CRACK MANAGEMENT OF HYDROGEN PIPELINES

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ABSTRACT

The climate emergency is one of the biggest challenges humanity must face in the 21st century. The global energy transition faces many challenges when it comes to ensuring a sustainable, reliable and affordable energy supply. A likely outcome is decarbonizing the existing gas infrastructure. This will inevitably lead to greater penetration of hydrogen. While the introduction of hydrogen into natural gas transmission and distribution networks creates challenges, there is nothing new or inherently impossible about the concept. Indeed, more than 4,000 kilometers of hydrogen pipelines are currently in operation. These pipelines, however, were (almost) all built and operated exclusively in accordance with specific hydrogen codes, which tend to be much more restrictive than their natural gas equivalents. This means that the conversion of natural gas pipelines, which have often been in service for decades and have accumulated damage and been subject to cracking threats (e.g. fatigue or stress corrosion cracking (SCC)) throughout their lifetime, can be challenging.

This paper will investigate the impact of transporting hydrogen on the crack management of existing natural gas pipelines from an overall integrity perspective. Different cracking threats will be described, including recent industry experience of those which are generic to all steel pipelines but exacerbated by hydrogen and those which are hydrogen specific. The application of a Hydrogen Framework to identify, characterise, and manage credible cracking threats to pipelines in order to help enable the safe, economic and successful introduction of hydrogen into the natural gas network will be discussed.

NOMENCLATURE

AIDE *Adsorption-Induced Dislocation Emission*
AYS *Actual Yield Strength*
CP *Cathodic Protection*
EU *European*
ERL *Estimated Remaining Life*
FAD *Flow Assessment Diagram*
FCGR *Fatigue Crack Growth Rate*
GMAW *Gas Metal Arc Welding*
GW *Girth welds*
HE *Hydrogen embrittlement*
HEAC *Hydrogen Environment Assisted Cracking*
HEDE *Hydrogen-Induced Decohesion*
HELP *Hydrogen-Enhanced localised Plasticity*
HIC *Hydrogen Induced cracking*
HISC *Hydrogen-Induced-Stress Cracking*
HFI *High Frequency Induction*
HpH *High pH SCC*
H_2 *Gaseous hydrogen*
H_2S *Hydrogen Sulphide*
ILI *In-Line inspection*
ΔK_{th} *Threshold Stress Intensity Factor range*
K_{IH} *Threshold Stress Intensity Factor*
K_{Max} *Maximum Stress Intensity Factor*
NG *Natural Gas*
PIM *Pipeline Integrity Management*
PpH_2 *Partial pressure of gaseous hydrogen*
SAW *Submerged-Arc Welded*
ERW *Electrical Resistance Welded*
NNpH *Near-Neutral pH SCC*
SCC *Stress-Corrosion Cracking*
SIF *Stress Intensity Factor*
SMAW *Shielded Metal Arc Welding*
SMYS *Specified Minimum Yield Strength*

1.0 INTRODUCTION

The COP 21 Paris Climate conference in 2015 provided a strong push for global governments to tackle climate change, with real purpose, and to drive the transition to low-carbon economy. This shift will inevitably involve decarbonisation of the world's energy infrastructure in almost every respect from generation to distribution with ambitious objectives up to 2050. As part of the '*net-zero emission energy equation*', hydrogen has been championed as a vital player of the future energy mix [1].

The deployment of hydrogen requires transportation, it is very likely that this will revolve around the integration of hydrogen into natural gas (NG) infrastructure [2]. Existing NG pipeline networks have several attributes that make them potent strategic allies, *e.g. they can provide cost-effective long transportation distance, and operational flexibility vs demand*. A consortium of major natural gas operators in Europe has recently shared a practical vision of their '*European Hydrogen backbone'* [3], and how existing (and newer) local systems could be connected to supply hydrogen from industrial sources to users on a wide geographical scale. The extent of the system is estimated at almost 40,000 km by 2040 (Figure 1).

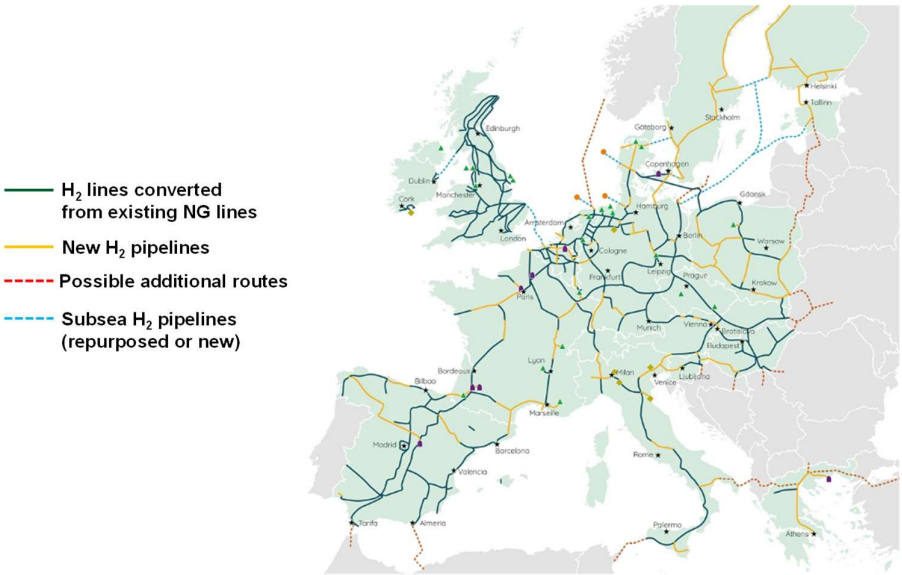

Figure 1. Vision of European Hydrogen Backbone by 2040

There are nonetheless, and inevitably, national directives in place, which require the gas infrastructure duty holders to determine the techno-economic conditions for injecting hydrogen into the current networks [2]. Of course, this includes demonstrating; (i) that the pipelines will remain fit-for-service to operate, (ii) that practical and detailed integrity management decisions can be taken to ensure long-term safety, and compliance to the 'Zero Incidents' objective.

Over 4,500 km of hydrogen pipelines are currently in operation worldwide. Some European countries have already seen the presence of up to 50% hydrogen in a previous era of their distribution system, and before the introduction of natural gas e.g. the use of "Town gas" in the UK [4]. Whilst this shows there is nothing new or inherently impossible about the concept of hydrogen pipelines, the vast majority of current hydrogen pipelines were designed, operated and purpose-built for hydrogen service in accordance with applicable industry standards (e.g. ASME B31.12. [5]), and "Town gas" also contained a significant amount of carbon monoxide, which helps mitigate against hydrogen embrittlement. ASME B31.12, and other existing codes, tend to be more restrictive in terms of both allowable loading and material requirements than their natural gas equivalents. It is unreasonable to expect that pipelines designed specifically (with lower constraints) for natural gas can be directly converted to hydrogen without due diligence.

Due to the nature of the interaction of hydrogen with the steel materials used in the transmission and distribution transportation systems, there is a need to reflect on how pipeline engineers will tackle the influence of hydrogen on crack management. This paper discusses some critical items and gaps, which need to be addressed to refine the overall picture, and increase confidence in this decision-making. The basis for discussion has been intentionally inclined towards the European NG transmission market (80% of hydrogen deployment projects were located in Europe in 2021 [6]).

2.0 THE '*DNA*' OF NATURAL GAS TRANSMISSION PIPELINES

It is necessary to understand the characteristics of the existing NG infrastructure before discussing further pipeline integrity, and the potential impacts of hydrogen transportation.

