Transport of Hydrogen in Existing Natural Gas Pipelines Design Considerations

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1.0 Introduction

Hydrogen is increasingly of interest as an energy vector facilitating the world's decarbonization efforts. As a part of this undertaking, natural gas pipeline operators are investigating using hydrogen as a blend gas in existing natural gas pipelines or converting pipelines entirely to hydrogen use.

Current regulated limits on hydrogen in natural gas range from 0% to 10% depending on the specific locale and pipeline system in question[1]. Several demonstration projects around the world are underway, however, to support increased blending within the natural gas pipeline networks (e.g. HyDeploy, HyBlend, H2 Commons).

This paper is intended to provide an overview of some key considerations necessary when evaluating these existing pipeline systems. <u>It is not comprehensive and should not be considered as a prescriptive guide or manual for complete evaluation or approval of a given pipeline system or component for blend gas or hydrogen service.</u>

1.1 Summary Outlook

Gas transport networks vary in materials, date of construction, fabrication techniques, and inspection methods applied. Over the past 50 years, materials and welding fabrication methods have advanced considerably. Currently, some national natural gas specifications already allow the blending of up to 10% hydrogen. There is a general consensus that levels of hydrogen can be increased to higher content levels, and that the integrity of the pipelines is generally not the limiting factor:

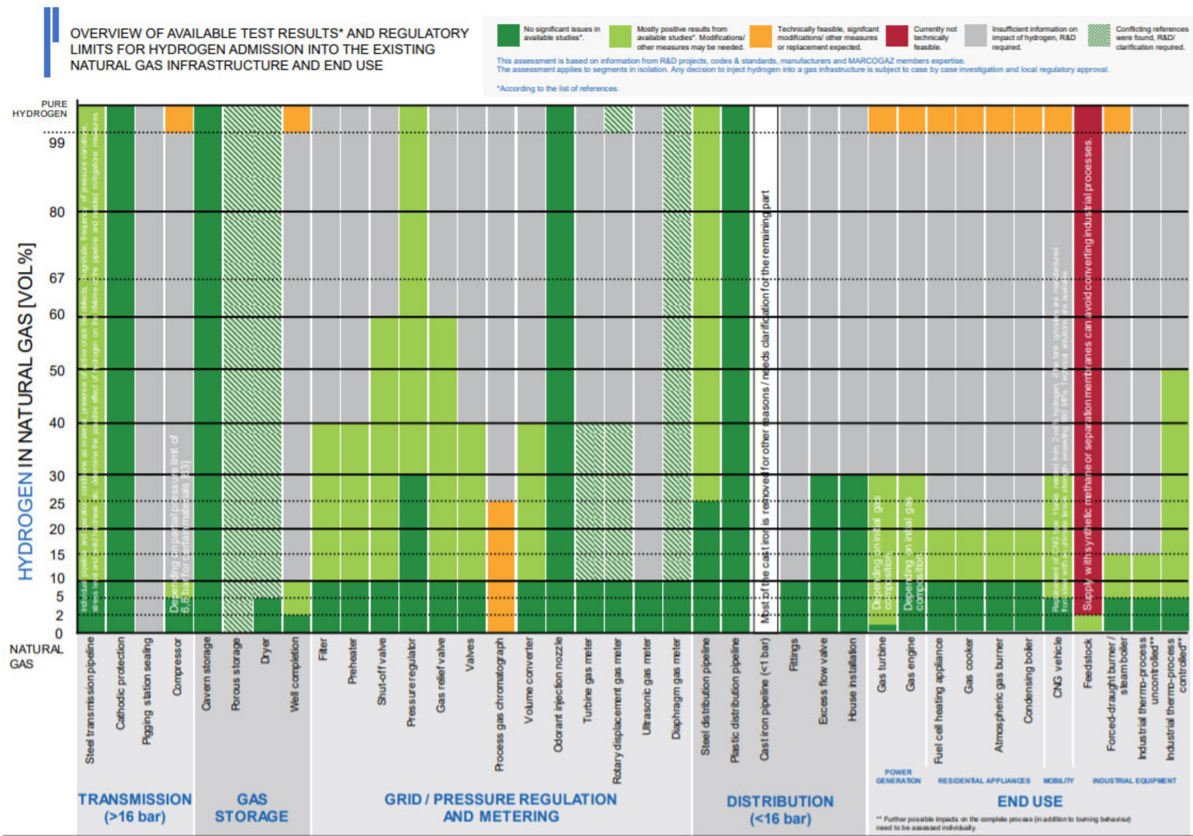
"Research and lessons learned from first hydrogen projects by European gas TSOs [Transmission System Operators] show that dedicated hydrogen pipelines do not differ significantly from natural gas pipelines…Similarly, existing natural gas pipelines need little modification to be fit for 100% hydrogen transport as the pipeline materials are generally fit for hydrogen transport as well."[2]

