in carbon emissions, the envisaged use of hydrogen as a primary energy medium for nations is underway. Like other energy sources, hydrogen will need to be generated, stored, transported, and finally consumed. Pipelines are a highly cost-effective method of transportation, and existing pipeline infrastructures are being assessed for their suitability to transport hydrogen around the globe, as blended within natural gas transport or ultimately as pure hydrogen.

The nature of natural hydrogen itself as an energy medium brings new considerations in its handling throughout its lifecycle. The use of pipelines as a means of primary H2 transportation directly infers alternative and additional requirements for public safety and pipeline integrity beyond the natural gas hydrocarbon infrastructures of the last 80 years. There is anticipation within governmental and industry groups to convert and utilize large portions of the existing hydrocarbon infrastructure for hydrogen.

Pipeline integrity principles and knowledge in both conversion of service as well as ongoing maintenance may be directly applied in many cases, while others may be adopted with some specific validation. For purposes here, these principles include threat management practices and known techniques for detection, mitigation, prioritization leading to mitigation (or removal) of a threat.

https://doi.org/10.52202/072781-0025

Such practices also include forecasting of pipeline integrity at future points in time, namely through methods for time-dependent flaw growth and remaining life predictions. A primary method in quantitatively assessing both current and forecasting future pipeline integrity states, is Inline inspection (ILI).

We outline this paper in terms of pipeline integrity, threat management practices and the use of ILI within some stated presumptions for the cases of mass-transport of hydrogen in pipelines.

Hydrogen Lifecycle in Energy Infrastructures

The production of Hydrogen to date has been for industrial purposes and consumption, including fundamental production of modern chemicals and metals as widely used by society.

For a Hydrogen based infrastructure for energy, it presumes to displace hydrocarbon fuels as a primary distributed source such as in Figure 1.

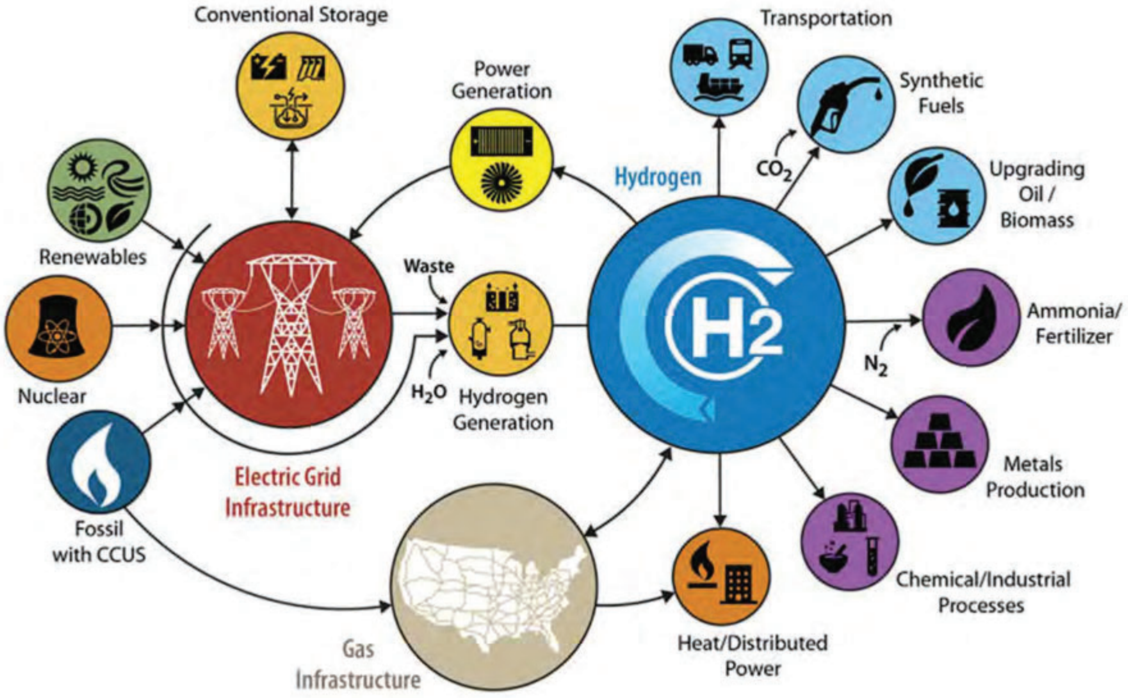

Figure 1. Overview of hydrogen in energy and industry

Hydrogen does not occur naturally in abundance and would be intended to be generated through electrolysis, or potentially through chemical processes such as methane reforming.

Globally, each nation and region have generated strategies for clean energy and the role of Hydrogen similarly. Each broadly considers generation capacity, role in distribution and usage of Hydrogen in the context of current energy sources and availability. Each strategy also highlights needs for significant investments for the transition.

For the United States, the Department of Energy (DOE) has created a strategic program and roadmap for the generation, distribution, and use of Hydrogen as a primary energy source.
[Ref 35,36]. It presumes growth of hydrogen production through assumed future capacities of hydrogen generation through "green" renewables, "blue" reforming and other phased means. It is also addressing and presuming a role for Carbon Capture, which presumes to require its own pipeline network for CO2 capture and sequestration. Most prominently it highlights the need for both social acceptance and for broad infrastructure investments.