Age

The distribution of NG transmission pipeline age is presented in Figure 2 [7]. Around 60% of the European network is more than 30 years old (and 45% is over 40 years old) and is operating beyond its initial design life. Pipelines commissioned between 10 and 20 years ago represent roughly 20% of the overall length, and only less than 5% has been commissioned in the last 10 years.

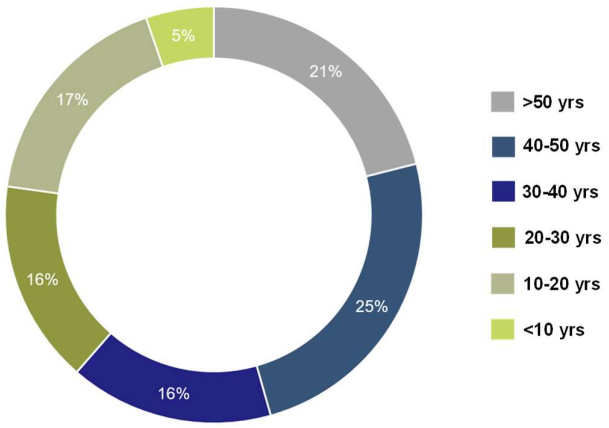

Figure 2. Age of natural gas transmission lines in Europe (as per 2021)

Steel grade

Figure 3 shows the distribution of NG pipeline steel grades in 2019 [7]. The approximate length of grade vs. age is also presented. Figure 3 indicates that nowadays the European gas system is built in large proportion (approximately 60%) with steels of API 5L [8] X52 (L360), X60 (L415) and Grade B (L245) equivalent strengths; the majority of these were commissioned prior to the 1980s. There is a relatively low length of X42 (L290) spread throughout the years. Higher strength grades such as X65 (L450) and X70 (L485) were introduced towards the end of the 1970s, but the majority of these grades are less than 30 years old. The highest common grade, X80 (L555) has only really been used in the last 10 years.

As a further point of caution, it should be noted the grade only refers to the Specified Minimum Yield Strength (SMYS), the Actual Yield Strength (AYS) could differ and be higher. It is not uncommon for material nominally supplied as X52 to have an actual strength, which would meet X60 or even X65 requirements. In addition, both steel specifications and steelmaking practises have evolved significantly over the past 50 years. An X52 pipe manufactured in 2021 will be very different in terms of chemical composition, material properties and microstructure to its equivalent manufactured in the 1960s.

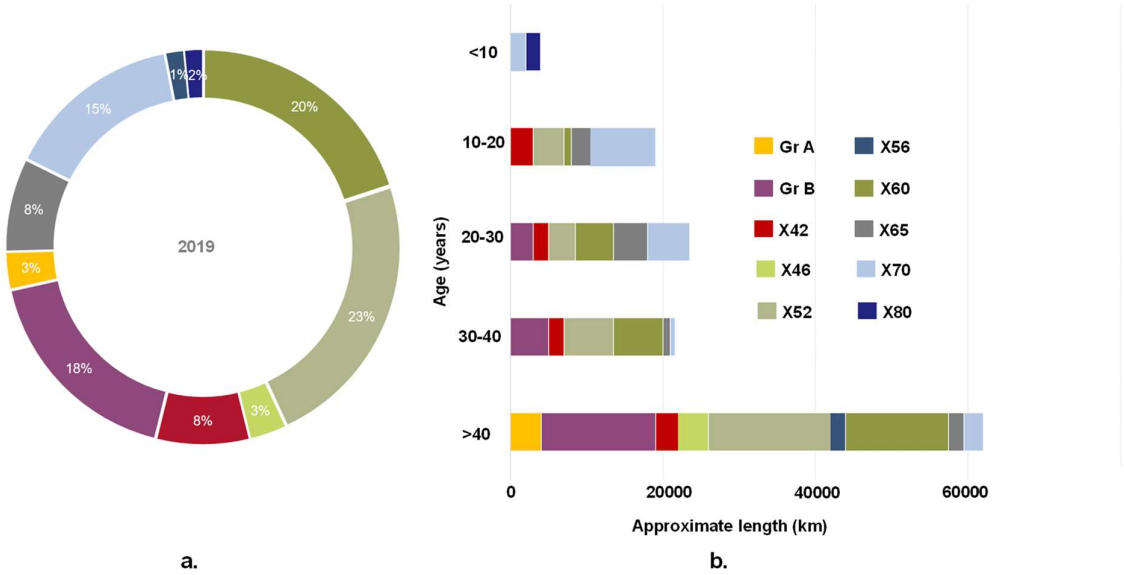

Figure 3. Steel grades in natural gas transmission lines in Europe (a) 2019 distribution; (b) versus age

Coating type

Figure 4 shows the distribution of external coating types applied at construction for the European NG transmission network in 2019 [7]. The approximate length of coating vs. age is also presented. It shows that almost 50% of the infrastructure is coated with Polyethylene (PE). The available figures do not make a distinction between tape wrap and factory-applied PE. Cold-applied tapes and Two-layer PE coatings were both developed in the 1950s. Pipeline coating practices are likely to have differed between geographical regions; for example, western European operators may have historically favoured the use of factory-applied PE (over tape), whilst the use of tape wrap may have been more prominent on Eastern European pipelines. In recent times, there is a clear preference by operators to design pipelines with factory-applied PE. A significant proportion (up to 40%) of the system is also coated in coal tar and bitumen, which is symptomatic of the age of the system and earliest construction practices. Such coatings have generally been in place, in the majority, for more than 40 years.

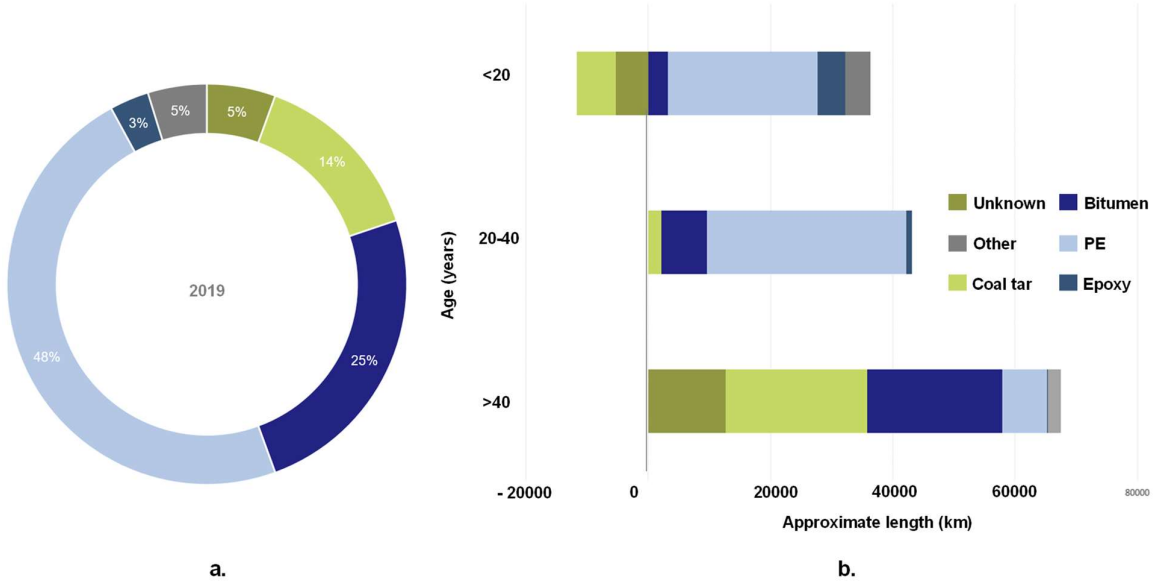

Figure 4. Coatings in natural gas transmission lines in Europe (a) 2019 distribution; (b) versus. age

3.0 NATURAL GAS PIPELINE CRACKING - EXISTING THREATS

3.1 Cracking Threats

Pipeline Integrity Management codes (for example ASME B31.8S [9]) require that all integrity threats are identified, evaluated and mitigated adequately. Figure 5 illustrates the distribution of generic failure causes in natural gas transmission pipelines in Europe in modern times [7].