These types of generalized statements are readily found throughout literature but neglect or gloss over important potential limitations. As with all engineering design challenges, there is no "one-size-fits-all solution."[2] A thorough assessment will be necessary for each individual pipeline to be converted. Low levels of blending may be practical in many cases while high levels of blending or conversion to 100% hydrogen will impose many more challenges and limitations on the allowable pipeline operating conditions. Full conversion to hydrogen in particular would likely require a lower allowable operating pressure in many transmission pipelines resulting in significant de-rating of the pipeline capacity. With this high level consideration and based on significant anticipated growth in the hydrogen market, it is expected that there will be a mix of

[1] https://www.iea.org/articles/special-focus-on-gas-infrastructure
[2] European Hydrogen Backbone - How a Dedicated Hydrogen Infrastructure Can Be Created, Report by European Gas Operators, JULY 2020.

opportunistic use of existing pipelines, renewable natural gas (RNG) where hydrogen is not suitable, and new dedicated hydrogen pipelines.

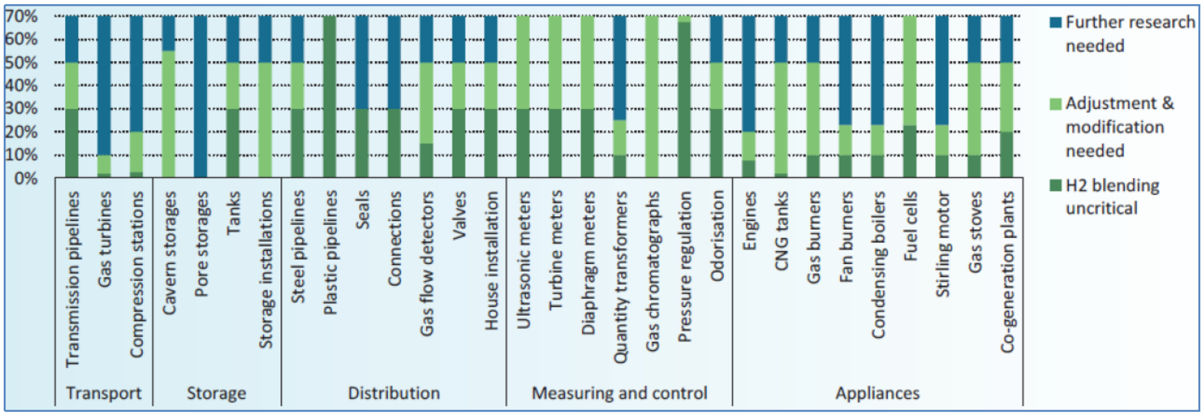
A summary of the technical readiness for various components of existing natural gas infrastructure and end user equipment to handle hydrogen-natural gas mixtures has been prepared by Marcogaz, a non-profit representing the European gas industry[3]:



This summary indicates that there is broad technical readiness with no major material replacement requirements on most components for blending up to 10%. There are, however, several caveats and potential factors that could limit the allowable blending to below 10% in certain systems.

One of the major gas utilities in the United States, Pacific Gas and Electric (PG&E), has published a similar chart with somewhat varied but similar views on allowable blending limits[4]:

[3] Overview of Available Test Results and Regulatory Limits for Hydrogen Admission into Existing Natural Gas Infrastructure and End Use (https://www.marcogaz.org/wp-content/uploads/2021/04/TF_H2-427.pdf)
[4] https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/Whitepaper_PipelineHydrogenAnalysis.pdf



The following sections of this report provide additional discussion and background on some of the issues associated with blending of hydrogen into existing natural gas pipeline systems.

2.0 Process and Equipment Design Considerations

2.1 Energy Density and Pipeline Capacity

Hydrogen has a lower volumetric energy density compared to natural gas. The consequence of this difference in properties is that an increase in blended gas volumetric flow rate is required to deliver the same amount of energy content as unblended natural gas, even at the same operating pressure. For example, at a 20 vol% hydrogen blend rate, the required flow should be increased approximately 15% to maintain the same delivered energy.

