U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)
Final Report No. 24-30994-5000932R

Literature Review on Reinspection Intervals for Pipelines Carrying Hydrogen or Hydrogen/Natural Gas Blends

Michiel P. Brongers, PE
July 26, 2024

Intentionally blank

Final Report No. 24-30994-5000932R

Draft Report

Literature Review on Reinspection Intervals for Pipelines Carrying Hydrogen or Hydrogen/Natural Gas Blends

to

U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)

on

July 26, 2024

Prepared by

Michiel P. Brongers, PE
Principal Engineer

Approved by

Dyke Hicks
Director of Operations

Kiefner and Associates, Inc.
6185 Huntley Rd. Suite J
Columbus, OH 43229

Disclaimer

This document presents findings and/or recommendations based on engineering services performed by employees of Kiefner and Associates, Inc. The work addressed herein has been performed according to the authors' knowledge, information, and belief in accordance with commonly accepted procedures consistent with applicable standards of practice, and is not a guarantee or warranty, either expressed or implied.

The analysis and conclusions provided in this report are for the sole use and benefit of the Client. No information or representations contained herein are for the use or benefit of any party other than the party contracting with Kiefner. The scope of use of the information presented herein is limited to the facts as presented and examined, as outlined within the body of this document. No additional representations are made as to matters not specifically addressed within this report. Any additional facts or circumstances in existence but not described or considered within this report may change the analysis, outcomes and representations made in this report.

Executive Summary

This literature review critically examined the methodologies currently employed in the U.S., Europe, and other countries, to determine in-line inspection (ILI) reinspection intervals for transmission pipelines containing hydrogen gas or natural gas/hydrogen blends. An in-depth comparison and discussion about Codes and Standards was also provided.

The scope of this literature review included:

1. Identification and sizing of ILI features,
2. Commentary on reinspection intervals in relevant Codes and Standards,
3. Discussion on accelerated fatigue and stress corrosion cracking (SCC) crack growth rates (CGRs) due to the presence of hydrogen,
4. Discussion on the effects of the pressure regime in gas pipelines,
5. Experiences with converting existing pipelines, experiences from hydrogen-blending, pipeline conversions to hydrogen, and new hydrogen pipeline construction, in the U.S. and internationally,
6. Status on joint industry projects (JIPs),
7. Crack-related failure causes, pre-existing defects, and hydrogen embrittlement mechanisms, and
8. A review of pertinent Standards from Germany and the United Kingdom.

Several ILI technologies exist with the capability to detect cracks that are suitable for gas (hydrogen/natural gas) pipelines. This includes the latest in circumferential magnetic flux leakage (MFL) and helical MFL tools and considerations for ultrasonics. A summary of ILI technologies is provided here:

- **Traditional Ultrasonics ILI**
  Ultrasonics have taken the lead in crack detection, but they can be limited in the detection of certain crack morphologies due to the physics required. In a liquid system, the industry has seen enormous improvement and maturation of ultrasonic technology crack detection (UTCD) tools in detecting and sizing crack-like defects. However, this technology is typically not practical for use in gas lines due to the requirement of a liquid couplant medium, nor is it typically available or reliable in smaller-diameter pipelines.

- **Circumferential MFL ILI**
  Although circumferential tools have traditionally been used to screen for axial pipeline cracks, only recently have new developments occurred using multiple technologies on a singular platform to significantly advance the understanding of the capabilities of MFL combination technologies to provide detection and sizing of crack-like anomalies both on the axial and off-axis angles. Additionally, certain technologies are beginning to show reliable detection of circumferential cracks and off-axis cracks.

- **Helical MFL ILI**
  Helical MFL tools apply a magnetic field at an angle and provide an advantage over traditional axially-oriented MFL tools. Helical MFL can efficiently detect

crack-like defects in the pipe wall and long seams, including selective seam weld corrosion (SSWC), hook cracks, lack of fusion, and surface-breaking laminations.

- **Electromagnetic Acoustic Transmission (EMAT) ILI**
  EMAT tools utilize ultrasonic waves directly, eliminating the need for a liquid-coupled transducer, making EMAT technology particularly applicable for the gas pipeline industry. Now in their maturation stage, many EMAT tools continue to show promise for crack detection in gas pipelines. However, resolution issues limit EMAT in its capabilities of identifying and sizing crack-like indications. Thus, the probability of detection (POD) is good, while the probability of identification (POI) and probability of sizing (POS) is challenging.

- **Novel Ultrasonics ILI**
  Acoustic Resonance Technology (ART) is an innovative ultrasonic advancement in ILI for pipelines. Unlike traditional methods that require a liquid couplant, ART uses sound waves through high-pressure gas to acquire detailed measurements of the pipe wall, including crack detection. This is an emerging technology that has not been widely advanced.

Key findings from this literature review include:

- Global research performed over the past decades has yielded valuable insights, but the material property data originate from a relatively small number of research organizations, and the data are relatively limited in scope as related to pipeline steels for gas.
  - The data of accelerated fatigue CGRs, for example, are relatively limited in that they address only a few loading R-ratios (minimum stress divided by maximum stress). Typically, R=1.0 and R=0.5, while gas pipelines typically operate with less severe pressure fluctuations (R=0.9).
  - Where material properties are evaluated, the studies primarily report on yield or tensile strength. Fracture toughness data are scarce, and few data are reported on weld-related properties.
- Although integrity management is described in general terms, the specific connection between CGRs and inspection intervals is not included in most hydrogen-related Codes and Standards.
  - No documents were found that describe the methodologies for assessing hydrogen effects on specific defect types other than a general "crack-like" feature.
- The various Codes and Standards cross-reference each other, with most leading back to ASME B31.12 and BS7910.

- There are several methodologies for fatigue CGR assessments included in hydrogen-related Codes and Standards.
  - ASME B31.12 Code Case 220 is the only method that formalizes fatigue design curves for gaseous hydrogen that account for the loading R-ratio, the stress intensity factor range, ΔK, and the hydrogen gas pressure g(P) as a function of overall pressure, P.
- European (Germany, UK) Standards refer to American (ASME) and British (BS) Standards. American Standards do not reference European documents.
  - Taking into consideration that the European Hydrogen Backbone program with 35,700 miles of planned hydrogen pipelines (58.6% repurposed) in the near future, the American program is currently much smaller, with 1,500 miles of existing hydrogen pipelines. Learning from the European experience would be beneficial for the U.S.

Table of Contents

List of Tables

List of Figures

List of Acronyms and Abbreviations

AMPP	Association for Materials Protection and Prevention
API	American Petroleum Institute
ART	Acoustic Resonance Technology
ASME	American Society of Mechanical Engineers
CEPA	Canadian Energy Pipeline Association
CFR	Code of Federal Regulations
CGR	Crack Growth Rate
CP	Cathodic Protection
CVN	Charpy V-Notch (impact testing)
DG-ICDA	Dry Gas - Internal Corrosion Direct Assessment
DNV	Det Norske Veritas
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
DVGW	Deutscher Verein des Gas- und Wasserfaches e.V. (Germany)
EAC	Environmentally Assisted Cracking
ECA	Engineering Critical Assessment
ECDA	External Corrosion Direct Assessment
EHB	European Hydrogen Backbone
EMAT	Electromagnetic Acoustic Transmission
ERW	Electric Resistance Welded (pipe)
FA	Failure Analysis
FAD	Failure Assessment Diagram
FGCR	Fatigue Crack Growth Rate
FEA	Finite Element Analysis
FFS	Fitness for Service
FW	Flash Welded (pipe)
H2Hubs	Regional Hydrogen Hubs Program
H_2S	Hydrogen Sulfide
HAC	Hydrogen-Assisted Cracking
HA-FCG	Hydrogen-Assisted Fatigue Crack Growth
HCA	High Consequence Area
HE	Hydrogen Embrittlement
HIC	Hydrogen-Induced Cracking
HRC	Rockwell C Hardness
HV_{10}	Vickers Hardness (10-gram)
IGEM	Institution of Gas Engineers and Managers (United Kingdom)
ILI	In-Line Inspection
IM	Integrity Management
JIP	Joint Industry Project
LEFM	Linear Elastic Fracture Mechanics
LW	Lap Welded (pipe)
MAOP	Maximum Allowable Operating Pressure
MAWP	Maximum Allowable Working Pressure
$MAWP_r$	Reduced Maximum Allowable Working Pressure
MFL	Magnetic Flux Leakage

MFL-A	Axial MFL
MFL-C	Circumferentially aligned MFL
MOP	Maximum Operating Pressure
NaCl	Sodium Chloride
nnpH SCC	Near-Neutral pH Stress Corrosion Cracking
P2G	Power-to-Gas
PCI	Project of Common Interest
PE	Polyethylene
PFP	Predicted Failure Pressure
PHMSA	Pipeline and Hazardous Materials Safety Administration
POD	Probability of Identification
POE	Probability of Exceedance
POI	Probability of Detection
POS	Probability of Sizing
PRCI	Pipeline Research Council International
PWHT	Post-Weld Heat Treatment
RBI	Risk-Based Inspection
RI	Reinspection Interval
RL	Remaining Life
RP	Recommended Practice
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SIF	Stress Intensity Factor
SMYS	Specified Minimum Yield Strength
SOHIC	Stress Oriented Hydrogen-Induced Cracking
SSC	Sulfide Stress Cracking
SSWC	Selective Seam Weld Corrosion
STP	Special Technical Publication
TD	Transmission and Distribution
TOF	Time of Flight (diffraction)
TR	Technical Report
TSO	Technical Support Organization
UT	Ultrasonic Technology / Ultrasonic Testing
UTCD	Ultrasonic Technology Crack Detection
UTS	Ultimate Tensile Strength
YS	Yield Strength

List of Variables

da/dN	Crack Growth Rate
f	Frequency
ΔK	Stress Intensity Factor Range
$K_{Ic\text{-}H}$	Mode I Critical Stress Intensity Factor in Hydrogen
K_{min}	Minimum Stress Intensity Factor
K_{max}	Maximum Stress Intensity Factor
K_r	Toughness Ratio
K_{th}	Threshold Stress Intensity Factor
L_r	Load Ratio
P_f	Predicted Failure Pressure
R	Stress Intensity Factor Ratio, or Loading Ratio

1 INTRODUCTION

A previously funded and currently underway PHMSA project [1] is reviewing the integrity threat characterization resulting from hydrogen (H_2) gas pipeline service under 49 CFR Part 192 [2] requirements and ASME B31.8S Standard "Managing System Integrity of Gas Pipelines" [3]. This literature review by Kiefner and Associates, Inc. (Kiefner) used information from that study, along with other research published globally on the topic of time-to-failure of pipeline features identified by in-line inspection (ILI) and the required reinspection interval (RI) to prevent those features from becoming critical.

All anomalies discovered during an ILI require assessment, but only those assessed as potentially injurious require repair. For the anomalies remaining in the pipeline, their remaining life (RL) needs to be estimated. Then, the RL can be used to determine the necessary minimum reinspection interval. To achieve this goal, the current requirements from 49 CFR 192 Subpart M and O, as well as the Standards ASME B31.8S and ASME B31.12 Code for Hydrogen Piping and Pipelines [4], must be reviewed.

The main factors that influence inspection intervals as related to hydrogen embrittlement are the size and shape of defects, the local stress conditions, and the internal hydrogen concentration. The consequences of establishing inspection intervals that are too long can be disastrous, due to the increased risk of a leak or rupture. The consequences of establishing inspection intervals that are too short are primarily economic in nature but also carry the risk of drawing attention away from other integrity management activities. Thus, it is best to establish methods that accurately predict the remaining life so that hydrogen pipelines can be operated both safely and economically.

This literature review collected applicable experiences in setting reinspection intervals for pipelines with hydrogen gas or natural gas/hydrogen blends from various sources. These included real-world engineering critical assessments (ECAs), fitness-for-service (FFS) evaluations, failure analysis (FA) projects, and pilot projects.

2 OBJECTIVE

The objective of this literature review was to critically examine the methodologies currently employed in the industry in the U.S., Europe, and other countries to determine ILI reinspection intervals for transmission pipelines containing hydrogen gas or natural gas/hydrogen blends.

In the follow-on tasks of this work, the collection of documents from private and public research gathered in this literature review will be used as a baseline for demonstrating if and how the presence of H_2 gas impacts pipeline threat investigations and ILI reinspection intervals.

3 SCOPE OF WORK

The scope of this literature review included:

1. Identification and sizing of ILI features,
2. Commentary on reinspection intervals in relevant Codes and Standards,
3. Discussion on accelerated fatigue and stress corrosion cracking (SCC) crack growth rates (CGRs) due to the presence of hydrogen,
4. Discussion on the effects of the pressure regime in gas pipelines,
5. Experiences with converting existing pipelines, experiences from hydrogen-blending, pipeline conversions to hydrogen, and new hydrogen pipeline construction, in the U.S. and internationally,
6. Status on joint industry projects (JIPs),
7. Crack-related failure causes, pre-existing defects, and hydrogen embrittlement mechanisms, and
8. A review of pertinent Standards from Germany and the United Kingdom.

4 BACKGROUND

In the effort to fight the climate-changing effects of global warming, the use of low-carbon and carbon-free energy sources will increase dramatically over the coming decades. One strategy is to use hydrogen (H_2) gas as a fuel or a feedstock alternative to traditional oil and natural gas. Ideally, H_2 is produced from "green" energy sources, such as wind and solar, but other options are available, such as "blue" H_2 sourcing which requires capturing and storing of the carbon dioxide (CO_2) byproduct. In either case, the H_2 fuel/energy can be stored and/or transported to where it is needed.

Repurposing existing long-distance transmission pipelines will likely be the most economically feasible, socially accepted, and politically preferred method of transporting H_2 within the U.S. Conversion of existing pipeline systems constructed of early-vintage or more modern linepipe steels to hydrogen or hydrogen-blended natural gas can only be done if their structural integrity is ensured. This is especially relevant because approximately 50% of existing transmission pipelines were constructed before 1970.

As of 2019, the Pipeline and Hazardous Materials Safety Administration (PHMSA) reported [5] that 1,522 miles of U.S. pipelines were dedicated to pure hydrogen, and almost all were 20-inch diameter or less, see Figure 1. Most hydrogen pipelines were constructed after 1980. The majority of experience with them is for purpose-built lines of newer construction. In contrast, most existing natural gas and hazardous liquids transmission pipelines in the U.S. were constructed before 1980. Those lines may be considered the most likely candidates for repurposing to hydrogen or natural gas/hydrogen blended gas.

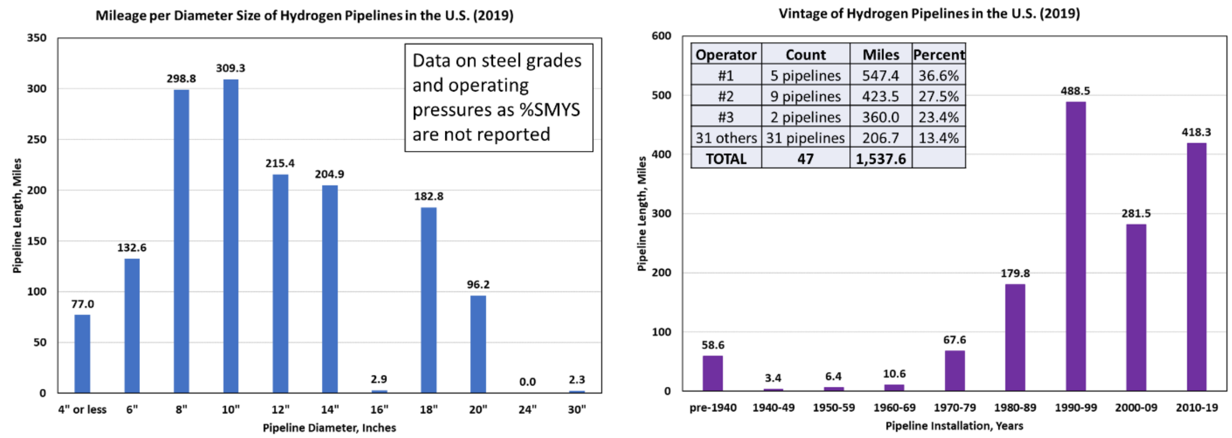


Figure 1. Length of U.S. Hydrogen Gas Transmission Pipelines by Diameter and Vintage

The ASME B31.12-2019 Code for Hydrogen Piping and Pipelines [4], incorporated by reference in 49 CFR 192, allows prescriptive or performance-based design. The maximum allowable operating pressure (MAOP) depends on the location class, seam weld type, temperature, specified minimum yield strength (SMYS), and ultimate tensile strength (UTS). An example (by the author of this literature review) per ASME B31.12-2019 is given in Figure 2. For a vintage pipeline (pre-1970) with pure hydrogen, the MAOP might be as low as 15% of SMYS with these guidelines. Pressures exceeding 15% of SMYS, and the versatility to allow natural gas blended with different concentrations of hydrogen are economic necessities.

Conditions (worst case)	Property	Option A (prescriptive design)	Option B (performance-based design)
Location Class 4 (46+ buildings)	Constant x P(test), but not exceeding Design Factor x SMYS	MAOP = 0.555 x P(test), but not > 40% SMYS	MAOP = 0.555 x P(test), but not > 40% SMYS
Location Class 4	Design Factor, F	0.40	0.40
ASTM A139 Electric Fusion Welded	Longitudinal Joint Factor, E	0.80	0.80
Temperature = 450F (max)	Temperature Derating Factor, T	0.867	0.867
SMYS =< 80 ksi, and UTS 82-90 ksi, and P(system) = 3,000 psig	Material Performance Factor, Hf	0.542	0.542
% SMYS	Calculated Design Pressure, P	15.04%	15.04%

Conditions (best case)	Property	Option A (prescriptive design)	Option B (performance-based design)
Location Class 1 (11-25 buildings)	Previous MAOP, but not exceeding Design Factor x SMYS	Previous MAOP, but not > 50% SMYS	Previous MAOP, but not > 72% SMYS
Location Class 1	Design Factor, F	0.50	0.72
Seamless	Longitudinal Joint Factor, E	1.00	1.00
Temperature = 250F or less	Temperature Derating Factor, T	1.000	1.000
SMYS =< 52 ksi, and UTS <66 ksi, and P(system) = < 1,000 psig	Material Performance Factor, Hf	1.0	1.0
% SMYS	Calculated Design Pressure, P	50.00%	72.00%

Figure 2. Example Calculation for Design Pressure as %SMYS, Per ASME B31.12-2019

Hydrogen has been used since the early 1900s, and much is known about the deleterious effects that atomic hydrogen can have on the mechanical properties of carbon steel, the common material for the construction of oil and gas pipelines. Research by Briottet and Ez-Zaki [6] has shown that exposure of steel under tensile stresses to gaseous (molecular) hydrogen can cause dissociation into atomic hydrogen that can diffuse into the steel. As a result, the mechanical properties can degrade with time. However, these effects only become pronounced under certain risk conditions, referred to as “threats” to the pipeline.

49 CFR 192 [2] provides requirements for (a) threat identification, (b) data gathering and integration, (c) risk assessment, (d) plastic transmission pipeline, and (e) actions to address particular threats:

1. Third party damage
2. Cyclic fatigue
3. Manufacturing and construction defects
4. Electric resistance welded (ERW) pipe
5. Corrosion
6. Cracks

The author of this literature review incorporated these particular threats into a list of hydrogen-related threats, as shown in Table 1. This list is not intended to be exhaustive but aims to identify most of the threats mentioned in the literature.

For threats that affect the exterior surface of the pipeline, it may not be intuitive to expect hydrogen effects from internal hydrogen. However, when atomic hydrogen diffuses into the pipe wall from the inside surface, it will likely concentrate in areas of elevated stress, which can be caused by external effects.

Table 1. Hydrogen-Related Threats to Pipelines

• **At pre-existing manufacturing defects**
○ Cold welds
○ Laminations
○ Hook cracks
○ Inclusions
○ Hard spots
○ Scabs
○ Slivers
○ Blisters
• **At mechanical/third-party damage**
○ Plain (smooth) dents
○ Dents with stress concentrator (gouge or groove)
○ Dent with corrosion
○ Multiple dents
○ Dent in girth or seam weld
○ Gouges
○ Scratches
○ Buckles
○ Ovalities
• **At service-induced cracks**
○ Stress corrosion cracking (SCC)
○ Pressure fluctuations/cyclic fatigue
○ Hydrogen-induced cracking (HIC)

• **At corrosion metal loss areas – external or internal pipe surface**
○ High stress in local thin areas
○ Selective seam weld corrosion (SSWC)
• **At welds**
○ Long-seam welds
▪ Lack of fusion
▪ Lack of penetration
▪ Undercut
▪ Under trim/over trim
▪ Porosity
○ Low-toughness long-seam weld
○ Defect in or near an ERW seam
○ Girth welds
• **At areas of elevated stress**
○ Weld residual stresses
○ Earth movement
○ Pipeline field bends
○ Pipe manufacturing stresses
○ Arc burn on pipe body
○ Coupling
• **At welded sleeves and fittings**
○ Type B sleeves
○ Puddle welds
• **At fittings and sharp transitions susceptible to crack initiation**
○ Wrinkle bends
○ Threaded or welded fittings
○ Valves
○ Diameter transitions
○ At geometric constraints
• **At locations that may experience an impact**

Table 2 is a comparison of the integrity threats defined in the 2004 [7] and 2022 [3] versions of ASME B31.8S. Overall, the threats in both versions are mostly the same. While two different words are used in the two versions, more specificity is provided for girth welds and for weather-related and outside force threats in the later version. The differences include:

- Use of the word "resident" instead of "stable" threat,
- Use of the words "random or time independent" instead of "time independent,"

- More detail for girth welds in the welding/fabrication-related threat: "Defective pipe girth weld (circumferential) including branch and T-joints" instead of "Defective pipe girth weld," and

- Addition of four weather-related and outside force threats: Addition of "excessive hot or cold weather (outside the design range)," "high wind," "hydro-technical," and "geotechnical."