These generic threats encompass other multiple subset categories or mechanisms, and can lead to defects of various physical morphologies e.g. corrosion can cause general metal loss, pitting, or pinholes. More importantly, and for the scope of this paper, they can also lead to sharp defects and cracking. Cracking has lately received focus from regulatory bodies, due to the increasing number of incidents, and the insidious and aggressive nature of the involved degradation mechanisms.

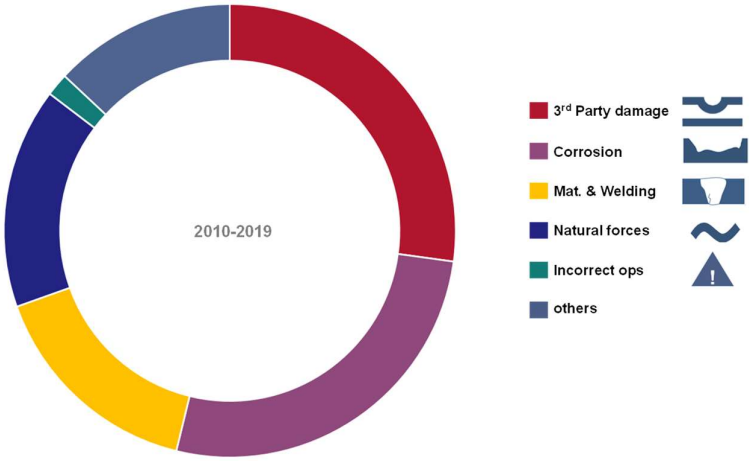

Figure 5. Failure causes in gas transmission pipelines in Europe, 2010-2019

Cracks and crack like defects can be introduced into linepipe during the manufacturing and construction processes [10]. The nature and propensity of these types of cracking are largely dependent on the original quality of the steel and the related pipemaking, welding and construction processes. There are also historic differences in the amount and type of NDT applied during construction, together with the acceptance criteria used. This means that the kinds of pre-existing manufacturing or construction defects which can realistically be present in pipelines will vary hugely according to age and original construction standards. For instance, older ERW pipes tend to more susceptible to lack of fusion. A sample of linepipe and construction weld crack-like features is given in Figure 6. Besides these weld related features, parent material can also be susceptible to manufacturing related crack-like flaws, e.g. the presence of laminations. The latter are generally not of structural concern if parallel to the pipe surface; however they can become significant for integrity if running at an angle ('sloping') or breaking the pipe surface.

Manufacturing and construction features are usually too small to cause failure or they would have been identified during hydrotesting pre-commissioning. However, if they remain in the pipeline, they can act as nucleation points for time-dependent cracking mechanisms, which could lead to in-service loss of containment.

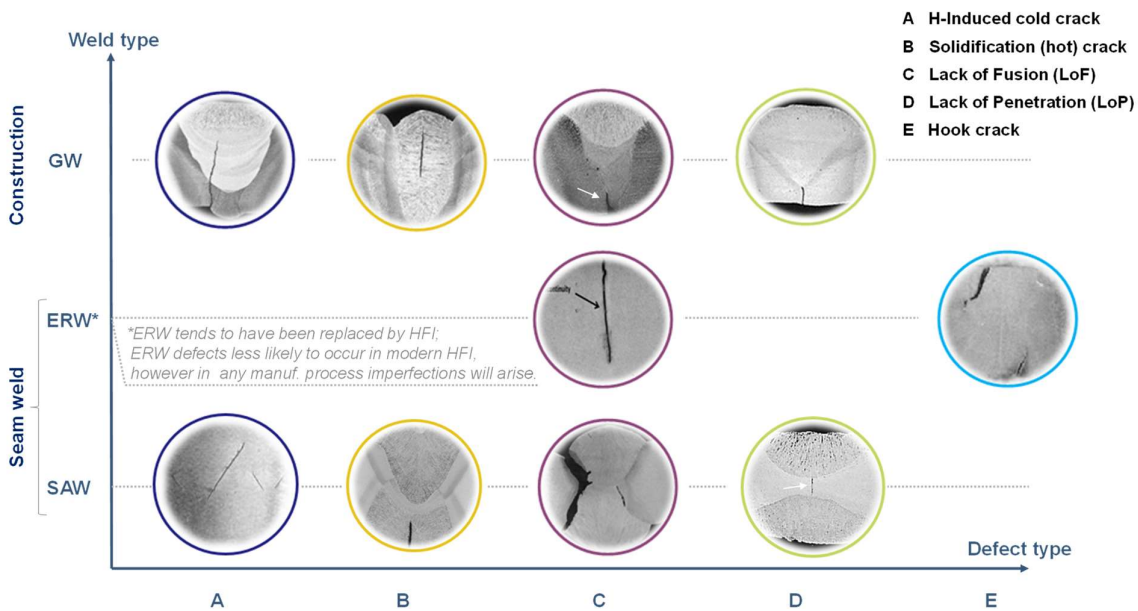

Figure 6. Typical welding defects introduced during linepipe manufacture and construction

There are three classic time-dependent cracking mechanisms to consider for NG onshore pipelines:

(i) Fatigue,
(ii) *External* Stress-Corrosion Cracking (SCC),
(iii) Embrittlement due to Cathodic Protection (CP) overprotection.

In the world of NG transmission operations, fatigue is not normally considered as an important threat as major and frequent load cycles would not be expected even if the pipeline is used for linepack storage of NG. However, external SCC (3.2) is a '*hot'* topic in the onshore pipeline industry, and an important consideration for the management of NG pipeline integrity [11], [12]. Embrittlement from CP (3.3) is also given due attention by most pipeline operators.

3.2 External Stress-Corrosion Cracking

The first ever encounter the industry had with external SCC occurred following the failure and ignition of a 24" diameter NG pipeline, in Louisiana (USA) in 1965. Since this first instance, the problem has been identified in many other countries worldwide. In the last 5 years, there have been several NG pipelines which failed due to external SCC e.g. Brazil (2015, 2019), Argentina (2019). European NG operators are not immune to the challenge, and integrity management activities are ongoing to address the issue. Incidents of pipeline failures due to external SCC have been experienced on the *'old continent'*(e.g. France (oil), 2019, Italy (gas), 1994 [13]).

There are two specific mechanisms which have been reported to lead to external SCC i.e. Near-Neutral pH - (NNpH) and High-pH - (HpH) SCC (Figure 7). Broadly speaking the incidence of these threats is closely linked to a type of external coating which:

(i) Is prone to disbondment, and
(ii) Has high electrical-resistivity properties, such that its loss of adhesion leads to full or partial CP shielding, and hence to localised corrosion processes.

Typical coatings which can create such conditions, and for which external SCC has been identified, are PE tape wraps, coal tar and asphalt (and Heat Shrink Sleeve field joint coatings). Age is also an important

parameter. HpH SCC is considered a high threat after 20-30 years of service (though failures have occurred earlier), while NNpH SCC incidents have occurred after 10-20 years depending on conditions.

Approximately 45% of the EU NG transmission system is more than 40-year old and is built with coatings, subject to disbondment and CP shielding. This suggests that a large proportion of existing NG pipelines are potentially at risk of SCC, and could become further exposed to a higher SCC threat in the near-term. Our experience suggests that EU pipelines are more predisposed to NNpH SCC than to HpH SCC, although both mechanisms are potential risks.