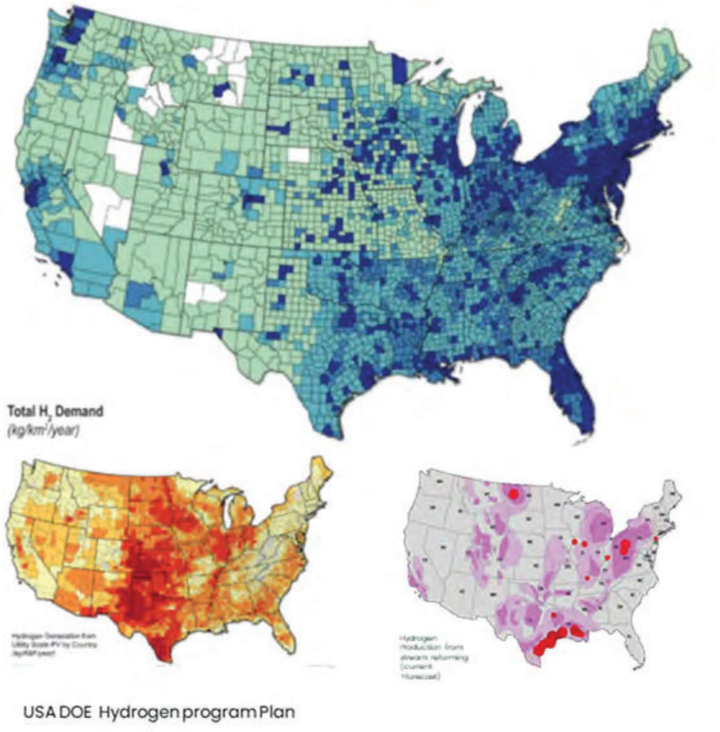

Figure 2. USA DOE hydrogen program

Australia released its Hydrogen strategy in 2019 which looks at both national energy interests and options of energy infrastructure. [Ref 37]. Australia's strategy and plan also highlights the possibility of net Hydrogen export for international energy markets.

Canada's Hydrogen strategy was published in Dec 2020. [Ref 38] from their Department of Natural Resources. While it addresses similar optics of national energy interests and requirements, it highly focuses on transition opportunities based in existing production industries and energy sectors.

https://doi.org/10.52202/072781-0025

Europe has outlined goals for energy transition, summarized as the EU Hydrogen Backbone [Ref 1]. The infrastructure of this backbone presumes reuse and conversion of its widespread current natural gas infrastructure of transportation pipelines and distribution networks. It also envisages means for Hydrogen storage including repurposing of existing natural salt caverns as used for hydrocarbons, as well as reinjection of carbon by-products back into depleted hydrocarbon fields (such as under the North Sea).

Depending on the approach and scale to be adopted in generation and usage, a new parallel role has also emerged for Carbon Capture, where carbon emissions by-products (CO, CO2) are to be captured at points of emissions vs being released. Captured by-products will also need their own infrastructure of transport and sequestration, of which pipelines are expected to play a role. [Ref 2,3,4,5].

Such use of Carbon Capture is expected in the definition of blue hydrogen production scenarios where H2 generation as from methane reforming produces carbon by-products to be captured. It also is expected for any scenarios where emissions from current electrical power generation have carbon by-products (so to include CO2 transport from combustion to final sequestration).

Descriptors for sources of hydrogen generation have adopted a colour spectrum terminology such as in Figure 3.

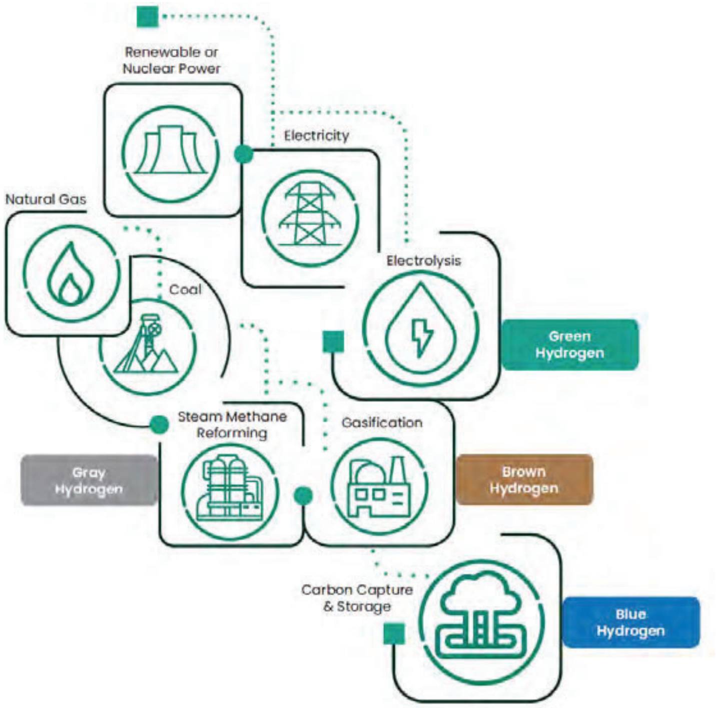

Figure 3. Hydrogen generation methods with adopted “colors”

The role of transmission pipelines will continue to evolve, including as a means of interim storage as pipeline networks are redirected according to new generation sources, consumption needs and roles in carbon capture (current hydrocarbon reservoir locations are not presumed to be the same as future hydrogen generation locations) [Ref 6].

As the generation of hydrogen scales up, initial methods considered include blending of hydrogen gas with natural gas which includes during transport within pipelines [Ref 1,5]. Reported experiences and practices today recommend treating situation of hydrogen blends as a conversion of service of a pipeline [Ref 6,7,8,9], including with an assessment of threats that the presence of hydrogen brings.

Fundamental considerations in a Conversion of Service are:

- Line pipe materials and assessment for compatibility
- Weld materials and assessment for compatibility
- Compressor stations and components
- Valves and components
- Gaskets (such as at flanges or other joining points)
- Potential threat populations as from prior history and integrity programs
- Pipe routing (reclassification of class location due to population and surroundings of pipeline)
- Preparation, testing, drying to ensure removal of water content with H2 (or C02) present.

In lower H2 gas concentrations within a primarily natural gas fluid, studies have highlighted minor operational differences. In high concentrations, including the 100% Hydrogen case, the thermal content of hydrogen gas as well as compressibility has inferred higher pressures and higher flow speeds will be required to meet the same energy flow of current natural gas pipeline delivery [Ref 12].

Presumed new pressure levels and operational practices will evolve but also in accordance with safety considerations. Evolving standards like ASME recommend assuming higher class locations for hydrogen pipelines as well as specific integrity management processes to consider and factor embrittlement effects on materials (in both line pipe, welds and other components) [Ref 7].

