THE ECONOMICAL REPURPOSING PIPELINES TO HYDROGEN – WHY PERFORMANCE TESTING OF REPRESENTATIVE LINE PIPES IS KEY?

Dr Sandana, D.[1] , Gallon, N.[2], Burkinshaw, O.[3]
[1] ROSEN, Newcastle upon Tyne, NE12 8BS, UK, Dsandana@rosen-group.com (Presenting Author)
[2]ROSEN, Newcastle upon Tyne, NE12 8BS, UK, NGallon@rosen-group.com
[3]ROSEN, Newcastle upon Tyne, NE12 8BS, UK, OBurkinshaw@rosen-group.com

ABSTRACT

The introduction of hydrogen in natural gas pipeline systems introduces integrity challenges due to the nature of interactions between hydrogen and line pipe steel materials. However not every natural gas pipeline is equal in regards to the challenges potentially posed by the repurposing to hydrogen. Existing codes and practices penalise high-grade materials, on the basis of a perceived higher susceptibility to hydrogen embrittlement in regards to their increased strength. This philosophy challenges the realisation of a hydrogen economy, because it puts at economical and technical risk the conversion of almost half of the natural gas transmission systems in western countries.

The paper addresses the question whether pipe grade is actually a good proxy to strength and predictor to assess the performance of steel line pipes in hydrogen. Drivers that could affect the suitability of pipeline conversion in hydrogen from an integrity management perspective, and industry experience of other hydrogen-charging applications are reviewed. In doing so, the paper challenges the basis of the assumption that low-grade steels (up to X52 / L360) are automatically safer for hydrogen repurposing while, at the other end of the spectrum, higher-grade materials (>X52 / L360) are inevitably less suitable for hydrogen service.

Ultimately the paper discusses that materials sampling and testing of representative line pipes populations should be placed at the core of hydrogen repurposing strategies, in order to safely address conversion and to maximize the hydrogen chain value. The paper addresses alternatives to make the sampling smart and cost-effective.

Key words: Hydrogen, Repurposing, Pipeline integrity

NOMENCLATURE

AYS *Actual Yield Strength*
CP *Cathodic Protection*
FCGR *Fatigue Crack Growth Rate*
FFS *Fitness-For-Service*
HE *Hydrogen embrittlement*
HEAC *Hydrogen Environment Assisted Cracking*
HIC *Hydrogen Induced cracking*
HISC *Hydrogen-Induced-Stress Cracking*
H_2 *Gaseous hydrogen*
H_2S *Hydrogen Sulphide*
ILI *In-Line inspection*
K_{IH} *Threshold Stress Intensity Factor*
NG *Natural Gas*
SCC *Stress-Corrosion Cracking*
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 preceding 2050. As part of the '*net-zero emission energy equation*', hydrogen has been championed as a vital player of the future energy mix [1]. This push has been given added intensity by the increased focus on energy security following the invasion of Ukraine.

The deployment of hydrogen requires transportation, and given the many economic and legal obstacles to new pipeline construction, it appears inevitable that a large proportion of the future hydrogen pipeline network will consist of repurposed existing infrastructure. [2]. This is illustrated in Figure 1 by the 'European Hydrogen backbone' [3], which shows how existing (dark green) and new (orange) local systems could be connected to supply hydrogen from industrial sources to users on a wide geographical scale. The extent of the system is currently estimated at almost 53,000 km by 2040.

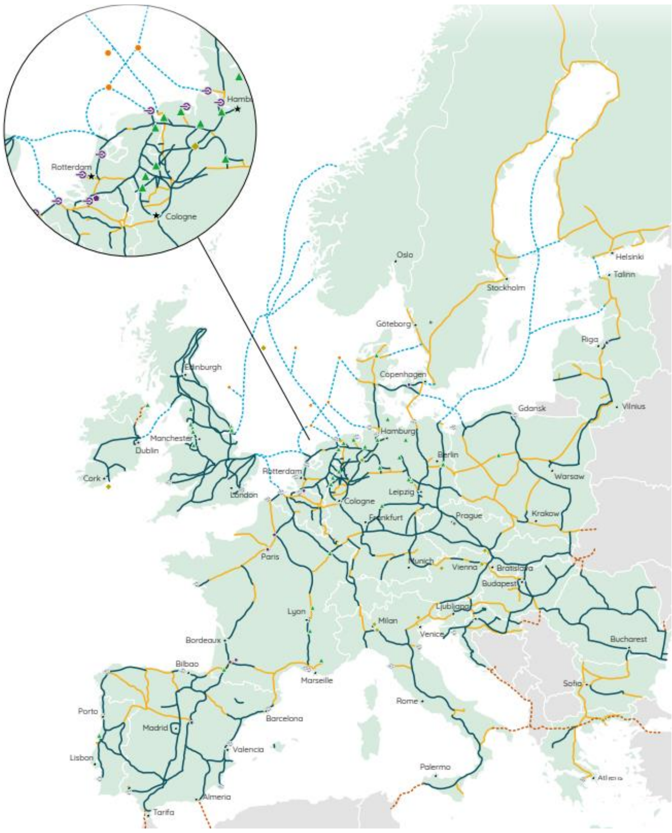


Figure 1. Vision of European Hydrogen Backbone by 2040

As widely discussed elsewhere [4] [5], it is unreasonable to expect that pipelines designed specifically for natural gas can be directly converted to hydrogen without due diligence. The conversion challenge is materialised by ASME B31.12 [6], which tends to be particularly more restrictive in terms of both allowable loading and material requirements for hydrogen pipelines than for their natural gas equivalents, in order to address the specific issue of hydrogen embrittlement. The code effectively "*punishes*" the use of higher strength grades (above X52/L360) by limiting utilisation (operational stresses).

The paper reviews and challenges the basis of this binary approach, that low-strength pipe grades (below X52) are automatically safe for hydrogen repurposing while, at the other end of the spectrum, higher-grade materials (above X52) are inevitably less suitable for hydrogen service.

A view to repurposing is presented in order to provide pipeline duty holders with an economical and pragmatic approach in order to establish the representative performance of materials for the targeted H_2 service. The latter is discussed as a key facet of pipeline repurposing, and tackle the issue of enforcing conservative operational (utilization) limits, which could prove uneconomical for the hydrogen transportation chain.

2.0 EXISTING CODES & RESTRICTIONS ON HIGHER GRADES FOR H_2 SERVICE

ASME B31.12 [6] is the most widely recognised code for the design and operation of hydrogen pipelines, as well as pipeline repurposing to hydrogen service, having been first issued in 2008 and with the current version published in 2019. ASME B31.12 has some requirements in common with, and to an extent was based upon, the harmonised CGA [57] / EIGA [8] / AIGA [79] industrial gas company guidelines (hereafter referred to as the "EIGA Guidelines"). Recently, various additional standards have also been published, notably by IGEM [10] and DVGW [11], and more standards are known to be in preparation at national, European and international levels.

Current codes differ in detail, but they do have some commonality. One consistent theme is the preference for lower grade materials. For example, the EIGA guidelines state that "it is recommended that only lower strength API 5L grades (X52 or lower) be used". Table GR-2.1.1-2 of ASME B31.12 states that grades up to X80 / L555 are "listed materials" and therefore may be used, however according to section PL-3.7.1 only X70 / L485 and below are acceptable for design Option A (prescriptive design, no testing in hydrogen required). Within current guidelines, even the use of grades above X52 / L360 (under ASME B31.12 Option A) come with a significant penalty due to both design factor limitations and the concept of the 'material performance factor'. For example, these Option A limitations mean that, in the case of a 32" diameter, 13.4 mm wall thickness, grade X70 / L485 pipeline recently assessed by the authors for conversion, the allowable operating pressure for hydrogen is less than half that for natural gas in some location classes. The IGEM TD/1 supplement [10] takes a similar approach. No clear justifications are given in these standards for the imposition of these punitive design factors for higher grades.

3.0 GRADES –AN ADEQUATE METRIC FOR MATERALS PERFORMANCE IN H_2?

3.1 Strength or Grade as an Indicator of Hydrogen Pipeline Performance

The fundamental feature of the interaction of hydrogen with pipeline steels is the absorption and diffusion of atomic hydrogen within the steel microstructure, which essentially leads to cracking due to hydrogen embrittlement (HE)[1]. The particular mechanism of HE remains an area of great debate, but engineering reasoning and research often point to the empirical evidence that higher tensile strength or hardness are more susceptible to hydrogen embrittlement [12] [13]. While there is a rational truth to the latter, the derivation that *"higher pipe grades are inevitably less suitable to hydrogen service"* is not as absolute, when considering the following topics – these will be further reflected upon in subsequent sections:

- Pipeline fitness for service (FFS) in hydrogen (e.g. against cracking)
- Microstructures vs. grades, and HE susceptibility
- The actual correlation of specified nominal grade versus actual strength and hardness.