Table 2. Integrity Threats Defined in ASME B31.8S-2004 [7] and ASME B31.8S-2022 [3]

#	Integrity Threats per ASME B31.8S-2004		Integrity Threats per ASME B31.8S-2022	
1	(a) Time Dependent	(1) External corrosion	Same	Same
2		(2) Internal corrosion		Same
3		(3) Stress corrosion cracking		Same
4	(b) Stable (1) Manufacturing related defects	(a) Defective pipe seam	**(b) Resident (1) Manufacturing related defects**	Same
5		(b) Defective pipe		Same
6	(b) Stable (2) Welding/ fabrication related	(a) Defective pipe girth weld	**(b) Resident (2) Welding/ fabrication related**	**Defective pipe girth weld (circumferential) including branch and T-joints**
7		(b) Defective fabrication weld		Same
8		(c) Wrinkle bend or buckle		Same
9		(d) Stripped threads/ broken pipe/ coupling failure		Same
10	(b) Stable (3) Equipment	(a) Gasket O-ring failure	(a) Resident – (3) Equipment	Same
11		(b) Control/relief equipment malfunction		Same
12		(c) Seal/pump packing failure		Same
13		(d) Miscellaneous		Same
14	(c) Time Independent – (1) Third party/ mechanical damage	(a) Damage inflicted by first, second, or third parties (instantaneous/ immediate failure)	**(c) Random or Time Independent (1) Third-party/ mechanical damage**	Same
15		(b) Previously damaged pipe (delayed failure mode)		Same
16		(c) Vandalism		Same
17	(c) Time Independent – (2) Incorrect operational procedure	Incorrect operational procedure	**(d) Random or Time Independent (2) Incorrect operational procedure**	Same

#	Integrity Threats per ASME B31.8S-2004		Integrity Threats per ASME B31.8S-2022	
18	(c) Time Independent – (3) Weather-related and outside force	(a) Cold weather	**(c) Random or Time Independent (3) Weather-related and outside force**	**(a) Excessive hot or cold weather (outside the design range)**
19		(b) Lightning		**(b) High wind**
20		(c) Heavy rains or floods		**(c) Hydro-technical: water-related threats**
21		(d) Earth movement		**(d) Geotechnical**
22				(e) Lightning

Table 3 combines Table 1 and Table 2 by showing how hydrogen-related threats compare with the current 2022 version of ASME B31.8S. Notably, some hydrogen-related threats are NOT included in ASME B31.8S, including:

- **X1 Time Dependent – Fatigue cracking**
  - At service-induced cracks
    - Pressure fluctuations/cyclic fatigue
- **X2 Time Dependent – Fittings and sharp transitions**
  - At fittings and sharp transitions susceptible to crack initiation
    - Wrinkle bends
    - Threaded or welded fittings
    - Valves
    - Diameter transitions
- **X3 (b) Resident (1) Manufacturing related defects**
  - At long-seam weld
    - Low-toughness
- **X4 (b) Resident (2) Welding/fabrication related**
  - At welded sleeves and fittings
    - Type B sleeves
    - Puddle welds

Conversely, there are threats listed in ASME B31.8S that are not likely to be negatively impacted by the presence of hydrogen, including:

- (b) Resident (2) Welding/ fabrication related
  - Stripped threads/broken pipe/coupling failure

- (b) Resident (3) Equipment
    - Gasket O-ring failure
    - Control/relief equipment malfunction
    - Seal/pump packing failure

- (c) Random or Time Independent (1) Third-party/mechanical damage
    - Vandalism

- (c) Random or Time Independent (2) Incorrect operational procedure
    - Incorrect operational procedure

- (c) Random or Time Independent (3) Weather-related and outside force
    - High wind
    - Hydro-technical: water-related threats
    - Lightning

Table 3. Hydrogen-Related Threats Mapped Versus Integrity Threats Defined in ASME B31.8S-2022 [3]

#	Integrity Threats per ASME B31.8S-2022		Hydrogen-Related Threats To Transmission Pipelines
1	Time Dependent	External corrosion	• At corrosion, metal loss areas ○ High stress in local thin areas ○ Selective seam weld corrosion (SSWC)
2		Internal corrosion	• At corrosion, metal loss areas ○ High stress in local thin areas ○ Selective seam weld corrosion (SSWC)
3		Stress corrosion cracking	• At service-induced cracks ○ Stress corrosion cracking (SCC)
X1	***NOT LISTED IN ASME B31.8S-2022*** Time Dependent – Fatigue cracking		• At service-induced cracks ○ Pressure fluctuations/cyclic fatigue
X2	***NOT LISTED IN ASME B31.8S-2022*** Time Dependent – Fittings and sharp transitions		• At fittings and sharp transitions susceptible to crack initiation ○ Wrinkle bends ○ Threaded or welded fittings ○ Valves ○ Diameter transitions ○ Geometric constraints
4	(b) Resident (1) Manufacturing related defects	Defective pipe seam	• At welds ○ Lack of fusion ○ Lack of penetration ○ Undercut ○ Under trim/over trim ○ Porosity
X3		***NOT LISTED IN ASME B31.8S-2022*** Low-toughness pipe seam	• At long-seam weld ○ Low toughness
5		Defective pipe	• At pre-existing manufacturing defects ○ Cold welds ○ Laminations ○ Hook cracks ○ Inclusions ○ Hard spots ○ Scabs ○ Slivers ○ Blisters

#	Integrity Threats per ASME B31.8S-2022		Hydrogen-Related Threats To Transmission Pipelines
6	(b) Resident (2) Welding/ fabrication related	Defective pipe girth weld (circumferential) including branch and T-joints	• At welds ○ Girth welds

7		Defective fabrication weld	• At areas of elevated stress
			  ○ Weld residual stresses
			  ○ Pipe manufacturing stresses

8		Wrinkle bend or buckle	• At areas of elevated stress ○ Pipeline field bends
9		(d) Stripped threads/ broken pipe/ coupling failure	N/A

X4		***NOT LISTED IN ASME B31.8S-2022***
		Repair sleeves and welded fittings
			• At welded sleeves and fittings
			  ○ Type B sleeves
			  ○ Puddle welds

10	(b) Resident (3) Equipment	Gasket O-ring failure	N/A
11		Control/relief equipment malfunction	N/A
12		Seal/pump packing failure	N/A
13		Miscellaneous	N/A
14	(c) Random or Time Independent (1) Third-party/ mechanical damage	Damage inflicted by first, second, or third parties (instantaneous/ immediate failure)	• At locations that may experience an impact

15		Previously damaged pipe (delayed failure mode)	• At mechanical/third-party damage
			  ○ Dents
			  ○ Gouges
			  ○ Scratches
			  ○ Buckles
			  ○ Ovalities

16		Vandalism	N/A
17	(c) Random or Time Independent (2) Incorrect operational procedure	Incorrect operational procedure	N/A
18	(c) Random or Time Independent	(a) Excessive hot or cold weather (outside the design range)	• At locations that may experience an impact
19		(f) High wind	N/A

#	Integrity Threats per ASME B31.8S-2022		Hydrogen-Related Threats To Transmission Pipelines
20	(3) Weather-related and outside force	(g) Hydro-technical: water-related threats	N/A
21		(h) Geotechnical	• At areas of elevated stress ○ Earth movement
22		(i) Lightning	N/A

To ensure the structural integrity of a pipeline carrying hydrogen or a hydrogen-natural gas blend, the owner/operator will need to have confidence in the continued resistance to failure of the pipeline and be assured that any pre-existing flaws are acceptable to remain in the pipe. Therefore, integrity management (IM) engineers address the various threats with a process called Engineering Critical Assessment (ECA), in which the current flaw size, stress conditions, and growth rate are used to estimate remaining life (RL). Common practice is that pipeline reinspection intervals are set at 50% of the RL. There are different methods for ECAs, including API RP 1176 Recommended Practice (RP) for Assessment and Management of Cracking in Pipelines [8] and API 579-1/ASME FFS-1 Fitness-For-Service [9].

The most popular method to inspect for pipeline flaws is ILI, which provides a snapshot of the location and sizes of detected features in time. Some features will be stable and not grow with time, e.g., a dent is not expected to become deeper. Other features may have the potential for future growth in size, e.g., a crack may become deeper and longer from pressure-cycle fatigue, and lamination may grow laterally from internal pressure build-up along its edges.

ECAs of ILI-detected features consider the current flaw dimensions and the longitudinal and through-thickness growth rates to calculate the RL defined as the time-to-leak or time-to-rupture for the pipeline. A reinspection interval can then be set at a time shorter than the RL, so that any growing features can be reinspected, reassessed, and repaired or removed before they become critical. The Pipeline Research Council International (PRCI) Pipeline Repair Manual [10] describes which repairs may be used for which types of defects.

At present, ASME Standard B31.8S and the 49 CFR 192 Code are written for pipeline threats without explicitly considering the presence of pure hydrogen or hydrogen-blended gas in the pipeline. ASME B31.8S and 49 CFR 192 are used to design for the mechanical integrity of hazardous gas pipelines, but they inherently assume that the gas contained within the pipeline does not interact with the material of construction (steel). This is not necessarily true in the case of hydrogen, and that is problematic as the RL of hydrogen-affected features can be dramatically shorter than the RL of similar features in a more benign environment.

5 LITERATURE REVIEW

5.1 ILI Technology Capabilities

The application of ILI technology should be considered in a way that can capture the absence of crack-like indications or show that no anomaly above the acceptable limits presently exists in the pipeline. Therefore, understanding the physics of each ILI technology is important in understanding what limitations exist when applying appropriate response times to the data collected.

5.1.1 Ultrasonic Technology (UT)

A reliable and accepted technology for crack-focused ILI tools is ultrasonic technology crack detection (UTCD) [11]. UTCD provides a direct measurement of defects through time of flight (TOF) diffraction and is designed for the detection of either circumferential or axial cracks. While this has been applied successfully on liquid pipelines, the nature of UTCD tools requiring a liquid medium prevents broad-scope practical application within gas pipelines due to economic and practical considerations. Ultrasonic technology/testing (UT) crack tools can typically detect cracks with a minimum length of 20 mm (0.79 inch) and a depth of 1 mm (0.039 inch) in the pipe base metal. Conventional UT crack tools are able to detect cracks below 0.001 mm (0.00004 inch) opening with high probability [12], [13].

5.1.2 Magnetic Flux Leakage

Axial magnetic flux leakage (MFL-A) is the most commonly applied ILI technology for detecting volumetric metal loss within gas pipelines [14]. The physics of circumferentially aligned MFL (MFL-C) tools provides better detection and sizing for axially aligned defects, as well as the implementation of combining high- and low-magnetization technology for stress pattern detection, which is useful for positively identifying cracks [15]. Alternatively, helical MFL technology, which places the magnetic field at an angle, has also had success in detecting planar anomalies within both the pipe body and seam.

However, there is a limitation within the physics of MFL as crack defects produce minimal flux leakage and are therefore difficult to detect reliably. The application of more sensors and higher sampling frequencies can lead to higher resolution data. This is the subject of the current advancements in this technology [16]. With an increase in validation data, the algorithms can be better informed to process MFL-C data and can therefore detect and size "crack-like" or "linear indications." The terminology of "crack-like anomaly" is often used in lieu of confidently identifying a crack, until validation data could be obtained. As the technology and algorithms for these tools improve, ILI vendors can more confidently report cracks as cracks. Recently, new developments using multiple technologies on a singular platform have significantly advanced the understanding of the capabilities of MFL combination technologies to provide detection and sizing of crack-like anomalies both on the axial and off-axis angles [17].

5.1.3 Electromagnetic Acoustic Transmission

Electromagnetic acoustic transmission (EMAT) inspection technology was originally designed for the detection of stress corrosion cracking (SCC) [18]. EMAT tools utilize ultrasonic waves directly, eliminating the need for a liquid-coupled transducer, making EMAT technology particularly applicable for the gas pipeline industry. EMAT has been validated extensively over the last couple of decades [19] and is currently the most used technology for crack inspection in gas pipelines [20], [21]. However, EMAT technologies have limitations in detection and sizing due to resolution issues. The discrimination of defect types, such as SCC, disbonded coating, gouging, or corrosion features, can be difficult for EMAT, leading to potentially false positives and unnecessary and costly digs [22]. Ongoing testing and validation projects continue to improve the qualitative defect sizing process of varying threats of interest.

5.1.4 Acoustic Resonance Technology

Acoustic resonance technology (ART) is an inspection technique that has applications for both gas and liquid pipelines to provide highly accurate pipeline wall thickness data [23]. ART enables precise measurements by using ultrasound waves and is often used in high pressure gas systems. The technology can be applied for crack inspection by obtaining detailed wall thickness measurements. However, ART has not been widely validated or used at the time of this report.

5.1.5 Importance of ILI Run Quality in Data Collection

Regardless of the specific ILI technology, pipeline cleanliness has an important impact on the detection and sizing of features [24]. The build-up of deposits from corrosion can cause problems in detection and sizing for all ILI tools. Ensuring the pipeline is clean prior to any application of an ILI will improve the performance and quality of received data [25].

Flow parameters can also affect an ILI vendor's ability to collect sufficient quality data to analyze and meet their own specifications. Pipelines operating at low flow or low pressure may not be suitable for ILI. Alternatively, many gas pipelines operate at high flow rates, and reducing flow velocities for inspection is problematic. Operational conditions before and during inspection must be considered to properly analyze the ILI features and the future operation with hydrogen to understand the impact it may have on both detected and undetected features.

5.2 Identification and Sizing of ILI Features

All ILI tools are designed to detect features and anomalies within certain specifications. These include both a probability of detecting a particular feature and correctly classifying that feature. Once correctly classified, the feature can be sized, and the sizing of the detected feature should fit within the specified tolerance provided by the vendor. This is well understood by the industry but is repeated here for clarity. When analyzing ILI results specifically for features susceptible to degradation by hydrogen, there can be challenges in finding, positively identifying, and sizing those features. Vendors express the capabilities of their ILI tools by reporting the probability of detection (POD), probability of identification (POI), and probability of sizing (POS) for detected features. All three are important for understanding features that may be affected by hydrogen.

It is important that all threats are detectable so that none are overlooked in the assessment. It is essential that the tools selected can detect and identify the relevant threats to the pipeline and that the size of the features is within the range of the specifications of the tool(s). The threats must be identified correctly, as ECAs of features vary by feature type. The current size of a detected feature is also a critical input for the calculation of its RL. An undersized defect may appear to have a longer life than it does. Conversely, an oversized defect may result in shorter RL results than necessary. Probability of Exceedance (POE) measures are used with other statistical tools to understand the probability of a defect being under- or oversized. These are critical analyses to confidently evaluate the RL of the pipeline.

Once the detected feature is understood from this point of view, the application of the effect of hydrogen on that feature can be analyzed. This is the subject of the current study. The industry has a robust understanding of the current state of technologies in detecting hydrogen-affected anomalies but has not analyzed in a systematic way the effect that hydrogen may have on both the features and their growth over time to understand the remaining life a pipeline may have by transporting hydrogen or hydrogen blends. Undersized or oversized defects or an incorrect understanding of the hydrogen effects on those defects will exacerbate the remaining life calculations and operator responses in detrimental ways.

5.2.1 Identifying Which Features Could Be Hydrogen-Susceptible

Physical damage from hydrogen presents itself in the steel microstructure as microcracks that can develop into macroscopic cracks. Any crack-like feature, irrespective of its origin from hydrogen damage or from another reason, can be susceptible to accelerated growth in the presence of hydrogen in the microstructure. Therefore, when performing an ILI on a hydrogen or blended natural gas/hydrogen pipeline, it is essential that the inspection method can detect crack-like defects in addition to other features, such as metal loss or mechanical damage. Welds may be more susceptible to hydrogen-damage than base metal because of the weld microstructures and weld geometries. Thus, ILI of hydrogen or natural gas/hydrogen blended pipelines needs to be specifically tuned for features at welds.

As of December 2023, PHMSA Project 985, "Review of Threat Characterization Resulting from Hydrogen Gas Pipeline Service," is being conducted by Engineering Mechanics Corporation of Columbus (Emc^2), focusing on three main integrity challenges [26]. They describe them as follows:

1. Axial surface cracks in low-toughness ERW seam welds.

    a. For an axial crack in a hard ERW seam weld case, one aspect recently noted was that all pipe flaw evaluation procedures use the base-metal stress-strain (or flow stress) with the weld-metal toughness. However, for the hard seam weld, the material strength in the ligament is much higher than the base metal. As a result, the ligament may have considerably less plasticity, and the crack-driving force's plastic part should be much lower. A preliminary Finite Element Analysis (FEA) showed that the J-integral ratio (ratio of energy per unit fracture surface area in a material) $J_{applied,\ weld\ metal}$ / $J_{applied,\ base\ metal}$ is just under a factor of 3, which is quite a significant difference.

b. In addition, the change in the critical crack size as a function of the change in toughness will be evaluated. For instance, there could be toughness changes even with small amounts of hydrogen, and the question is how significant the toughness change for different materials is on the critical crack sizes. The changes are anticipated to be more significant for larger flaw sizes and lower initial toughness material.

2. Cracks in hard spots.

   a. Hard spots came from local overcooling when the steel was in plate form, resulting in microstructure changes to martensite and bainite, which are hard and more susceptible to hydrogen stress cracking. Hard spots fail from axial cracks developing in them over time.

   b. Preliminary FEA is being performed to check the interaction between stresses (pressure induced hoop stress, through-thickness bending stress, flat spot rounding stress, and residual stress) and the measured hardness profile, using different models.

3. Integrity of repair sleeves.

   a. A common repair procedure is the application of a Type B steel sleeve, which consists of welding two 180-degree sections together over the pipe and sealing the ends with fillet welds to make it pressure-containing. The welds are not subject to post-weld heat treatment (PWHT). The fillet welds are made to the surface of possibly-affected pipe in hydrogen service. In addition, when hydrogen gas enters the annular space (in case the sleeve is used over a leak), then the fillet welds of Type B welded sleeves can become prime locations for hydrogen damage.

   b. It is known that hydrogen distribution within steel is a function of stress-strain. Some preliminary FEA modeling demonstrated that multi-bead welding processes and weld overlays cause significant alteration in the through-thickness stress and strain profiles. These will result in a correspondingly different hydrogen distribution.

5.3 Commentary on Reinspection Intervals in Codes and Standards

In this section, a discussion about reassessment intervals is given based on the following Codes and Standards: API RP 1176 [8], API RP 579-1/ASME FFS-1-2021 [9], BS 7910-2019 [27], NACE SP0502-2010 [28], API 570 [29], 49 CFR 192 [2], 49 CFR 195 [30], ASME B31.8-2022 [31], ASME B31.8S-2022 [3] versus ASME B31.8S-2004 [7], ASME B31G-2023 [48], CEPA SCC RP [34], and ASME STP-PT-011 [35].

The various codes are based on the intrinsic correlation between defect size and shape (as determined by inspection such as ILI), local stress concentration (fracture mechanics), and H atom accumulation (models and numerical solutions) to determine the pipeline's increased susceptibility to hydrogen embrittlement.

5.3.1 API RP 1176-2016 [8] Recommended Practice for Assessment and Management of Cracking in Pipelines

API 1176 Paragraph 8.5 provides a general description of reassessment intervals of crack-like flaws. It is noted that identical text is included in API RP1160-2019 Paragraph D2.1 [44], as follows:

> ***Paragraph 8.5 "Reassessment Interval Determination"***
>
> *The remaining life calculations performed from either ILI or hydrostatic testing and the applicable growth model are used to determine the reassessment interval. An appropriate factor of safety should be applied to remaining life calculations, and the result is added to the date of the previous assessment. The factor of safety should consider the level(s) of conservatism applied to the remaining life calculation and also should take into account the risk associated with the pipeline. Consideration should also be given to the overall timeframe because very short calculated times to failure can be overly sensitive to input assumptions.*
>
> *Aside from regulatory requirements, the reassessment needs to occur before any potential cracks reach a critical size, taking into account the uncertainties associated with tool technology and inputs to the remaining life calculations. The assessment method chosen needs to be able to detect or eliminate the size of cracks that have determined the interval.*

5.3.2 API RP 579-1/ASME FFS-1 2021 [9] Fitness-For-Service

API 579 provides general comments on RL determination. These are important because RL is the basis for setting reinspection intervals. The goal is to reinspect well before the RL is consumed, so that action can be taken, if needed.