Increased operating pressure can be considered to reduce this volumetric flow impact but for pipelines operating near their maximum allowable operating pressure (MAOP) this may not be practical. Additionally, increased pressure may negatively impact metallurgical considerations discussed further in Section 3.0 and Appendix A. Blending of high hydrogen levels or full conversion to hydrogen service may require reduced operating pressure to address materials related concerns which further impacts energy delivery capacity. As such, peak required pipeline demand throughout the year needs to be evaluated to ensure adequate capacity is available as higher blends of hydrogen are used.

2.2 Compression and Compression Drivers

Natural gas pipeline networks utilize compression stations to boost gas pressure ensuring delivery from the producers to consumers within the pipeline service area. These stations use a variety of compressor models based on the size, required duty cycle, age of facility, etc. Additionally, many of the compressors utilize a portion of the pipeline gas to drive the machines via gas engines or gas turbines. These drivers, unless specifically designed for hydrogen, have strict performance limits on the allowable hydrogen content. The limits are often 5% or less to minimize change in parameters such as methane number, Wobbe index, and laminar flame speed. Higher hydrogen content in gas engine fuel, for example, can lead to engine knocking, higher NOx emissions, and increased component wear. Any conversion to blend gas or hydrogen on systems including compression facilities require analysis of the specific machines impacted.

2.3 Non-Industrial Consumers / End Users

Most home appliances in Europe since the early 1990s have been tested with 23% H_2 / 77% methane (test gas G222) supporting the general belief that commercial and residential appliances generally can accommodate up to 20% hydrogen blend without significant concern. Considering, however, the vast number and types of appliances in existence across the world and the limited scope of testing on hydrogen enriched natural gas there remains some uncertainty on this point so a reasonable safety margin should be considered. This represents a natural socioeconomic barrier to blending in many pipeline systems much above 20 vol% in the near future. Other end user systems have even stricter limits that require consideration if applicable to the pipelines being considered. Compressed Natural Gas (CNG) vehicles, for example, currently have a 2 vol% hydrogen limit.

2.4 Hydrogen Leakage Rates

Hydrogen is a very small molecule with a tendency towards leakage through flanged joints, couplings, and valve stem seals. Studies have estimated that the leakage rate for hydrogen is approximately triple that of methane[5]. In the context of an industrial pipeline, this amount of leakage is still so low as to be of little concern, but additional caution may be warranted for any confined areas.

Of greater consideration is full conversion of a natural gas pipeline to hydrogen service. Currently natural gas is odorized to help identify leakage. Hydrogen, however, does not have a standard odorant and addition of typical odorants may be detrimental to hydrogen consumers from the pipeline. A comprehensive safety evaluation should be considered based on the locale and routing of the proposed pipeline system.

3.0 Metallurgical Considerations

3.1 Hydrogen Degradation and Embrittlement Overview

Hydrogen can cause many degradation mechanisms in steel. However, the prerequisites for these mechanisms vary, and some mechanisms are not met in typical pipeline applications considering dry conditions (i.e. no liquid water) and ambient temperatures. Hence, only specific hydrogen degradation mechanisms may be active based on process conditions, and the risk of these mechanisms will then depend on the steel properties and conditions.

In the below matrix, all hydrogen degradation mechanisms that need to be considered for steel are listed, and comments are given on the applicability to hydrogen transport pipelines.

[5] M. W. Melaina, O. Antonia, and M. Penev, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, Technical Report, NREL/TP-5600-51995, March 2013

Hydrogen Degradation and Embrittlement Mechanisms (Note 1)			
Mechanism	**Description**	**Temperature - Pressure Range**	**Active in an ambient temperature transport line?**
HTHA [6)]	HTHA – High Temperature Hydrogen Attack	> 200°C /3.5bara > 400°F / 50psi	No
Cracking as a result of Hydrogen charging in aqueous environments [7)]	HSC – Hydrogen Stress Cracking SSC -Sulfide Stress Cracking Hydrogen Blistering HIC / SOHIC – (Stress Oriented) Hydrogen Induced Cracking	Ambient / H_2S partial pressure above 0.07 bara (1 psia)	No (No significant H2S, and No free liquid water)
Delayed Cracking [8)]	Hydrogen "cold" cracking at hard zones after welding.	Below ~100°C / N.A.	No (Welding / manufacturing process related)
HEAC [9)]	HEAC – Hydrogen Environment Assisted Cracking (type of slow stable cracking)	Ambient / > 4bara (60psia)	Possible, under certain circumstances (Crack tip plasticity driven, at large defects or high stress concentrations and/or residual weld stress)
HAFCG [10)]	HAFCG – Hydrogen Assisted Fatigue Crack Growth	Ambient / > 4bara (60psia)	Possible, but only in rare cases Requires substantial cyclic pressure amplitude and large number of cycles. Should not apply.