[1] Hydrogen-Induced Cracking (HIC) is not considered in the arguments of this paper. HIC is considered as less credible in a gaseous hydrogen environment (compared to sour environments)

Moreover, it is worth arguing whether the predilection of favouring lower grade materials up to X52 / L360 for gaseous hydrogen service is actually over-conservative, when considering the practices and recommendations in place for other more severe hydrogen charging applications[2]. The conundrum is best represented by the design of line pipe for sour service requirements (Figure 2). In this application, cracking due to hydrogen embrittlement (i.e. Sulphide stress cracking (SSC)) is generally controlled by hardness restrictions (<248 HV) for the most severe conditions, but it is interesting to observe that the standard explicitly approves the use of line pipe of grades up to X65 / L450 (i.e. above X52 / L360) [14]. The use of high strength grades up to X80 / L555 is also indicated to be acceptable in milder H_2S conditions [15].

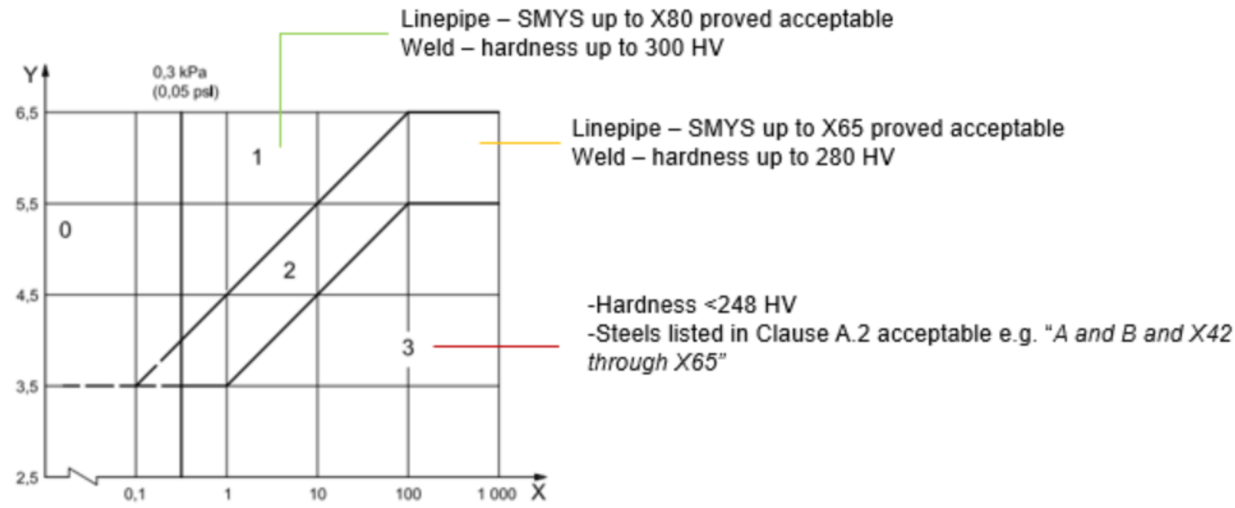


Figure 2-ISO 15156 / MR0175 requirements for pipeline steels in sour service

It is already necessary to stress that pipeline grades are not equal against (particularly) their age (due to manufacturing and microstructure developments), and that the validity of the sour standard requirements shall be cautioned against its year of revision and the quality of manufacturing and construction applicable at the time. Nonetheless, the latter example illustrates the conservatism that may exist around unduly (i.e. with no further assessments) restricting the use of grades above X52 / L360.

Another representative example is given by the current guidelines tackling the threat of HE due to Cathodic Protection (CP) overprotection (i.e. Hydrogen-Induced Stress Cracking (HISC)); most allow the use of grades up to X80 before considering an increased susceptibility to HISC, and implementing limitations in CP polarisation [16] [17] [18] [19]). It is nevertheless worth stressing that this type of HE cracking has led to in-service incidents in multiple instances on grades as low as X52 / L360 or X60 (in combination of high plastic strain [20] [21]). The same applies for sour service, particularly for vintage or "non-sour rated" steels and in the presence of hard spots. This highlights another key message: all low strength materials are not automatically immune to HE cracking challenges. The suitability of conversion to hydrogen service requires a holistic review of the pipeline fitness-for-service and the variables augmenting its risk profile against hydrogen transportation.

[2] Sour service and CP overprotection are acknowledged to be a more aggressive H_2 charging environment than gaseous H_2 due to the nature of the surface reactions leading to the hydrogen absorption into the lattice (electrochemical vs. dissociation)

3.2 Pipeline FFS in H_2: other key materials properties & correlation with grades?

Cracking and fracture toughness

A key issue posed by the threat of Hydrogen Embrittlement is the vulnerability of the pipeline to cracking. In the case of gaseous hydrogen transportation, the processes of HE leading to cracking are described by two main mechanisms, which are a function of the nature of the stress cycling, i.e.:

(i) Hydrogen Environmentally Assisted Cracking (HEAC): this relays the direct H_2 dissociation and absorption at pre-existing[3] crack tips, and embrittlement of the crack front leading to growth under static stress

(ii) Hydrogen-Assisted fatigue: this is effectively fatigue accelerated by HE at the crack tip front and accordingly to the reactions described by HEAC.

As eluded above, the existing B31.12 -option A approach of "*discriminating*" grades above X52 in hydrogen service is specifically designed to tackle the susceptibility to HE. However, it is necessary to take a more global fitness-for-service view (beyond likelihood), and reflect that other materials properties are as, or even more, critical in regards to the cracking challenges [5] posed by hydrogen conversion. Figure 3 gives an idea of the distribution of density and maximum depth of cracks, which exists in gas lines globally, as captured in the ROSEN Integrity Data Warehouse (IDW). Many of these are tolerable with NG service, but how these behave and affect the useful safe life in hydrogen needs to be assessed accordingly.

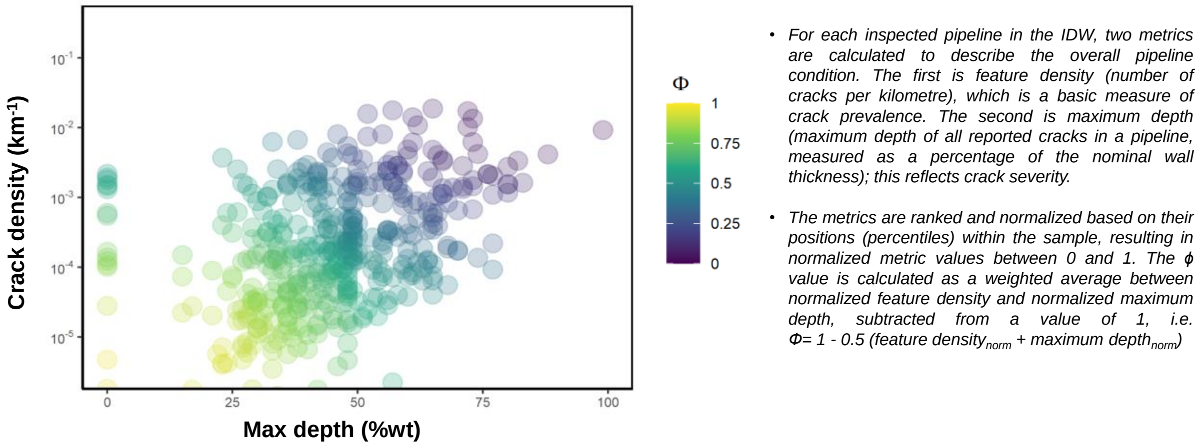


Figure 3. Distribution of crack-like features in the global gas pipeline population (ROSEN IDW)

Fracture toughness is unquestionably the most fundamental property when it comes to crack management, and assessing the pipeline fitness and safe operational life against the presence and severity of cracks [22][23]. Fracture toughness characterises the resistance of the steel against the presence of cracking and its unstable propagation; higher toughnesses are therefore beneficial.

For the sake of the argument, it is already worth noting that higher strength grades will generally tend to have higher actual in-air toughness than lower strength grades. For example, considering older line pipe steels of grades typically L360 / X52 and lower, consisting of normalised ferrite-pearlite microstructures, strength was largely achieved by addition of carbon and increased pearlite fraction; for such materials an increase in strength often came with a trade-off in toughness. For modern microalloyed line pipe steels (typically L360 / X52 and higher) strength is achieved in large part by grain refinement and controlled microstructures, through control of chemical composition and thermomechanical

[3] Whether gaseous hydrogen is able to induce cracking in bulk material away from existing crack tips is at this time unclear; it is nevertheless reasonable to think this may be possible over time, especially in the presence of stress raisers, plastic deformation and/ or susceptible microstructures (e.g. hard spots)

processing. This increases both strength and toughness (Figure 3 [24]). Considering a 'modern' microalloyed X65/ L450 material compared with a 'vintage' normalised ferrite-pearlite X42 / L290 material, the X65 / L450 material is likely to have significantly higher toughness (in air).