> ***Paragraph 2.5.2 "Guidance on Remaining Life Determination"***
>
> *Each FFS Assessment Part in this Standard provides guidance on calculating a remaining life. In general, the remaining life can be calculated using the assessment procedures in each Part with the introduction of a parameter that represents a measure of the time dependency of the damage taking place. The remaining life is then established by solving for the time to reach a specified operating condition such as the maximum allowable working pressure (MAWP) or a reduced operating condition MAWPr.*
>
> *RL estimates typically fall into one of the following categories:*

a) The RL Can be Calculated with Reasonable Certainty – … An appropriate inspection interval can be established at a certain fraction of the RL. The estimate of RL should be conservative to account for uncertainties in material properties, stress assumptions, and variability in future damage rate.

b) The RL Cannot be Established with Reasonable Certainty – … Remediation methods should be employed, such as application of a lining or coating to isolate the environment, drilling of blisters, or monitoring. Inspection would then be limited to assuring remediation method acceptability, such as lining or coating integrity.

c) There is Little or No RL – In this case remediation, such as repair of the damaged component, application of a lining or coating to isolate the environment, and/or frequent monitoring is necessary for future ***operation.***

5.3.3 BS 7910-2019 [27] Guide to Methods for Assessing the Acceptability of Flaws in Metallic Structures

British Standard BS 7910 provides a recommended sequence for carrying out an assessment of a known flaw, as follows:

Paragraph 5.2 Sequence of assessment

a) Identify the flaw type, i.e., planar, non-planar, or shape.

b) Establish the cause of the flaw.

c) Establish the essential data, relevant to the particular structure.

d) Determine the size of the flaw.

e) Assess possible material damage mechanisms and damage rates.

f) Determine the limiting size for the final modes of failure.

g) Based on the damage rate, assess whether the flaw would grow to this final size within the RL of the structure or the in-service inspection interval, by sub-critical crack growth.

h) Assess the consequence of failure.

i) Carry out sensitivity analysis.

j) If the flaw would not grow to the limiting size, including appropriate factors of safety, it is acceptable. The safety factors should take account both of the confidence in the assessment and of the consequences of failure.

5.3.4 NACE SP0502-2010 [28] Pipeline External Corrosion Direct Assessment Methodology

The effects of hydrogen on corrosion growth rates are not often reported, as hydrogen-assisted crack growth is considered much more of a concern. Text from NACE SP0502 is provided here for its general methodology of determining remaining life and reinspection intervals.

NACE SP0502 indirectly refers to ILI for setting reassessment intervals during the ECDA "Post-Assessment" step, as follows:

> ***Section 1: General***
>
> *1.1.6 External Corrosion Direct Assessment (ECDA) applications can include but are not limited to assessments of external corrosion on pipeline segments that:*
>
> *1.1.6.3 Have been inspected with another inspection method as a method of establishing a reassessment interval.*
>
> *Section 6: Post Assessment*
>
> *6.1.3 The conservatism of the reassessment interval is not easy to measure, because there are uncertainties in the remaining defect sizes, the maximum corrosion growth rates, and the periods of a year in which defects grow by corrosion. To account for these uncertainties, the reassessment interval defined herein is based on a half-life concept. An estimate of the true life is made, and the reassessment interval is set at one-half that value.*
>
> *6.1.3.1 Basing reassessment intervals on a half-life concept is commonly used in sound engineering practice.*
>
> *6.1.3.2 The estimate of true life is based on conservative growth rates and conservative growing periods.*
>
> *6.1.3.3 To ensure unreasonably long reassessment intervals are not used, the pipeline operator should define a maximum reassessment interval that cannot be exceeded unless all indications are addressed. …*

5.3.5 API 570-2016 [29] Piping Inspection Code

API 570 applies (with some exceptions) to hydrocarbon and chemical process piping that has been placed in service. A portion of the API 570 Code that addresses inspection intervals is included here for reference. Note that a difference with the above-discussed NACE SP0502-2010 [28] is that if risk-based inspection (RBI) is done, then the half-life concept for reinspection does not necessarily need to be followed.

6 Interval/Frequency and Extent of Inspection

6.1 General

To ensure equipment integrity, all piping systems and pressure-relieving devices shall be inspected at the intervals/frequencies provided in this section. Scheduled inspections shall be conducted on or before their due date or be considered overdue for inspection. Alternatively, an inspection due date may be determined through a risk assessment in accordance with API 580. This due date may exceed the typical half-life interval used in a more conventional analysis. Note not all RBI analysis produce an inspection interval, some generate an inspection due date based on acceptable risk criteria.

See API 570 Paragraph 7.13 for more information and requirements on overdue inspections, inspection deferrals, and inspection interval revisions.

5.3.6 49 CFR Title 49 Part 192 [2] – Transportation of Natural and Other Gas by Pipeline

49 CFR 192 specifies a 7-year maximum reinspection interval for pipelines in high consequence areas (HCAs) and a 10-year maximum reinspection interval for pipelines outside HCAs. Greater reinspection intervals may be established if conditions are met, as explained below.

Paragraph 192.937 "What is the continual process of evaluation and assessment to maintain a pipeline's integrity?"

(a) General. After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in § 192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section.

Paragraph 192.939, "What are the required reassessment intervals," has requirements for pipelines operating at or above 30% of SMYS and for pipelines operating below 30% SMYS. In both cases, for covered segments (those in HCAs), the maximum reassessment interval by an allowable reassessment method is 7 calendar years. An interval greater than 7 calendar years can be established, provided a confirmatory direct assessment is done in accordance with § 192.931.

Paragraph 192.931

For covered pipelines operating above 30% SMYS, operators using ILI to set a reassessment interval are required to do the following:

(a) Pipelines operating at or above 30% SMYS. (1) Pressure test or internal inspection or other equivalent technology. An operator that uses pressure testing

or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

(i) Basing the interval on the identified threats for the covered segment (see § 192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by § 192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, see § 192.7), section 5, Table 3.

For covered pipelines operating below 30% SMYS, operators using ILI to set a reassessment interval are required to do the following:

(b) Pipelines operating below 30% SMYS. (1) Pressure test, internal inspection or other equivalent technology following the requirements of (a)(1) of this section except that the stress level references in paragraph (a)(1)(ii) would be adjusted to reflect the lower operating stress level. If an established interval is more than 7 calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low stress reassessment in accordance with § 192.941.

For covered pipelines, the maximum reassessment intervals for different assessment methods are shown in Table 4 (reproduced from § 192.939.)

Table 4. Maximum Reassessment Interval for ILI Assessment, per 49 CFR 192.939

Assessment Method	***Pipeline Operating At or Above 50% SMYS***	***Pipeline Operating At or Above 30% SMYS, Up to 50% SMYS***	***Pipeline Operating Below 30% SMYS***
Internal Inspection Tool, Pressure Test of Direct Assessment	*10 years (*)*	*15 years (*)*	*20 years (**)*
Confirmatory Direct Assessment	*7 years*	*7 years*	*7 years*
Low Stress Reassessment	*Not applicable*	*Not applicable*	*7 years + ongoing actions specified in § 192.941*

(*) A Confirmatory direct assessment as described in § 192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.
(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

Paragraph 192.710 "Transmission lines: Assessments outside of high consequence areas" specifies assessment requirements for non-covered pipelines (those in Class 3 or 4 locations, those in moderate consequence areas that are ILI-capable, and those outside of HCAs) operating with an MAOP greater or equal to 30% of SMYS. Operators must perform initial assessments within a period not to exceed 10 years after the pipeline first meets the conditions, but no later than July 3, 2034. For reassessment, operators need to do the following:

> ***Paragraph 192.710***
>
> *(b) General (2) Periodic reassessment. An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.*

The Code requires the following about the assessment by ILI:

> ***Paragraph 192.710***
>
> *(c) Assessment method. The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:*
>
> *(1) Internal inspection. Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage (e.g., dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible…*

5.3.7 CFR Title 49 Part 195 [30] – Transportation of Hazardous Liquids by Pipeline

A discussion of reinspection intervals for liquids lines is provided here for reference. Hydrogen is unlikely to be transported as a liquid in pipelines because of the low temperature that would be required. However, if an existing liquids line is converted to transmit hydrogen gas or a hydrogen-natural gas mixture, the pipeline inherits a history of prior IM activities and a history of prior threats or degradation mechanisms that may be exacerbated by the introduction of hydrogen (e.g., crude sour service causing hydrogen embrittlement or bulging laminations.

49 CFR 195 specifies that a baseline assessment must be completed. The assessment interval for pipelines HCAs is within 5 years, and outside HCAs is within 10 years. Thus, for HCAs the interval for liquids pipelines is shorter (5 years) than for gas pipelines (7 years). The requirements for liquids are explained next.

Paragraph 195.452 “Pipeline integrity management in high consequence areas” requires for covered segments:

> ***Paragraph 195.452***
>
> *(d) When must operators complete baseline assessments?*
>
> *(1) All pipelines. An operator must complete the baseline assessment before a new or conversion-to-service pipeline begins operation ...*
>
> *(2) Newly identified areas. If an operator obtains information … demonstrating that the area around a pipeline segment has changed to meet the definition of a HCA, that area must be incorporated into the operator's baseline assessment plan within 1 year from the date that the information is obtained. An operator must complete the baseline assessment of any pipeline segment that could affect a newly identified HCA within 5 years from the date an operator identifies the area.*

and

> ***Paragraph 195.452***
>
> *(j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity? —*
>
> *(1) General. After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.*
>
> *(2) … The integrity analysis and evaluation must include consideration of the results of any baseline and periodic integrity assessments …*
>
> *(3) Assessment intervals. An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity … An operator must establish the assessment intervals based on:*
>
> - *the factors specified in paragraph (e) of this section,*
> - *the analysis of the results from the last integrity assessment,*
> - *and the information analysis required by paragraph (g) of this section.*

Paragraph 195.416 “Pipeline assessments” states for non-covered segments:

> ***Paragraph 195.416***
>
> *(a) Scope. This section applies to onshore line pipe that can accommodate inspection by means of ILI tools and is not subject to the IM requirements in § 195.452.*

(b) General. An operator must perform an initial assessment of each of its pipeline segments by October 1, 2029, and perform periodic assessments of its pipeline segments at least once every 10 calendar years from the year of the prior assessment or as otherwise necessary to ensure public safety or the protection of the environment.

5.3.8 ASME B31.8-2022 [31] Gas Transmission and Distribution Piping Systems

Paragraph 851.12.3 requires that the time interval between pressure tests should be based upon an ECA to prevent defects from growing to critical sizes. Paragraph 851.12.3(e) states that ILI is one of the methods that can be used to predict or confirm the presence of defects that may reduce the integrity of the pipelines.

Paragraph 851.12.3

(e) Other Inspection Methods. In-line inspection, external electrical surveys of coating condition and cathodic protection levels, direct inspection of the pipe, monitoring of internal corrosion, monitoring of gas quality, and monitoring to detect encroachment are methods that can be used to predict or confirm the presence of defects that may reduce the integrity of the pipeline.

5.3.9 ASME B31.8S-2022 [3] versus ASME B31.8S-2004 [7] Managing System Integrity of Gas Pipelines

As mentioned earlier, 49 CFR 192 [2] incorporates by reference the 2004 version of ASME B31.8S-2004 [7]. The current version is ASME B31.8S-2022 [3]. Some differences exist related to integrity assessment intervals. Specifically, the tables for prescriptive IM plans, which are reproduced below as Table 5 and Table 6, will be discussed next.

Table 5.6.1-1 in ASME B31.8S-2022 is similar to Table 3 in ASME B31.8S-2004, with a few key differences:

- The title of the 2022 version is "Integrity Assessment Intervals: Time-Dependent Treats, Internal and External Corrosion, Prescriptive Integrity Management Plan." The words "Internal and External Corrosion" were not included in the 2004 version.
- All factors are provided with two decimals in the 2022 version. Most were one decimal in the 2004 version.
- Factors 1.65 and 2.75 are provided in the 2022 version. Those were 1.7 and 2.8 in the 2004 version.
- The notes for direct assessment process were updated with references to NACE SP0204 [32] Stress Corrosion Cracking Direct Assessment (SCCDA) Methodology, NACE SP0206 [33] Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally

Dry Natural Gas (DG-ICDA), and NACE SP0502 [28] Pipeline External Corrosion Direct Assessment (ECDA).

The present literature review focuses on ILI reinspection intervals. Both versions of ASME B31.8S use the predicted failure pressure, P_f, and compare the P_f value to the MAOP. Depending on the MAOP as a percentage of SMYS, the maximum allowable integrity assessment interval is specified. For ILI, the interval can vary from as little as 5 years (P_f above 1.25 x MAOP, and MAOP above 50% SMYS) to as much as 20 years (P_f above 3.33 x MAOP, and MAOP below 30% SMYS) per the 2022 version of ASME B31.8S.

Figure 7.2.1-1 in ASME B31.8S-2022 (same as Figure 4 in ASME B31.8S-2004), reproduced here as Figure 3, graphically shows the timing for scheduled responses for time-dependent threats.

Table 5. "Table 3" from ASME B31.8S-2004

Table 3 Integrity Assessment Intervals: Time-Dependent Threats, Prescriptive Integrity Management Plan

Inspection Technique	Interval (Years) [Note (1)]	Criteria: At or Above 50% SMYS	Criteria: At or Above 30% up to 50% SMYS	Criteria: Less Than 30% SMYS
Hydrostatic testing	5	TP to 1.25 times MAOP [Note (2)]	TP to 1.4 times MAOP [Note (2)]	TP to 1.7 times MAOP [Note (2)]
	10	TP to 1.39 times MAOP [Note (2)]	TP to 1.7 times MAOP [Note (2)]	TP to 2.2 times MAOP [Note (2)]
	15	Not allowed	TP to 2.0 times MAOP [Note (2)]	TP to 2.8 times MAOP [Note (2)]
	20	Not allowed	Not allowed	TP to 3.3 times MAOP [Note (2)]
In-line inspection	5	P_f above 1.25 times MAOP [Note (3)]	P_f above 1.4 times MAOP [Note (3)]	P_f above 1.7 times MAOP [Note (3)]
	10	P_f above 1.39 times MAOP [Note (3)]	P_f above 1.7 times MAOP [Note (3)]	P_f above 2.2 times MAOP [Note (3)]
	15	Not allowed	P_f above 2.0 times MAOP [Note (3)]	P_f above 2.8 times MAOP [Note (3)]
	20	Not allowed	Not allowed	P_f above 3.3 times MAOP [Note (3)]
Direct assessment	5	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]
	10	All indications examined	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]
	15	Not allowed	All indications examined	All indications examined
	20	Not allowed	Not allowed	All indications examined

NOTES:

(1) Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time-dependent failure requires immediate reassessment of the interval.

(2) TP is test pressure.

(3) P_f is predicted failure pressure as determined from ASME B31G or equivalent.

(4) For the Direct Assessment Process, the intervals for direct examination of indications are contained within the process. These intervals provide for sampling of indications based on their severity and the results of previous examinations. Unless all indications are examined and repaired, the maximum interval for reinspection is 5 years for pipe operating at or above 50% SMYS and 10 years for pipe operating below 50% of SMYS.

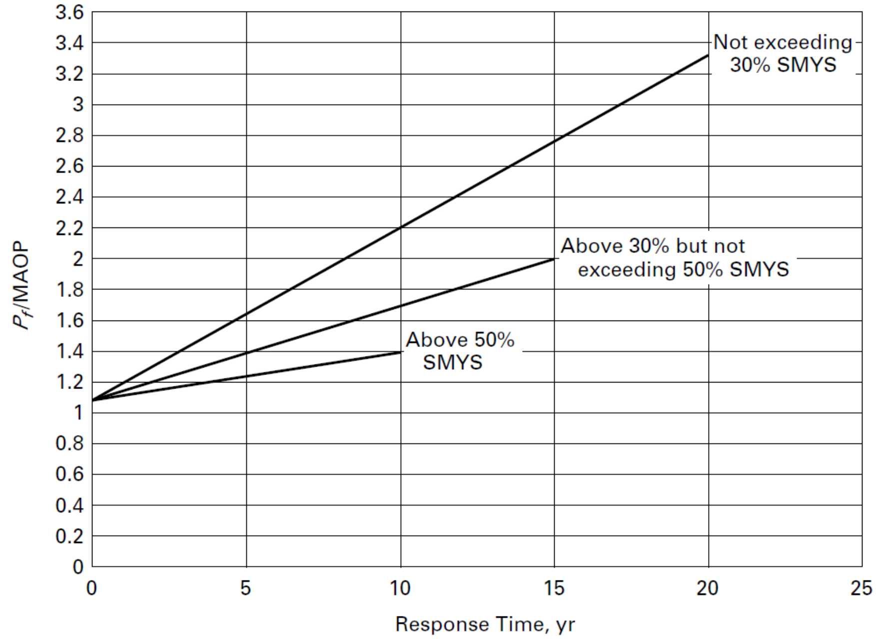
Table 6. "Table 5.6.1-1" from ASME B31.8S-2022

Table 5.6.1-1
Integrity Assessment Intervals:
Time-Dependent Threats, Internal and External Corrosion, Prescriptive Integrity Management Plan

		Criteria		
Inspection Technique	**Interval, yr [Note (1)]**	**Operating Pressure Above 50% of SMYS**	**Operating Pressure Above 30% but Not Exceeding 50% of SMYS**	**Operating Pressure Not Exceeding 30% of SMYS**
Hydrostatic testing	5	TP to 1.25 times MAOP [Note (2)]	TP to 1.39 times MAOP [Note (2)]	TP to 1.65 times MAOP [Note (2)]
	10	TP to 1.39 times MAOP [Note (2)]	TP to 1.65 times MAOP [Note (2)]	TP to 2.20 times MAOP [Note (2)]
	15	Not allowed	TP to 2.00 times MAOP [Note (2)]	TP to 2.75 times MAOP [Note (2)]
	20	Not allowed	Not allowed	TP to 3.33 times MAOP [Note (2)]
In-line inspection	5	P_f above 1.25 times MAOP [Note (3)]	P_f above 1.39 times MAOP [Note (3)]	P_f above 1.65 times MAOP [Note (3)]
	10	P_f above 1.39 times MAOP [Note (3)]	P_f above 1.65 times MAOP [Note (3)]	P_f above 2.20 times MAOP [Note (3)]
	15	Not allowed	P_f above 2.00 times MAOP [Note (3)]	P_f above 2.75 times MAOP [Note (3)]
	20	Not allowed	Not allowed	P_f above 3.33 times MAOP [Note (3)]
Direct assessment	5	All immediate indications plus one scheduled [Note (4)]	All immediate indications plus one scheduled [Note (4)]	All immediate indications plus one scheduled [Note (4)]
	10	All immediate indications plus all scheduled [Note (4)]	All immediate indications plus more than half of scheduled [Note (4)]	All immediate indications plus one scheduled [Note (4)]
	15	Not allowed	All immediate indications plus all scheduled [Note (4)]	All immediate indications plus more than half of scheduled [Note (4)]
	20	Not allowed	Not allowed	All immediate indications plus all scheduled [Note (4)]

NOTES:
(1) Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time-dependent failure requires immediate reassessment of the interval.
(2) TP is test pressure.
(3) P_f is predicted failure pressure as determined from ASME B31G or equivalent.
(4) For the direct assessment process, indications for inspection are classified and prioritized using NACE SP0204, Stress Corrosion Cracking (SCC) Direct Assessment Methodology; NACE SP0206, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA); or NACE SP0502, Pipeline External Corrosion Direct Assessment Methodology. The indications are process based and may not align with each other. For example, the External Corrosion DA indications may not be at the same location as the Internal Corrosion DA indications.

Figure 7.2.1-1
Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan



GENERAL NOTE: Predicted failure pressure, P_f, is calculated using a proven engineering method for evaluating the remaining strength of corroded pipe. The failure pressure ratio is used to categorize a defect as immediate, scheduled, or monitored.

Figure 3. "Figure 7.2.1-1" from ASME B31.8S-2022

5.3.10 ASME B31G-2023 [48] Manual for Determining the Remaining Strength of Corroded Pipelines

The ASME B31G Code applies to relatively smooth metal loss flaws. Wall thinning from metal loss (corrosion) increases the local stress, and when the stress is sufficiently high, that can result in increased susceptibility to hydrogen damage, such as loss of toughness and/or hydrogen-assisted cracking (HAC).

The B31G Code is limited in that it does not apply to other pipeline features/defects that may be susceptible to hydrogen damage, as listed in Paragraph 1.3 of the Code:

> ***Paragraph 1.3***
>
> *(a) crack-like defects or mechanical surface damage not completely removed to a smooth contour by grinding*
>
> *(b) metal loss in indentations or buckles resulting in radial distortion of the pipe wall larger than 6% of the pipe outside diameter, unless a Level 3 assessment is performed in accordance with para. 2.4*

(c) grooving corrosion, selective corrosion, or preferential corrosion affecting pipe seams or girth welds

(d) metal loss in fittings other than bends or elbows

(e) metal loss affecting material having brittle fracture initiation characteristics [see paras. 1.7(e) and 1.7(f)] unless a Level 3 assessment is performed in accordance with para. 2.4

(f) pipe operating at temperatures outside the range of operating temperature recognized by the governing standard or operating at temperatures in the creep range

The Code does provide a general statement about (corrosion) flaw size as a factor for ILI reassessment intervals. There is no prescriptive maximum time specified in this document. Paragraph 1.9 of the Code states:

Paragraph 1.9

When evaluating anomalies identified by inline inspection, use of larger factors of safety will result in smaller flaws being left in service following field investigation and pipeline repairs. This can increase the reassessment interval to the next inline inspection.

5.3.11 CEPA SCC RP (2007) [34] Stress Corrosion Cracking Recommended Practices

CEPA provides a flow chart for an SCC Management Program in Figure 4.2, reproduced here as Figure 4. CEPA first evaluates if a pipe segment is susceptible to SCC and establishes a susceptibility reassessment interval. CEPA then evaluates the severity of existing SCC into four categories per Table 4.1, reproduced here as Table 7. The severity categories depend on the calculated failure pressure, the maximum operating pressure (MOP), and safety factors. The reinspection intervals are determined, taking into account new weightings and factors since the prior round of investigation.

CEPA notes that the reassessment interval should not exceed ten years in Paragraph 4.3.3.

Paragraph 4.3.3 Determine SCC Susceptibility Reassessment Interval

The reassessment interval should not exceed ten years under ideal conditions. In assessing the above "non-ideal" conditions the operator may choose a shorter reassessment interval. As well, the operator should choose to further inspect for SCC if an opportunity allows itself, such as through excavations for other purposes. This will allow the operator to validate or even extend the reassessment interval.