Note 1: This assessment applies only steel grades up to API 5L X70 in material strength requirements.

From the above matrix it may be concluded that for hydrogen transport pipelines, the only expected degradation mechanisms are HEAC and HAFCG, with the note that only in specific circumstances will these types of cracking mechanisms occur. A detailed explanation of HEAC and HAFCG is provided in Appendix A of this document.

[6] API RP 941, Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants
[7] NACE SP0472, Methods and Controls to Prevent In-Service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments
[8] EN 1011-2, Welding – Recommendations for welding of metallic materials – Part 2: Arc welding of ferritic steels, Annex C "Avoidance of hydrogen cracking (also known as cold cracking)" and D "Heat affected zone toughness and hardness"
[9] API TR 934-F part 3, Subcritical Cracking of Modern 2.1/4Cr-1Mo-1/4V Steel Due to Dissolved Internal Hydrogen and H2 Environment, Research Report
[10] SAND2012-7321, September 2012, Technical Reference for Hydrogen Compatibility of Materials

3.2 Engineering Considerations

Repurposing of existing natural gas transport pipelines to hydrogen pipelines will require a screening of the quality of the weld seams including a review of the weld qualifications, line pipe toughness tests, and examination history (e.g. radiography/ultrasonic test results of all the welds).

When this information is still available, an engineering critical assessment (ECA) or fitness-for-service (FFS) review can be performed on the applied materials and welds. An ECA will determine a maximum allowable flaw size for the new hydrogen service condition and determines new acceptance criteria for the nondestructive examinations (NDE).

If the required information for a proper ECA is not available, additional design margins may be applied on top of the original design basis. This approach will necessarily have considerable conservatism and likely leave part of the pressure-carrying capacity of the original transport line unused.

It must be noted that a design assessment should not be based on "design by rule" requirements as per the Code ASME B31.12[11] for new hydrogen pipelines. Applying these rules to existing pipelines not originally built for hydrogen may result in the unnecessary rejections.

By applying FFS, the conservatisms of the design by rule criteria of the Code are replaced by the more accurate fracture mechanics-based criteria of API 579-1[12] and this provides a realistic assessment with an overall higher likelihood of acceptance.

3.2.1 Surface Flaws and Fitness-for-Service

Fitness-for-service calculations with fracture mechanics are based on a maximum flaw size and a given material toughness and determine the stress loading which results in slow stable crack initiation. The smaller the crack to be considered in the analysis, the higher the loading that can be applied before a crack is anticipated to grow. This means that the internal surface quality of the pipeline (i.e. the sizes of any flaws which are present) will directly determine the allowable partial pressure of the hydrogen in the system.

Before any FFS analysis can start, it is sensible to perform a detailed internal surface examination and map the inner diameter surface condition of the pipeline by intelligent pigging with dedicated non-destructive examination capability.

Once the types, sizes and orientations of the surface flaws are available, an integrity analysis FFS can be performed, and the maximum allowable pressure can be calculated. The maximum pressure can be used to choose the desired hydrogen partial pressure.

[11] ASME B31.12: "Hydrogen Piping and Pipelines"
[12] API 579-1: "Fitness For Service"

If internal examination is not feasible, one may be able to make a conservative estimate of a maximum flaw size, based on the original construction code or standard with an additional safety margin.

3.2.2 Hydrogen Partial Pressure

For the FFS assessments, the combination of the pipe wall stress and the proposed hydrogen partial pressure threshold to resist HEAC or HAFCG will determine whether there will be a likelihood of crack propagation and whether or not a known surface flaw may be able to grow over time into a leak or a pipe rupture.

Once the desired hydrogen partial pressure limit is determined (which may require iterations of calculations described above), one can either set the given hydrogen concentration limit based on the design pressure, or use a higher concentration of hydrogen and reduce the overall design pressure of a system. Either option can be used to mitigate the cracking risk.

Lowering the pressure can be a method to allow pure hydrogen into the existing transport pipeline. This philosophy is already incorporated in ASME B31.12[11] paragraph IP-2.2.1 "pressure – temperature design criteria", where a "material performance factor" on the system design pressure in relation to the yield strength of the employed steel for new pipelines may be used to ensure the integrity in hydrogen service. The use of these conservative factors, however, follows a design by rule approach that may result in increased rejection rates compared to a fitness-for-service evaluation.