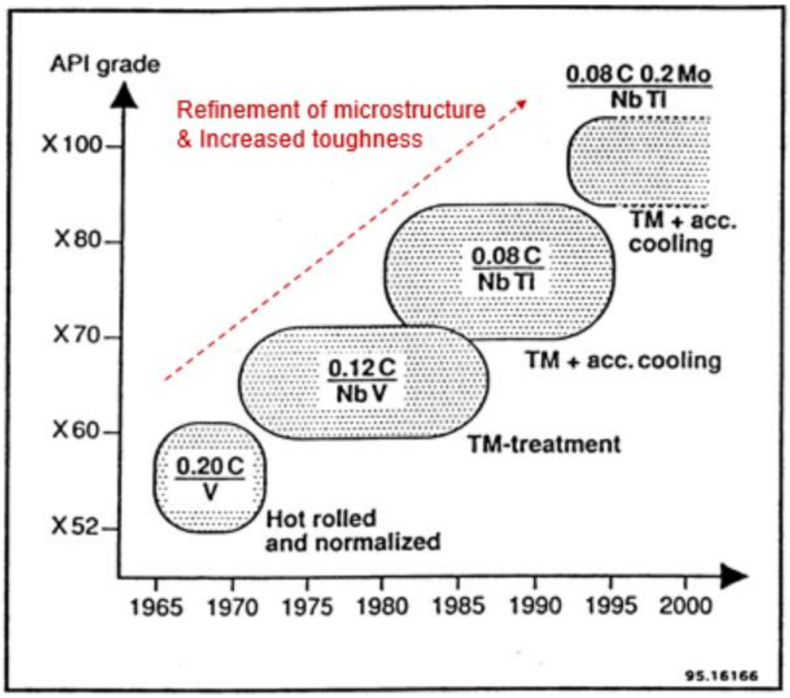


Figure 4. Development of line pipe steels and effect on strength (as API grade) [24]

Actual examples of this were found from previous testing conducted by the authors on two ex-service pipeline materials as summarised in Table 1. For the X42 / L290 pipe, the Charpy[4] (CVN) absorbed energy values are found to be relatively low. For the X70 / L485 pipe, the Charpy values are high, and shear area is also higher than the X42 / L290 material. Although an over-simplification, Table 1 suggests that the X70 / L485 material would have higher toughness values than the X42 / L290 material in hydrogen even following a 90% knock-down in toughness.

Table 1 – Properties as tested for a low strength (<X52) and a high Strength (X70) steel

Grade	YS (ksi)	UTS (ksi)	Y/T	Uniform Elongation (%)	Location	Test Temperature	Individual Impact Energy (J)	Shear Area (%)
X42 / L290	53	72	0.74	35	Pipe body	0°C	19, 16, 18	80, 70, 70
X70 / L485	72	96	0.75	34	Pipe body	0°C	308, 258, 275	100, 100, 100

The argument that increasing strength and grades tend to come with higher actual toughness is also mirrored by the minimum Charpy specification as defined by API 5L PSL 2: For diameters of 30" (762 mm) and lower, the minimum value increases from 27 J for grades of X70 / L485 and below, to 40 J for X80 / L555 and higher.

[4] Charpy impact data are often taken as a proxy for true fracture toughness. Higher Charpy results are often thought of as implying higher fracture toughness, and hence a lower failure probability from cracking.

Consequently, it is difficult to justify why a pipeline operator should view the X70 / L485 material as inferior or higher risk compared to X42 / L290 for hydrogen service. Even if higher strength materials (>X52) were assumed to be relatively ‘more susceptible’ to hydrogen embrittlement, the resulting implications for pipeline integrity are not as absolute. Higher grades could ultimately benefit from a higher resistance to the presence of cracking.

External mechanical interferences and elongation

Third party damages (dents, gouges) and geohazards threats (bending/ longitudinal stresses) are key integrity threats under natural gas service. The pipeline propensity to failure against these threats is mainly dictated by the pipeline materials “ductility”. A direct consequence of this is that these topics are likely to become even more critical under gaseous hydrogen operations, due to the potential loss of “ductility” resulting from HE. While there is ongoing research to quantify the actual impact of hydrogen on assessing these threats, the current practices and guidelines [6] [25] have already taken conservative approaches in applying strict knock-downs to ductile limits (e.g. strain) commonly applicable in natural gas [26].

The elongation property is generally considered as a representative proxy for ductility, i.e. a higher level of total elongation is often considered as entailing a higher ductility. There is a general expectation that increasing strength leads to decreasing ductility. This is mirrored by the specification minimum requirements for elongation as defined by API 5L PSL2, which decrease with increasing pipe grade (i.e. 22% for Grade B / L245 and X42 / L290, to 15% for X80 / L555).

Higher grades may therefore suffer from a higher vulnerability than low grades. However, this analysis may be too conservative in all cases and needs to be cautioned, mainly because elongation vs. grades is not a direct correlation due to influences of microstructures. This is well illustrated by Table 1, which shows in this case that a X70 / L485 grade has comparable (albeit marginally lower) uniform elongation than for X42 / L290 (i.e. 34 vs. 35%). The “Y/T” ratio, which is also another design proxy for the ability of the line pipe material to tolerate plastic strain, show comparable levels. Nevertheless, the key question remains whether these two materials are really equal in regards to hydrogen, and to which extent the respective ‘ductile’ properties will be degraded. In that respect, empirical evidence would suggest that the X70 / L485 should be the most affected by hydrogen, but this is not deterministic as illustrated in Figure 5 [27]. As an additional note, most work and specifications concentrate on total elongation as a measure. A better measure of ductility in the context of pipeline operation is uniform elongation (i.e. elongation before maximum load / onset of necking). The effect of hydrogen on uniform elongation is less defined but the limited data available implies it is less significant that on total elongation [25].

Figure 5 [27] shows the total elongation of various grades in hydrogen. Looking past the misleading and inappropriate trend line on the chart, it can be clearly seen that some higher grades (X70, X65) display, against expectations, a less degraded “ductility” in hydrogen, compared to in air, than lower-strength grades (e.g. X52, X60). This is a good illustration of the conservatism undertaken in using the sole use of grade in evaluating hydrogen performance, and in assuming better suitability of low grades over high grades in all cases.

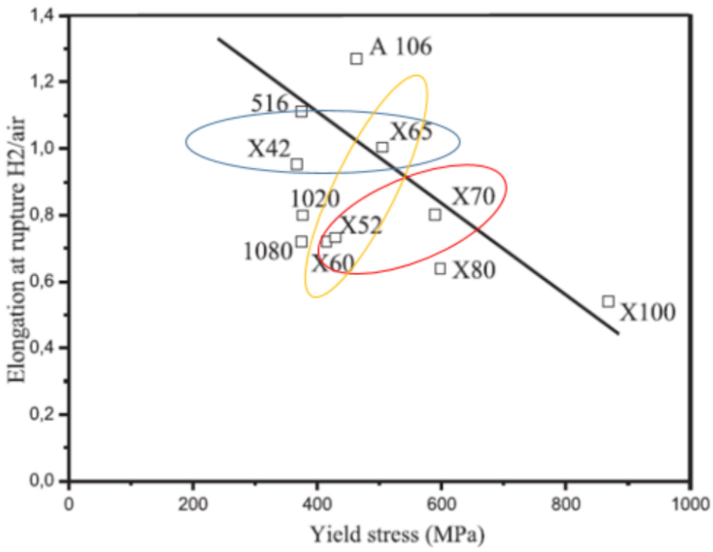


Figure 5 – Total Elongation ratio of various grades in hydrogen vs. air

Hard spots

Hard spots are localized areas with increased hardness compared to surrounding base metal. They generally consist of martensite or other microstructures with elevated hardness, such as bainite or mixtures of martensite and bainite. Martensite is the most concerning threat due to its high hardness and brittle behaviour. Hard spots are generally thought to be induced from localized upsets in the thermal cycle.

Of all the existing threats putting pipelines at risk today, hard spots have become one of the more heavily scrutinized in the last several years due to in-service incidents and changes in regulations, particularly for gas transmission pipelines in the United States of America (USA) [28]. Due to their nature, hard spots will become an even bigger focus for the topic of conversion to hydrogen. This is recognised in ASME B31.12, which states that all “metallurgical notches” (which include arc strikes etc. as well as, inplicitly, conventional “hard spots”) “*shall be prevented or eliminated in all pipelines intended to operate at hoop stress levels of 20% or more of the SMYS.”*

From work conducted in the USA, Tran et al. [28] [29] show that material hardness anomalies have been typically detected on pipes manufactured pre-1970, particularly vintage pipelines from 1950-1960. It is worth noting that the length of post-1980 line pipes inspected for hard spots remains negligible compared to that pre-1970s. Nevertheless, the fact that operators in the USA primarily focus on pre-1970 pipes are a testimony of the perceived susceptibility of vintage pipelines against hard spots. Tran et al. [29] explain that hard spots have typically been observed in older vintage pipes that use plate as feedstock, mainly due to the technology limitations and quality control issues in plate or pipe manufacturing methods before 1970.

The proportion of natural gas transmission pipelines of vintage age (pre-1980) in North America and Europe accounts for approximately 65% [30] and 45% [5] respectively. If we consider the history of the introduction and usage of line pipe grades (as specified by API 5L) in Figure 6, it is clear that an overwhelming majority (>65-70%) of vintage pipelines installed pre-1980 would have been of low strength grades, Grade A to X52. Existing natural gas transmission pipelines of low strength grades (≤ X52) are therefore likely to be more prone to hard spots because of age, while higher pipe grades are likely to have benefited from improved manufacturing practices.