For completeness, some initiatives have started to investigate hydrogen transport and storage in an alternative form as ammonia. Ammonia pipelines exist in limited forms today but may be considered as their own type of hazardous material transport pipeline (high corrosivity, toxicity) and are not considered here.

Pipeline Integrity

To start with an initial and somewhat alternative premise for the context of threats for blended hydrogen pipelines, an assumption can be made for threats being any forms of stress concentrators. This premise would include stress concentrators as classical physical flaws but also may be generalized to any localized region where a change in its mechanical or metallurgical properties has occurred.

https://doi.org/10.52202/072781-0025

With hydrogen transportation the inclusion as threats of areas with atypical compositional or metallurgical properties may need to be considered while they are not considered active threats with current hydrocarbon pipeline integrity practices. Examples include features such as an arc burn produced by accidental contact with a welding electrode or a grinding burn produced by excessive force on a grinding wheel during maintenance. They may also include more distinctive conditions identified such as manufacturing impurities (inclusions, laminations) in line pipe as sites for hydrogen permeation and concentration.

The integrity discussion below presumes that there are existing populations of all threats in some form in the pipeline that are unknown until quantified and calibrated through various means (typically from ILI, but also pressure testing and/or direct assessment/examination modelling).

With geometric time dependent flaws, conventional integrity practices would confer a "critical flaw" size that is deemed potentially injurious in near to medium term [Ref 9,10,11]. This approach is applicable for time dependent threats, but cracking will take the focus here. Critical flaw sizes may be determined for given line pipe by establishing a safe pressure target, setting properties assumptions of the strength of materials, and using expected operating conditions. With these criteria, and working through the relevant failure assessment methodology, it can be calculated into an equivalent flaw size as "critical". Hence, it is presumed that definitions and conditions for tolerable flaw criteria will also achieve consensus amongst stakeholders while likely being more stringent than today.

With the presumption of additional conservatism over equivalent hydrocarbon pipelines as for crack and time dependent features in the near term due to hydrogen embrittlement of the materials, it would lead to smaller critical flaw sizes and related acceptability levels (if any) of remaining flaws. If also combined with the potential accelerated growth rates of time-dependent flaws, such exercises then deduce a need for earliest possible detection and preferably for smallest possible features through regular monitoring activities.

Growth modelling of a flaw itself with an assumption of simultaneous crack initiation and growth in parallel with the flaw becomes a tangible scenario. This would include corrosion, cracking, deformation and combinations, but also external forces (changing over time) coincident with conventional time dependent flaws and for regions of alternate material properties.

Susceptibility and Confirmation of Presence

The impact of introducing hydrogen into carbon steel pipelines is currently under significant investigation to establish practical and effective operational conditions and criteria. Understanding the susceptibility of a pipeline to hydrogen induced effects logically are recommended to come from conversion-of- service activities, or within fundamental design activities, where a threat/risk model for a given pipeline would be established [Ref 6].

The conditions for susceptibility will have its basis from threats addressed in natural gas pipeline practices and experiences. This includes known damage mechanisms such as cracking, corrosion, mechanical damage, deformation, and external forces.

If susceptibility for hydrogen embrittlement is treated simply as “Yes” or “No” for a given location, then:

- If No – then may presume no immediate concern, but engage for longer term monitoring activities to ensure some level of detection of an initiation at a future time. Scope and threat conditions may be expanded.
- If Yes – then may presume given a baseline of pipeline state and an assumed accelerated pace of deterioration of damage mechanisms, then integrity planning would factor immediate response and mitigation with lower acceptability thresholds.

Susceptibility considerations must include monitoring for the presence of water (aqueous Hydrogen) as it would be considered a primary factor in steel permeation and embrittlement [Ref 7,11].

An assumption is that the presence of any stress concentrator areas will be immediately addressed, given presumed higher safety protocols and a lower acceptable tolerance for any potential injurious anomalies. In context, such practices and tolerability have similarities in integrity management of sour service and specialty service pipelines.

For “low” count populations of potential flaws, immediate remediation programs to address all reported threats is practical and cost-effective for risk mitigation. For “high” count populations of potential flaws, additional means of assessments and validation are required to establish criticality and injuriousness within a risk mitigation prioritization framework, which may still involve remediation of all reported threats [Ref 13].

Quantification and Location of Damage Mechanisms and Threats

Monitoring activities are presumed to include practices as from current natural gas practices and procedures. But distinctly use of ILI as a foundational and quantitative dataset across threat types [Ref 6,7]. In previous work [Ref 14], guidance was provided as recommended elements for a reliable assessment based in ILI inspection including for future forecasting and remaining life prediction. With some adaptation to terminologies used here, these were:

1. A reliable measurement performance for detecting, discriminating, and sizing flaws and potential stress concentrators.
2. An excavation program with accurate field and laboratory direct observation to evaluate threat types, calibrate risk/susceptibility models, catalog characterization of flaws in the pipeline and determine ILI tool predictive performance. This process includes updates to

https://doi.org/10.52202/072781-0025

operator practices and threat modelling as well as providing reliable data feedback to the ILI vendor for improvements particularly for non-conventional flaws and conditions.

Comprehensive flaw assessment methodologies, particularly fracture mechanics-based methods with representative material properties data as to be used for prioritizing excavations and future life cycle/re-inspection intervals prediction.

Damage Mechanisms

Cracking

Practices for crack management threats were initiated for liquid lines, where pressure cycling and material fatigue are prominent. It quickly evolved to gas pipelines as well with external cracking mechanisms being formally classified (SCC – Stress Corrosion Cracking) and being independent of internal pipeline product. CEPA [Ref 15] and API 1176 [Ref 11] address multiple forms of cracking that has factored hydrogen within different cracking formation mechanisms. It is presumed that there is a presence of flexure stress (fatigue) in the presence of initiators or impurities in the line pipe material (or weld) as a concentrator site for hydrogen, which leads to cracking.

A very fundamental point is the notion of the crack feature as a material "discontinuity" and especially with a population of those features present in the pipeline as "growing discontinuities". With this point in mind, a crack growth lifecycle is shown in Figure 4. Modelling of cracking growth presumes a multi-stage "bathtub" behaviour as originally stated by Perkins and adopted by CEPA and API [Ref. 15, 11].