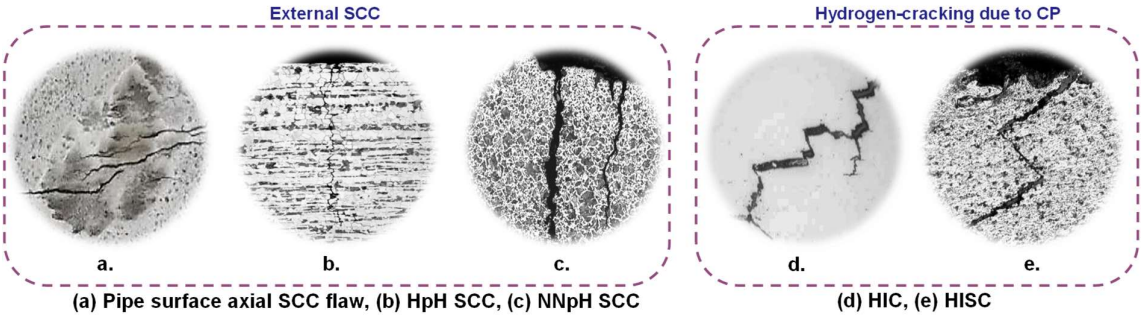

Figure 7. Pipeline External Environmental-Assisted Cracking mechanism

3.3 Hydrogen cracking due to CP overprotection

The risk of hydrogen cracking of pipeline steels due to CP overprotection has widely been commented upon in the industry [14]. Overprotection relates to the application of an OFF-CP potential typically more negative than the -1200 mV CSE criteria [15]. As part of the pipe surface electrochemical (reduction) reactions induced by CP, atomic hydrogen is adsorbed (H_{ads}) onto the steel surface. Two subsequent mechanisms end-up competing between each other,

(i) H recombination and desorption, and
(ii) H absorption (H_{abs}) into the microstructure.

The latter is responsible, in the presence of overpolarisation, for CP-driven hydrogen damage mechanisms. Essentially, these encompass (i) *Hydrogen-Induced cracking (HIC)*, due to entrapment and recombination at lattice imperfections, and (ii) *Hydrogen-Induced-Stress-Corrosion Cracking (HISC),* which relays the initiation or enhancement of cracking due to Hydrogen Embrittlement (HE) of lattice and of existing crack tips (Figure 7). HIC is usually seen as stepwise internal cracks that may connect to adjacent blisters on different planes, generally parallel to the steel surface. HISC damage occurs under the influence of internal or external loads (in opposition to HIC) and is generally found as transgranular cracks (though intergranular modes have been seen on higher strength materials).

The susceptibilities to these mechanisms have been reported to be largely associated with:

(i) The presence of hard spots and martensitic microstructures of hardness typically >HV 400
(ii) Steel materials with high yield strength (YS) typically >550 N/mm²[15] (some guidelines consider steel grades equivalent or higher than X80 before considering polarisation limitations [16] [17])
(iii) The additional presence of substantial plastic deformation, localised e.g. geometric anomalies (dents) due to 3rd party damage, or macroscopic deformation due to geohazards. The latter point is of particular importance in the case of lower grades. HISC has actually been observed in multiple instances in grades as low as X52 or X60 in the presence of overprotection and high plastic strain (e.g. gouges) [18][19].

As commented earlier (Figure 3), the European NG transmission system is designed in a large proportion with grades comparable to or higher than X52, and hence is exposed to HISC if the aforementioned conditions of high strain and polarisation are present. The prevalence of martensitic hard spots within

the European system is unquantified, but the authors' recent experiences with pipelines of similar age in North America imply they may be relatively common. The topic of CP-driven hydrogen mechanisms has become, over the last decade, of increased importance for NG operators (i) who operate long-distance transmission lines in order to compensate (high) separation distance between rectifiers and underprotection issues, or (ii) those who are addressing the issue of High Voltage AC (HVAC) interferences by CP overpolarisation.

4.0 IMPACT OF HYDROGEN ON CRACK MANAGEMENT OF EXISTING EU NG LINES

Critically, we need to appraise whether we are in position to reliably and safely manage cracking once hydrogen is introduced, and what are the key gaps or areas which will require further detailed investigation. To address this, it is essential to assess how hydrogen interacts with pipeline steel materials, and what would be the impact on existing (historical) and new (post-hydrogen commissioning) threats.

4.1 Impact of hydrogen on pipe steel materials

The topic of the interaction of hydrogen with pipeline steels has been largely discussed elsewhere [20]. The aspects, which are pertinent for this paper, are summarised in relation to (i) the interaction and induced damage, (ii) the role of grade / microstructure, (iii) the impact on mechanical properties.

Interaction and 'degradation' mechanisms

The phenomenon of the interaction of hydrogen with steel has been briefly described in section 3.3 in the case of CP application. Clearly, the fundamental feature is the absorption and diffusion of atomic hydrogen within the steel microstructure, which leads to the classic, well documented and aforementioned, hydrogen damage mechanisms of HIC and cracking due to hydrogen embrittlement (HE). It is important to observe that any level of absorption of atomic hydrogen from a gaseous hydrogen transport point of view, although physically possible, is not at the same scale as it would be in the case of CP overprotection or sour (wet H_2S) operations. Hence, the threats of HIC and HE-induced cracking are expected to be less significant, if exposure to gaseous hydrogen is solely considered.

The particular mechanism of HE remains an area of great debate (e.g. HELP vs. HEDE vs. AIDE). The argument is beyond the scope of this paper, but it is nevertheless interesting to note that a consensus appears to have been reached by which cracking due to gaseous hydrogen service is believed to *solely* take place in the presence of pre-existing flaws or cracks. This phenomenon is predominantly described by Hydrogen-Environment Assisted Cracking (HEAC), which relays the direct hydrogen dissociation and absorption at crack tips, and embrittlement of the crack front leading to growth under stress [20]. The practical implications of HE are discussed in the following sections.

Role of grade / microstructure

There seems to be a wide agreement, in reflection of industry experience of other HE-related mechanisms (SSCC and HISC) and other experimental work, that the use of lower grade materials is encouraged in hydrogen service. However this direction is not necessarily reflected in guidelines. For example, ASME B31.12 [5] does explicitly allow the use of grades up to X80 for hydrogen service, but tempers this by stating that the allowable stresses should be restricted to an extent that the use of higher grades has little or no economic benefit. Yet, the non-mandatory Appendix A of ASME B31.12 [5] indicates that only grades up to X52 are proven for service in hydrogen gas in line with the AIGA / EIGA [21] guidelines.

Fundamentally, an essential facet is that the interaction of hydrogen and steel, and the potential severity of hydrogen issues, will be determined by the specific nature of the steel microstructures and chemistries [22], not just the grade. Research [23] conducted during the development of ASME B31.12 [5] shows that bainitic or bainitic/feritic microstructures seem to be more resistant to hydrogen than pearlite-containing steels, although further quantification is required. This has important implications, when for

example assessing the behaviour of hydrogen in a higher strength "modern" steel (relatively clean and a bainitic or bainitic / ferritic microstructure) against that of "vintage" steel (with ferrite / pearlite microstructure). Likewise, martensitic structures should be more susceptible to HE, and high sulphur pipe chemistries more prone to HIC irrespective of grade.

The importance of microstructure becomes evident when considering the related field of sour service steels. It is common for modern TMCP pipe steels of grades equivalent to X65 or X70 to be "sour rated", while older pipe steels of grades as low as X52 can be susceptible to sour-related hydrogen cracking.