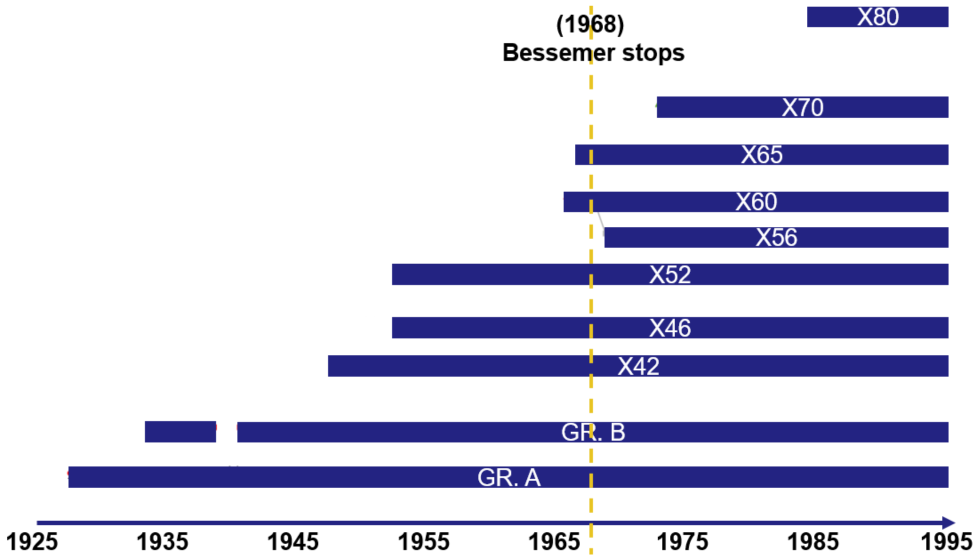


Figure 6 - History of usage of API 5L pipe grades

3.2 The line pipe microstructures vs. grades, and HE susceptibility

The mechanism(s) of hydrogen embrittlement remain in the arena of ongoing research and debate. Various theories have been proposed, mainly:

- Hydrogen Enhanced Localised Plasticity (HELP)
- Hydrogen Enhanced Decohesion (HEDE)
- Adsorption Induced Dislocation Emission (AIDE).

These are well described by Lynch [31], and a detailed description beyond the scope of this paper. The actual mechanism to be considered is likely to be a hybrid of the different theories. A key facet of HE is that its severity is fundamentally modulated by a multitude of variables describing the materials at the microstructural level e.g. phases, constituents, precipitates, non-metallic inclusions, grain sizes, the number and structure of slip planes, residual stresses. Nevertheless, often the susceptibility of HE of steels is first (simplistically) summarised to the type of microstructures (and chemistry) defining the line pipe material, due to their role in the diffusion and solubility of hydrogen. The effect of hydrogen on typical steel line pipe microstructures is described in Table 2 [32, 33, 34, 35, 36, 37, 38].

Table 2 - Effect of Hydrogen on Material Properties for Different Microstructures

Microstructure Phase	**Effect on Material Properties**
Ferrite (polygonal)	Significantly degraded
Pearlite	Relatively immune
Ferrite (acicular)	Significantly degraded
Bainite	Good resistance
Untempered martensite	Severely degraded
Tempered martensite	Good resistance

With this in mind, it is then interesting to review the type of microstructures, which have been targeted to achieve the various pipe grades; although an over-simplification, some trends are outlined below and in Figure 7 [39,40]:

- Low strength grades (≤X52 / L360) consist typically of polygonal ferrite and pearlite, especially for older manufacture.

- Pipe grades in the rage of X52 / L360 to X65 / L450 are typically achieved with fine-grained (microalloyed) ferrite with lower pearlite fraction
- Higher pipe grades (typically X70 / L485 or higher) may consist of acicular ferrite or / and bainite

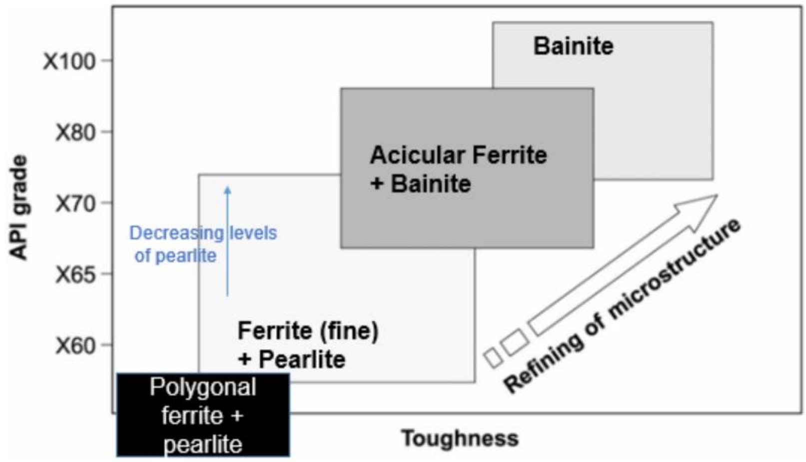


Figure 7 – Schematic of Typical microstructures vs Line pipe steel grades

Looking at Table 2 and Figure 7 at a glance, it could be simply inferred that low strength pipe grades (consisting of ferrite) could be more susceptible to hydrogen embrittlement than higher strength grades, which could benefit from the use of bainitic microstructures, the latter being reported as less susceptible to hydrogen embrittlement. There are however two key points of caution to be highlighted:

- There are obvious overlaps between different domain of microstructures and pipe grades. In other words, a grade can be achieved by different process routes and therefore microstructures. For example, a L415 / X60 pipe manufactured in an HFI mill (coil feedstock) will have a very different microstructure to one manufactured in a UOE / SAW mill (plate feedstock), which will in turn be very different from a seamless pipe (which may be quench and tempered). Subsequently, line pipe materials of a same nominal grade are not all equal against HE susceptibility and hydrogen service.

  This is also well illustrated in Figure 8 [41]; it shows three (3) different materials of X80 grade. The X80 materials show different responses in fracture toughness reduction when increasing hydrogen partial pressure. It is also interesting to note that the lower grade (Grade B) shows empirically a more degraded fracture toughness at higher fugacities of hydrogen than two X80 materials, which reflects upon the arguments made earlier in section 3.1. This again highlights the oversimplification of B31.12-Option A in regards to categorising performance in hydrogen only against grade, and the conservatism in restricting the use pf higher grades.

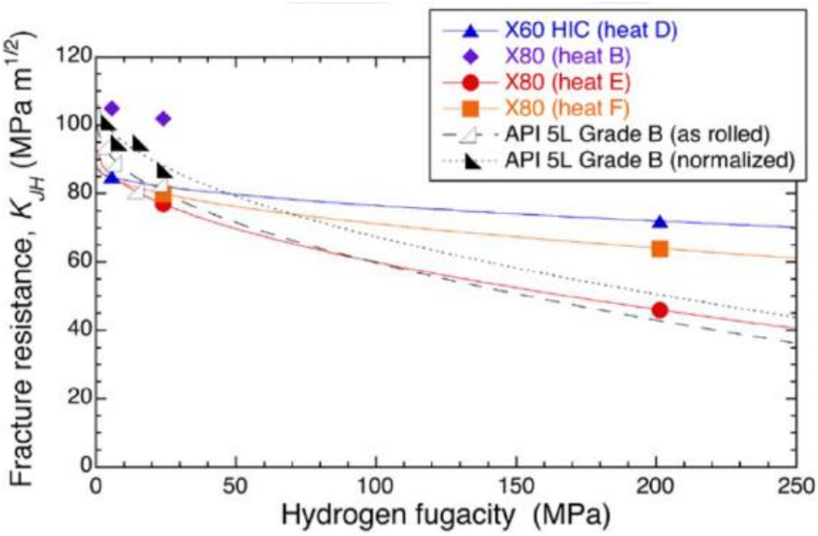


Figure 8 – Effect of hydrogen gas pressure on fracture toughness on pipeline grades

- In the first instance, this seems contradictory to the general perceived trends of higher strength pipe grades experiencing more severe reductions in material ductility and fracture toughness properties. But, this consensus is equally not as accurate in all cases as reflected before with Figure 5 and Figure 8. Therefore it appears that reasoning the susceptibility to HE with grades is not as deterministic. A simple explanation to this is that the behaviour of line pipe in hydrogen cannot be simply related to microstructural composition. HE is a multivariate and complex problem, from which variables associated with the microstructural (e.g. phases, chemistry) and macroscopic (e.g. grade, mechanical properties, stresses) level cannot be independently extracted and assessed in isolation. There is also the role of absolute stress to take into account, higher grade materials will generally operate at higher absolute stresses. Again, isolating the importances of material susceptibility and absolute stress is very challenging.