CEPA provides a note regarding the safety factor (SF) in Paragraph 4.3.4.

> ***Paragraph 4.3.4 Classify the Severity of SCC***
>
> *The safety factor (SF) is a value defined by each pipeline company. Minimum values may be between 1.25 and 1.39 for pipeline segments in Class 1 areas. However, the SF should incorporate not only minimum values prescribed by applicable codes for new pipelines but also historical data relating to possible unique material properties of the pipeline segment, failure history (SCC or otherwise), consequences not captured by Class locations, uncertainty in data, and any other relevant information about the pipeline segment that would suggest a greater SF is required.*

CEPA also provides guidance on reinspection intervals in Paragraph 5.6.

> ***Paragraph 5.6 Re-inspection Intervals***
>
> *Based on the results of the investigations (i.e., ILI data, excavation results, survey analysis or hydrotesting), the operator should complete the SCC susceptibility analysis again using new weightings or factors based on the results from the first round of investigation. For example, if an operator originally prioritized 1980s vintage pipe as low priority and several SCC colonies were confirmed to only exist in the 1980s vintage pipe, then any other 1980s vintage pipe would need to be re-evaluated at a higher priority for investigation and condition monitoring.*

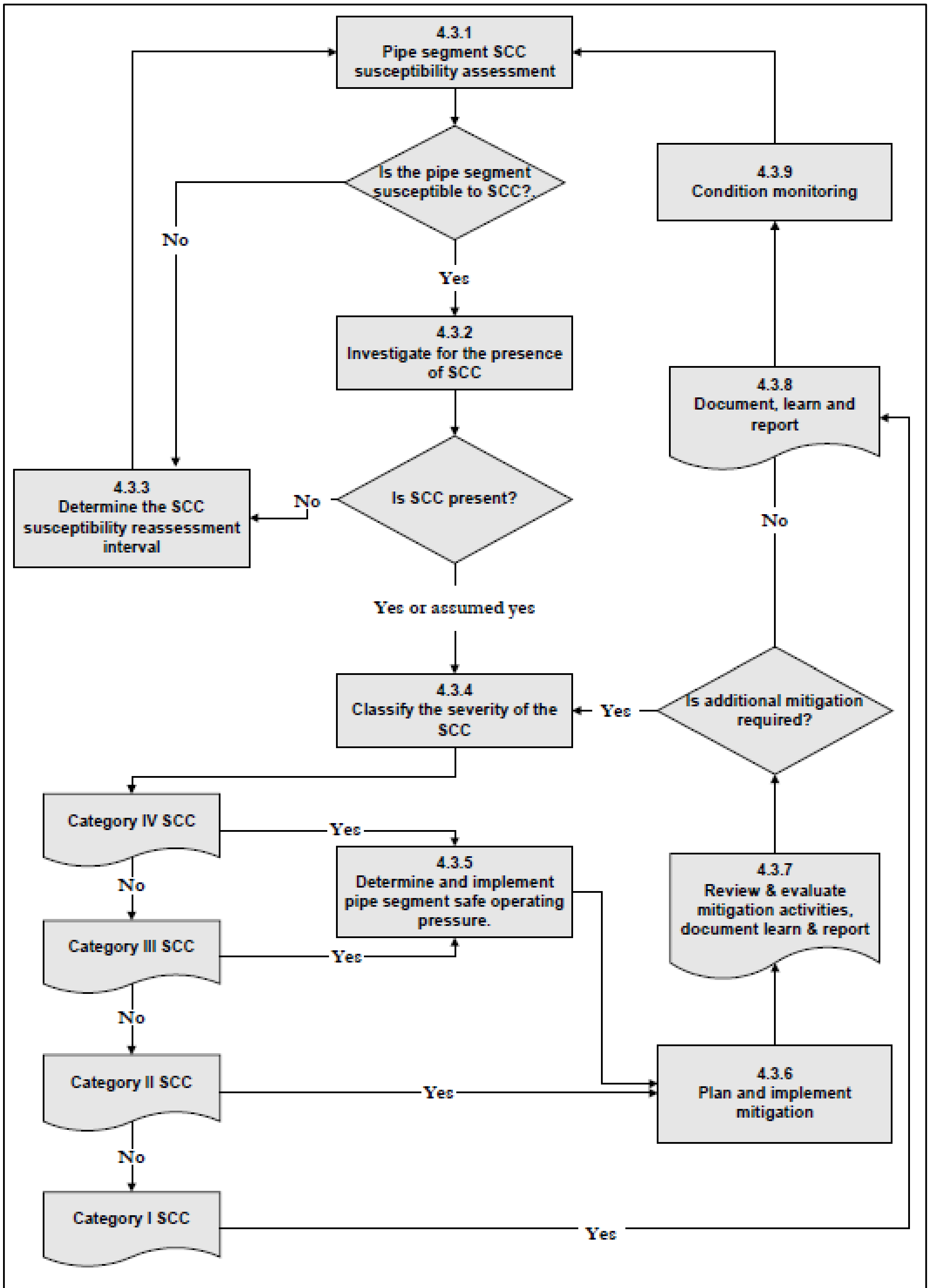


Figure 4.2: The CEPA SCC Management Program

Figure 4. "Figure 4.2" from CEPA SCC RP-2007

Table 7. "Table 4.1" from CEPA SCC RP-2007

Table 4.1: SCC Severity Categories

Category	Definition		Description
I	$SCC_{failure\ pressure} \geq 110\% \times MOP \times SF$	A failure pressure greater than or equal to 110% of the product of the MOP and a company defined safety factor. (Typically equating to 110% of SMYS).	SCC in this category does not reduce pipe pressure containing properties relative to the nominal pipe properties. Toughness dependent failures are not expected in this category.
II	$110\% \times MOP \times SF \rangle SCC_{failure\ pressure} \geq MOP \times SF$	A failure pressure less than 110% of the product of the MOP and a company defined safety factor, but greater than or equal to the product of the MOP and a company defined safety factor.	No reduction in pipe segment safety factor.
III	$MOP \times SF \rangle SCC_{failure\ pressure} \rangle MOP$	A failure pressure less than the product of the MOP and a company defined safety factor but greater than the MOP.	A reduction in the pipe segment safety factor.
IV	$MOP \geq SCC_{failure\ pressure}$	A failure pressure equal to or less than MOP.	An in-service failure becomes imminent as the MOP is approached.

5.3.12 ASME STP-PT-011 (2008) [35] Integrity Management of SCC in Gas Pipeline HCAs

ASME Special Technical Publication (STP) PT-011 presents the methodology to establish the interval for the next retest based on the SCC CGR for a hydrostatic pressure test. The same methodology can be applied to establish the intervals for reinspection by ILI. More information is given in response to a question in the STP:

> *Paragraph 5.3 Question 3: Where Hydrostatic Testing, SCC DA or Crack Detection ILI have been chosen as the assessment methods, what are the appropriate re-test intervals?*
>
> *For HCAs that are classified as possibly susceptible to SCC, pipeline companies are required to undertake periodic assessments using hydrostatic testing, ILI or direct inspection. Reassessment intervals should be short enough to assure the safety of the pipeline but not so short that they involve needless effort and expense or subject the pipeline to needless pressure fluctuations.*
>
> *In principle, the maximum re-inspection interval could be determined from the CGR, the size of the largest flaw that could exist in the pipeline and the size of a flaw that would cause a failure at the operating pressure. For companies that do*

not have specific information about possible CGRs on their pipelines, it is necessary to find another means of determining the appropriate intervals for reassessment (presented in Appendix D of SPT-PT-011).

A model has been developed that provides a technical basis for establishing subsequent hydrostatic re-test intervals based upon the test pressure, the MAOP, the tensile properties of the steel and the length of previous intervals. The principal assumption upon which the model is based is that a crack that already exists in the pipeline has a greater chance of reaching critical size than a crack that might initiate some time in the future. On that basis, subsequent intervals can be calculated by Equation (1):

$$t_n = t_p\ (\alpha/\beta) \qquad (1)$$

where
t_n = *length of the next interval*
t_p = *sum of the lengths of the previous intervals*
α = *difference between the test pressure and MAOP*
β = *difference between the pressure corresponding to the flow stress and the test pressure.*

Predictions from the model have been tested against histories of 13 valve sections that have experienced either high-pH or near-neutral-pH SCC and have been subjected to multiple hydrostatic re-tests. Within those 13 valve sections, eight in-service failures occurred after the initial hydrostatic tests. Five or six of those eight probably would have been prevented if the intervals from this method had been used rather than the ones that were, but no more re-tests, in total, would have been required. The only two service failures that would have occurred with a 3-year first interval and subsequent intervals determined from this method occurred on a valve section that had been tested to only 90% SMYS.

Reassessment intervals for ILI can be established in two alternative ways. If accurate measurements of crack sizes are available from successive runs, crack growth rates can be calculated by comparing the sizes of specific cracks at the two different times. However, if sufficiently accurate data are not available to follow the growth of individual cracks, the maximum size crack that is left in the line can be used to calculate an equivalent hydrostatic test pressure, and then the hydrostatic re-test model above can be used to establish subsequent intervals.

STP-PT-011 provides guidance on the failure life of SCC based on the crack severity. More information is given in response to a question in the STP:

Paragraph 5.6 Question 6: How should crack severity be defined and how should severity determine what kinds of remedial actions are appropriate?

For Noteworthy cracks, categories of crack severity are based upon critical cracks at other stress levels, using the actual interacting length and maximum depth. For example, taking 125% and 110% of MAOP in addition to 110% SMYS gives rise to a hierarchy of crack severity based on Predicted Failure Pressure (PFP) 1 as follows:

- *Category 1: Predicted Failure Pressure is above 110% SMYS*
- *Category 2: Predicted Failure Pressure is above 125% MAOP and below 110% SMYS*
- *Category 3: Predicted Failure Pressure is above 110% MAOP and below 125% MAOP*
- *Category 4: Predicted Failure Pressure is below 110% MAOP*
- *Category Zero: Is used to describe those cracks that are below the threshold for Noteworthy cracks*

Finally, cracks of any length that are greater than 30% through-wall depth, for which grinding is often not allowed by regulations, are grouped separately (These Deep Cracks also are categorized as Noteworthy).

The formulation of these severity categories enables an estimate to be made of the minimum remaining life at operating pressure, for each severity category. Estimates are based on the time taken for the crack depth to increase to the critical depth to cause failure at the operating pressure.

For example, for a typical pipeline operating at 72% SMYS, using a representative growth rate of 0.012 inch/year (0.3 mm/year) the following estimated minimum lives are obtained for each severity category:

- *Category Zero: failure life exceeds 15 (short) to 25 (shallow) years*
- *Category 1: failure life exceeds 10 years*
- *Category 2: failure life exceeds 5 years*
- *Category 3: failure life exceeds 2 years*
- *Category 4: failure may be imminent.*

5.4 Accelerated Fatigue or SCC CGRs Due to Presence of Hydrogen

The growth of pipeline defects is commonly modeled either as crack growth using a fracture mechanics approach, or metal loss/corrosion growth using a global or local stress analysis approach. In hydrogen service, crack growth is considered the primary concern for linepipe steels. Later in this chapter, a discussion about corrosion growth modeling is included for its general methodology of determining remaining life and reinspection intervals.

Depending on the circumstances, linepipe steels can behave in a brittle, ductile, or mixed-mode manner. Therefore, the assessment of flaw criticality usually includes aspects of both brittle and ductile failure. The approach is formalized in the failure assessment diagram (FAD) methodology described in standards such as API RP 579-1 [9]. The FAD-based assessment procedure computes a toughness ratio, K_r, and a load ratio, L_r. The assessment point with coordinates (K_r, L_r) is compared with the FAD curve, which represents the failure locus.

As with all engineering data, there is variability in measurement values. This creates uncertainty in the calculations used as part of a remaining life risk assessment for specific defects. For both fatigue and SCC, it may not be known if a threshold value exists, below which no crack growth will occur. There are always variations in the CGRs that are determined from materials testing in a laboratory, from ILI run-to-run comparisons, and from direct inspections and metallurgical examination of cracks found on a pipeline. Even tests intended to be identical will produce some spread in their CGR results. In addition, CGR data obtained from laboratory-tested specimens are often faster than actual CGRs observed on pipelines. This can lead to overly conservative conclusions. To ensure that realistic comparisons and predictions can be made, it is recommended that (1) CGRs should be presented as ranges and (2) the source of the CGRs should be provided.

The following Codes and Standards provide information about cyclic fatigue and/or stress corrosion cracking (SCC) growth rates for linepipe steels: BS 7910-2019 [27], API RP 579-1/ASME FFS-1-2021 [9], ASME B31.12-2019 [4], ASME Boiler and Pressure Vessel Code Section VIII [36], API 1176-2016 [8], CEPA SCC RP [34], and ASME STP-PT-011 (2008) [35]. Growth rates and material properties affected by hydrogen are discussed next.

5.4.1 BS 7910-2019 [27] Guide to Methods for Assessing the Acceptability of Flaws in Metallic Structures

British Standard BS 7910 provides a table and figure for the fatigue endurance limit of steel in air. The values are not reproduced here, as BS 7910 does not provide comparative information for hydrogen-affected steel. The standard does include general guidance statements related to hydrogen effects. Text from selected paragraph is as follows:

Paragraph 5.1 Modes of failure and material damage mechanisms

> *5.1.i Embrittlement: this type of damage can be caused in some materials by irradiation, temper embrittlement, or by caustic, hydrogen or hydrogen sulphide rich environments.*
>
> *5.1.viii Hydrogen and hydrogen sulphide related cracking: the damage rate is a function of material, pressure, temperature, concentration of H_2 or H_2S, etc.*

Paragraph 8.5.2.3 Stress relieved welds

> *… thermal stress relief has the beneficial effect of removing hydrogen from embedded slag inclusions and account is taken of this in deriving the permissible lengths of inclusions.*

Paragraph 8.7.4 Background to the assessment of embedded non-planar flaws

> *Larger inclusions are tolerable in stress relieved welds (than in as-welded welds) and it is believed that this is entirely due to the elimination of hydrogen from the voids as a result of PWHT.*

Paragraph 10.3.3 Environmentally assisted cracking

> *The extent and duration of chemical transients, the high probability of environmental chemistry modification in cracks and crevices and the possibility that hydrogen embrittlement (HE) processes can affect buried flaws should also be taken into account.*

Paragraph 10.3.3.2 Stress corrosion cracking

> *SCC results from the conjoint action of an aggressive environment and a static applied or residual stress. It includes cracking due both to metal dissolution and to HE.*

Annex L (informative) Fracture toughness determination for welds

> *Weldment fracture toughness data are required for the fracture assessment of flaws in welds (weld metal and associated HAZ). The assessment of flaws such as HAZ hydrogen cracking, lack of side wall fusion flaws and in-service fatigue cracks which can propagate through the HAZ require HAZ toughness data, while weld metal toughness data are necessary for assessing weld metal hydrogen cracks, solidification cracks, lack of root fusion flaws, etc.*

5.4.2 API RP 579-1/ASME FFS-1 2021 [9] Fitness-For-Service

This recommended practice, abbreviated "API 579," contains Part 7, "Assessment of Hydrogen Blisters and Hydrogen Damage Associated with HIC and SOHIC." Part 7 is dedicated to high-temperature hydrogen damage.

The high-temperature failure mechanisms of hydrogen-induced cracking (HIC), stress oriented hydrogen-induced cracking (SOHIC), and hydrogen blistering are common in the chemical/petrochemical process industries but are uncommon in natural gas pipelines. Exceptions may include when the gas contains hydrogen sulfide (H_2S) and free water, if the temperature is above ambient, if the pipeline is constructed with spiral-welded pipe, and/or if the steel has laminations in its microstructure.

API 579 addresses hydrogen effects on material properties in Part 9 "Assessment of Crack-Like Flaws" as follows:

Paragraph 9F.4.6.2 "Hydrogen Effects on Fracture Toughness and Flaw Assessment"

Hydrogen dissolved in ferritic steel can significantly reduce the apparent fracture toughness of a material. Fracture initiation is enhanced when hydrogen diffuses to the tip of a crack. If rapid unstable crack propagation begins, however, diffusing hydrogen cannot keep pace with the growing crack; therefore, the resistance to rapid crack propagation increases with increasing rate and the rate slows to establish equilibrium between the growth rate and the hydrogen delivery rate.

In other words, the toughness corresponding to initiation of fast fracture in a hydrogen-charged steel will not fall below the arrest toughness because the ability of atomic hydrogen to affect toughness is limited by diffusion rates to the crack tip. The arrest toughness lower bound does not protect against subcritical hydrogen-driven growth, which may continue at an equilibrium rate governed by diffusion kinetics and other factors.

If the hydrogen concentration is less than or equal to 1 ppm, then the hydrogen effects on fracture toughness are negligible.

> *a) Fracture Toughness – To account for the loss in fracture toughness when the hydrogen concentration is greater than 1 ppm, a material dependent temperature shift or the use of the arrest toughness is used. If actual fracture toughness data is available, it may be used in the assessment.*
>
> > *3) Carbon Steels and Low Chrome Alloys that are not Defined Above – A temperature shift cannot be accurately defined for these materials because of the lack of test data. Therefore, the arrest toughness in terms of the Master Curve shall be used as a conservative estimate or lower bound of the resistance of a ferritic steel containing dissolved hydrogen to rapid unstable crack propagation. Note, the arrest toughness does not provide a threshold against subcritical crack growth.*

API 579 provides material data for crack growth calculations in Paragraph 9F.5 "Material Data for Crack Growth Calculations" for fatigue, SCC, HAC, and corrosion-fatigue as follows:

Paragraph 9F.5.1.3 "Crack Growth by Hydrogen Assisted Cracking"

This covers a broad range of crack growth mechanisms that are associated with absorbed hydrogen in the metal. This includes HE, HIC, SOHIC, and sulfide stress cracking (SSC). In contrast to the other failure mechanisms, HAC susceptibility is highest at ambient and moderate temperatures and low strain rates.

a) HAC occurs when hydrogen is absorbed by a material during a corrosion process, or by exposure to high-temperature and/or high-pressure hydrogen gas, *and diffuses to a pre-existing flaw as atomic hydrogen, and stresses are applied, including residual stresses, to the flaw. The crack will continue to propagate at an increasing subcritical velocity until fracture occurs as long as the stress intensity factor resulting from the applied and residual stresses exceeds a critical threshold value, Kth, and a critical concentration of atomic hydrogen is maintained in the vicinity of the crack tip either by continuous absorption of hydrogen from the external surface, or by redistribution of internal lattice hydrogen and internal sources such as hydrogen traps in the material. The rapid, hydrogen accelerated propagation condition is dictated by the value of the material toughness in the presence of absorbed hydrogen at the crack tip. This toughness is designated as* $K_{Ic\text{-}H}$.

b) Within a linear elastic fracture mechanics (LEFM) methodology, a HAC crack growth model can be determined from test specimens that relate the CGR to the combined applied and residual stress intensity factor, the material/environment constants, and loading (strain) rate.

A simple form of the HAC crack growth curve is shown in Figure 9F.8(b)

This figure is reproduced here as Figure 5.

A typical crack growth model for HAC is shown in paragraph 9F.5.5.2.

The reference links to paragraph 9F.5.2.2 "Paris Equation," which is for fatigue in air. (Not reproduced here.)

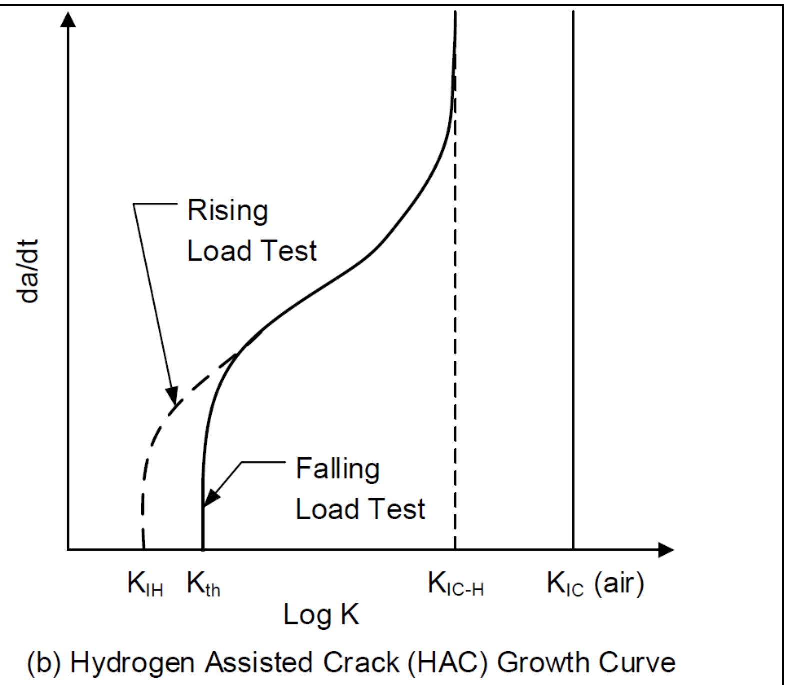


Figure 9F.8 – Crack Growth Behavior – Stress Corrosion Cracking and HAC

Figure 5. "Figure 9F.8(b)" from API RP 579-2021

API 579 Section 9F.5.4 refers to ASME B31.12 [4] and ASME Boiler and Pressure Vessel Code Section VIII [36], Division 3 for HAC growth rate models. These documents are further discussed below.