Guidelines [5][21], including ASME B31.12, recommend a maximum hardness of 20-22 HRC for line-pipe and welds for gaseous service to mitigate the severity of HE; this criteria generally mirrors or is more severe than sour service requirements.

Impact on mechanical properties

It is widely acknowledged that gaseous hydrogen transport will ultimately lead to a degradation of steel mechanical properties. The degradation result is symptomatic of HE, and manifests as a major decrease in ductility and fracture toughness [20]. The reduction in ductility is dependent on the pipeline material as well as the hydrogen partial pressure. Ductility (as measured by total elongation or reduction in area of a slow strain rate test) appears to decrease by 20-80% in hydrogen, with the extent of this drop varying due to the material and test method used.

Similarly, most sources agree on a reduction of 35-70% in fracture toughness, while 1% hydrogen in blend has been reported as being sufficient to lead to more than a 50% decrease in fracture toughness [20]. The wide variation in reported fracture toughness results is indicative of the uncertainties which remain regarding the effects of hydrogen. In addition to the microstructural influences noted above, testing parameters (e.g. test geometry or strain rate) can have a major effect on the reported results. It is already known that it is not appropriate to relate our ubiquitous measure of 'toughness', the (high strain rate) Charpy test results to true fracture toughness. An unfortunate consequence of the additional materials issues with hydrogen service is that the Charpy test result is an even less relevant measure of fracture toughness.

Remarkably, gaseous hydrogen does not seem to affect the steel yield strength [20].

These effects are discussed below.

4.2 Impact of Hydrogen on existing threats, and manifestation of new threats

Fatigue

We discussed earlier that the fatigue threat in operated NG transmission lines is generally negligible due to the low fluctuation frequency, and the question is whether this remains the case in hydrogen service. There is evidence [20], which confirms that fatigue crack growth rates (FCGR) increase, and fatigue endurance decreases, in gaseous hydrogen and with increasing hydrogen pressure. Current data [24] also hint that there is no "safe" lower bound of admissible hydrogen below which the impact on FCGR can be discounted. The effect of hydrogen on the severity of fatigue growth compared to air varies across the stress intensity factor range ΔK. However this behaviour is further complicated in regards to load ratio (R), pressure fluctuation frequency (f), and H_2 partial pressure (Pp H_2), which might explain certain disparities [25] [26] in trends between different sources. In some cases, the crack growth rate in hydrogen is accelerated by a factor of more than 100 compared with that in air.

Whilst there is a clear influence of hydrogen in reducing the fatigue endurance of steel materials, the question that needs to be addressed from the outset is whether fatigue cracking may be initiated. One key consideration is that there are numerous crack features, which would have been introduced as part of manufacturing, and during NG service as discussed earlier; these could theoretically provide sufficient drive for the nucleation of fatigue cracks. For example it has been discussed that 'dormant'

crack-like flaws can be activated in both X52 and X70 in 100% H_2 [26]. Figure 8 gives an idea of the distribution of density and maximum depth of cracks, which is present in gas lines globally, as captured in the ROSEN Integrity Data Warehouse (IDW). Many of these are tolerable with NG service, but if the predicted accelerated fatigue crack growth rates are realized under hydrogen they may limit the useful safe life of some pipelines.

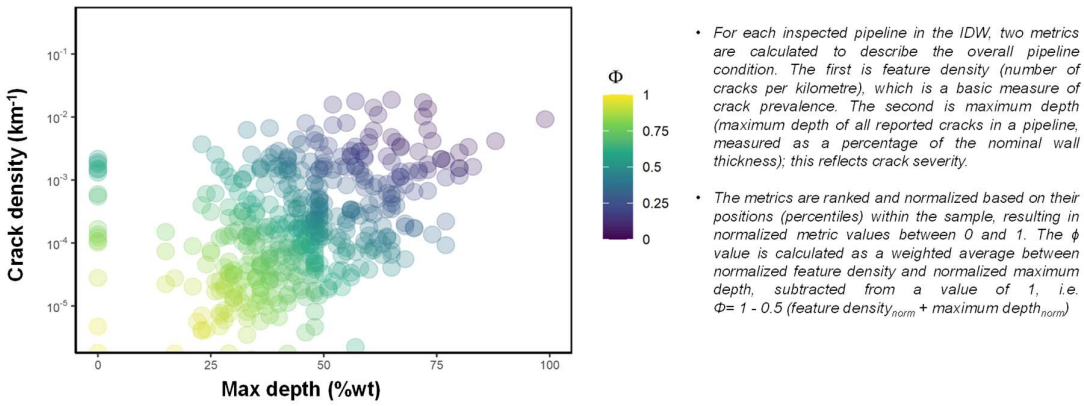

Figure 8. Distribution of crack-like features in the global gas pipeline population (ROSEN IDW)

It is interesting that some investigations [25] have however 'ruled out' the significance of fatigue (over 100 years) in hydrogen in consideration of typical NG fluctuations. This might be non-conservative (the assessment was carried out on a limited dataset of thin wall material), and detailed flow hydraulic studies on how the transmission lines will be operated in hydrogen service are awaited. Certainly, the long-term introduction of 'green' hydrogen will be associated with production fluctuations, and potentially *'linepack storage'*, which would lead to a greater fatigue threat.

It is unlikely, at least yet, that a single library of fatigue ΔK_{th}, and growth rates will cover the spectrum of steel and weld materials, load ratios, cycle load frequency, PpH_2 that might be applicable across the entire hydrogen network. It is the authors' view that caution should prevail and pipeline duty holders will need to assess the fatigue threat regarding to the pipe material 'DNA', operational spectrum, and existing crack distribution specific to their own systems rather than depending on the interpretation of other public data. It will be thus required to establish (i) profile of steel grades, (ii) population of joints against specific batches and microstructures, (iii) population of welds against WPQR criteria, (iv) expected flow hydraulics in hydrogen service.

External SCC

As previously discussed European pipelines are most likely to be subject to NNpH SCC[1], and we argued the transmission lines could become further exposed to a higher susceptibility in the near-term. Field experience (in NG) shows that, in general, a great share of NNpH SCC will remain dormant, whilst only up to 5% may continue growth until failure. Continued growth or reactivation has been reported to be further promoted by '*underload*'-mode of pressure fluctuation, residual stresses, and by the presence of hydrogen at the crack tip, whether hydrogen is generated by (surrounding) CP overprotection or by corrosion processes. The influence of hydrogen is particularly important as; (i) it lowers the stress intensity factor necessary for the transition from initiation to steady-growth (propagation), and (ii) it increases the SCC growth rate. This key facet of NNpH SCC has obviously ramifications when it comes to pipeline conversion to hydrogen service.

Plainly, the key question is whether hydrogen penetration and diffusion from the internal surface during gaseous hydrogen service can, over time, lead to an escalation of the external NNpH SCC threat. It is

[1] *In the USA and South America, High-pH SCC should be considered*

reasonable to consider this would be indeed the case as '*additional'* hydrogen may (i) further reduce the stress thresholds for initiation (stage I) and steady-growth (stage II) , (ii) increase the density of SCC cracks continuously growing in stage II and to failure, (iii) increase the growth rates of 'conventional' NNpH SCC. Although the amount of hydrogen absorbed into the pipe wall during gaseous hydrogen transport is thought to be relatively low compared to other common sources of hydrogen in steel (for example welding or an active CP system) the fact that there is a constant source of hydrogen means that it cannot be discounted. The authors believe this is a critical gap, which is not being addressed in current State-of-Art (SOA) reviews and will have a critical impact on future crack management strategies. The key items to investigate with a test program would need to include the impact of PpH_2, of materials (e,g. grade and microstructure), of CP (including overprotection), of fluctuations[2] , of crack depths and Stress Intensity Factors[3].