For external cracking, initiation, current cracking (SCC) stage timing is as is for current hydrocarbon pipelines. For hydrogen influences as internal source, it is (conservatively) assumed that an acceleration through the stages compared to hydrocarbon, as hydrogen may permeate within the material (as line pipe or weld) from the inside to the outside.

In comparison, SCC (external) conditions for Stage 1, typically are mediated through corrosion control practices. However crack initiation may still occur.

Of note is Stage 2 where crack growth is "mechanically driven" and assumed in the presence of hydrogen embrittlement. Key conditions include stress-dependent loading interactions and frequency where the crack is growing at its fastest rate. Growth mechanism modelling may factor the localized stress state at a crack tip.

By Stage 3 rapid crack growth of sizable cracks occurs and failure is imminent. Remediation and integrity management measures are expected to be taken prior to reaching this stage.

https://doi.org/10.52202/072781-0025

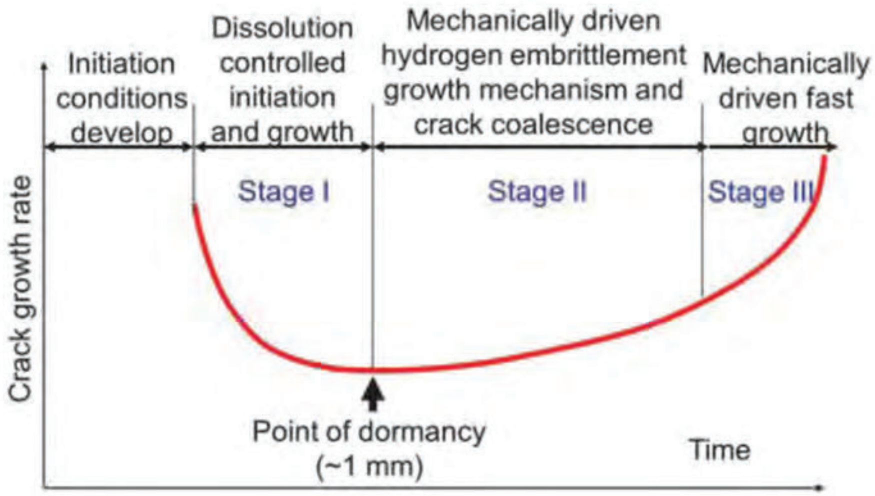

Figure 4. API 1176 [Ref 11] – modified crack lifecycle for nnPH

In context - H2 has always been a factor in SCC susceptibility, particularly for aqueous hydrogen but with SCC, it presumes the direct external surface of the pipe with the presence of water. Crack threats are categorized broadly within environmental cracking (including Hydrogen induced cracking), fatigue cracking and SCC. API outlines an inclusive list of conditions (all must be present) for H2 effects to be applicable. These are: poor coating state, water presence (internal or external), high CP potentials, known high hardness material values, higher observed crack growth [Ref 11].

Cracking definitions have typically been defined around the formation mechanism of the cracking as it evolved out of susceptibility model for conditions to be monitored. However, the physical embodiment of the crack itself is what factors into the (fracture mechanics) assessment for integrity [Ref 18].

Recent efforts in the transition to hydrogen pipelines has focused on the threat of cracking as due to potential embrittlement of the material due to the presence of hydrogen itself. Comprehensive fracture mechanics methods consider pipeline material properties, with material toughness being a primary factor and influence in the sensitivity of results and to the determination of severity and risk.

One study looking specifically at the EU gas transmission network concluded that around 70% of European pipelines are API 5L Gr. B, X46 or X52; steel grades that are expected to show good compatibility with hydrogen transport without modification [Ref 16].

However, findings by Sandia National Laboratories on behalf of the US Department of Energy, reported that the deterioration of fracture resistance in pipeline steel is somewhat unrelated to the concentration of the hydrogen blend in the pipeline. At a given pressure, the proportion of fracture resistance lost at 1% H2 blend was similar to that for 100% H2 [Ref 17].

https://doi.org/10.52202/072781-0025

At any time through the pipeline operating life, there is the potential for conditions to initiate for cracking, hence susceptibility assessment and active monitoring have been recommended practices.

Historic Context of Pipeline Crack Management and the Role of ILI

As cracking threats gained prominence in integrity planning, ILI and assessment methods were initiated and evolved. Attempts to apply non-destructive techniques started in the 1970s, with commercial systems pioneered and introduced by Baker Hughes for USCD (Ultrasonic Crack detection) for liquid pipelines in the 1990s and EMAT (Electromagnetic Acoustic Transduction) for gas pipelines in the 2000s. Integrity programs since then have evolved to reliably utilize high performance crack ILI systems [Ref. 14,18,19,20].

Reported features from ILI related to cracking include “crack-like”, “crack field” and “weld anomalies” as the primary feature types of interest as axially oriented features (where a rupture threat from hoop stress is the expected failure mode). EMAT may also include indicators of localized coating damage.

EMAT ILI systems for crack detection and characterization are available today across most diameters of long distance pipelines (8-42”) as shown in Figure 5.

(a) (b)

Figure 5. EMAT ILI systems for (a) Large diameter (24-42”) and (b) small-mid diameter (8-20”)

An ironic factor of early EMAT systems was the inability to discriminate material flaws and discontinuities from cracking [Ref 20,21]. EMAT systems today address, and report discriminated features distinctly. And for purposes of early detection of stress concentrators as preferred in the blended hydrogen scenario, the identification of inclusions, laminations and manufacturing flaws becomes preferential in collected data. This ability is an example of potential evolution of capabilities.

It is envisaged that crack ILI will continue to evolve with Hydrogen pipelines as well as form part of a robust integrity management program.

A core principle of Engineering Critical Assessment (ECA) of cracks (including SCC, seam weld cracks, girth weld cracking, laminations, and weld anomalies) is based in fracture mechanics and fatigue crack growth methodologies [Ref 10] as well as an understanding of reported ILI features and interpretations such as crack profiling and crack field statistics. [Ref 14]. Updates to ILI crack profiling was recently evaluated and validated [Ref 18] for achieving reduced conservatism in fitness-for-service assessments as summarized in Figure 6. Such approaches would apply to validation of cracking assessment in hydrogen pipelines.