5.4.3 ASME B31.12-2019 [4] Code for Hydrogen Piping and Pipelines

Also mentioned in API 579, the ASME B31.12 Code provides an equation for fatigue CGR that can be used with performance-based design for carbon steels in gaseous hydrogen in pipeline service up to 20 MPa (3,000 psig), with reference to the work by Slifka, et al. [37] and Amaro, et al. [38]. Equation (2) is applicable for a stress intensity factor ratio $K_{min}/K_{max} = R < 0.5$,

$$\boxed{\frac{da}{dN} = a_1 \Delta K^{b_1} + \left[\left(a_2 \Delta K^{b_2} \right)^{-1} + \left(a_3 \Delta K^{b_3} \right)^{-1} \right]^{-1}} \qquad (2)$$

where da/dN is the CGR, ΔK is the stress intensity factor range, and a1, a2, a3, b1, b2, b3 are contacts given in Table PL-3.7.1-5 of ASME B31.12, as reproduced below in Table 8. In the above equation, the SI units of da/dN are in mm/cycle and the K-values in MPa*sqrt(m). In U.S. customary units, da/dN is in inch/cycle and the K-values in ksi*sqrt(inch).

Table 8. "Table PL-3.7.1-5" from ASME B31.12-2019

Table PL-3.7.1-5 Material Constants for Fatigue Crack Growth Rate, *da/dN*

Material Constant	Values SI	U.S. Customary
$a1$	4.0812 E−09	2.1746 E−10
$b1$	3.2106	3.2106
$a2$	4.0862 E−11	2.9637 E−12
$b2$	6.4822	6.4822
$a3$	4.8810 E−08	2.7018 E−09
$b3$	3.6147	3.6147

5.4.4 ASME Boiler and Pressure Vessel Code Section VIII [36], Division 3

As mentioned in API 579, ASME B&PV Code Section VIII Division 3, Article KD-10 provides procedures for testing to determine fatigue crack growth constants in hydrogen. In lieu of testing for fatigue CGRs in hydrogen environments for pressure vessels meeting criteria specified in ASME BP&V Code Case 2938 [39], this Code Case may be used for performing fatigue crack growth calculations. Technical background for the development of this Code Case was given in a 2019 paper by San Marchi, et al. [40].

5.4.5 API RP 1176-2016 [8] Recommended Practice for Assessment and Management of Cracking in Pipelines

API 1176 is an industry consensus document that provides industry-proven practices in the IM of cracks and threats that give rise to cracking mechanisms. The RP applies to pipeline systems defined in 49 CFR 192 [2] and 49 CFR 195 [30]. The RP does not cover defects associated with lap-welded (LW) pipe and selective seam weld corrosion (SSWC). Next, the CGRs mentioned in API 1176 and some hydrogen-related topics are discussed.

> ***Paragraph 3.1 Terms and Definitions***
>
> ***3.1.21 environmentally assisted cracking (ECA): Corrosive attack of the*** *pipe metal caused by exposure to specific environments either internal or external to the pipe and resulting in any of several forms of metal cracking.*
>
> *EXAMPLE: EAC includes but is not limited to hydrogen-induced cracking (HIC), stress-oriented hydrogen-induced cracking (SOHIC), sulfide stress cracking (SSC), or stress corrosion cracking (SCC).*

API 1176 Paragraph 6.2.1 "Stress Corrosion Cracking" does not mention hydrogen effects on the CGR of SCC. However, CGRs for near-neutral pH SCC (nnpH SCC) are described in API 1176

Annex H "Prediction of Crack Growth with Consideration of Variable Loading Conditions on Oil and Gas Pipelines in Near-neutral pH Environments."

API 1176 Paragraph 6.2.2 "Other Forms of Environmentally Assisted Cracking" provides the following comments:

- API 1176 comments on hydrogen effects for the threats of SSC, HIC, and SOHIC in the presence of free water and H_2S.
- API 1176 comments that if weldments on the pipe have created HAZs with hardness of Rockwell C 22 (22 HRC) or more, cracking can occur. The reference for this hardness value is NACE MR0175/ISO 15156 [41].
- API 1176 comments that hard spots, or hard zones on the seam line, having hardness levels in excess of 250 HV10 Vickers Hardness (22 HRC) are prone to hydrogen embrittlement and/or stress cracking in the presence of a significant atomic hydrogen flux.
    - Service failures have occurred as a result of hydrogen exposure of hard spots or hard zones.
    - The creation of hard spots is also associated with high carbon equivalent, which was allowed in the upper range of older versions of API 5L [42] by some pipe mills.
    - Additional information on a pipe manufacturer's susceptibility to hard spots is given in a 2004 INGAA report [43].
- API 1176 comments that hydrogen has a deleterious effect on steel properties. Lower toughness can be expected, in addition to crack growth due to fatigue.

API 1176 Paragraph 6.3.2 "Electric Resistance Welded (ERW) and Electric Flash-Welded (FW) Seams" comments that laminations are generally considered benign unless they contribute to the formation of a hydrogen blister are oriented in a manner where they can eventually grow to the inner or outer wall of the pipe through pressure cycles, or intersect another stress riser, such as a girth or seam weld.

API 1176 Paragraph 14.4.3 provides guidance on grinding:

> ***Paragraph 14.4.3 Grinding for Assessment***
>
> *Grinding can be useful where the apparent surface breaking portion of a lamination is just a surficial scab that coincides with it. However, surface blistering could be indicative that hydrogen charging has created the lamination and the potential presence of HIC.*

API 1176 Annex provides additional information on SCC assessments:

Annex A (normative) SCC Additional Information

A.2.4. Stress Cycling

In near-neutral pH environments, crack growth is driven interactively by dissolution and hydrogen. Atomic hydrogen is generated by corrosion reactions at the crack tip, on the crack walls, and on the disbonded pipe surface. Some of this hydrogen diffuses into the steel and is transported to the high stress zones at and near the crack tip, embrittling the area.

The presence of hydrogen weakens interatomic bonds and promotes brittle crack growth. Alternatively, in the high triaxial stress zone ahead of the crack tip, it can promote the flow of dislocations along slip planes, localizing strain and enhancing the coalescence of micro-voids, potentially leading to the formation of a microcrack.

API 1176 Annex F provides additional information on hydrogen effects:

Annex F (informative) Hydrogen Effects

API 1176 comments that hydrogen can affect both the toughness as well as the crack growth rate of steel under cycle loading. Where hydrogen effects are suspected, lower bound toughness might be appropriate. Additionally, higher fatigue crack growth rates are observed for steel that is charged with hydrogen due to applied cathodic protection (CP) potential or corrosion related to sour service.

The potential for hydrogen effects can be a factor if all the following conditions exist:

- *coating is suspected to have failed or to be in poor condition,*
- *water is present for a majority of the year,*
- *CP potentials are sufficiently high to produce adverse effects from atomic hydrogen, such as the formation of hydrogen blisters or cracking in hard microstructures,*
- *high hardness has been measured on the pipe,*
- *higher crack growth due to fatigue has been observed.*

API 1176 Annex H comments that where these factors are not present, hydrogen effects are not likely.

Annex H (normative) Prediction of Crack Growth with Consideration of Variable Loading Conditions on Oil and Gas Pipelines in Near-neutral pH Environments

Paragraph H.2 Crack Growth Mechanisms

This paragraph describes a revision of Parkins' 1987 bathtub model for nnpH SCC, with three stages:

- Stage I – Dissolution controlled crack initiation and growth.
- Stage II – Mechanically drive crack growth in the presence of hydrogen embrittlement.
- Stage III – Mechanically driven fast crack growth.

Figure H.4 from the RP is reproduced here as Figure 6.

For Stage II, Annex H comments on loading frequency as follows:

> *b) Loading Frequency—The variable rate of pressure fluctuations affect time-dependent contributions to crack growth, including the rate of corrosion, the rate of hydrogen diffusion and segregation to the crack tip, and the degree of crack tip blunting caused by low temperature creep and hydrogen facilitated local plasticity.*

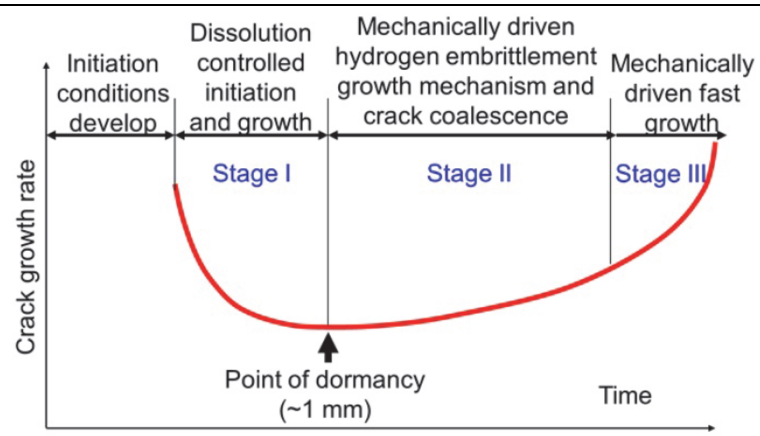


Figure H.4—Revised Three-stage Bathtub for Crack Growth in Near-neutral pH Environments

Figure 6. "Figure H.4" from API 1176-2016

Paragraph H.3 "Effect of Loading Interactions on Crack Growth Rate" discusses the effects of underloading and overloading and R-ratio.

Paragraph H.3 Effect of Loading Interactions on Crack Growth Rate

> *The CGR (da/dN) as a function of stress intensity factor range (ΔK), maximum stress intensity (Kmax), and loading frequency (f) is expressed in Equation (3).*

$$\frac{da}{dN} = a\left(\frac{\Delta K^{\alpha} K_{\max}^{\beta}}{f^{\gamma}}\right) + b \qquad (3)$$

Where a, n (=2), α (=0.67), β (=0.33), and γ (=0.033) are all constants; α+β=1; and b is the contribution of SCC, which was found to be about one order of magnitude lower than the first term in Stage II crack growth and can be ignored.

API 1176 Annex G (informative) provides fatigue C and n constants that can be used in fatigue calculations. The fatigue crack growth parameters are reported for line pipe in air, aqueous environments, sweet crude, sour crude, and sodium chloride (NaCl) environments. The parameters are listed in API 1176 Table G.1, reproduced here as Table 9.

API 1176 Paragraph 8.2.1 comments on Paris Law CGRs. However, the possible contribution of hydrogen effects is not presented separately in these CGRs.

Paragraph 8.2.1 Paris Law

Corrosive or hydrogen enriched environments can increase crack growth rates by an order of magnitude compared with rates for nonaggressive environments.

Table 9. "Table G.1" from API RP 1176-2016

Table G.1—Survey Sampling of Line Pipe Fatigue Crack Growth Parameters

Source	Application	C ksi (in.)$^{0.5}$	C Pa (m)$^{0.5}$	n
API 579-1	Welds	8.61E-10	1.65E-08	3.00
Barsom and Rolfe	"Typical," ferrite-pearlite steels	3.60E-10	6.89E-09	3.00
Vosikovsky[50]	X65, in aqueous environments	5.20E-10	9.59E-09	2.82
Vosikovsky[51]	X65 in air, ΔK < 18 ksi (in.)$^{0.5}$ [20 MPa (m)$^{0.5}$]	6.8E-11	1.3E-09	3.5
	X65 in air, ΔK > 18 ksi (in.)$^{0.5}$ [20 MPa (m)$^{0.5}$]	2.7E-09	5.2E-08	2.5
	X65, sweet crude, ΔK < 31 ksi (in.)$^{0.5}$ [34 MPa (m)$^{0.5}$]	1.4E-12	2.7E-11	4.8
	X65, sweet crude, ΔK > 31 ksi (in.)$^{0.5}$ [34 MPa (m)$^{0.5}$]	3.8E-08	7.3E-07	1.9
	X65, sour crude, ΔK < 23 ksi (in.)$^{0.5}$ [25 MPa (m)$^{0.5}$]	7.3E-14	1.4E-12	6.4
	X65, sour crude, ΔK > 23 ksi (in.)$^{0.5}$ [25 MPa (m)$^{0.5}$]	8.9E-9	1.7E-07	2.7
Andreason and Vitovec	Grade B	2.15E-13	4.12E-14	5.40
Keller et al. (DOE)	X52	4.30E-11	8.24E-10	3.77
San Marchi et al./ Stahlheim et al.	TMCP	1.34E-13	2.56E-12	3.50
Vintage line pipe, early 1950s	Youngstown DC-ERW	1.12E-10	2.14E-09	3.31
	Kaiser SSAW	1.51E-11	2.89E-10	4.01
	A.O. Smith EFW	2.33E-11	4.46E-10	3.89
Lambert et al.	X60, fatigue component of SCC lab testing with SCC crack growth rate of 0.0927 mm/yr (0.00365 in./yr)	1.53e-14	2.92E-13	3.97
Maxey	10-in. and 12-in. OD X52 ERW (in air)	2.12E-11	4.06E-10	4.00
Maxey	10-in. and 12-in. OD X52 ERW pipes (NaCl environment at free corrosion potential)	8.33E-11	1.59E-09	3.60

The various rates listed above are compared in Figures G.1 and G.2, below. It is noted that the API 579-1 rate is an upper bound to the other reported values except at very high levels of applied ΔK. Generally, values for ΔK will rarely exceed 50 ksi (in.)$^{0.5}$ ([55 MPa (in.)$^{0.5}$] in fatigue analyses. The data presented here are intended to indicate the potential range of values and not meant to imply that these values apply specifically to any particular pipe of pipe.

5.4.6 CEPA SCC RP (2007) [34] Stress Corrosion Cracking Recommended Practices

The CEPA SCC RP comments on the influence of hydrogen on SCC of pipelines.

> ***Paragraph 8.2.2 Condition Assessment for the Mitigation of Category II-IV SCC***
>
> *Condition assessments for the mitigation of Category II to IV SCC require:*
>
> - *A determination of SCC growth rates.*
> - *Utilization of SCC growth rates to establish intervals for mitigation.*

Paragraph 8.2.2.1 “SCC Growth Rates” provides SCC growth rates based on laboratory testing with simulated field conditions, beach mark observations on fracture surfaces from actual service, data from multiple SCC ILIs separated by several years, SCC size distribution data from field inspections, and growth rates derived from operating failures. However, the possible contribution of hydrogen effects is not presented separately in these CGRs. The CGRs are summarized here as follows:

- Lab tests: ranging from 0.06 mm/year (0.00236 inch/year) to 0.88 mm/year (0.0346 inch/year).
- Beach marks: no CGR distribution reported.
- Multiple ILIs: no CGR distribution reported.
- Field inspections: CGRs in order of 10-9 mm/sec (0.00124 inch/year).
- Operating failures: time-averaged CGRs.
    - NPS 36 pipeline: 0.3 mm/year (0.0118 inch/year) and 0.63 mm/year (0.0248 inch/year).
    - NPS8 and NPS10 ruptures: both at CGR of 0.16 mm/year (0.0063 inch/year).
    - SCC adjacent to these failures: 0.03 mm/year (0.00118 inch/year) to 0.13 mm/year (0.00512 inch/year).

CEPA provides more explanation about the use of growth rates as follows:

> ***Paragraph 8.2.2.1 SCC Growth Rates***
>
> *5. Growth rates derived from failures*
>
> *Ideally the growth rates should be derived from SCC features that are isolated, located at the toe of the weld or within sparse SCC colonies for the pipe segment under consideration. Rates derived from field observations should take precedence over laboratory results. In the absence of field growth data, however, laboratory results may initially be used for selecting appropriate growth rate values. Current failure criteria for SCC features apply to single or co-linear flaws.*
>
> *Although it is understood that, based on the growth model presented in Figure 2.1 (reproduced here as Figure 7), the total SCC growth cycle is nonlinear, linear growth can be approximated for each stage of the cycle. This approach implies limitations to the applicability of a calculated growth rate to the particular stage of growth. It also assumes uniform growth; that is, growth rates will be constant regardless of the depth, length, or proximity of SCC features. In practice, SCC*

growth rates should not be used to estimate life expectancy up to the point of failure, but to some point before failure where rapid mechanical growth of the feature is not occurring.

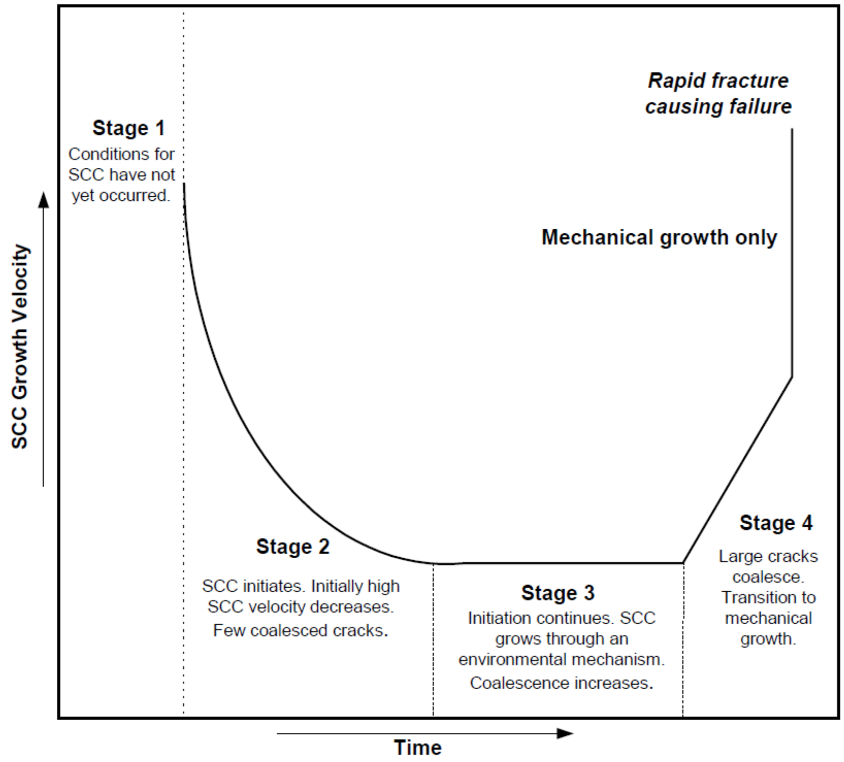


Figure 2.1: Bathtub Model: Life Cycle of SCC Growth in Pipelines (Parkins, 1987)

Figure 7. "Figure 2.1" from CEPA SCC RP-2007

The CEPA SCC RP comments on other hydrogen-related effects as follows:

Paragraph 2.4 SCC Overview

Crack growth is typically characterized as brittle and exhibits a cleavage-like fracture surface through the grain. However, evidence of small amounts of plasticity is often associated with the fracture path, suggesting a more complex growth mechanism is involved. Mechanisms have been proposed to explain the observed brittle propagation in an otherwise ductile material. These mechanisms typically speculate that atomic hydrogen plays a role in causing embrittlement of strained material immediately ahead of the crack tip.

Paragraph 7.3.3 Buoyancy Table

A failure is described in which HIC initiated beneath high-sulphur content buoyancy control weights. The condition underneath the weights was strongly anaerobic, a condition associated with nnpH SCC.

Paragraph 9.2 Cathodic Protection

Cathodic overprotection was identified as detrimental as it can promoted coating degradation, and the formation of alkaline environments conducive to high-pH SCC. Hydrogen gas generation and accumulation beneath disbonded coatings are also side effects of overprotection.

The recommended polarized or "off" potential range for the operation of cathodic protection systems is between -850 mV and -1100 mV. It is recommended to avoid potentials more negative than -1100 mV because they may promote the generation of hydrogen. Hydrogen can lead to hydrogen embrittlement of the pipe material, blistering and ultimately shielding of the coating materials.

5.4.7 ASME STP-PT-011 (2008) [35] Integrity Management of SCC in Gas Pipeline HCAs

Throughout this STP, the authors used a "representative" CGR for SCC as 0.012 inch/year (0.3 mm/year).

5.4.8 ASME B31.8S-2022 [3] Managing System Integrity of Gas Pipelines

ASME B318S-2022 requires using an "appropriate" growth rate for SCC assessments. The Code does not specify what rate to use, nor does it prescribe how the rate should be established.

For SCC crack growth, the following is provided in ASME B31.8S-2022:

Paragraph 7.2.4 Limitations to Response Times for Prescriptive-Based Program.

When time-dependent anomalies such as internal corrosion, external corrosion, or SCC are being evaluated, an analysis using appropriate assumptions about growth rates shall be used to ensure that the defect will not attain critical dimensions prior to the scheduled repair or next inspection.

Paragraph A-4.4 Integrity Management

The severity of SCC indications is characterized by Table A-4.4-1, reproduced here as Table 10. Several alternative fracture mechanics approaches exist for operators to use for crack severity assessment. The values in Table A-4.4-1 have been developed for typical pipeline attributes and representative SCC growth rates, using widely accepted fracture mechanics analysis methods.

Note that a table similar to Table A-4.4-1 was not included in the 2004 version of ASME B31.8S.

For fatigue crack growth, the following is provided in ASME B31.8S-2022:

> ***Paragraph 2.2 Threat Identification***
>
> *If the operational mode changes and pipeline segments are subjected to significant pressure cycles, pressure differential, and rates of change of pressure fluctuations, fatigue shall be considered by the operator, including any combined effect from other failure mechanisms that are considered to be present, such as corrosion.*

Note that ASME B31.8S-2022 make no specific mention of hydrogen effects in relation to either fatigue or SCC CGRs.