It is noted that the threat of HpH SCC, despite less prevalent in EU, should not be entirely discarded. Whilst hydrogen has a negligible effect in the realisation of HpH SCC, the role of gaseous hydrogen in potentially accelerating the crack growth rate over time should be also considered.

Hydrogen cracking due to CP overprotection

As discussed earlier, the European NG transmission system is exposed to HISC if the conditions of high strain and CP overprotection are present. HISC is likely to remain a major threat for operators managing underprotection issues of long distance lines, or addressing the issue of HVAC interference by deliberate CP overpolarisation. Once more, it is necessary to determine whether gaseous hydrogen service may act synergistically with CP overprotection and increase the extent of HISC initiation and crack growth, whilst also reducing the required critical stresses.

Another interesting problem would be to evaluate whether gaseous hydrogen can lower the CP polarisation necessary for the initiation of HISC. Fundamentally, it is essential to evaluate if hydrogen-stress cracking can be produced under hydrogen service at levels of polarisation defined by industry CP criteria, and under which stress / strain levels.

Under gaseous hydrogen conditions, HIC is not considered to be a major threat, at least not at the same scale that is reported under H_2S service due to the much lower permeation of hydrogen. Physical evidence is yet to be produced that this threat is credible in hydrogen service, even for high-Sulphur and lamination-containing materials. It would be nonetheless a worthwhile academic exercise to verify that the low perceived susceptibility of HIC is valid.

Mechanical growth of Pre-existing defects under static load (by HEAC)

There does not appear to be any risk of hydrogen cracking if the sole impact of hydrogen gaseous transportation is considered on intact surfaces (although there is a theoretical risk associated with hard spots or welds), due to limited hydrogen permeation. However, we discussed that steady growth of pre-existing sharp flaw could be produced in hydrogen service under static load, by HEAC.

ASME 31.12 option B [5] includes a requirement for "performance based" pipeline designs to ensure that the maximum stress intensity factor at a crack is less than a threshold value (K_{IH}) above which stable crack growth may occur in hydrogen under a static load. This threshold is measured at constant load or displacement using the methods of ASTM E1681 [27] and a minimum value of 55 $MPa.m^{1/2}$ is required. The derivation of the 55 $MPa.m^{1/2}$ minimum value is unclear, however it is thought to have been selected using engineering judgement. It should also be emphasised the current test method for K_{IH} determination within ASME B31.12 is based on ASTM E1681 and requires either constant load or constant displacement loading (with additional safety factors introduced for constant displacement loading). The test is based on a 1000 hour exposure period, and sub-critical growth of >=0.25 mm is classed as a failure. The implications of 0.24 mm crack growth in a thin wall pipe, and whether this crack would

[2] *e.g. Lower frequency and / or higher load ratios (R ratios) might promote threat in opposition to NG service*
[3] *e.g. susceptibility to initiation or continued growth of cracks <1mm depth might be increased over time*

continue to grow if the exposure period was longer than 1000 hours, do not appear to have been considered.

As pointed out earlier, the criterion has implications for the conversion of existing pipelines. There are a number of sources that for example report fracture toughness values in hydrogen of less than 55 $MPa.m^{1/2}$. At the same time, the criterion might be over conservative if operational frameworks and defect dimensions do not warrant such levels; equally it may not be conservative in exceptional cases where K_{max} falls above the threshold value. It will be useful to see if flexibility can be brought to the ASME B31.12 criterion. In particular, qualifying materials against the minimum acceptance criterion of 55 $MPa.m^{1/2}$ may be unnecessarily restrictive and operators should consider testing at high stress intensity factors to demonstrate an improved resistance to hydrogen assisted cracking. The outcome of such a review could give operators further flexibility in qualifying their assets against baseline conditions and expected modes of operation.

It is also critical to consider that this criterion does not consider the occurrence of other time-dependent crack threats e.g. SCC, HISC as discussed above.

4.2 Impact of Hydrogen on crack management

Crack management is one of the most challenging disciplines from a pipeline integrity management (PIM) perspective. As any PIM topic, it revolves around the thorough documentation of (i) Threat evaluation, (ii) Pipeline condition vs. threat, (iii) Pipeline Remaining life, (iv) Management and planning. The key challenges and gaps are discussed below in regards to the conversion of NG pipelines to hydrogen service.

Threat assessment and evaluation

It is clear that there are multiple time-dependent crack threats, which can be present in hydrogen-converted pipelines. Many of them originate from 'old' construction practices and previous NG service (SCC, HISC, HIC) and susceptibility is likely to become greater under hydrogen service over time. Others are specifically related to gaseous hydrogen (fatigue, mechanical growth of pre-existing defects by HEAC). Understanding the nature, credibility and severity of these threats is essential when it comes to 'designing' the most appropriate inspection program, evaluating inspection results, and developing cost-effective management plans. There are key gaps, which are yet to be addressed, in order to support the decision-making process in hydrogen service. These have been discussed earlier.

One of the recurrent themes of any crack threat assessment resides in the understanding of the materials' 'DNA'. The role of the materials and mechanical properties is particularly acknowledged in most hydrogen service guides. The use of low strength grades (e.g. up to X52) and lower bound hardness (up to 20-22 HRC) are generally encouraged for hydrogen service. Almost half of the EU NG system has been built with grades equivalent to or higher than X52 (and 15% consists of X70 / X80 steels); see Figure 3. Note, it is not uncommon for material nominally supplied as X52 to have an actual strength which would meet X60 or even X65 requirements. Whether or not grade and hardness limitations can be alleviated in future standards, it will still be important that pipeline duty holders reach a full understanding of the population of steel strengths and materials in their respective systems. We discussed earlier that hydrogen interaction with steel is modulated by microstructure/chemistry (not necessarily grade), and it is unlikely that a single archive of key mechanistic parameters (e.g. fatigue ΔK_{th}) and crack growth rates will encompass the wide spectrum of materials (and operations) across any future hydrogen network. It is the author's view that caution shall be the watchword and pipeline duty holders will need to assess (by testing) the likelihood and crack growth rates regarding to their specific system 'DNA' to avoid undue conservatism or lack of care .

Understanding material populations and characteristics is difficult for long pipelines, especially on older systems, for which construction details or original mill test certificates may not be available. Certain standards (ASME B31.12, PL-3.21 [5]) recommend material sampling every mile to provide some

evidence of the materials present. Such an approach is far from practical. There are much more cost-effective alternatives. ROSEN's RoMat-PGS In-Line Inspection (ILI), for example, can provide a valuable picture of the pipe properties (Figure 9) in regards to material and construction differences, from which populations of similar pipe can be identified, and intelligently targeted sampling strategies derived. This approach has multiple benefits which are discussed in more detail elsewhere [28].

It is worth noting that although RoMat-PGS will identify the variations in material microstructure and chemistry across pipeline length, it will not provide the actual detail on steel chemical composition (e.g. %sulphur) and nature of metallurgical phases (e.g. martensite). These specific attributes will need to be extracted by field verification at targeted locations.