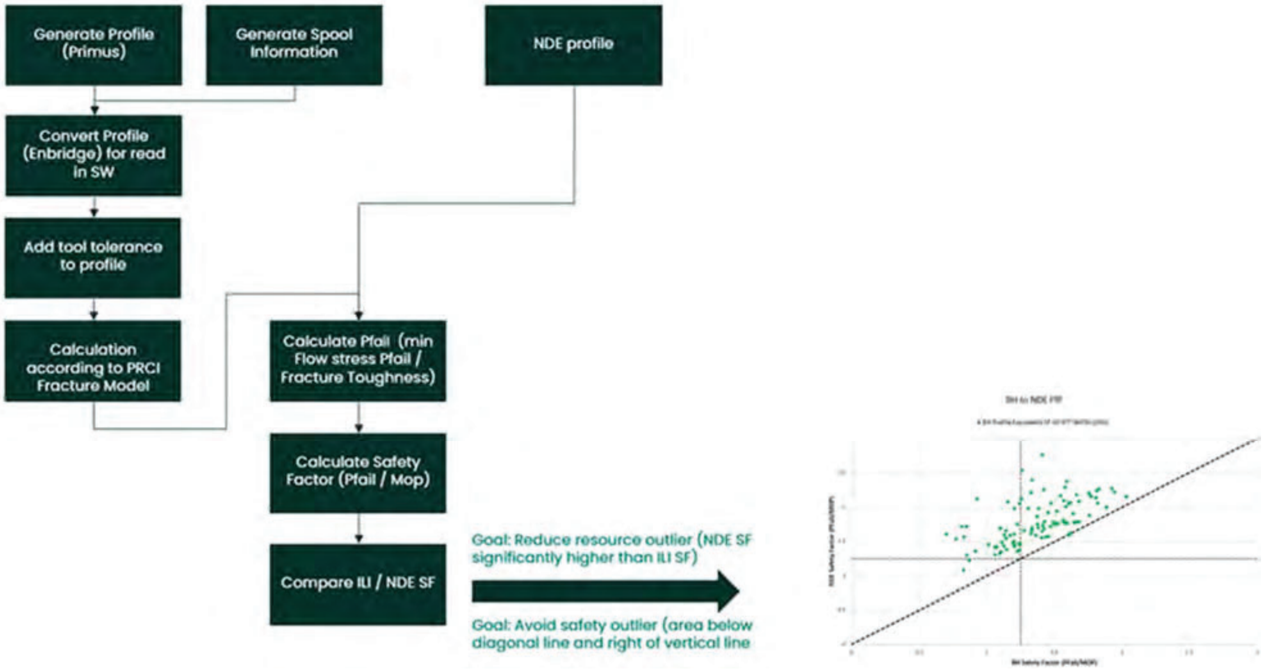

Figure 6. Overview of approach in validation of ILI crack profiles for fitness for service with less conservatism

Hard Spots

Hard spots are distinguished as localized areas of material in pipe that is typically of higher "hardness" than the line pipe specification. As material hardness is identified as a potential threat susceptibility condition for blended H2 operations, the identification of hard spot areas becomes a factor to address higher risks of failure from defects due to a localized reduction in material fracture toughness.

ILI technologies specifically for localized material difference detection have existed since the1990s, with even early ILI technologies being sensitive to localized material differences since the 1970s. The most common measurement approach is from remnant magnetic field detection and interpretation.

https://doi.org/10.52202/072781-0025

An example of an ILI signal response for a confirmed hard spot area is shown in Figure 7. Note that signals are distinctive and repeatable. In some cases, other material impurities may also be detectable.

Detected and reported areas of interest may also then be aligned with ILI crack, corrosion, deformation and strain data for a more comprehensive evaluation and assessment.

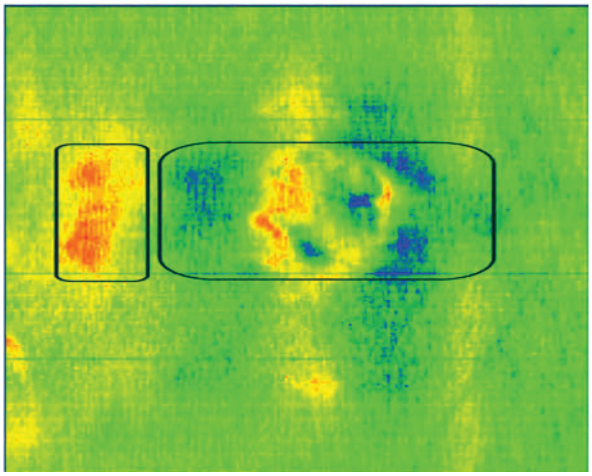

Figure 7. Example of ILI signal response for a hard spot in line pipe

Corrosion, Gouging/Damage and the Rise of Combination ILI Systems

Monitoring for corrosion and external damage (mechanical damage) remains a prominent activity for pipeline integrity as it predicates early detection of conditions, primarily as corrosion and volumetric wall anomaly characterization but also for external cracking (SCC) susceptibility.

As with cracking threats, the threat of corrosion or gouging may be presumed to be an indicator to cracking initiation and accelerated embrittlement crack failure, even from internally permeated hydrogen. For gas pipelines, high performance MFL (Magnetic Flux Leakage) as shown in Figure 8, is recognized as the most reliable means of ILI inspection for corrosion and gouging/damage threats.

With presumed more conservative acceptability criteria for the case of flaws in hydrogen pipelines, the presence of any such flaws through detection by ILI, is presumed to trigger response and remediation activities. Defect specific sizing tolerances per reported defect has been recently introduced. As a per-defect tolerance, it provides less conservatism and enables a better understanding of risk and prioritization of severity. Such methods will also certainly likely be advantageous to the critical assessment of metal loss features in the presence of Hydrogen.