3.3 Component Considerations

3.3.1 Pipeline Materials

Conventional natural gas transport pipelines are commonly designed to a pressure of 1000 psig/66 barg or higher and constructed of steels with an elevated specified minimum yield strength up to 485 N/mm^2 (i.e., API 5L grades X70 / L485 and lower). These steels are stronger than the conventional materials used for hydrogen process piping applied in refineries, which have a much lower specified minimum yield strength of 240–260 N/mm^2 (i.e., ASTM A106 Gr. B / A105N). For transport pipelines, the higher strength results in thinner pipe with an overall higher applied wall stress, which could potentially result in a lower hydrogen cracking resistance, compared to the thicker, less strong process pipe material.

For gas distribution networks (<16 barg), the piping used would typically be of lower strength grade and be more in line with the materials applied for handling hydrogen in refineries.

For plastics, the initial impression is that polyethylene pipes, which appear predominately in the distribution network are not affected by the presence of hydrogen[13] and leakage rates are acceptable[14].

3.3.2 Welds

Welds and their heat affected zones (HAZs) may be more vulnerable to hydrogen embrittlement cracking mechanisms of HEAC and HAFCG than the line pipe base material. Weld heat affected zones typically have higher hardness (tensile strength) and lower toughness than the base metal because of weld restraint and microstructure transformations during welding. They also retain higher residual stresses originating from the welding process heat cycles. But unless a pre-existing defect is present, normal weldment microstructures or stress states in steel grades up to X70 are deemed unlikely to be of any negative influence on the integrity. Low pressure distribution systems are commonly not made of high strength steels and consequently these sections are expected to have low hardness levels in the welds or HAZs.

Existing pipelines are originally not fabricated to strict hardness control limits, like the 235HV10 specified in ASME B31.12. It is not clear why a hydrogen pipeline weld/HAZ hardness needs to fulfill such strict hardness criteria above what is normally applicable for the mitigation of delayed cracking (i.e. 275HV10[15] with high hydrogen charging welding processes). The difference requires consideration in the ECA/FFS assessment.

3.3.3 Flanges

In principle, hydrogen lines are designed with as few flanges as possible. Flanges are main sources of leakage. Underground lines for natural gas will have few flanged joints, except at compressor/metering stations. In the gas industry, there used to be many Ring Type Joint flanges with soft iron gaskets. More recently, the majority of flanges are Raised Face with graphite-filled spiral wound gaskets or Kammprofile gaskets with graphite layers. The change was made due to reasons that are not unique to hydrogen service. Both flange types are acceptable for hydrogen service.

Whereas flanges can be sources of leaks, hydrogen has the advantage that it will not blanket the surroundings, as the gas is lighter than air. Sufficient safety measures must be taken (HVAC indoors, gas detection, ATEX compliant equipment, heat detection cameras for possible hydrogen jet fires that are invisible for the human eye), but the current flange infrastructure should be suitable for hydrogen service.

[13] Technical and economic conditions for injecting hydrogen into natural gas networks, Final report, June 2019, French Natural Gas Infrastructure Operators Association.
[14] M. W. Melaina, O. Antonia, and M. Penev, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, Technical Report, NREL/TP-5600-51995, March 2013
[15] API Standard 1104, Welding of Pipelines and Related Facilities, Table 6.

3.3.4 Valves

For hydrogen process piping, the common selection are gate valves. However, for gas transport pipelines it is common to apply soft-seated ball valves, often lubricated, with PTFE seating material and EPDM seals. The solubility of hydrogen in thermoplastics and elastomers can be high. Also, the polymers in the soft seats of the ball valves may not be resistant to the hydrogen partial pressure and may exhibit swelling after depressurization. In addition, the resistance against and compatibility with hydrogen of the lubricants must be verified. With these considerations, a detailed verification or testing program for all valves in the system is recommended.

4.0 Conclusions

Despite some technical challenges, it is fundamentally possible to repurpose natural gas transport lines for hydrogen transport. Caution is warranted in making general conclusions about the allowable hydrogen content and/or allowable pipeline operating pressure. The unique characteristics of each pipeline system including pipe material, valves, and instrumentation, as well as its associated end users' needs to be considered.