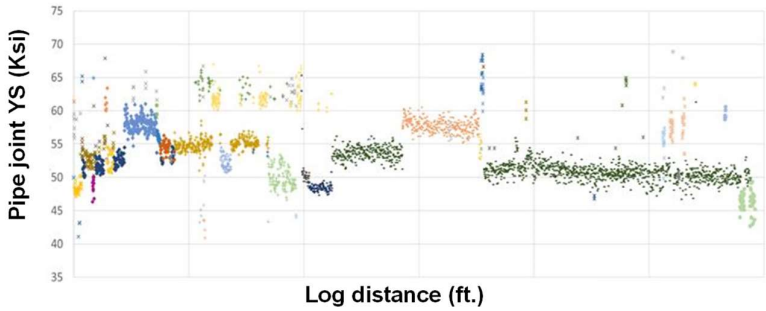

Figure 9. Steel populations identified by RoMat-PGS along a full pipeline length

For obvious reasons, the identification of hard spots is also likely to become a hot topic in order to address safe operations versus hydrogen-driven crack threats. There are ILI tools, based on the concept of dual-magnetisation (e.g. ROSEN's RoMat DMG), which have been developed to detect the presence of martensitic hardspots [29].

Pipeline integrity and remaining life

We discussed that a reduction of 35-70% in fracture toughness could be expected in steel pipe transporting gaseous hydrogen. Essentially, this means that the dimensions of crack-like features, which are critical to pipeline integrity, could be significantly reduced. Whilst there have been numerous studies on the effect of hydrogen on fracture toughness and ductility, it appears that the effect of these reduced properties on realistic pipeline defects and safe operational conditions has received little attention. The issue is expected to be more significant for lower toughness materials than for high toughness. This is because failure in what is now a lower toughness material may shift from being plastic collapse controlled to fracture controlled. In contrast, in a very high toughness material failure is and will remain plastic collapse controlled, despite a reduction in the absolute toughness, so that the reduction has a small (or possibly no) effect. Understanding fracture toughness of material populations (including the welds) is therefore critical when it comes to crack assessment.

Tolerable crack sizes at seam weld toes (for SAW pipes) are likely to be more affected than in parent materials in hydrogen, due to the stress raising effect of the weld toe, which increases the stress intensity factor and so the driving force for failure by fracture. The effect will be even greater in the case of crack-flaws at girth welds, due to the presence of residual stresses. If the '*original*' toughness of a girth weld is low and there is a significant reduction in fracture toughness when exposed to hydrogen, defects that are acceptable on a workmanship basis to current codes (e.g. Section 9 of API 1104 [30]), may become unacceptable. Planar features such as lack of side wall fusion and root undercut would be expected to be the most sensitive to any effects of hydrogen as they have a high stress concentration at the tips.

There is a requirement to review the suitability of flaw acceptance assessment methods. For example, crack assessment methods which use a measured fracture toughness criterion expressed as a stress intensity factor (BS 7910 [31], API 579 [32]), will be sensitive to changes induced by hydrogen.

Superficially other methods where the fracture toughness is estimated from the Charpy energy may be less affected. However, this is potentially non-conservative as there is an explicit or implicit correlation between Charpy energy and true fracture toughness in these methods. These correlations are empirical. As it is assumed (with very limited experimental confirmation) that the Charpy energy is not affected by hydrogen, but the data show that true fracture toughness is reduced, such empirical correlations will not be valid for hydrogen service.

It is also not clear how any effects of reduced material ductility should be included in collapse-based assessment methods (such as NG-18) in the case of high toughness materials. Certainly the '*equation'* of crack fitness-for-service may need to integrate the potential variation of fracture toughness behaviour between an internal and an external crack, respectively to the active threats possibly present. An internal surface breaking crack might indeed show a greater reduction in fracture toughness than an embedded or external surface crack, but the effect of time will need to be considered.

In parallel, there could be a challenge [33] for the detection of critical cracks in hydrogen pipelines. It seems that there may be some line pipe materials for which the dimensions of flaws which could lead to failure, will be smaller in hydrogen than in natural gas. For pipelines where the materials are of relatively low toughness these critical flaw dimensions in hydrogen service could be at the borderline of, or even below, reliable crack detection limits. However, since we already know that existing pipelines contain numerous crack like defects, and reliable operation requires pipelines to have a reasonable tolerance to damage it is possible that pipelines or pipeline segments made from these lower toughness materials may not be economically feasible for conversion.

Remaining life

Once some level of understanding is reached on the presence and sizing of cracks, and on the sizing of critical flaw dimensions, it is then necessary to establish the system's remaining life in regards to time-dependent cracking threats and associated growth. Broadly speaking, the combination of lower acceptable critical flaw dimensions, and increased growth rates would suggest that in the case of active cracking mechanisms, there is a greater risk for pipeline integrity and the remaining life of converted hydrogen pipelines could be significantly compromised.

Today crack growth rates for SCC and fatigue are estimated based on mechanistic models (when available[4]), testing and industry experience. With a conversion to hydrogen service, this emphasis on growth rate modelling and testing will undoubtedly increase. As for modelling in general, it is unlikely one single generic model will be able to simulate crack behaviour over the wide spectrum of metallurgies, operational cycling and defect types. Rather, it is likely any such model will be system, and even location, specific. A pertinent example is the fatigue growth law defined in ASME B31.12 [5], whose development has been restricted to a limited range of steel grades, and for low loading ratio (i.e R=0.5), which is not necessarily representative of what would be expected in hydrogen service. The latter is particularly significant as data shows that the fatigue crack growth rate may increase at higher R ratios. Thus the ASME law may not represent an upper bound for all cases.

Because of the complex variation of hydrogen related crack growth behaviour with metallurgy, loading conditions, and PpH_2, the authors suggest that a safer approach would require operators to validate crack growth rates under hydrogen service by testing representative materials taken from the system, WPQRs, operating conditions and SIFs representative of respective systems.

Management – Sampling and testing, Inspection and CP

As discussed earlier and elsewhere [28], reaching an adequate picture of the distribution of the materials population in pipelines considered for conversion to hydrogen will be essential to assess material suitability, susceptibility and fitness-for-service vs crack threats, and thus safely manage integrity. The

[4] *In the case of NNpH SCC, there is not at this time an industry-wide approved mechanistic model.*

deployment of an intelligently-targeted sampling approach, integrating for example the use of RoMat-PGS, should play a more vital role to alleviate the burden of more prescriptive and non cost-effective methods. Critically the definition of a specific material populations will need to assimilate the concept of variation in microstructure and chemistry, rather than only grade. The detection of hard spot clusters (e.g. RoMat DMG), geometric anomalies and high bending strain areas (e.g. geohazards) across systems will also become a greater necessity in regards to the associated increased hydrogen-driven crack threat susceptibility. The hydrogen interactions with materials and the cross-effect of multiple variables influencing the hydrogen-influenced cracking mechanisms are complex. It is reasonable to infer that a safer approach would require operators to validate crack threat susceptibilities, fracture toughness and growth rates under hydrogen service by testing with respect to materials, WPQRs, operating conditions and SIFs representative of the respective pipelines.

In order to manage certain pressure cycling-driven threats (e.g. fatigue, NNpH SCC), an alternative would be for operators to adopt a conservative lower bound ΔK_{th} and endurance assumption and to reduce pressure and pressure cycling. It may not however be practical, especially given that a pressure increase of about 10% to 20% is required to maintain the same energy throughput for 100% hydrogen compared with natural gas [34]. It is also possible that requirements to store green hydrogen in the pipeline system by linepack, due to the variability of wind and solar power, will increase pressure cycling.

Integrity driven assessment programs (i.e. ILI, hydrotest, Direct Assessment) will remain an important necessity to address pipeline condition and integrity. As for every other service conversion exercise, and perhaps more so in the case of hydrogen conversion, a baseline inspection of the pipelines will be required. Yet, another problem would be to define appropriate re-inspection intervals. As indirectly pointed above, the interval between inspections will probably be dictated by growth rates derived by industry modelling and (preferably) by representative testing. Due to the possible order of magnitude increase of growth rates, this implicitly suggests that the frequency of inspection will have to be increased. There may be cases where safe and economic integrity management is not feasible, given rapid crack growth and small critical crack sizes. These situations will have to be identified and hydrogen conversion may not be viable (unless other mitigation alternatives are considered), just as the use of some materials is just not appropriate for highly corrosive well products.