Advanced MFL systems have the capability for Girth Weld Anomaly assessment, where circumferential crack-like features may be detected and reported.

https://doi.org/10.52202/072781-0025

Figure 8. MFL Tool with Caliper, IMU and Longitudinal Strain measurement systems

Pipeline Strain from External Forces and ILI

There is a premise and assumption that pipeline force cycling may not solely be from pressure but potentially in conjunction with external forces/geotechnical forces that may also cause pipeline damage, even with low cycling frequencies.

In today's MFL ILI platforms, they are typically run with associated high-performance "IMUs" (Inertial Measurement Units) to collect motion measurements of the tool in the pipeline which was pioneered by Baker Hughes in the late 1980s [Ref 22]. This inertial measurement data can be processed to provide continuous GPS location data of the centerline of the pipeline, provide independent insight for characterization of dents and other deformation features that may be present, and be interpreted for representative bending strain (curvature) of the pipeline at all points.

Abnormal or unexpected levels of bending strain are indicators of external force/geotechnical forces on the pipeline which may pose an imminent threat. A primary use for this method includes geotechnically active areas (prone to landslides), areas near active geological faults or areas prone to large pipeline movements due to seasonal changes such as muskeg/swamp conditions, offshore oceanic forces, or ground frost-heave (such as in northern Canada and Alaska) [Ref 24].

And when such strain events are coincident with time dependent flaws (like cracking and/or corrosion) such as reported by MFL or EMAT systems, a more detailed engineering assessment is to be considered, as assessments of time-dependent flaws in isolation are not applicable [Ref 25].

ILI Reporting of Longitudinal Strain

New ILI technology has been introduced that provides independent reporting of longitudinal strain distinctly from conventional ILI IMU methods [Ref 26]. It was initially motivated from a need to monitor for geohazard conditions beyond bending strain itself, such as for potential initiation of buckling and wrinkling due to compressive forces.

After H2 introduction, the strain capacity of both base material and girth welds may be affected by H2 embrittlement, further increasing the risk of failure.

https://doi.org/10.52202/072781-0025

ILI Applications for Weld Susceptible Cracking – Girth Weld Assessment

Girth weld anomaly analysis involves MFL, IMU and strain measurement data to provide prioritized assessment for potential girth weld cracking. Abilities for the identification of girth weld and spiral weld cracking based on advanced MFL ILI technologies was previously presented [Ref 27].

The adoption of these methods has grown from recent history in North America due to concerns of weld undermatching where a high rate of girth weld failures since 2019 has occurred in USA both in active pipelines and in newly constructed pipelines. Causes are due to use of higher strength pipe than stated SMYS, and inconsistent infield welding procedures leading to HIC and HAZ softening, which significantly lowered the strain capacity for external forces and pipeline movement [Ref 28]. As a hydrogen enabled issue, this should be presumed to be more prominent and distinctive for hydrogen blended pipelines' integrity.

Predictive Methods for Remaining Life / Future Integrity State

All ILI data-based integrity assessment methods will have practices for monitoring, growth prediction and remaining life estimation. Criteria for feature response and action to identified change (growth) are then according to operator and industry practices. Such methods are envisaged to be adoptable, and necessary, for blended hydrogen pipeline scenarios. Fundamentally for ILI based integrity programs, change detection is the basis for growth rate estimation.

Within the evolution of pipeline integrity practices, flaw growth methodologies started with corrosion. Baker Hughes were principal authors in the generation of the primary industry guidelines for corrosion growth including for deterministic and probabilistic treatments [Ref 29].

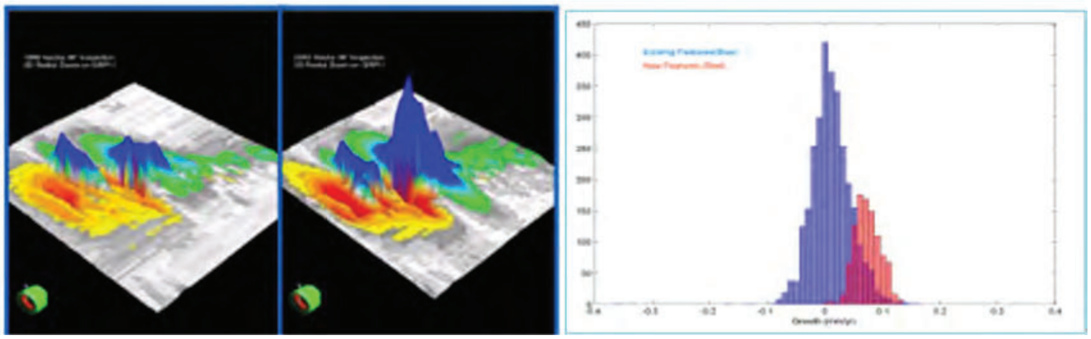

Figure 9. Example of flaw growth rate estimation from ILI signals

The key aspects of this method were to provide practical, consistent, and systematic means to establish rates of growth. It also identified the opportunities for managing localized and varied growth rates within a defect population, the direct use of ILI based signal change detection for more accurate growth rate estimation over ILI reported box methods, and guidance to address and validate "very high" or "improbable" rates of predicted growth in practical terms [Ref 30]. The concepts and methods from corrosion are shown in Figure 9 and have since been adapted and applied for other threat types.

An increasing direction of interest takes the form of more holistic assessment, where coincident features and conditions to overall threats take form in integrity programs, which address a high volume and variety of scenarios for potential loss of containment through any means as expressed in Figure 10 [Ref 25, 30]. For hydrogen pipeline integrity, such an approach may be necessary over conventional natural gas methods, as the sensitivities of threats and their combinations have a different interaction and set of outcomes over hydrocarbon scenarios.