The International Energy Agency (IEA) has reported current "upper blending limits of around 20% to 30%, depending on the pipeline pressure and regional specification of steel quality."[16] This paper supports the IEA claim in some applications such as low pressure distribution networks but highlights that practical blending limits may be 10% or lower in many other systems of interest.

Transmission pipeline blending in particular has the greatest limitations due to higher pressure operation, typical materials of construction, compression station considerations, and the broad range of downstream users. To be able to decide how much hydrogen a given pipeline will be able to handle, an engineering critical assessment (ECA) and/or fitness-for-service (FFS) analysis is recommended, including detailed inspection of the pipeline and an assessment of the material properties.

For pure hydrogen gas transport operation, the assumption is that the process conditions will always be under ambient temperature and dry, avoiding the swift hydrogen degradation mechanisms of high temperature hydrogen attack and wet sour service cracking. The remaining predictable hydrogen degradation mechanisms can then be assessed to determine the lifetime integrity and safety criteria of ECA and/or FFS. This analysis will be the basis for acceptance of existing pipelines repurposed to pure hydrogen transport.

[16] https://events.development.asia/system/files/materials/2016/09/201609-international-energy-agency-hydrogen-and-fuel-cells-technology-roadmap.PDF

Appendix A: Mechanistic Description of Hydrogen effects in pipeline steels: HEAC and HAFCG

A.1 Hydrogen Solubility/Ingress

For hydrogen to diffuse into steel, molecular hydrogen needs to dissociate into mono-atomic form. However, at room temperature, the dissociation rate is very low. Solubility and diffusivity for ferritic and austenitic steels at room temperature is given in Figure 1 below. The maximum solubility in ferritic steel is $2*10^{-3}$ ppm/bar$^{1/2}$. For 100 bar (10 MPa), solubility is then calculated to be around $2*10^{-2}$, or 0.02 ppm, which is in the same range as reported.

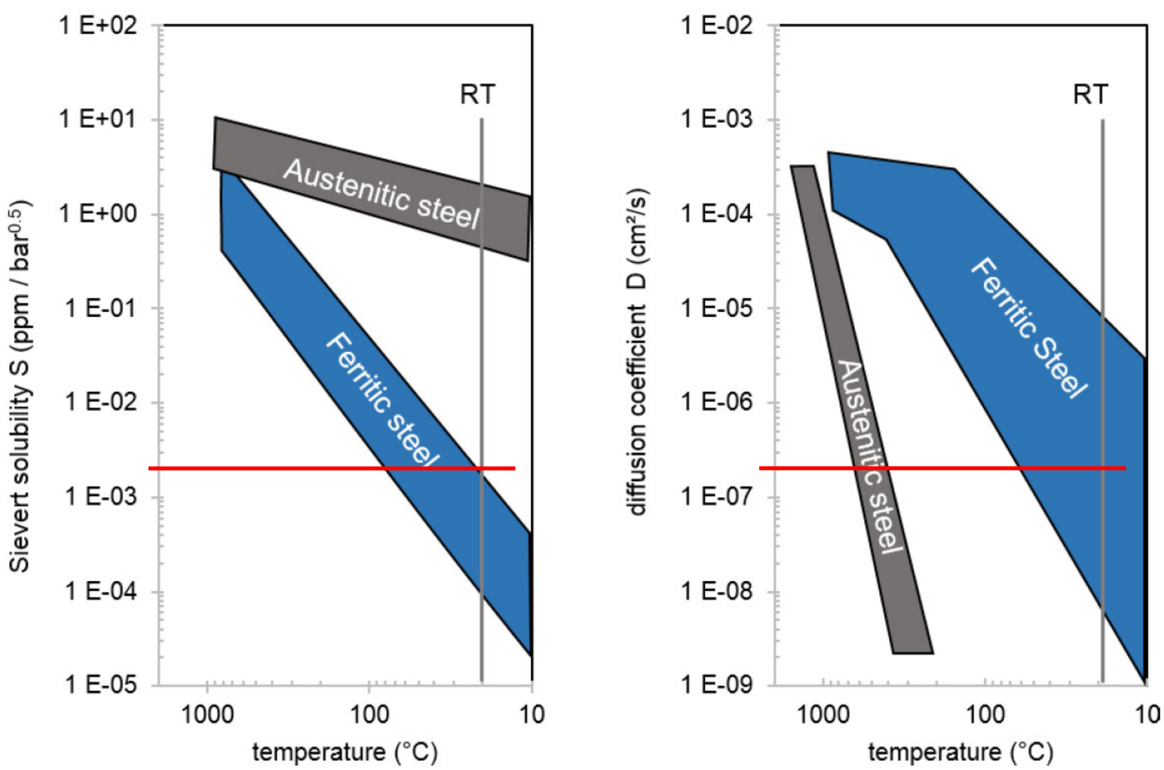
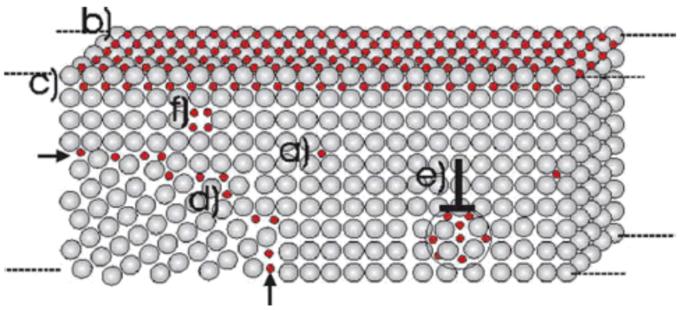