There could be some appetite to develop empirical relations in regards to materials grade, microstructure and chemistry in order to infer hydrogen performance. While the exercise would be beneficial from a screening point of view, the previous observations suggests that this may not be entirely free of erroneous responses due to the complexity of the problem. An example of the complications involved is shown below. Table 3 shows two pipe materials of nominal specified grade X52, with an almost identical chemical composition and identical delivery condition. However they display totally different mechanical behaviours. Material#1 has much higher actual yield and tensile strengths, but Material #2 has much improved mechanical 'ductile' properties. Indeed, Material #2 displays a better total elongation, and better "Y/T" ratio. In this case, Material#2 is of PSL 2 specification and therefore meets a minimum Charpy requirement, which is not the case of Material#1 (PSL 1). The performance of these two materials in hydrogen environments in the presence of a crack, dent or other integrity threat, might be expected to differ very significantly (despite this, the material performance factor (H_f) for both materials would be the same under B31.12-Option A). It would be interesting how these cases are tackled in future HE susceptibility screening methods.

Table 3 –Nominally specified X52 Materials with similar chemistry & different mechanical properties

Material	Grade	Element Concentration (wt.%)									YS (ksi)	UTS (ksi)	Y/T	E(%)
		C	Mn	Si	P	S	Al	Nb	V	Ti				
#1	X52M	0.04	1.06	0.20	0.01	0.001	0.03	0.03	-	0.01	78.7	81.2	0.97	36
#2	X52M	0.04	1.07	0.21	0.01	0.002	0.034	0.032	-	0.014	61.1	72.4	0.84	42

3.3 “Nominal” pipe Grade compared to actual strength

As discussed earlier, pipe grade has been used as a proxy to strength in order to discriminate the performance of line pipe materials in hydrogen, and current guidelines favour the use of low strength grades up to X52. Unfortunately, for line pipe steels, grade is not even a good predictor of actual pipe strength and its value therefore becomes even less clear. Figure 9 shows the ranges for YS and UTS permitted by API 5L PSL 2. The dashed red lines indicate the areas of overlap in allowable strengths between each of the grades. For UTS, there is overlap in the permitted ranges between all grades from Grade B / L245 to X80 / L555. For YS, there is overlap in the permitted ranges from Grade B / L245 to X65 / L450, and from X52 / L360 to X80 / L555. Note that for PSL1 pipe, and pipe manufactured before 2000, there may have been no maximum YS or UTS stated; in this context, line pipe with high actual strength could have been certified to any grade.

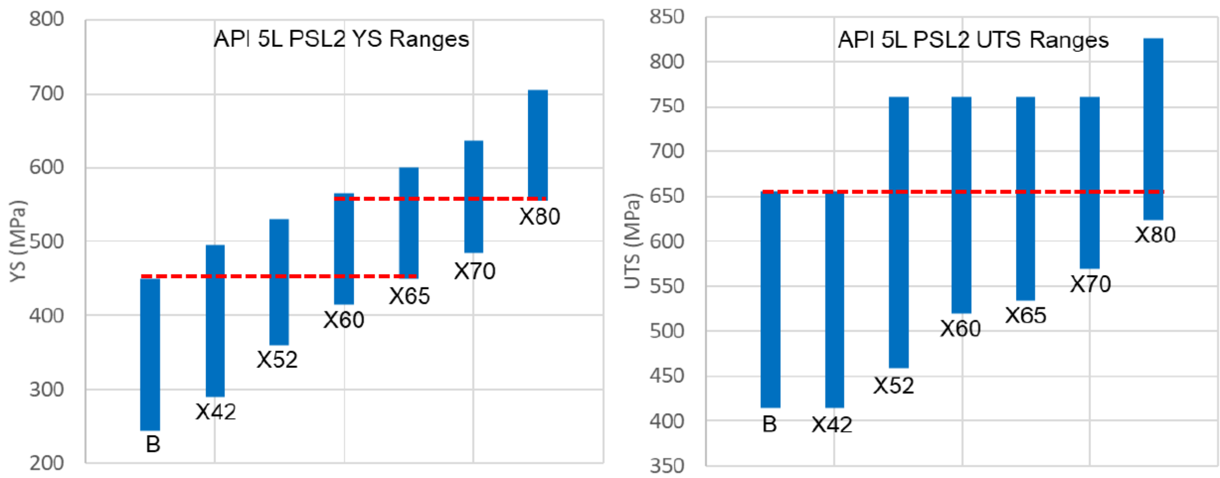
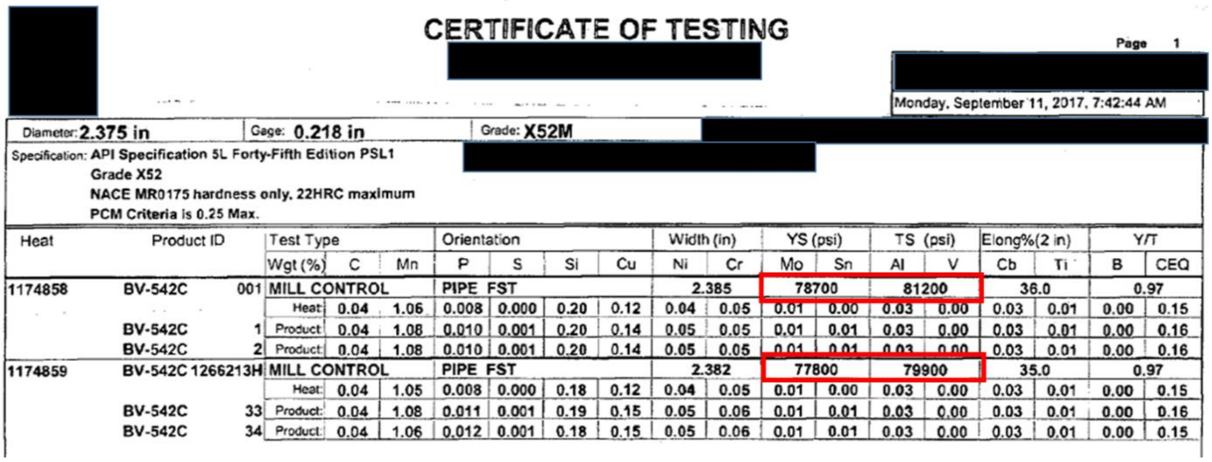


Figure 9 – Yield and tensile strength ranges for API 5L grades

Considering these very significant overlaps, it becomes an obvious conclusion that the ‘nominal’ or certified pipe grade cannot be used as reliable indicator of actual YS or actual UTS. Although it may be expected as a very broad rule of thumb that higher actual strength pipe will be certified as higher nominal grades, this is not always the case for a number of reasons relating to operational efficiencies, cost optimisation and customer preferences.

To illustrate the variations that exist within a single nominal grade, an extract of an MTR is shown in Figure 10, with actual measured YS and UTS highlighted by the red boxes. Considering these values (YS of 78.7 ksi and UTS of 81.2 ksi), it might be assumed at face value that this is X70 / L485 pipe (though in fact the UTS only meets the SMUTS for X65 / L450). In this case, the MTR is actually for X52 / L360 pipe certified to API 5L PSL1, manufactured in 2017.

This is a very clear illustration of how assumptions of hydrogen performance based only on specified pipe grade can be dangerous. Based on criteria within standards such as ASME B31.12, as X52 / L360 this pipe would have a material factor (H_f) of 1.0, whereas had this material been certified as X65 / L450 it would have an (Option A) H_f of 0.776, forcing a 22% reduction in the design pressure, despite identical actual properties.



CERTIFICATE OF TESTING

[redacted]

Page 1

[redacted]

Monday, September 11, 2017, 7:42:44 AM

Diameter: 2.375 in | Gage: 0.218 in | Grade: X52M [redacted]

Specification: API Specification 5L Forty-Fifth Edition PSL1 [redacted]
Grade X52
NACE MR0175 hardness only, 22HRC maximum
PCM Criteria is 0.25 Max.

Heat	Product ID		Test Type			Orientation				Width (in)		YS (psi)		TS (psi)		Elong%(2 in)		Y/T	
			Wgt (%)	C	Mn	P	S	Si	Cu	Ni	Cr	Mo	Sn	Al	V	Cb	Ti	B	CEQ
1174858	BV-542C	001	MILL CONTROL			PIPE FST				2.385		78700		81200		36.0		0.97	
			Heat	0.04	1.06	0.008	0.000	0.20	0.12	0.04	0.05	0.01	0.00	0.03	0.00	0.03	0.01	0.00	0.15
	BV-542C	1	Product	0.04	1.08	0.010	0.001	0.20	0.14	0.05	0.05	0.01	0.01	0.03	0.00	0.03	0.01	0.00	0.16
	BV-542C	2	Product	0.04	1.08	0.010	0.001	0.20	0.14	0.05	0.05	0.01	0.01	0.03	0.00	0.03	0.01	0.00	0.16
1174859	BV-542C	1266213H	MILL CONTROL			PIPE FST				2.382		77800		79900		35.0		0.97	
			Heat	0.04	1.05	0.008	0.000	0.18	0.12	0.04	0.05	0.01	0.00	0.03	0.00	0.03	0.01	0.00	0.15
	BV-542C	33	Product	0.04	1.08	0.011	0.001	0.19	0.15	0.05	0.06	0.01	0.01	0.03	0.00	0.03	0.01	0.00	0.16
	BV-542C	34	Product	0.04	1.06	0.012	0.001	0.18	0.15	0.05	0.06	0.01	0.01	0.03	0.00	0.03	0.01	0.00	0.15