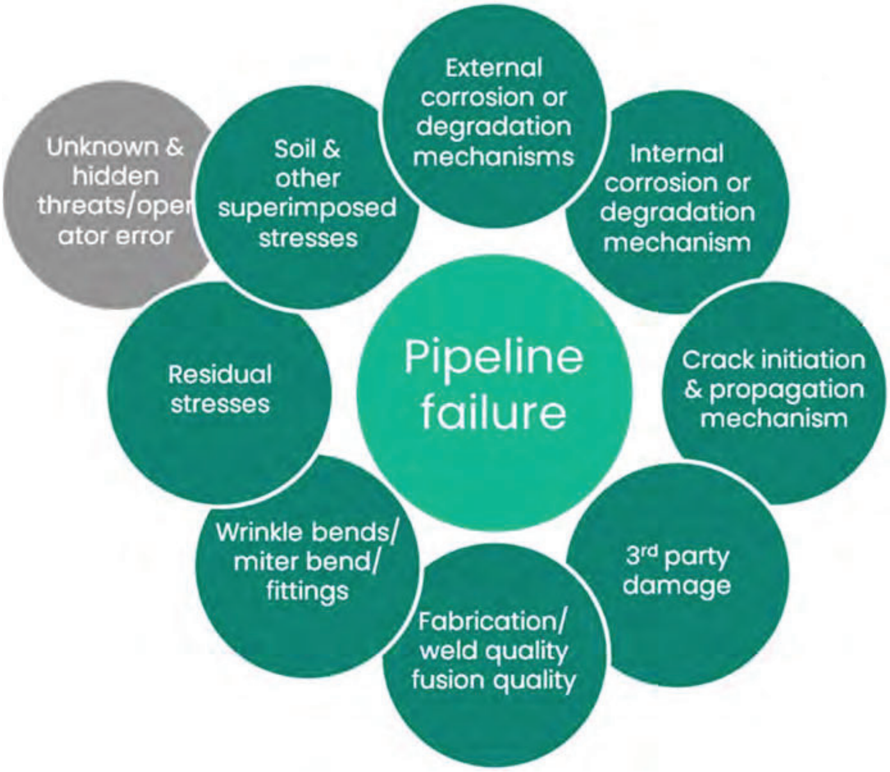

Figure 10. Overview of aspects of interacting threats

Most significantly is the use and application of Machine Learning both to ILI signal interpretation but also to predictive analytics for significance of reported features and remaining defect populations. The availability of high count and variety of field validated samples lead to the opportunity for "Big Data" machine learning approaches [Ref 32,33].

Such techniques and methods are naturally structured to manage large volumes of disparate data. They may also involve engineering calculations, practices, and techniques as guiding principles as well as independent explicit checks as boundary conditions of predicted results and historic results.

https://doi.org/10.52202/072781-0025

ILI Tool Readiness for Operation in Hydrogen Blended Lines

In the context of ILI systems history, the readiness of ILI for blended or pure Hydrogen pipelines comes with the experience and perspective of readiness for other pipeline products. Over time this has come to include: methane gases including H2S, refined liquid products, CO2 & non hydrocarbon gases, aromatics (ethylenes), ammonia, etc. [Ref 34].

For the blended hydrogen case, the first consideration is safety. As with hydrocarbon pipelines, areas of highest risk are typically the ILI/pigging launch and receive systems of pipelines, where conditions of explosive gas, air and fuel are present. The application of ATEX practices for pipeline ILI/pigging activities has been used for several decades, where typically risk of a potential explosive environment is mitigated (removed) by purging of the facilities and access points, of the explosive gas by a non-flammable gas. Of note is decompression behaviours of hydrogen depending on pressure and state as would be found in ILI/pigging receiving traps.

In more extreme cases by analogy, there are similar and parallel procedures for ILI/pigging in sour-service (H2S) and hazardous product lines that have also been used for several decades.

For ILI tool system compatibility and run endurance within a blended Hydrogen environment, the assessment is like that for elements of the pipeline itself with initial assessments dating back to the EU NaturalHy project of 2006-2009 [Ref 3,34]. A compatibility assessment includes the expected forms of Hydrogen as gaseous, aqueous/ionic, and scenarios of the presence of water, etc. It reviews effects on materials as the metallics, elastomers (seals), as notably mimics topics noted in the conversion of service of a pipeline. Monitoring of ILI vehicles and components for damage is already built into active maintenance practices. Materials and technologies for sealing such as in valves and compression equipment are a source that ILI can also draw from, as such sealing materials become qualified for hydrogen service. There is strong confidence that compatibility can be addressed in ILI operations in hydrogen lines scaled to match hydrocarbon and/or other hazardous product pipelines.

Operationally, there is a significant change in ILI tool flow dynamics expected depending on the % of hydrogen in the product mix, particularly as it will affect gas compressibility, drag, and bypass. For those ILI systems equipped with active variable bypass "speed control" systems, operations at high flow rates will need to be investigated and validated. However, at one time, that was also an unknown and concern of active ILI speed control systems for hydrocarbon gas pipelines. Today, such systems are used several times every day in pipelines around the world.

https://doi.org/10.52202/072781-0025

Summary

The progression of current hydrocarbon integrity and inspection practices has occurred over the last 50+ years. From that experienced basis, their applicability to blended hydrogen pipelines is expected to evolve to address the need of future energy transition pipelines.

Further stringent criteria and conservatism are envisaged for hydrogen pipeline integrity at least until experiences with hydrogen pipeline operations as core energy infrastructures become more prevalent and common.

Technologies that have been developed and advanced for monitoring of conventional pipelines are the basis for pipelines of the future energy transition. The application of current crack ILI inspection technologies is mature and will have application for hydrogen pipelines. It is anticipated that the multitude of technologies needed to manage the threats are available and as a better understanding of critical flaw sizes and specific threats are better established by the pipeline industry, technologies will evolve to meet these potentially higher expectations.