CP is an important part of pipeline integrity management in order to mitigate external corrosion (including electrical interference issues). There is a fundamental question whether and to what extent CP and gaseous hydrogen can synergistically interact with time-dependent crack threats under hydrogen service. It is not unreasonable to think that the combination of CP and gaseous hydrogen has the potential to increase the likelihood and growth of all the cracking threats described in this paper, depending on polarisation, PpH_2, metallurgy and stress levels. Plainly, the acceptability of the industry CP criteria (-850 to -1200mV) needs to be reassessed in regards to the aforementioned crack threats in hydrogen service. This has even bigger implications in the case of HISC, and to some degree NNpH SCC, when overprotection is used as a means to address underprotection issues on long-distance pipelines or combat corrosion problems generated by HVAC interferences.

It is worth noting that certain impurities (e.g. oxygen, carbon monoxide) have been identified as potentially interfering with hydrogen absorption and therefore reducing the impact of hydrogen on embrittlement and time-dependant crack mechanisms. Further work is required to confirm effectiveness, practicality (e.g. impact on gas quality and end-users) and suitability of such operational mitigation.

An overall approach to a crack management framework for NG pipelines converted to hydrogen service, and summarising key points, is presented in Figure 10. This is a more detailed translation of the overall framework for hydrogen conversion presented by the authors elsewhere [4, 28].

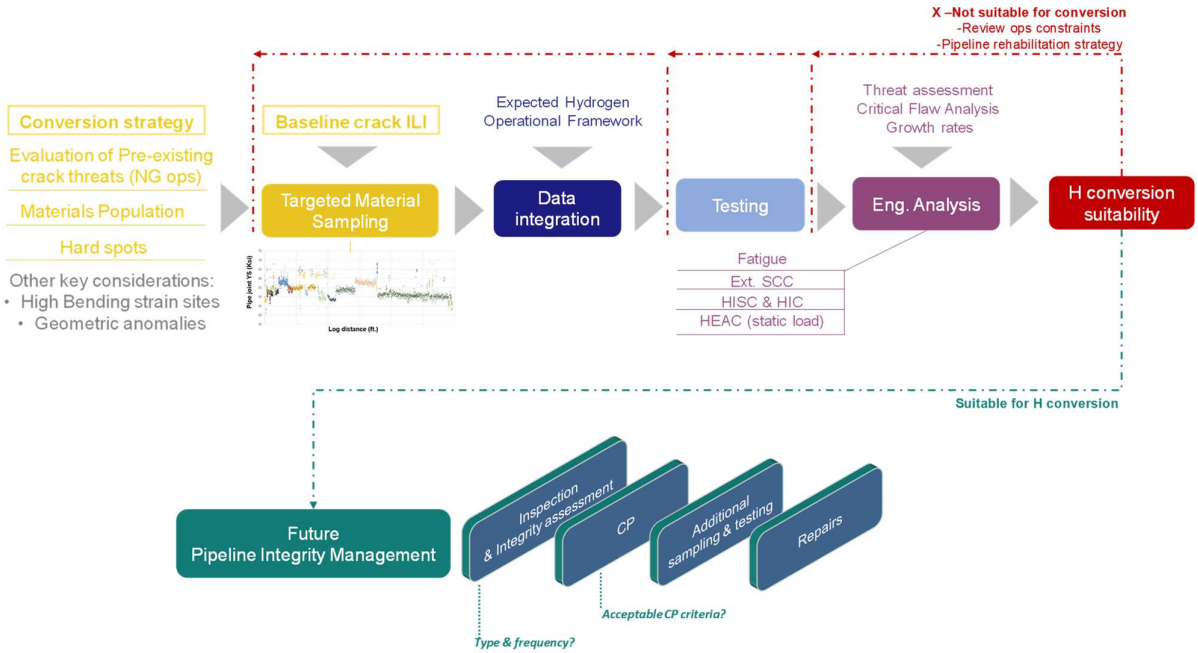

Figure 10. Approach to crack management framework for NG pipelines converted to hydrogen service

5.0 CONCLUSIONS

Existing European NG transmission pipelines are not immune to cracking threats. Some already exist (e.g. NNpH SCC, HISC) and the magnitude of these threats is likely to increase over time. It is feasible that the degradation caused by these mechanisms will be amplified under hydrogen service. Fundamental research is required to determine to what extent and under which conditions (e.g. CP polarisation, PpH_2, stress/strain) the effects of hydrogen will be most serious.

Other threats, which are not significant under NG service, may become real issues. Specifically, the threat of fatigue cracking will be intensified under hydrogen service in regards to the potential acceleration of growth rates by a factor of 100. Pipelines that may be converted to hydrogen contain existing sharp defects, which could provide sufficient drive for the nucleation of fatigue cracking. Whether the threat is credible or significant will need to be assessed case by case against specific system 'DNA', expected operational framework e.g. loading cycle and defect characteristics. A clear understanding of expected hydrogen service hydraulics and mode of operations ('blue' vs 'green' hydrogen) will be required.

On the other hand, existing hydrogen standards impose, with a certain degree of contradiction, restrictions on grades (up to X52), chemistries, hardness (21-22 HRC) and K_{IH} criterion ($\geq$55 MPa.m$^{1/2}$); these limits have significant implications for the conversion of EU NG lines. Of importance, the ASME B31.12 criterion of 55 MPa.m$^{1/2}$ does not consider the susceptibility to external SCC and HISC. Whether these limits, can be relieved in the benefit of engineering assessments more specific to a system 'DNA', condition and operations remains to be seen.

At minimum we would require materials performance confirmation by testing. In line with the complex inflection of the hydrogen interaction with materials and the cross-effect of multiple variables influencing the hydrogen-influenced cracking mechanisms, it is unlikely that a single library (e.g. crack growth rates, ΔK_{th} values) or crack growth modelling will cover the spectrum of existing pipeline systems behaviour against hydrogen. It is argued that a safer approach to integrity management would require operators to validate representative material susceptibility, fracture toughness and crack growth

rates under hydrogen service by testing with respect to materials, WPQRs, operating conditions and SIFs representative of respective systems.

The deployment of intelligently-targeted sampling approach, integrating for example the use of pipe strength internal inspection systems, will be required to alleviate the burden of more prescriptive and less reliable methods. Critically the definition of a specific material population will need to assimilate the concept of variation in microstructure and chemistry, rather than only grade. The detection of hard spot clusters, geometric anomalies (e.g. gouges, dents) and high bending strain areas (e.g. geohazards) across systems will also become a greater necessity to address the crack management of hydrogen-converted pipelines. The prevalence of martensitic hard spots within the European system is unquantified, but the authors' recent experiences with pipes of similar age in North America imply they may be relatively common.

There is a requirement to review the suitability of flaw acceptance assessment methods. The potential variation of fracture toughness behaviour between an internal and an external crack, and the implications for the crack fitness-for-service equations where certain toughness and ductility levels are assumed will need to be considered.

Finally, another challenge is that for some lower toughness line pipe materials (for example at girth welds, or some seam weld types) the critical flaw dimensions in hydrogen service could be very small, due to the toughness reduction effect of hydrogen exposure. Meaning that those pipelines already contain many features that may not be acceptable for safe hydrogen conversion and the features may be at the borderline or below current crack detection thresholds. The generally older pipelines constructed from these materials may not be economically viable for conversion to hydrogen. These pipelines and pipeline segments must be reliably identified to allow for economic alternatives to be considered.

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