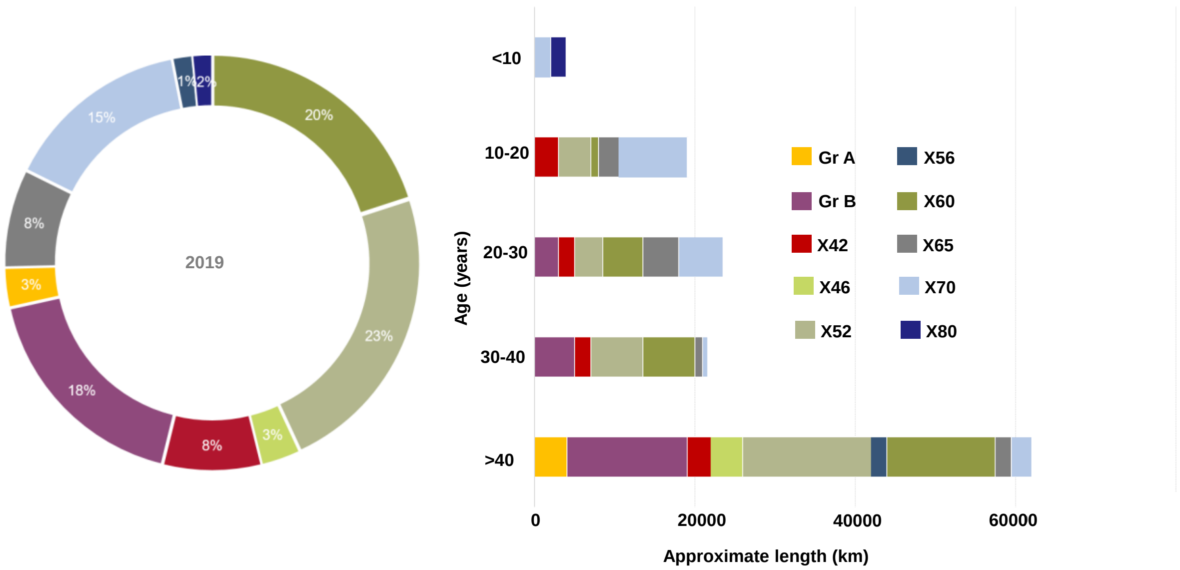
Figure 10 – Example MTR for X52 pipe with YS and UTS meeting X65

4.0 HYDROGEN CHAIN VALUE & CONVERSION APPROACH OPPORTUNITES

4.1 Existing B31.12 code vs hydrogen chain value challenges

Almost 50% of the existing European and North American gas transmission network is manufactured from grades above X52 / L360 [5] [30]; this is illustrated by Figure 11 for Europe [5]. Note this proportion is actually higher if we consider the issue of nominal minimum specified grade versus actual strength as discussed in section 3.3.

Thus, following the current edition for ASME B31.12 – Option A [6] would reduce allowable operating pressures for a significant proportion of existing pipelines once converted to hydrogen service, effectively reducing available energy throughput capacity within Europe compared with that currently transported via natural gas. While this provides a practical path to conversion, this also raises interesting questions on the hydrogen transportation chain efficiency. If we factor the lower energy efficiency of hydrogen, the enforcement of further utilization limits, without engineering due diligence, could prove uneconomical in the case of hydrogen.



a. b.

Figure 11- Steel Grades in European Natural Gas Transmission Lines by a) Grade and b) Age

4.2 Existing B31.12 code vs conversion integrity challenges

B31.12-Option A uses pipe grade as a proxy to strength in order to discriminate the performance of line pipe materials in hydrogen; effectively the code (as most other existing guidelines) favours the use of low strength grades up to X52, and penalizes higher strength grades (>X52).

The paper points to the fact that this simplistic binary approach, centered on grades, has important technical flaws: Not every grades up to X52 are automatically suitable for conversion, while grades above X52 are not inevitably unsuitable to conversion. The suitability of conversion to hydrogen service requires a holistic review of the pipeline fitness-for-service and the variables augmenting its risk profile against hydrogen transportation.

- Specified nominal grade is a poor proxy for strength: For example, for YS, there is overlap in the permitted ranges from Grade B / L245 to X65 / L450, and from X52 / L360 to X80 / L555.
- Nominal grade is not a reliable predictor for the "materials performance" of line pipe in hydrogen, and its susceptibility to HE. Higher grades do not display (against expectations), a more degraded "ductility" and fracture toughness in hydrogen than lower-strength grades in *every* case. HE is a multivariate and complex problem, from which variables e.g. grade cannot be assessed in isolation.
- Line pipe materials of a same nominal grade are not all equal against HE susceptibility and hydrogen service. Grades can be achieved by different process routes and microstructures.
- Even if higher strength materials (>X52) were assumed to be relatively 'more susceptible' to hydrogen embrittlement, the resulting implications for pipeline integrity and fitness-for service are not as absolute. Higher strength grades will generally tend to have higher actual toughness than lower strength grades Higher grades could ultimately benefit from a higher resistance to the presence of cracking, albeit suffering (hypothetically) from greater knock-down factors.
- Pipe grades up to X52 have suffered in-service incidents in other more severe hydrogen charging applications, showing these are also not automatically immune to HE issues.
- General integrity - low-strength streels ≤ X52 steels may be less susceptible to hydrogen embrittlement, but this population also comes with somewhat greater integrity issues (e.g. hard spots) and a poorer baseline condition than for higher strength steels, mainly due to age, and imperfect manufacturing, construction, installation and corrosion mitigation practices. [30] [42]

4.3 Conversion approaches – the importance of testing

Whilst grade is not a useful indicator of 'material performance' for hydrogen pipelines, it is recognised that it is challenging to define an alternative metric that is similarly simple and readily available for conversion of existing pipelines. There could be some eagerness to upgrade the B31.12 option A into a more complex empirical relation between microstructure, chemistry and grade in order to propose a quantification of line pipe HE susceptibility. The success of such enterprise remains to be seen, but it is likely that any proposed models could come with erroneous responses due to the complexity of the problem at a multiscale level. The challenge is somewhat analogous to that has been experienced for deriving robust materials-based correlations for other Stress-Corrosion Cracking mechanisms encountered in the pipeline industry, which has proved very difficult, and not resolved [[43]]. If the Option A approach of limiting hoop stress below that allowed for natural gas is maintained, the rewards achieved by this approach in terms of economic future operation are also likely to be low.

Another path would be to consider the in-air toughness or Charpy values and apply conservative 'knock-down' factors, such as that specified in the IGEM/TD/1 supplement. However, Charpy and fracture toughness data in air are not readily available for a majority of existing pipeline systems. Charpy (CVN) testing has only been required since 2000, yet only for pipelines specified to API 5L PSL 2. It might be possible to assume minimum values applicable based on pipe characteristics (e.g. type, age, geography).

But this process may not be entirely free of errors, or at best may not be representative of actual material properties, which could lead to lack of diligence, or over-conservatism (restricting future energy throughput).

It is also interesting to note that certain tentative research points to the potential existence of a "great leveller", that the hydrogen affected material properties of all steel microstructures converge around the same level (currently assumed to be close to the 50 ksi.in$^{1/2}$ / 55 MPa.m$^{1/2}$ threshold stress intensity factor defined in ASME B31.12). This approach is currently the subject of much research but as noted above, given that hydrogen embrittlement is an atomic / microstructural effect it appears unlikely that this will be true for all applications, and there is the risk of unnecessary over-conservatism being applied in some cases.

Keeping in mind the relatively very limited global experience and track record of safely operating extensive repurposed hydrogen pipeline systems, the industry should not underestimate the need, at least in the short term, to characterise and qualify asset-specific performance and integrity for future hydrogen service. The only pragmatic answer at present to demonstrating suitability for hydrogen service is through risk-driven approaches, supported by a combination of appropriately conservative assumptions and selective, targeted destructive testing in hydrogen

Reflecting on the aforementioned techno-economic issues, it seems vital and logical that duty holders proceed to the actual assessment of materials performance in hydrogen by the testing of line pipe representative to their respective systems, in order to address conversion safely and without undue conservatism. This alternative is actually captured by B31.12 Option B. In particular, ASME B31.12 permits Option B designs to use the same design factors as their natural gas equivalents, and the material performance factor to be set to 1 if the existing line pipe material can be "qualified" in gaseous hydrogen.

A key requirement for such alternatives is that the duty holder shall have a suitable understanding of the materials populations existing across existing pipeline distance, in order to proceed to the targeting and testing of all representative materials. The drawback is that understanding material populations and characteristics could be challenging for long pipelines, especially on older systems, for which construction details or original mill test certificates may not be available. In this case ASME B31.12 currently mandates material sampling every mile (1.6 km) to provide some evidence of the materials present. This approach is very onerous and not practical in many cases. It aligns with US regulations introduced in 2019, in which gas transmission pipeline operators must verify material properties and attributes where not adequately documented, at a rate of 1 per mile. The authors have published a number of conference papers critiquing the challenges and drawbacks of this 'one size fits all' approach and have advocated for 'smarter' approaches [44], [45], [46], [47].