Table 10. "Table A-4.4-1" from ASME B31.8S-2022

Table A-4.4-1
SCC Crack Severity Criteria

Category	Crack Severity	Remaining Life
0	Crack of any length having depth <10% WT, or crack with 2 in. (51 mm) maximum length and depth <30% WT	Exceeds 15 yr
1	Predicted failure pressure >110% SMYS	Exceeds 10 yr
2	110% SMYS ≥ predicted failure pressure >125% MAOP	Exceeds 5 yr
3	125% MAOP ≥ predicted failure pressure >110% MAOP	Exceeds 2 yr
4	Predicted failure pressure ≤110% MAOP	Less than 2 yr

5.4.8.1 API RP 1160-2019 [44]

API RP 1160 discusses the influence of hydrogen on laminations and hard spots as follows:

> ***10.2.3 Non-linear Growth Rates***
>
> *Fatigue crack growth and growth from environmental cracking are non-linear. API RP 1176 [8] provides guidance on calculating growth rates for these threats.*
>
> *Laminations have the potential to grow in the presence of hydrogen from CP systems or sour crude. Lamination growth from hydrogen is also referred to as hydrogen blistering or bulging. Growth rates for hydrogen blisters can depend on several factors including the hydrogen evolution rate, amount of hydrogen present and properties of the steel, and can be difficult to determine.*
>
> *One effective method to establish a growth rate can involve aligning data from ILI and deformation tools to determine if internal bulging has occurred at a lamination and how much the internal deformation has changed between two ILI runs.*
>
> ***11.2.6.2 Hydrogen-Induced Cracking***

HIC can occur in hard spots or at internal discontinuities such as laminations or large inclusions. Controlling the amount of hydrogen present (i.e., adequate CP system control) in the environment and eliminating hard spots can be used to prevent or mitigate HIC.

5.5 Effects of Pressure Regime in Gas Pipelines

According to a 2023 Det Norske Veritas (DNV) white paper [45], gas pipelines are typically subject to many low amplitude (ripple) loads and a few large amplitude loading events associated with large pressure fluctuations. Pipeline operations typically fall into two regimes:

- Low ΔK/high R-ratio. Typically, there are many cycles in this range.
- High ΔK/intermediate R-ratio. Usually, there are fewer deep unload cycles.

Where ΔK indicates the changes in the stress state of the crack tip, for example, due to pressure fluctuations, and R-ratio is the ratio of the minimum and maximum loads during the fatigue loading.

DNV argues that to assess the integrity of pipelines, operators need to understand the fatigue performance over a wide range of amplitudes. In addition to fatigue loading, pipelines are typically subject to high mean loads, emphasizing the importance of the fracture toughness characteristics of the material. See Figure 8, which shows the typical operating conditions of a gas pipeline.

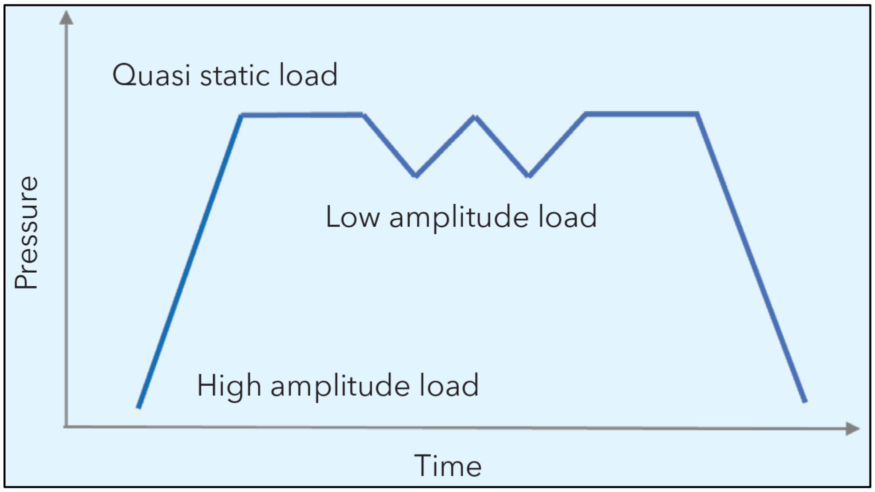


Figure 8. Typical Operating Conditions of a Gas Pipeline; Reference [45]

5.5.1 Effect of Fatigue on Existing Defects

Welds always have defects. Adding hydrogen into the pipeline network changes the pipeline operating environment. Due to the existing defects, this may accelerate crack propagation or fatigue failures and thus adversely impact pipeline integrity.

According to the 2023 DNV white paper [45], when considering the potential conversion of natural gas pipelines for hydrogen, operators need to evaluate the likelihood that expected pressure cycles will produce acceptable (very low) fatigue crack growth. Operators can then establish a threshold value for the pipelines. Based on the frequency of pressure cycles, operators can also estimate the amount of time until a crack reaches its selected maximum depth. An example developed by DNV regarding crack depth evolution is presented in Figure 9.

- The example explores the effects of pressure cycles from 218 psig (15 bar) to 435 psig (30 bar) amplitude (R-ratio = 1.0) on crack depth evolution, for a 36-inch (914 mm) diameter, 0.486-inch (11.9 mm) wall thickness, Grade X70 pipeline with an initial defect of 0.118-inch (3 mm; 25.2% of wall thickness) depth, and 0.984-inch (25 mm) length.

- In this example, the initial defect would not grow significantly when the pressure variation is 218 psig (15 bar; light blue line). However, it grows 10 times faster in the case of pressure variation of 435 psig (30 bar; light green line). This indicates that in this example, 218 psig (15 bar) could be used as the threshold value to direct operational practices to achieve the desired pipeline life.

- In this example, a crack depth of 0.4 a/t (40% of wall thickness) would be reached in 3,000 cycles for pressure fluctuations of 363 psig (25 bar) and in 5,000 cycles for pressure fluctuations of 290 psig (20 bar). Thus, the remaining life is longer with smaller pressure fluctuations, and a reinspection interval may consequently also be longer.

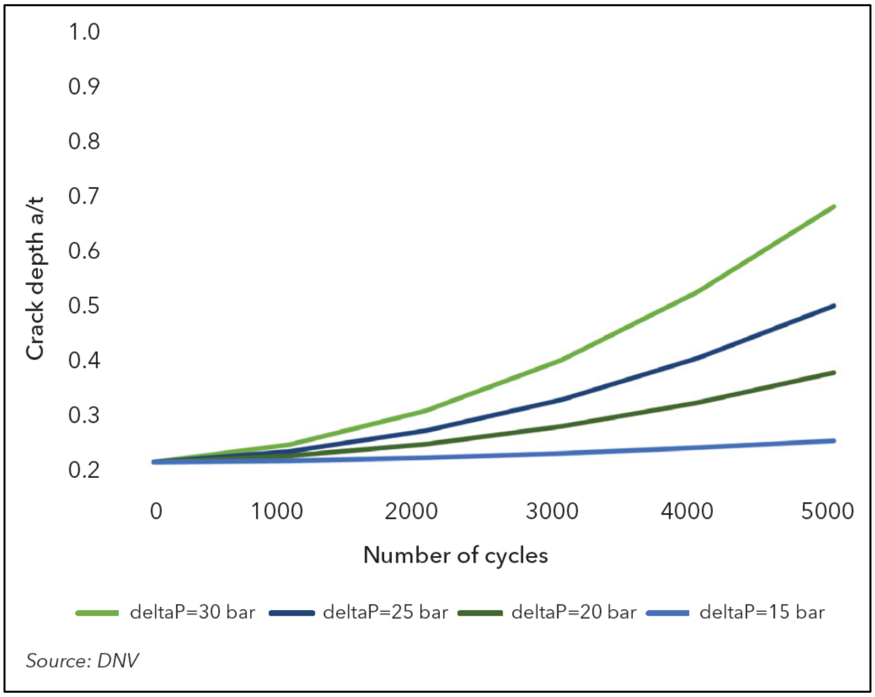


Figure 9. Example of Crack Depth Evolution; Reference [45]

5.5.2 Modeling Fatigue CGR in Hydrogen Gas

In ongoing work by Kathamukkala et al. [46] from the Arizona State University for the U.S. DOT, a proposed hydrogen-assisted fatigue crack growth (HA-FCG) model is used and modified to improve the overall predictions, specifically at low gas pressures. Their Q3 2023 status update reported that the uncertainty in the model parameters was taken into consideration, that probabilistic predictions were obtained, and that the model was benchmarked against the ASME B31.12 Code with confidence bounds. Some of the results are included next.

A HA-FCG model was proposed in 2022:

$$C_{hydrogen} = C_{air} \times \left[1 + \left(\{4.6 - 4.6\, exp^{-0.05P}\} \times 3^{2(1+R)} \times f^{-0.08} \times q\right)\right]$$

and

$$C_{eff} = \left[\left(\frac{C_{hydrogen} + C_{air}}{2}\right) + \left[\left\{\left(C_{hydrogen} - C_{air}\right) * tan^{-1}(3(\Delta K - 10.5))\right\}/\pi\right]\right]$$

Where C_{air} and $C_{hydrogen}$ are the Paris' constants under air and hydrogen, respectively. P, R, f, and q are the gas pressure, stress ratio, loading frequency, and hydrogen sensitivity factor, respectively. ΔK is the stress range and 10.5 is the kink point value in this model.

In 2023, the above model was modified to improve the CGR predictions. The modified form of the equations is as follows:

$$C_{hydrogen} = C_{air} \times \left[1 + \left(\{4.6 - 3.6\, exp^{-0.05P}\} \times 3^{2(1+R)} \times 1.2f^{-0.15} \times q\right)\right]$$

and

$$C_{eff} = \left[\left(\frac{C_{hydrogen} + C_{air}}{2}\right) + [\{\left(C_{hydrogen} - C_{air}\right) * tan^{-1}(3(\Delta K - \Delta K_o))\}/\pi]\right]$$

In the above equations, ΔK_0 = 12.5 for gas pressures below 7 MPa (1,015 psig), and ΔK_0 = 10.5 for gas pressures of 7 MPa (1,015 psig) and above. Hence, the kink point value has been increased for low gas pressures. Table 11 lists the mean values for the parameter q for different pipeline steels.

Figure 10, for a vintage and a modern Grade X52 steel, shows the FCGR data measured from experiments in air and in 5.5 MPa (797 psig) and 34 MPa (4,931 psig) hydrogen gas, compared with modeled curves.

Figure 11, for a Grade X70 steels, shows the FCGR data measured from experiments in air and in 5.5 MPa (797 psig) and 34 MPa (4,931 psig) hydrogen compared with modeled curves. This figure also shows the effect of frequency. Lower frequencies give rise to higher CGRs per cycle.

Figure 12, for a Grade X100 steel, shows the FCGR data measured from experiments in air and in 1.7 MPa, 7 MPa, and 21 MPa hydrogen gas, compared with modeled curves. Again, in this figure, the effect of frequency shows. Lower frequency gives rise to higher CGR per cycle.

Table 11. "Task 4 - Table 1" from Kathamukkala et al. [46]

Table 1. Mean values for parameter *q*

Grade	q_{before}	$q_{updated}$
X52	0.63	0.41
X70	0.35	0.25
X100	0.19	0.32

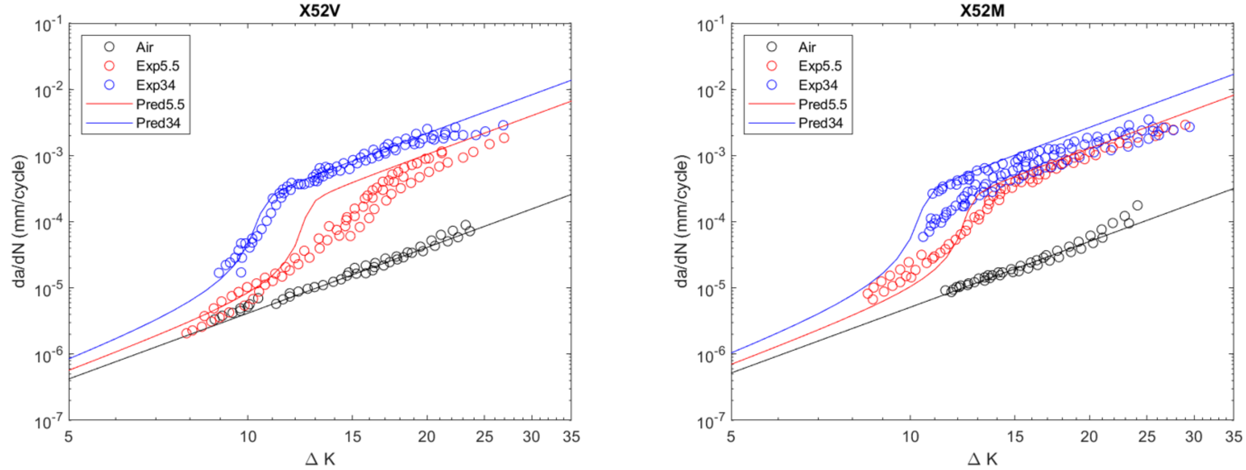


Figure 1. Experimental and predicted FCGR curves for X52 vintage (left) and X52 modern (right) steels.

Figure 10. "Task 4 - Figure 1" from Kathamukkala et al. [46]

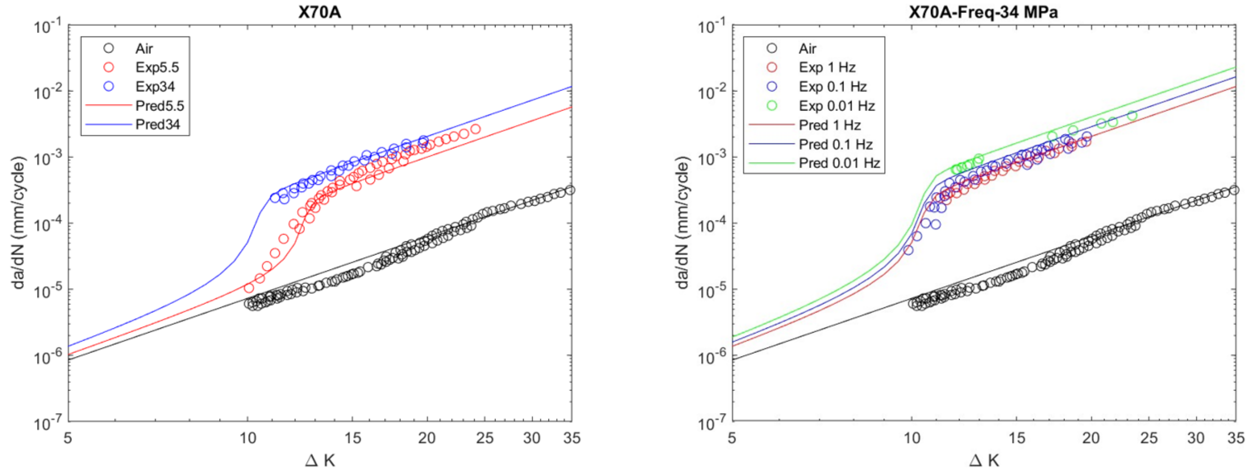


Figure 2. Experimental and predicted FCGR curves for X70A (left) and X70A frequency effect (right) steels.

Figure 11. "Task 4 - Figure 2" from Kathamukkala et al. [46]

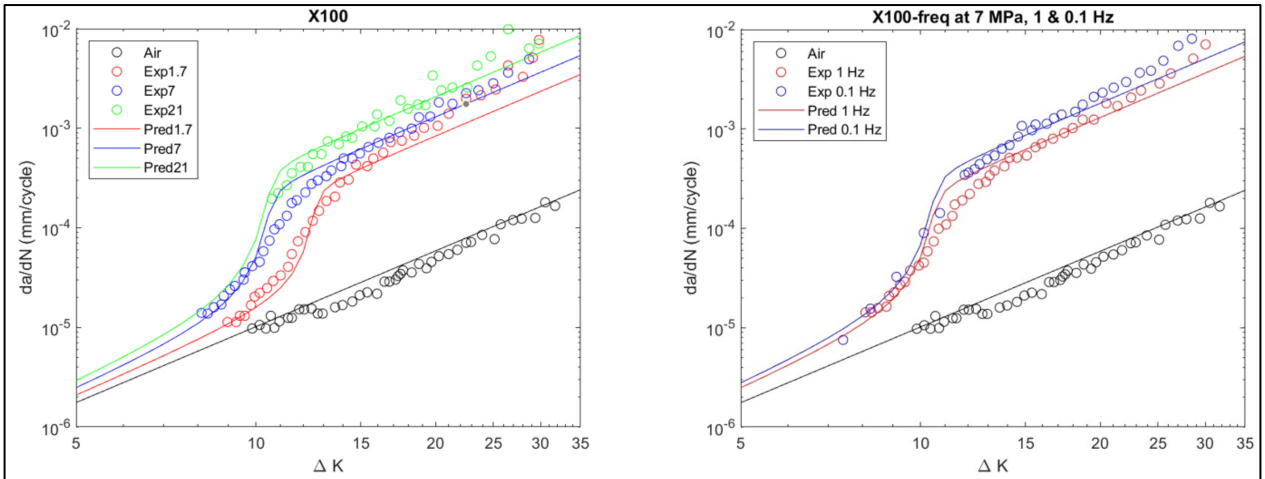


Figure 4. Experimental and predicted FCGR curves for X100 (left) and X100 frequency effect (right) steels.

Figure 12. "Task 4 - Figure 4" from Kathamukkala et al. [46]

A reliability analysis (details not included here) was also conducted. Kathamukkala et al. concluded that all the experimental data under hydrogen was contained within the upper 9% confidence bounds for all three tested steel grades. It was observed that the model's upper confidence bounds were higher as compared to the ASME B31.12 curve in the near-threshold region for most of the data, indicating better growth rate predictions from the newer model.

5.6 Experiences from Converting Existing Pipelines

In an October 2022 EPRI Report 300202505 "Transitioning Line Pipe to Hydrogen Service – Integrity Management" [47], DNV identifies the integrity, risk, and operational factors that operators should consider when transitioning a pipeline that was not originally designed to hydrogen standards to hydrogen service. Reference to this document is provided here, although the author of this present literature review does not have access to a copy of this EPRI report.

5.6.1 Effect of MAOP

The maximum allowable pressure (MAOP) of a pipeline has a strong effect on its transport capacity and is an important step in the assessment. The MAOP can be determined by using Option A (prescriptive) or Option B (performance-based) from standard ASME B31.12 [4]. Option A limits the pressure up to 50% of that possible for natural gas, depending on the steel grade, which is not economically feasible in most cases. For this reason, gas operators are more interested in Option B, allowing them to keep a higher maximum operating pressure (MAOP).

The remaining strength of corroded pipelines for oil and gas operations have traditionally been assessed using methods defined in standards such as ASME B31G [48] or DNV-RP-F101 [49]. The question is whether these methods are applicable to assess pipelines under high-pressure hydrogen environments without modifications or calibration. This is an area of current research both in DNV and international research institutes (The European Gas Research Group, European Pipeline Research Group).

Recent research of hydrogen conversion readiness supports application of MAOP reduction and minimizing pressure fluctuations to limit the negative effects of hydrogen in natural gas transmission piping [50]. However, the research also indicates mitigation measures for any identified defects should be done and material testing should be performed to confirm fracture toughness for both pipe and weld base materials where they may be unknown or not previously validated.

5.7 Experiences from Hydrogen-Blending Pilot Projects

This section of the literature review discusses experience and lessons learned from pilot projects and real-world system studies with different hydrogen-blending percentages.

5.7.1 Knowledge Gap on Gas Blends

The authors of the 2023 DNV white paper [45] identified that there is a lack of knowledge on different blends of hydrogen. The blend of hydrogen versus natural gas will affect the gas properties in many aspects. ASME B31.12-2019 [4] is applicable for gas with ≥10% hydrogen.

However, some of the requirements, such as impact radius and arrested crack length are based on the 100% hydrogen case and do not account for the different properties of blends – especially in cases where most of the blend is natural gas. DNV found that there is a need for guidelines related to the assessment of the integrity and safety of natural gas grids for natural gas/hydrogen mixtures with different hydrogen concentrations.

5.7.2 The European Hydrogen Backbone Initiative

The European Hydrogen Backbone (EHB) [51] is a continent-wide effort by more than 30 pipeline operators to connect locations of hydrogen production with storage sites and end users through a network of transmission pipelines. The EHB network will consist of repurposed and new onshore and offshore pipelines connecting many major cities across the entire Europe. It is planned that by 2040, a hydrogen network of 23,000 km (14,292 miles) will exist, 75% of which will consist of converted natural gas pipelines.