Figure 1: Hydrogen solubility and diffusivity in steel at various temperatures and pressures [from: J. Klett *et al.* "Reducing the risk of hydrogen-induced cold cracks in hyperbaric wet welding of high- strength steels by using austenitic welding consumables"]

Diffusivity is reported in the literature to be around $2*10^{-7}$ cm^2/s, fully aligned with the figure above. We can illustrate the diffusion rate of hydrogen by calculating the "random walk" distance with the formula $x = \sqrt{(D*t)}$. In 24h, the average random diffusion distance of any hydrogen atom will be 1.3 mm. It goes without saying, that within a relatively short time, most of the hydrogen atoms will have reached an external surface or an internal trap.

Figure 2 is a schematic depiction of hydrogen absorption sites in a metal lattice. Because at ambient temperature lattice solubility is essentially zero, any absorbed hydrogen will segregate to lattice imperfections or the surface. Dry surface pickup of hydrogen must therefore progress via or through lattice defects emanating from the surface into the steel, transporting the hydrogen into the steel with the movement of these defects.



Trap theory states that hydrogen amasses at microstructural defects such as voids, dislocations, grain boundaries, and precipitates, which in turn act as traps. In this figure, we show a schematic demonstrating the hydrogen accumulation at different microstructural features, including (a) normal interstitial lattice sites, (b) surface sites, (c) subsurface sites, (d) grain boundaries, (e) dislocations, and (f) vacancies. It is observable that, depending on the characteristics of the defects and traps, the effect on the diffusing hydrogen can vary significantly. Some traps are attractive, subjecting the hydrogen to an attractive force that influences the diffusion; others are physical in nature, with no long-range forces such that the hydrogen randomly falls into the trap. Reprinted from Pundt and Kirchheim, Annu. Rev. Mater. Res. **36**, 555 (2006).[58] Copyright 2006 Annual Reviews.

Figure 2: Hydrogen trap sites inside a metal lattice. Note that a): “interstitial lattice sites” are not available as a trap site for ambient temperature conditions (zero lattice solubility)

For highly stressed areas, such as crack tips or high stress concentrations at or near high weld residual stresses, plastic deformations (i.e. dislocations, see Figure 2 type “e)”) provide a mechanism for hydrogen to be dragged along into the material. This can lead to high hydrogen concentrations at sites where dislocations pile up.

At ambient temperature, defects such as dislocations can transport hydrogen only a few µm locally into the steel and will not cause bulk embrittlement. Without cracks or major surface defects, there are no active, plastically deforming zones that will transport hydrogen.

High stress cyclic loadings induce local plastic deformation, which are movements of dislocations that lead to microscopic material protrusions areas for hydrogen to diffuse into. Preferential slip planes in which these dislocations move also provide a path for hydrogen to be further transported into the material for a short distance in a fashion similar to what is described above.

For hydrogen transport pipelines, electrochemical hydrogen charging mechanisms must be prevented from occurring. Therefore, liquid water (which may function as the electrolyte) and inadequately designed cathodic protection should be avoided.

A.2 Hydrogen Enhanced Crack Growth in Steel and Embrittlement

The fundamental principle of embrittlement by hydrogen is that it starts by lowering cohesion between atoms in steel. For decohesion to become significant, a high local concentration of hydrogen must develop. Only then, some effect of hydrogen on the integrity of steel may develop. For a dry, pressurized, hydrogen pipeline system, local hydrogen ingress may enhance the following mechanisms of crack growth under the applicable loads.