Developing smarter sampling strategies using material-population in-line inspections

For piggable pipelines, the use of material-population in-line inspections (ILI), e.g. RoMat-PGS, capable of unveiling pipe properties in regards to materials and construction differences can be more cost-effective: rather than the recommended approach of destructive testing once a mile, testing can be targeted at individual populations. It ensures that no populations are missed[5] [48]. The PGS technology is based on high-resolution eddy current measurements, with the signal response being a function of specific aspects of the pipe chemistry and microstructure. Proprietary algorithms are then used to translate the response into values for yield strength (YS) and ultimate tensile strength (UTS) for each joint. Outputs from this can then be incorporated with data from other sources (both ILI and records) to fully characterise the pipeline and separate out individual pipe "populations". Each individual population is defined by a unique set of shared characteristics (including strength, wall thickness, nominal joint length, pipe type etc.), as a result of this a single population can therefore be confidently associated with a single construction campaign and original pipe mill. This population approach defines

[5] If sampling occurs once a mile, it is very probable that short diversions, repairs or other small populations will be not be sampled, while multiple samples will be taken from the main population and therefore be effectively repeats

the "Pipeline DNA" and allows for the development of smarter and cost-effective sampling strategies of the pipeline and hence for a more robust assessment of the pipeline performance against hydrogen service.

The initial output from a PGS run is an estimation of the YS or UTS associated with each pipe or bend within the inspected pipeline, as shown in Figure 12.

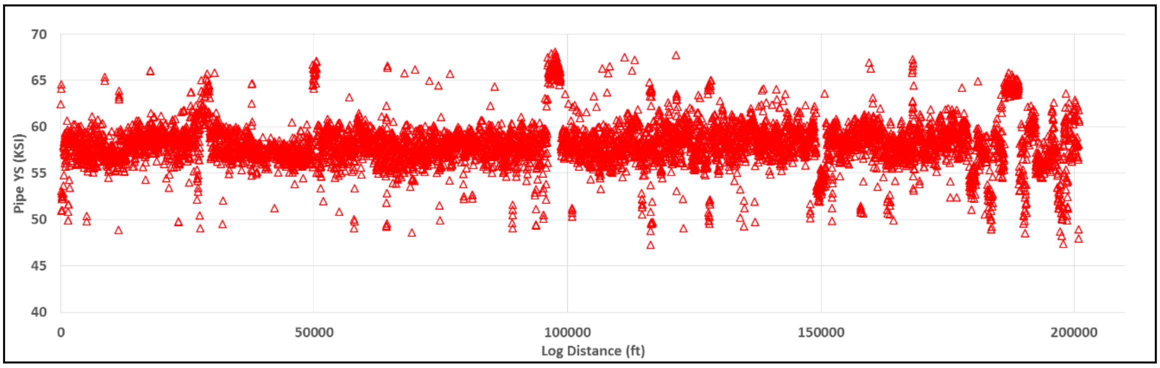


Figure 12 - YS along the pipeline

In the above graph, each point represents a single pipe joint (normally ~12 m length). This output can be used as a stand-alone resource to identify potential strength outliers, however full value is achieved when the data is integrated with other sources to define populations, fully characterise the pipeline and identify the "Pipeline DNA". A completed example is shown in Figure 13, where each data point represents the median strength value attributed to a single pipe. Each population is defined by a unique coloured symbol in the plot.

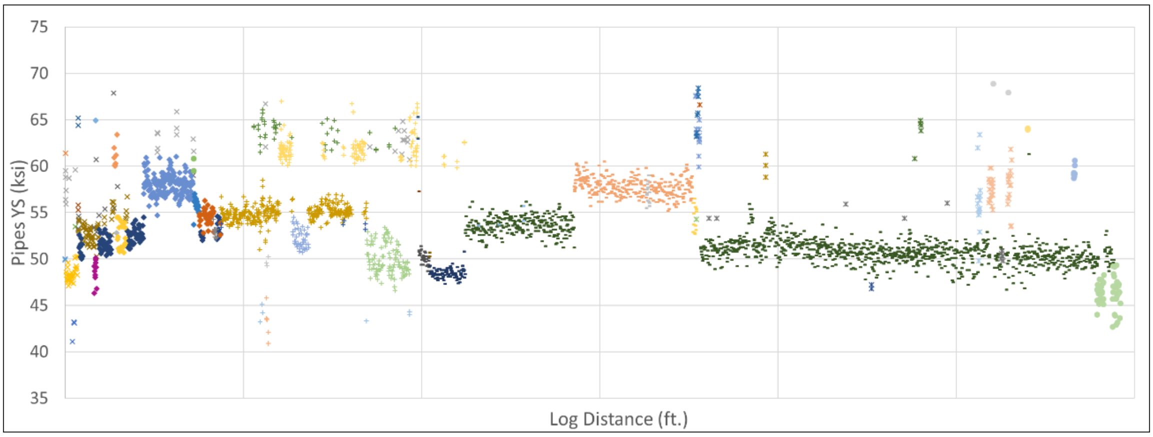


Figure 13 - Populations identified along the full pipeline length

The "Pipeline DNA" can then be overlaid with other datasets, for example suspect crack-like indications from an EMAT inspection or hard spot locations from RoMat DMG, to identify if these hard spots are associated with individual populations.

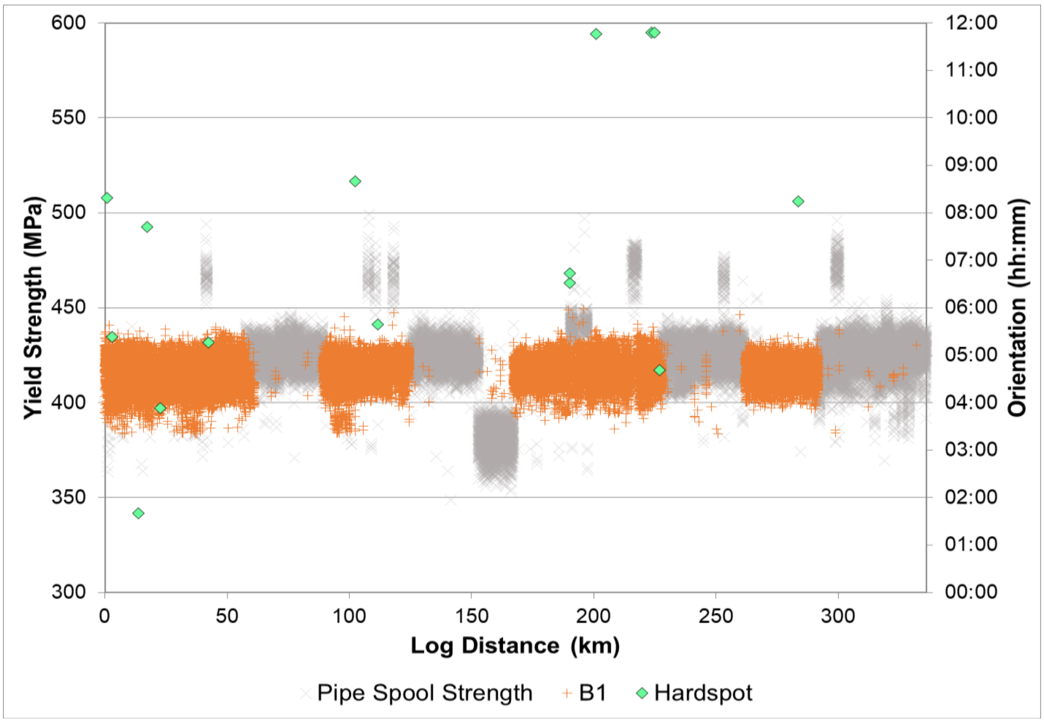


Figure 14 – Hard spots concentrated in a single population

Figure 14 shows an example of this approach, where it can be seen that all 15 hard spots identified in an over 300 km long pipeline were present in population B1, and thus associated with a single mill and construction campaign. No hard spots were identified in any other populations.

This "Pipeline DNA" approach enables a step-change in the approach to assessing materials for suitability for hydrogen service. Rather than the recommended, but blunt, approach of destructive testing once a mile, testing can be targeted at individual populations. This approach has multiple benefits over the standard recommendations. Firstly it ensures that no populations are missed (if sampling occurs once a mile then it is very probable that short diversions, repairs or other small populations will be not be sampled, while multiple samples will be taken from the main population and therefore be effectively repeats). Secondly verification testing can be targeted at areas which may be of concern, for example if a particular population has an anomalously high strength, a high concentration of hard spots or crack-like indications then these can be targeted during verification digs. Additional confidence can be gained in the representative nature of any features which are excavated. For example if all reported hard spots are concentrated in a single population, there is more likelihood that they will be of the same morphology and created by the same mechanism than if they were in different populations. Assessment techniques can therefore be used with more confidence. Destructive testing and evaluation can be targeted at the highest risk locations, both increasing confidence in the test results and minimising the number and cost of verification digs required.