References

1. EU Hydrogen Backbone, https://ehb.eu/
2. UK Government, "The Ten Point Plan for a Green Industrial Revolution," Nov. 2020.
3. NaturalHy consortium. "Preparing for the hydrogen economy by using the existing natural gas system as a catalyst," project no.: SES6/CT/2004/5026 61, sixth EU framework, 2009.
4. EU Hydrogen Alliance. https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen_en
5. EU Commission "A hydrogen strategy for a climate-neutral Europe" Brussels 2020
6. Huising, O.J.C, Krom, A.H.M. "H2 in an Existing Natural Gas Pipeline," Proceedings of the 13th International Pipeline Conference, IPC2020-9205, 2020.
7. ASME B31.12, "Hydrogen Piping and Pipelines," The American Society of Mechanical Engineers, 2019.
8. European Industrial Gases Association, "Hydrogen Pipeline Systems," EIGA, IGS 121/14, Brussels, 2014.
9. ASME B31.8S, "Managing System Integrity of Gas Pipelines," The American Society of Mechanical Engineers, 2020
10. API 579-1 Fitness for Service. American Petroleum Institute, 2021.
11. API 1176 Recommended Practice for Assessment and Management of Cracking in Pipelines, 2021.
12. Ramboll. G.A. "Hydrogen as Energy Carrier - Comparison with Gas and Electricity," in Hydrogen in Pipelines, 2021.
13. Adianto, R., Skow, J., Sutherland, J., "The Benefits of Accurate ILI Performance on Pipeline Integrity Programs For Axial Crack And Metal Loss Corrosion Threats," Proceedings of International Pipeline Conference, Paper No. 2016-64612 2016
14. Slaughter, M. Spencer, K. Dawson, S.J., Senf, P. "Comparison of multiple crack detection in-line inspection data to assess crack growth," Pipeline Pigging and Integrity Management Conference, 2011.

https://doi.org/10.52202/072781-0025

15. Canadian Energy Pipeline Association. "Stress Corrosion Cracking Recommended Practices," SCC Working Group, 3rd ed, 2015.
16. Pluvinage, G. "Mechanical Properties of a Wide Range of Pipe Steels Under Influence of Pure Hydrogen or Hydrogen Blended with Natural Gas," International Journal of Pressure Vessels and Piping, vol. 190, 2021.
17. Ronevich J. and C. S. Marchi, "Hydrogen Blending into Natural Gas," Sandia National Laboratories, 2019.
18. Tappert, S. Lamborn, L. "Leveraging ILI Crack Profiles," Pipeline Pigging and Integrity Management Conference, 2023.
19. Bott, S., Foreman, G., Hubert, Y., Senf, P., Sutherland, J., "A Study of Crack Detection Ultrasonic Calls Relating to the Different Types of Cracking Discovered in Pipelines When using Crack Detection ILI," Pipeline Pigging and Integrity Management Conference, 2016.
20. Sutherland, J. Tappert, S. Kania, R. Kashammer, K. Marr, J. Mann, A. Rosca, G. Garth, C. "The role of effective collaboration in the Advancement of EMAT inline inspection technology for pipeline integrity management -A case study," Proceedings of International Pipeline Conference, Paper No. 2012-90021, 2012
21. Tappert, S. Allen, D. Mann, A. Balzer, M. Van Boven, G. "Inline Inspection for crack in gas pipelines – Enhancements derived from 5 years operational experience" Proceedings of International Pipeline Conference, Paper No. 2008-64087, 2008.
22. U.S. Patent 4945775 "Interial Based Pipeline Monitoring System. 1990.
23. Czyz, J. Wainselboin, S. "Monitoring Pipeline Movement and its Effect on Pipe integrity using inetial/caliper inline inspection" IBP575_03, Rio Pipeline Conference, 2003.
24. Czyz J.A., Fraccaroli C., Sergeant A.P., "Measuring Pipeline Movement in Geotechnically Unstable Areas Using an Inertial Geometry Pipeline Inspection Pig," ASME 1-st International Pipeline Conference, 1996.
25. Yablonskikh, Y. ElSeify, M. Dawson, J. "Strain Demand and Capacity Assessment Based on In Line Inspection of Axial and Bending Strains," Pipeline Pigging and Integrity Management Conference, 2021.
26. Dewar, D. Elseify M. "ILI of Axial strain, technique, case studies and best practices." Pipeline Technology Conference, 2017.
27. Feng, Q. Gu, B., Sutherland, J., Tao, C., Wei, Y., "Evolution of Triax Magnetic Flux Leakage Inspection for Mitigation Of Spiral Weld Anomalies" Proceedings of International Pipeline Conference, 2010.
28. USA Pipeline and Hazardous Materials Safety Administration "Low strength in High Grade Pipe," Advisory bulletin ABD 10-03.
29. Dawson, S.J., Wharf, J., Nessim, M. "Development of Detailed Procedures for Comparing Successive ILI Runs to Establish Corrosion Growth Rates," PRCI EC 1-2 Final Report, 2008.
30. Dawson, J., Hurd, G., 'Assessing Repeat ILI Data Using Signal-to-Signal Comparison Techniques'. Pipeline Pigging and Integrity Management Conference, 2018
31. Bluck, M., Dawson, J., Fisher, I., Sutherland, J., "Holistic Data Approach & Results: How the Latest Enhancements In Ili Technology Benefit Engineering Criticality Assessments," Proceedings of International Pipeline Conference, Paper No. 2010-31284, 2010
32. Hurd, G. Elliott, J. Farnie, S. Sutherland, J. "Advancing In-line Inspection technology and Pipeline Risk Management through Advanced Analytics of Big Data" Pipeline Pigging and Integrity Management Conference, 2019.
33. Hurd, G. Miller, S. "Exceeding Performance Standards of Pipeline Inspection and Integrity with Complex and Challenging Defects," Pipeline Pigging and Integrity Management Conference, 2021.

34. Pipeline Products Compatibility Assessment. Baker Hughes internal practices.
35. USA Department of Energy. “Department of Energy Hydrogen Program Plan,” 2020. (https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/hydrogen-program-plan-2020.pdf)
36. USA Department of Energy, “US National Clean Hydrogen Strategy and Roadmap” , June 2023. (https://www.hydrogen.energy.gov/library/roadmaps-vision/clean-hydrogen-strategy-roadmap)
37. COAG Council (Government of Australia), “Australia’s National Hydrogen Strategy,” 2019.
38. Department of Natural Resources (Government of Canada), “Hydrogen Strategy For Canada,” Dec 2020.

https://doi.org/10.52202/072781-0025

https://doi.org/10.52202/072781-0025