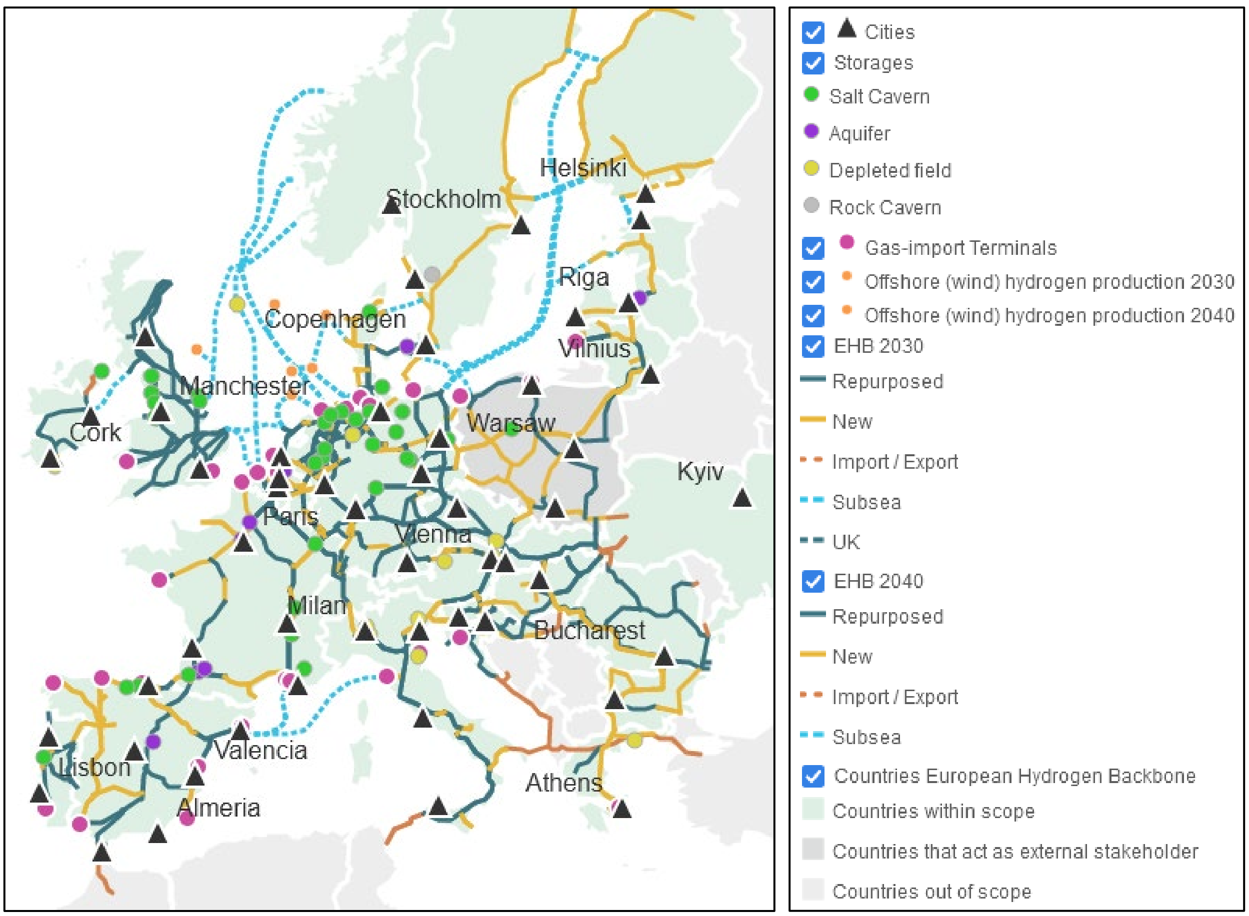


Figure 13. European Backbone Map [51]

The EHB will supply hydrogen through five (5) corridors [52], as shown in Figure 14.

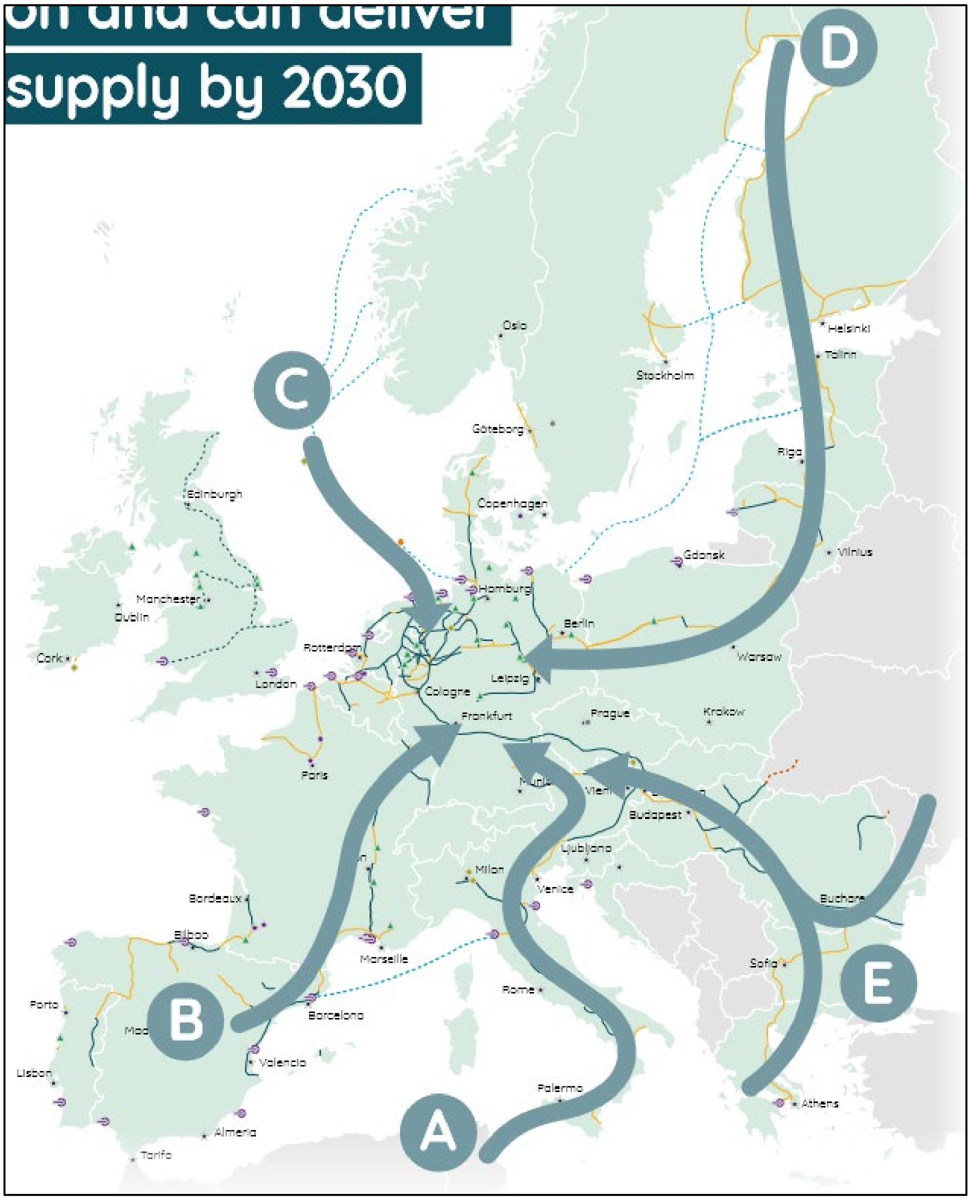


Figure 14. Five Corridors of the European Hydrogen Backbone [52]

These five corridors represent the collective vision of the 31 gas infrastructure companies that are part of the EHB initiative. The five hydrogen supply corridors are:

- Corridor A: North Africa & Southern Europe
  - 11,000 km (6,835 miles), of which 60% will be repurposed pipelines.
  - Includes the new SoutH2 Corridor Pipeline.

- Corridor B: Southwest Europe & North Africa

- 11,000 km (6,835 miles), of which 60% will be repurposed pipelines.
  - Includes the new H2Med Project.

- Corridor C: North Sea
  - 12,000 km (7,456 miles), of which 70% will be repurposed pipelines.

- Corridor D: Nordic and Baltic regions
  - 13,500 km (8,389 miles), of which 45% will be repurposed pipelines.

- Corridor E: East and South-East Europe
  - 10,000 km (6,214 miles), of which 60% will be repurposed pipelines.

The above numbers are summarized in Table 12. If all the plans come to fruition, the EHB backbone is expected to have approximately 35,700 miles of hydrogen transmission pipelines. Thus, Europe is leading the development of hydrogen infrastructure in a major way.

Table 12. Summary of Existing and New Pipelines in European Hydrogen Backbone

EHB Corridor	Total Miles	Percent Repurposed	Existing Pipelines	New Pipelines
A	6,835	60%	4,101	2,734
B	6,835	60%	4,101	2,734
C	7,456	70%	5,219	2,237
D	8,389	45%	3,775	4,614
E	6,214	60%	3,728	2,486
Total	**35,729**	**58.6%**	**20,924**	**14,805**

The SoutH2 Corridor Pipeline (part of Corridor A) and the H2Med Project (part of Corridor B) are discussed next.

5.7.2.1 The SoutH2 Corridor Pipeline

The SoutH2 Corridor [53], also known as the "Hydrogen Corridor Italy-Austria-Germany," is a pipeline project connecting North Africa with Italy, Austria, and Germany that is intended to be part of the EHB. There are infrastructure companies in Europe that are promoting this development. The corridor location is shown in Figure 15.

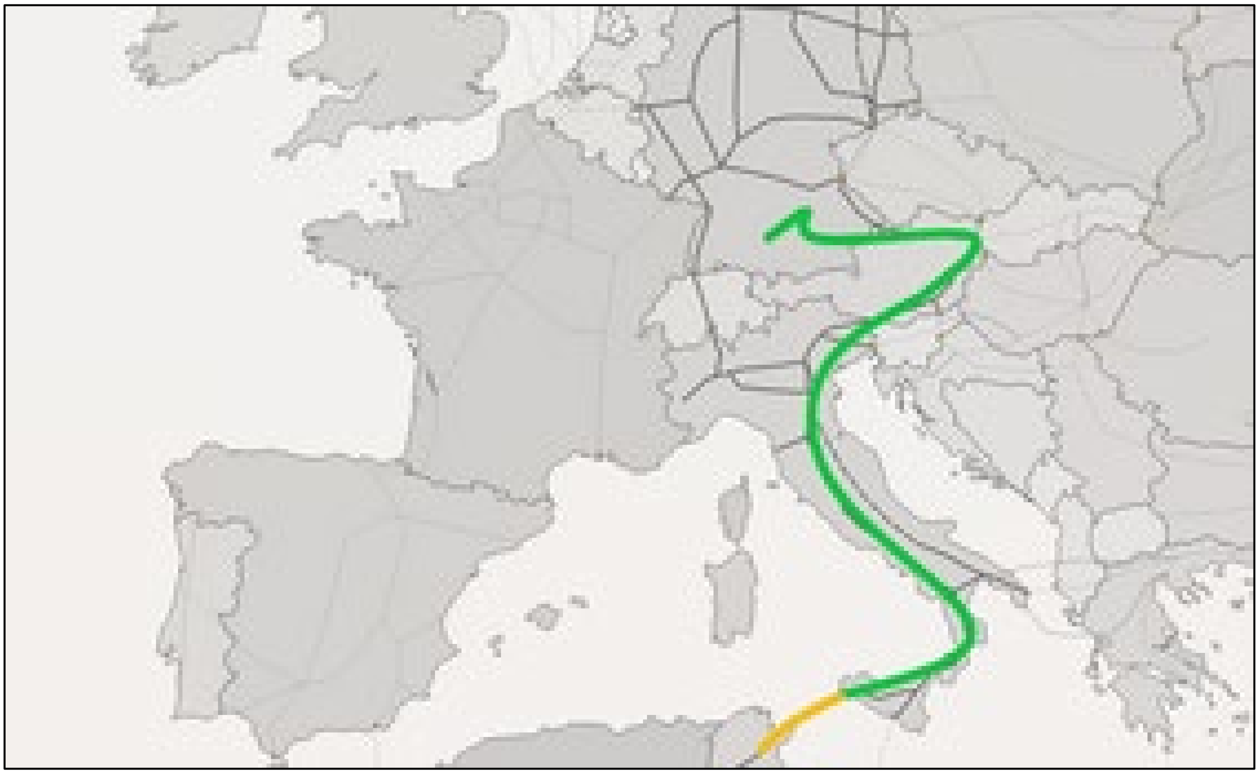


Figure 15. Location of SoutH2 Corridor [53]

The development of the SoutH2 corridor, which is part of an interconnected and diversified European "hydrogen backbone", will also contribute significantly to the security of supply. The SoutH2 corridor, which is expected to be fully operational as early as 2030, consists of the following individual Projects of Common Interest (PCIs) project candidates:

- "Italian H_2 Backbone" by Snam Rete Gas,
- "H_2 Readiness of the TAG pipeline system" by Trans Austria Gasleitung GmbH,
- "H_2 Backbone WAG + Penta-West" by Gas Connect Austria GmbH, and
- "HyPipe Bavaria - The Hydrogen Hub" by bayernets GmbH.

The initiative is centered around the utilization of existing repurposed midstream infrastructure to transport hydrogen, with the inclusion of some new dedicated infrastructure, where necessary. A high proportion of repurposed pipelines (>70%) will enable cost-effective transportation, while access to favorable renewable hydrogen production locations (wind and solar) in the southern Mediterranean region (Southern Italy, Tunisia, and Algeria) will enable competitive production.

5.7.2.2 H2Med Project

The H2Med Project [54] is a transnational initiative to interconnect the hydrogen networks of the Iberian Peninsula to Northwest Europe. This initiative, which is part of the EHB, was launched by France, Spain, and Portugal, with strong support from Germany, and promoted by the Technical Support Organizations (TSOs) of these countries: Enagás, GRTgaz, OGE, REN, and Teréga.

As part of the H2Med project, two new pipelines will be constructed: The 248 km (154 miles) long, 28-inch diameter CelZa pipeline linking Portugal and Spain, and the 450 km (280 miles) long, 28-inch or 42-inch diameter BarMar pipeline linking Spain and France. The latter pipeline includes a sub-sea portion connecting Barcelona to Marseille, see Figure 16.

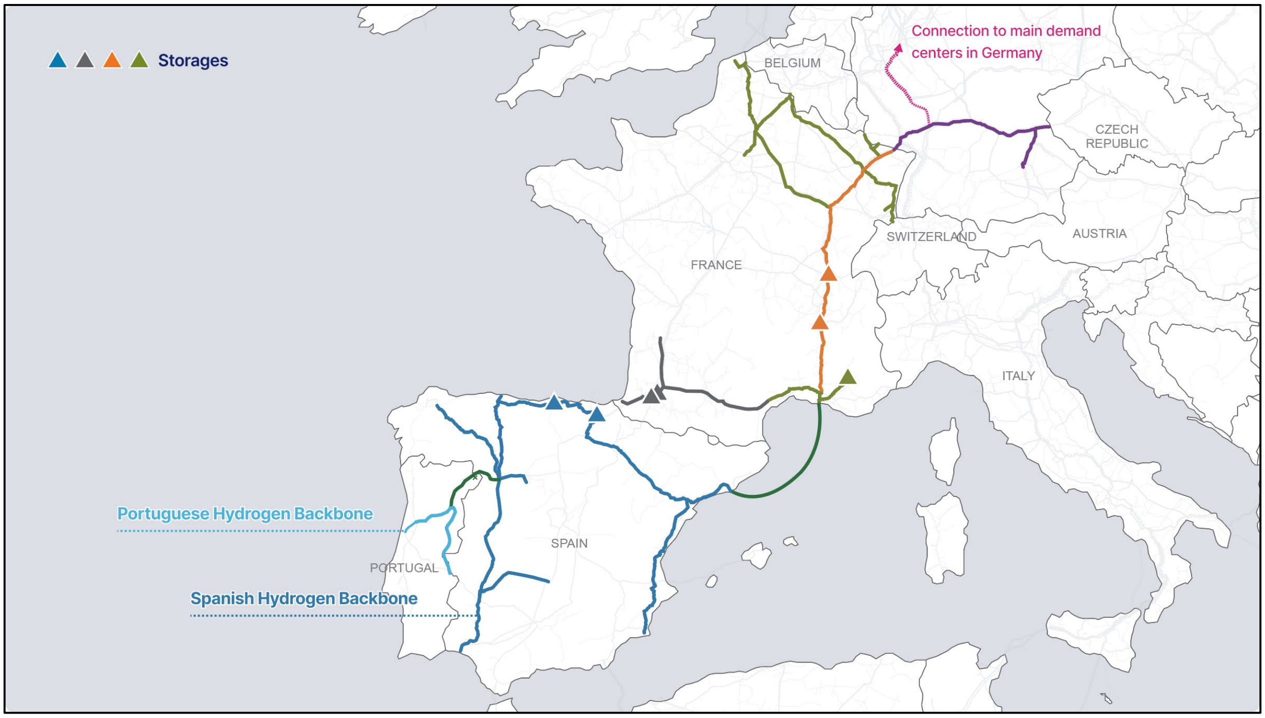


Figure 16. Location of H2Med Project [54]

5.7.3 The U.S. Regional Hydrogen Hubs Program (H2Hubs)

As discussed in Section 4 BACKGROUND, in 2019, the U.S. had (and still has) approximately 1,500 miles of hydrogen pipelines. This is a relatively small mileage compared to the European Hydrogen Backbone Initiative, which has 35,700 miles of hydrogen pipelines planned.

In October of 2023, the U.S. Department of Energy (DOE) announced the Regional Hydrogen Hubs Program (H2Hubs). This initiative includes up to $7 billion in funding through the Bipartisan Infrastructure Law [55] to establish seven regional clean hydrogen hubs across America. While "delivery" of clean hydrogen is one of the topics being touted, information on the length of any new or repurposed pipelines is not readily available at this time [56]. In fact, the description of the Appalachian Hydrogen Hub is the only one that mentions pipelines. The names and areas of the U.S. hydrogen hubs are as follows:

1. Appalachian Hydrogen Hub (Appalachian Regional Clean Hydrogen Hub (ARCH2); West Virginia, Ohio, Pennsylvania),
    a. "The strategic location of this H2Hub and the development of hydrogen pipelines, multiple hydrogen fueling stations, and permanent CO_2 storage also have the potential to drive down the cost of hydrogen distribution and storage."
2. California Hydrogen Hub (Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES); California),
3. Gulf Coast Hydrogen Hub (HyVelocity H2Hub; Texas),
4. Heartland Hydrogen Hub (Minnesota, North Dakota, South Dakota),
5. Mid-Atlantic Hydrogen Hub (Mid-Atlantic Clean Hydrogen Hub (MACH2); Pennsylvania, Delaware, New Jersey),
6. Midwest Hydrogen Hub (Midwest Alliance for Clean Hydrogen (MachH2); Illinois, Indiana, Michigan), and
7. Pacific Northwest Hydrogen Hub (PNW H2; Washington, Oregon, Montana).

5.7.4 Hydrogen Blending Projects

5.7.4.1 GRHYD Demonstration Project (United Kingdom)

The GRHYD demonstration project [57] led by the French energy company ENGIE was launched in 2014 with twelve industrial partners. This was a (renewable electric) power-to-gas (P2G) project. The first two years were devoted to a phase of technical and sociological studies, followed by a five-year demonstration phase of two uses of hydrogen injection: transport and residential housing.

- The transportation demonstrator was the industrial scale Hythane® fuel (composed of hydrogen and natural gas) project, which included a bus fueling station with a fleet of approximately 50 buses fueled by a hydrogen/natural gas blend of 6% to 20% hydrogen.
- The residential demonstrator included a newly built neighborhood of approximately 200 homes in the Capelle La Grande district of the Dunkerque Urban Community, which was supplied with a variable hydrogen/natural gas blend with up to 20% hydrogen.

Inaugurated in 2018, the experimentation ended in 2020.

Alliatt and Pierre [58] reported the success of the project. They stated that in France, natural gas infrastructure operators consider the “H_2 injection and blend” route to be among the solutions to be promoted to facilitate the integration of H_2 into the networks while taking into consideration:

- Injection of 6 vol% H_2 blend is possible in the short term in most gas infrastructures (except sensitive).
- 10 vol% H_2 in 2030 is an achievable target with anticipation of adaptations and changes to the prescription.

5.7.4.2 HyDeploy (United Kingdom)

Isaac [59] in 2019 described the HyDeploy project as UK’s first practical project to demonstrate that hydrogen can be safely blended into the natural gas distribution system without requiring changes to appliances and the associated disruption. The project was funded under Ofgem’s Network Innovation Competition and was a collaboration between Cadent Gas, Northern Gas Networks, Progressive Energy Ltd, Keele University, Health & Safety Laboratory, and ITM Power. The site of the project was the gas distribution network at Keele University. While the British limit for hydrogen blending was 0.1 mol% at the time of the project at Keele, testing was permitted to inject hydrogen at 20 mol%.

One component of the project was a materials program of experimentation to understand the mechanical property implications of soaking known materials in a blend of hydrogen and natural gas. This built confidence that the network and all operating components, such as control valves, would maintain operational integrity throughout the trial. None of the exposed appliances required remedial work to be undertaken because of the blended gas.

The interaction of hydrogen with materials present in the Keele system was evaluated by soaking specimens in pure methane (simulating 100% natural gas), pure hydrogen, and reference gas G222 (23 mol% hydrogen in natural gas) at 22 psig (1.5 barg) in a chamber for up to 6 weeks, followed by mechanical property testing. The tensile testing measured the total elongation at failure, modulus of elasticity, ultimate tensile strength, and proof strength. Note: Proof strength signifies the limit on the elastic region when a specimen is loaded with tensile stress. Yield strength can be defined as the amount of tensile stress that will produce a specified amount of permanent deformation (most commonly 0.2%). Proof strength is typically between 85-95% of the yield strength.

- The results of the tensile testing for the suite of materials tested showed no noticeable effects on the tensile properties of materials on the network resulting from exposure to the hydrogen blends at the operational pressures.

Following the initial trial at Keele, HyDeploy is now being executed to blend natural gas with up to 20% hydrogen for use in homes. This effort matches the December 2023 strategic policy decision by the UK Government to support the blending of up to 20% hydrogen by volume into gas distribution networks.

5.7.4.3 Assessing 2% to 100% Hydrogen/Natural Gas Mixture Pipeline (Czech Republic)

In their 2023 white paper [45], DNV described a project for the Czech Republic's gas transmission system operator, NET4GAS, to evaluate the suitability of its gas transmission system for mixtures of hydrogen and natural gas, from 2% to 100% hydrogen. This assessment included integrity aspects, safety, metering, operation, and maintenance topics.

To the knowledge of the author of this present literature review, the results of this assessment have not been shared publicly.

5.7.4.4 Assessing Hydrogen Blending Ratios for Gas Pipeline (India)

In their 2023 white paper [45], DNV described a project for India's natural gas pipeline operator, Pipeline Infrastructure Limited (PIL), to evaluate the readiness of its infrastructure to incorporate hydrogen and natural gas, at blending ratios of 5%, 10%, 15%, 50%, and 100% hydrogen. The assessment included transmission pipelines, interconnects and spur lines, compressors, valves, and metering stations and equipment.