5.0 CONCLUSIONS

Existing hydrogen pipeline codes tend to "punish" the use of higher strength grades by limiting utilisation (operational stresses). This philosophy challenges the realisation of a hydrogen economy, because it puts at economical and technical risk the conversion of almost half of the natural gas transmission systems in Europe and North America.

The penalty is based on the assumption that higher strength materials are more susceptible to hydrogen embrittlement. While there is a rationale behind this assumption , the technical argument presented in this paper shows that the derivation that "low grade pipes are automatically safe for hydrogen repurposing" while, at the other end of the spectrum, "high grade pipes are inevitably less suitable for hydrogen" is as deterministic and is fundamentally flawed in many aspects.

Nominal Grade is not a reliable predictor, either for actual pipe strength or for the "materials performance" of line pipe in hydrogen. Hydrogen embrittlement is a multivariate and complex problem, from which variables from the microstructural and macrostructural levels cannot be assessed in isolation. The suitability of conversion to hydrogen service requires a holistic review of the pipeline fitness-for-service and the variables augmenting its risk profile against hydrogen transportation. For instance, low-strength streels ≤ X52 steels may generally come with somewhat greater integrity issues, mainly due to age, and a lower resistance to the presence of cracks.

Other schools of thoughts are underway to provide some "rule-of thumb" guidances (e.g. fracture toughness being a "great leveller" in hydrogen) or other empirical relationships to qualify the suitability of line pipe in hydrogen. Keeping in mind the relatively very limited global experience and track record of safely operating extensive repurposed hydrogen pipeline systems, the industry should not underestimate the need, at least in the short term, to characterise and qualify asset-specific performance and integrity for future hydrogen service. In reflection of this, it seems only vital and logical that duty holders place materials sampling and testing of representative system material populations at the core of hydrogen repurposing strategies. The knowledge of material populations and risk profiles should be the foundation of developing smart and cost-effective material sampling strategies (instead of the blunt and ineffective "1 dig per mile" approach posited by ASME B31.12).

6.0 REFERENCES

1 Hydrogen Council, How hydrogen empowers the energy transition, 2017
2 Technical and economic conditions for injecting hydrogen into NG networks, Report INIS-FR-20-0156, GRTGaz, June 2019
3 European Hydrogen Backbone, April 2022
4 Gallon, N., Guest, L., Horsley, A., Van Elteren, R., Palmer-Jones, R., Hydrogen getting into focus, Pipeline Technology Conference, Berlin, 2020
5 Sandana, D., Gallon, N., Andrews, R.M., Palmer-Jones, R., "Crack Management of Hydrogen Pipelines," International Conference on Hydrogen Safety, Edinburgh (Virtual), 2021.
6 ASME, ASME B31.12, Hydrogen Piping and Pipelines, New York, 2019
7 CGA, G-5.6 Hydrogen Pipeline Systems, 2013.
8 EIGA, IGC Doc 121/04/E Hydrogen Transportation Pipelines, 2004
9 AIGA, 033/14 Hydrogen Pipeline Systems.
10 IGEM, IGEM/TD/1 Edition 6 Supplement 2 , Communication 1849, High Pressure Hydrogen Pipelines, 2021
11 DVGW, Technischer Hinweis - Merkblatt DVGW G 409 (M) Umstellung von Gashochdruckleitungen aus Stahlrohren fur einen Auslegungsdruck von mehr als 16 bar fur den Transport von Wasserstoff
12 C. San Marchi, R. Shreshta and J. Ronevich, “Hydrogen Compatibility of structural materials in natural gas networks”
13 M. Martin, M. Connolly, F. DelRio and A. Slifka, “Hydrogen Embrittlement in Ferritic Steels,” Appl Phys Rev, 2020.
14 ISO 15156-2 / NACE MR0175, Materials for use in H_2S-containing environments in oil and gas production, Table A.2
15 ISO 15156-2 / NACE MR0175, Materials for use in H_2S-containing environments in oil and gas production, section A.4.3
16 Schoeneich, H-G., Considerations on the risk of hydrogen embrittlement of pipeline steel due to cathodic overprotection, Pipeline Technology Conference, Berlin, 2015
17 BS EN ISO 15589-1, Petroleum, petrochemical and natural gas industries. Cathodic protection of pipeline systems. On-land pipelines, 2017
18 BS EN 12954, General principles of cathodic protection of buried or immersed onshore metallic structures, 2019
19 NACE SP0169-2013, Control of External Corrosion on Underground or Submerged Metallic Piping Systems
20 Private industry meeting report, HISC in a dent, case history and lab tests, 1995
21 Punter, A., Fikkers, A.T., Vanstaen, G., HISC on a pipeline, Materials performance, June1992
22 British Standards Institution (BSI), “Guide to methods for assessing the acceptibility of flaws in metallic structures, BS 7910:2019,” December 2019
23 American Petroleum Institute (API) and The American Society of Mechanical Engineers (ASME), “Fitness-for-Service, API 579-1/ASME FFS-1,” API, Washington, December 2021.
24 N Yurioka, TMCP steels and their welding, Welding in the World, Vol 35 No.6 1995 375-389.
25 EPRG, Robert Andrews e al., Integrity assessment methods, EPRG report Project number 221/WP2/, 2021
26 American Society of Mechanical Engineers, “ASME B31.8-2020, Gas Transmission and Distribution Piping Systems, ASME Code for Pressure Piping, B31B31.8-2020,” New York, 2020.
27 EPRG, Neil Gallon et al., Hydrogen Transport Pipelines-Design/challenges and mitigations, EPRG221/220, 2020
28 Khan Tran, Simon Slater, Jason Edwards, Know your enemy – improvements in managing the threat of hard spots, IPC 2022 – 88362, IPC 2022, 2022
29 Khan Tran, Simon Slater, Jason Edwards, Sea Moran, A Reo, David Rutch, Making hard decisions, Pipelie Pgging and Integrity Conference (PPIM), 6-10 February 2023, Houston
30 Daniel Sandana, Neil Gallon, Ollie Burkinshaw, Arti Bhatia, Safe repurposing of vintage pipelines for hydrogen in North America, IPC 2022-87088, IPC 2022, 2022
31 Stan Lynch, Hydrogen embrittlement phenomena and mechanisms, Corrosion reviews Journal, volume 30 issue 3-4, 2012
32 Holbrook et al., “Control of hydrogen embrittlement of metals by chemical inhibitors and coatings”
33 Ronevich et al., “Understanding the bounds of oxygen mitigated hydrogen embrittlement in ferritic steels, SAND2019-11638C,” 2019.
34 Hayden et al., “ASME B31.12 hydrogen piping and pipeline code design rules and their

interaction with pipeline material concerns, issues and research," in ASME PVP, Prague, 2009
35 J. Ronevich, B.Somerday and C. S. Marchi, "Effect of Microstructure Banding on Hydrogen Assisted Fatigue Crack Growth in X65 Pipeline Steels"
36 Ghent University, "Literature Review: Chapter VI - Interaction between hydrogen and material characteristics (not public domain)"
37 Nanninga et al., "Role of microstructure, composition and hardness in resisting hydrogen embrittlement of fastener grade steels," Corrosion Science, vol. 52, pp. 1237-1246, 2010
38 T.Depover, E. v. d. Eeckhout and K.Verbeken, "The impact of hydrogen on the ductility loss of bainitic Fe-C alloys," Materials Science and Technology, vol. 32, pp. 1625-1631, 2016.
39 C, Garcia et al, On the strength of microalloyed steels: An interpretive review, Materials Science ad technology:A interpretive view Journal, volume 25, 2009
40 Carl-Peter Reip, Wolfgang Hennig, Rolf Hagmann, Bin Mohamad Suren Sabrudin , Ghosh Susanta and Weng Lan Lee, Thin slab processing of acicular ferrite steels with high toughness, IBP1073-05, Rio Pipeline 2005, 2005
41 CEN/TC 234 WI 00234080
42 Kiefner, J.F., Rosenfeld, M.J., for INGAA, "The Role of Pipeline Age in Pipeline Safety", 2012
43 Daniel Sandana, High-pH and ear-Neutral pH SCC of pipelines: challenges in susceptibility modelling, Pipelines International Journal, Issue 37, Fall 2018
44 O. Burkinshaw, S. Slater, M. Capewell and M. Smith, "Material Property Verification: Alternative Sampling Strategies," in PPIM, Houston, TX, 2021.
45 O. Burkinshaw and S. Slater, "The Role of ILI in the MAOP Verification Process," in PPIM, Houston, TX, 2019.
46 O. Burkinshaw, F. Niemeyer, A. Destefano and P. Hyrcius, "Case Study: A Combined ILI and Data Integration Approach to Determine the Material Properties of Undocumented Pipeline Sections," in PPIM, Houston, TX, 2021.
47 S. Slater, K. Dwyer, M. Ginten, T. Eiken and O. Burkinshaw, "An Integrated Approach for the Verification of Pipeline Material Using State-of-the-Art Technologies and Processes," in IPC, Calgary, Canada, 2018.
48 Gallon, N., Van Elteren, R., "Existing pipeline materials and the transition to hydrogen", Pipeline Technology Conference, Berlin, 2021