The first is the reduction of fatigue crack growth resistance. This HAFCG mechanism could become applicable for piping under highly fluctuating pressure or other (e.g. external) variable loading. HAFCG is a slow crack growth mechanism. Hydrogen has an enhancing effect on the crack growth rates and lowers the threshold stress intensity. The effect is dependent on the frequency of cycling, showing more effect for long cycle times, and it is dependent on the stress intensity, showing more effect are high stress intensity. It is a slow cracking mechanism because the ingress of hydrogen by movement of dislocations takes time.

The second cracking mechanism is called Hydrogen Environment Assisted Cracking (HEAC). It occurs when hydrogen lowers the stress intensity for slow, stable cracking under high sustained load in the presence of a crack/defect. As described, the process happens by the ingress of hydrogen under plasticity at a crack tip, where the dislocation movement in the plastic zone in front of the crack tip transports hydrogen into the area, embrittling the material just ahead of the crack tip, which then cracks/tears a bit, and the mechanism repeats continuously.

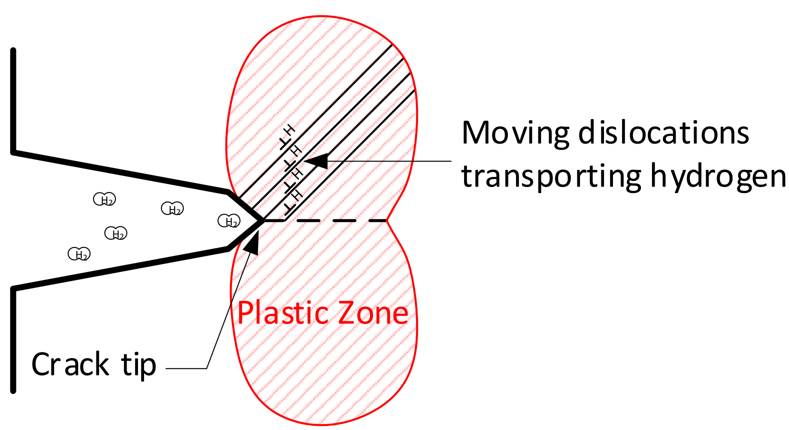


Figure 3: Schematic depiction of hydrogen absorption at a crack tip

The stress intensity required for such a mechanism has been empirically determined to be about 30-40 MPa√m for typical pressure boundary steels up to 485 MPa specified minimum yield strength[17]. Very high yield strength pipelines exceeding these levels (>X70) could have lower HEAC resistance and are not currently being considered for hydrogen pipelines.

[17] API TR 934-F part 3, Subcritical Cracking of Modern 2.1/4Cr-1Mo-1/4V Steel Due to Dissolved Internal Hydrogen and H2 Environment, Research Report

Ultimately, slow crack growth can lead to crack sizes that become critical/unstable. At that moment, a flaw reaches a size at which the stress in the wall will suddenly cause the flaw in the base material or weld to grow fast and uncontrolled (rupture).

There are secondary effects on steels that can be measured, like a hydrogen-induced reduction in tensile ductility, but these are not thought to be very relevant for the design of the pipeline, as gross plasticity should not occur.

With regard to the crack growth discussion it should be noted that gas transport lines are required to be designed and fabricated for appropriate crack arrest.[18] This is a safety requirement, implying that either the material shall have sufficient fracture ductility that will assure crack arrest or some crack arresting system must be installed that will prevent longitudinal cracks from running along a significant length of transport line.

As explained in the previous section, since the lattice solubility is extremely low at ambient temperatures and consequently there is no thermodynamic drive for diffusion of hydrogen into the steel, bulk “hydrogen embrittlement” should not occur, i.e., the fracture toughness of the steel should not be affected.

A.3 Variables Affecting HEAC - Hydrogen Partial Pressure

The hydrogen fugacity is both pressure and temperature related, and the effect of the hydrogen partial pressure can be correlated to HEAC initiation toughness. For pipeline steels with an elevated yield strength (up to X70 grades), the effect of hydrogen partial pressure becomes significant above $P_{H2} \geq$ 60psia (4 bara)[19].

[18] ASME B31.8 para. 841.1.2, EN 1594, EN 14161
[19] J. Solin, N. de Miguel, Labscale – Full scale experimental comparison - Mechanisms, Modeling, Experiments and Pressure Vessel Design, Mathryce dissemination workshop, Paris, September 18, 2015