To the knowledge of the author of this present literature review, the results of this assessment have not been shared publicly.

5.7.4.5 Assessing Suitability for Hydrogen Blending (South Korea)

In their 2023 white paper [45], DNV described a project for South Korea's LNG importer and pipeline operator, Korea Gas Corporation (KOGAS), to assess and demonstrate the viability and impact of blending hydrogen with natural gas at various ratios. The assessment included KOGAS' hydrogen demonstration project, with construction and operation of hydrogen injection facilities and equipment.

To the knowledge of the author of this present literature review, the results of this assessment have not been shared publicly.

5.7.4.6 Repurposing and Extending Infrastructure for Hydrogen (Denmark)

In their 2023 white paper [45], DNV described a project for Denmark's national transmission system operator, Energinet, to assess and advise on pipeline requalification for repurposing and possibly extending its gas network. The focus of the project was on identifying the major risks for project feasibility. Previously, DNV advised Energinet, as part of a conversion study for its Froslev to Egtved pipeline route, which is part of the Danish Hydrogen Backbone, to set up a connection to Germany for hydrogen.

To the knowledge of the author of this present literature review, the results of this assessment have not been shared publicly.

5.7.4.7 Assessing Hydrogen Readiness (Hungary)

In their 2023 white paper [45], DNV described a project for Hungary's gas transmission pipe operator, FGSZ, to examine the possibility of transporting hydrogen and hydrogen mixtures in its

72 km (48 miles) DN600 high-pressure natural gas pipeline. The project included different scenarios to assess the implications of exchanging natural gas with up to 100% gaseous hydrogen.

To the knowledge of the author of this present literature review, the results of this assessment have not been shared publicly.

5.7.5 Joint Industry Projects

The following pilot project and joint industry project (JIPs) are discussed here: HYREADY, H2Pipe, and In-Service Welding on Methane/Hydrogen Mixture Pipelines.

5.7.5.1 The HYREADY JIP

Within the HYREADY JIP [60], run by DNV, partners have prepared guidelines for the injection of hydrogen into natural gas systems. The HYREADY project gathers and evaluates existing information about the impact of hydrogen on natural gas systems for 2%, 5%, 10%, 20% and 30% blends in natural gas and for 100% of hydrogen. The guidelines developed as part of the project will provide support in the decision-making process in which a balance needs to be found between the aimed maximum hydrogen percentage and the cost of the needed countermeasures to overcome unacceptable consequences from the addition of hydrogen. These guidelines are intended to be converted further into DNV Recommended Practices.

5.7.5.2 The H2Pipe JIP: Transportation of Hydrogen Gas in Offshore Pipelines

In 2012, DNV launched a JIP [61] to develop a recommended practice for offshore hydrogen pipelines. The objective of the JIP is for this Recommended Practice to supplement the existing offshore pipeline standard, DNV-ST-F101 [49]. This would take a similar approach to the development of DNV-RP-F104 [62] for CO_2 pipelines. One of the goals of the JIP is to enhance the general understanding on how hydrogen gas affects the material properties exposed either to 100% H_2 gas or to a H_2/natural gas blend and further the real design limitations.

The JIP announcement noted that the ASME B31.12-2019 [4] Design Code may reduce conservatism for transporting hydrogen. However, B31.12 lacks offshore-specific design issues.

5.7.5.3 The In-Service Welding on Methane/Hydrogen Mixture Pipelines JIP

This JIP [63], also run by DNV, aims to determine if welding onto an in-service pipeline that contains a mixture of methane and hydrogen will result in an increased risk of hydrogen cracking and, if so, to develop guidance pertaining to measures that can be taken to mitigate the increased risk. In-service welds can be particularly susceptible to hydrogen cracking, and many pipeline operators do not allow hot tapping for this reason. The primary defense against hydrogen cracking is to strictly limit the introduction of hydrogen into welds by the proper use of low-hydrogen welding electrodes. Even when low-hydrogen electrodes are used, elevated weld hydrogen levels can result from hydrogen being present in the steel or from exposing the steel to elevated inside surface temperatures during in-service welding.

One of the goals of this JIP is to determine the extent to which pipe steel can become charged with hydrogen when transporting methane/hydrogen mixtures. The extent of elevated weld hydrogen will then be studied.

5.8 Crack-Related Failure Cases

In 2022, the Design, Materials and Construction Technical Committee of PRCI published Final Report PR-276-241503-R01 [64] "Causes of Crack Failures in Pipelines and Research Gap Analysis." In that study, the causes of 128 failures of oil and gas pipelines were investigated. In failure investigations, it is not always clear if hydrogen contributed to the failure. However, in 13 failure cases (approximately 10% of cases), hydrogen was implicated as a direct cause. A summary is shown in Table 13.

Table 13. Excerpt from "Table 9" from PRCI Report PR-276-241503-R01 [64]

Cracking Mechanism	Fluid		Total
	Gas	Liquid	
Hydrogen-Assisted Cracking (HAC)	2		2
Hydrogen Cracking	1		1
Hydrogen Embrittlement, High-pH SCC	1		1
Hydrogen-Induced Cracking (HIC)		2	2
Hydrogen-Induced Cracking (HIC), Lamination	1		1
Hydrogen Stress Cracking (HSC)	3		3
Intergranular Fracture, Hydrogen-Assisted Cracking (HAC)		2	2
Partial Weld, Fatigue Crack, Hydrogen-Induced Cracking (HIC)		1	1
Total	**8**	**5**	**13**

Additional details about the eight (8) PRCI-documented crack failures that occurred on natural gas pipelines are provided in Table 14. The Case Numbers refer to the occurrences analyzed in that project and references in a spreadsheet generated by the author and shared with PRCI. All these failures occurred in-service, involved pipelines of large diameter (16 – 36 inches), occurred on 1950s-1960s vintage pipe (1957-1969), happened on moderate strength steels (Grades API X52 - X60), and with the exception of one failure that occurred within one year, seven of the eight failures occurred after many years of service (17 – 58 years).

Table 14. Summary of Crack Failures in Gas Pipelines, in Which Hydrogen was Implicated as a Direct Cause

<table>
<tr><th>Install To Failure And Type</th><th>Diameter, Wall Thickness, Grade</th><th>Pipe Manufacturer, Seam Weld Type</th><th>External Coating Type</th><th>Crack Location</th><th>Geometry Features</th></tr>
<tr><td>1968-2010
Rupture
42 years</td><td>26”/0.281”
X60</td><td>National Tube
DSAW</td><td>Coal Tar Enamel, Glass Felt</td><td>GW</td><td>Not reported</td></tr>
<tr><td colspan="6">CASE 27: This 26-inch diameter, 0.281-inch wall thickness, API 5L Grade X60 natural gas transmission pipeline, manufactured by National Tube, with a double submerged arc welded (DSAW) long-seam weld and a coal tar enamel and glass felt coating was installed in 1968. The pipeline failed in March 2010 from a rupture. The direct cause of the failure was a tensile overload of a large crack in a girth weld (GW) that initiated during the original construction. An underlying cause was bending stress from pipe buoyancy in a rising water table, and the screw anchors used in the area of the failure were apparently not effective in the wetland soil surrounding the pipeline. The root cause was initiating a hydrogen-assisted crack (HAC) in the girth weld during the original construction. A contributing factor was that the operator was unaware of the integrity threat and was not collecting the necessary data to manage this threat.</td></tr>
<tr><td>1960-2018
Rupture
58 years</td><td>22”/0.250”
X52</td><td>AO Smith
Flash Weld</td><td>Asphalt Enamel</td><td>Base Metal</td><td>Not reported</td></tr>
<tr><td colspan="6">CASE 79: This 22-inch diameter, 0.250-inch wall thickness, API 5L X52 natural gas transmission pipeline, manufactured by A.O. Smith, with a flash welded (FW) long-seam weld and an asphalt enamel coating, was installed in 1960. The pipeline failed in 2018 from a rupture. The direct cause of the failure was hydrogen-assisted cracking (HAC). Leaks were also found. The root cause was hydrogen being generated by the cathodic protection (CP), which, in combination with an aged and defective coating, operated for decades at conditions near the pipe-to-soil potential limit of -1200 mV CSE.</td></tr>
<tr><td>1962-1992
Rupture
30 years</td><td>36”/0.406”
X52</td><td>Manufacturer not reported, Seam not reported</td><td>Not reported</td><td>GW, Base Metal</td><td>Weld Defect</td></tr>
</table>

Install To Failure And Type	Diameter, Wall Thickness, Grade	Pipe Manufacturer, Seam Weld Type	External Coating Type	Crack Location	Geometry Features
CASE 6: This 36-inch diameter, 0.406-inch wall thickness, API 5LX Grade X52 natural gas transmission pipeline from a not-reported manufacturer with a not-reported long seam weld type and a not-reported coating, was installed in 1962. A 24-inch diameter hot tap was installed in 1981 by welding a branch connection to the operating line. The pipeline failed in 1992 from a rupture at the toe of a hot tap stub weld, and the crack propagated by brittle fracture in two directions from the tee and was arrested in new material. The direct cause of the failure was the combined effects of a pre-existing weld defect (hydrogen crack), settlement of the adjacent branch piping, and line pressure. Underlying causes were the high carbon content of the material in conjunction with low heat input stringer bead welds at the toe of the stub weld that created a microstructure that was extremely susceptible to hydrogen cracking, even with the use of low hydrogen electrodes. The root cause was the non-compliant procedure to weld the NPS 24 stub to the NPS 36 carrier pipe, resulting in a hydrogen crack at the toe of the weld. However, this alone was insufficient to cause failure.					
1961-2016 Leak 55 years	36"/0.406" X52	Manufacturer not reported, DSAW	Not reported	Base Metal	Hard Spot
CASE 102: This 36-inch diameter, 0.406-inch wall thickness, Grade X52 gas transmission pipeline from a not-reported manufacturer with a double submerged arc welded (DSAW) long-seam weld and a not-reported coating was installed in 1961. The pipeline failed in 2016 from a leak. The direct cause of the failure was hydrogen embrittlement at a hard spot and/or high-pH SCC. The root cause of the hydrogen embrittlement was the presence of the hard spot (susceptible material), the state of stress, and the presence of cathodic protection. High pH was also considered a possible cause, but it was found to be less likely than hydrogen embrittlement.					
1957-2003 Rupture 46 years	30"/0.375" X52	AO Smith Flash Weld	Coal Tar Enamel	Base Metal	Hard Spot, Mill Defect
CASE 119: This 30-inch diameter, 0.375-inch wall thickness, API 5LX Grade X52 natural gas transmission pipeline manufactured by A.O. Smith with a flash welded (FW) long-seam weld and a coal tar enamel coating with felt wrap was installed in 1957. The pipeline failed in 2003 from a rupture. The direct cause of the failure was hydrogen-induced cracking (HIC) at a hard spot and co-existing mid-wall lamination. Underlying causes were the susceptibility of pipelines to manufacturing defects such as hard spots and laminations, and the challenges related to the inspection for and identification of such locations. The root cause was cathodic over-protection, which led to atomic hydrogen diffusing through the pipe wall and degradation of the hard spot over a period of time. A contributing factor was that the coal-tar enamel protective coating may have had some holidays.					
1969-1987 Leak 18 years	24"/0.406" X60	Manufacturer not reported, Seam not reported	Bituminous Asphalt	Base Metal	Bottom-Side Dent

Install To Failure And Type	Diameter, Wall Thickness, Grade	Pipe Manufacturer, Seam Weld Type	External Coating Type	Crack Location	Geometry Features
CASE 3: This 24-inch diameter, 0.406-inch wall thickness, API 5L Grade X60 gas transmission pipeline from a not-reported manufacturer with a not-reported longitudinal weld and a bituminous asphalt coating was installed in 1968. The pipeline failed in 1987 from a leak. The direct cause of the failure was a cracked dent at 6 o'clock, where the pipe lay on a rock. Underlying causes were the dent, coating damage, and cathodic protection (CP). The root cause was that the operator was unaware of the dent that occurred during pipe laying and that the operator had not identified the damage at a later time. Contributing factors were that, apparently, no hydro test was performed during the period in which the crack might have grown to a critical size.					
1967-1968 Leak 1 year	16"/0.250" X60	Manufacturer not reported, ERW	Not reported	Base Metal	Hard Spot
CASE 56: This 16-inch diameter, 0.250-inch wall thickness, X60 gas gathering pipeline from a not-reported manufacturer, with an electric resistance welded (ERW) long-seam weld, not-reported coating, and with cathodic protection, was installed in 1967. The pipeline failed in 1968 from a leak, and the direct cause of the failure was hydrogen stress cracking (HSC) at a hard spot. Underlying causes were the manufacturing methods for line pipe, where an arc burn on the steel surface can result in a local hard area, or "hard spot". The root cause was the presence of a hard spot in the line pipe. Contributing factors were the presence of H_2S in the pipeline and the lack of methods available to identify hard spots that lead to a run-to-failure integrity management approach.					
1957-1974 Rupture 17 years	30"/0.312" X52	Bethlehem Steel, DSAW	Asphalt Enamel	Base Metal	Hard Spot
CASE 101: This 30-inch diameter, 0.312-inch wall thickness, API 5L X52 gas transmission pipeline manufactured by Bethlehem Steel Corporation with a double submerged arc welded (DSAW) long-seam weld and an asphalt enamel coating was installed in 1957. The pipeline failed in 1974 from a rupture, and the direct cause of the failure was hydrogen stress cracking (HSC) at a hard spot. The root cause was the presence of a hard spot that was produced in the steel mill immediately after the final hot-rolling pass of the plate.					

The PRCI report showed that for gas pipelines, 61% of the crack-related failures had environmental root causes, and 39% of the crack-related failures had mechanical root causes. The distribution of environmental root causes of crack-related failure cases for gas pipelines is shown in Figure 17 and the distribution of mechanical root causes is shown in Figure 18.

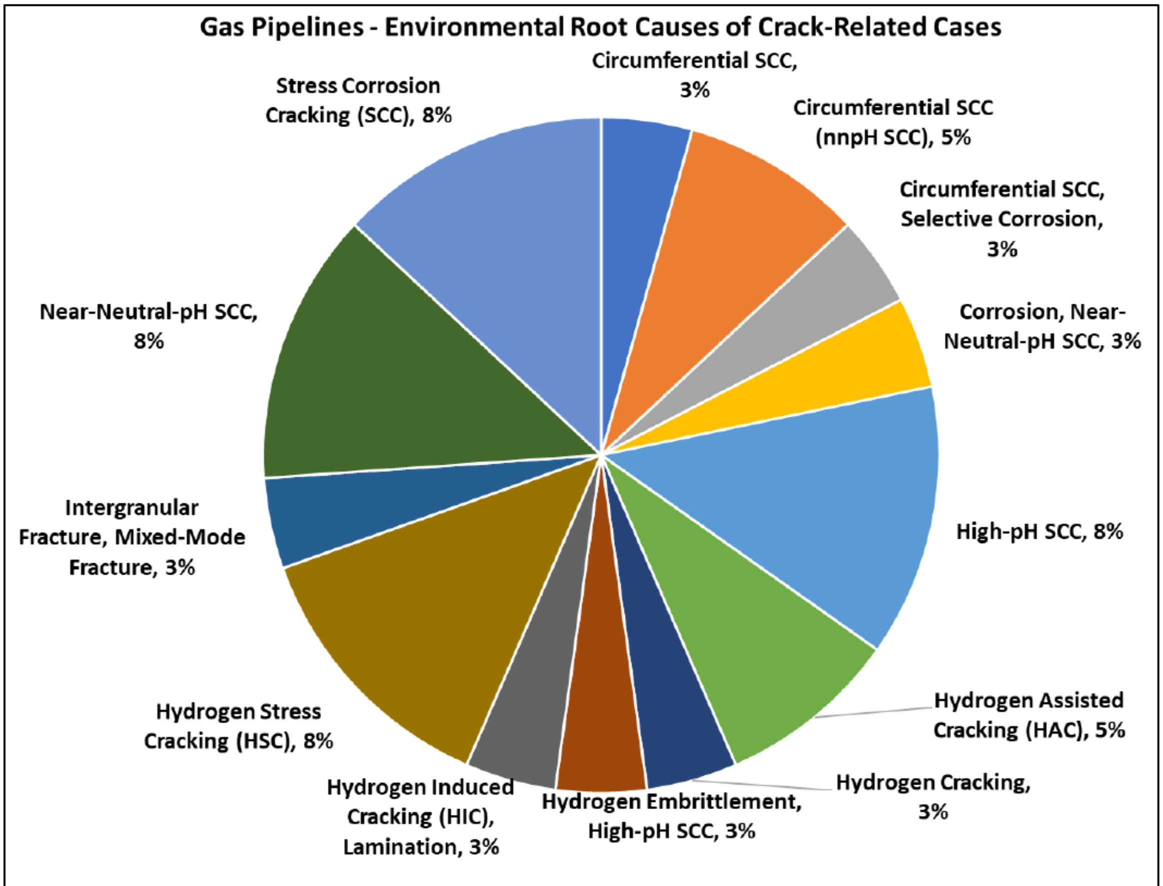


Figure 8 Distribution environmental root causes of crack-related cases for gas pipelines

Figure 17. "Figure 8" from PRCI Report PR-276-241503-R01 [64]

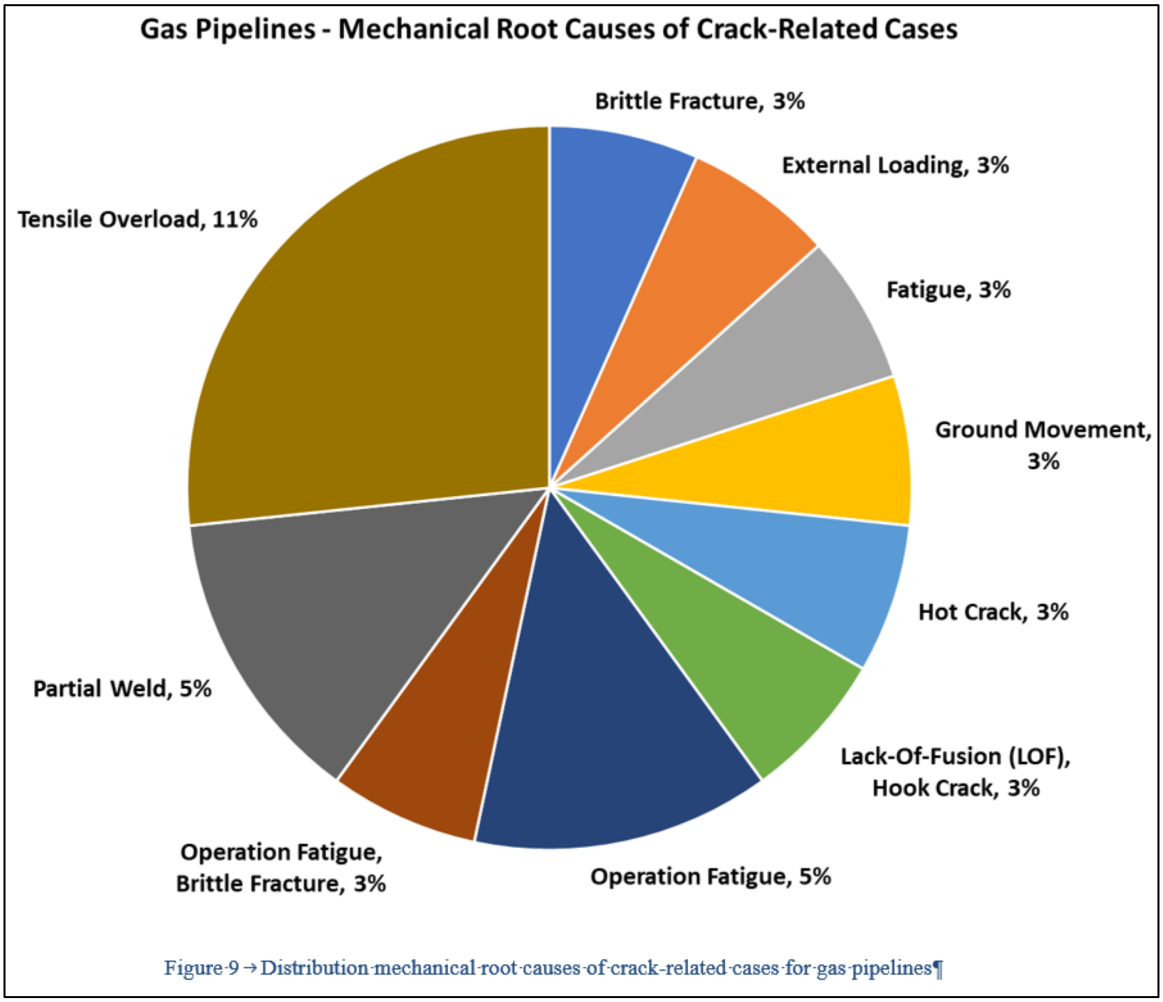


Figure 18. "Figure 9" from PRCI Report PR-276-241503-R01 [64]

5.8.1 New and Unknown Failure Modes

As DNV points out in their 2023 white paper [45], before a natural gas pipeline is filled with hydrogen, operators must understand and account for the challenges and impact of hydrogen. Hydrogen use in long-distance pipelines, for example, has been relatively limited to date. New uses could lead to new and unknown failure modes.

Regarding failure causes, switching to or blending in hydrogen gas can increase the potential for embrittlement of materials. As described in Section 4 BACKGROUND of this literature review, some damage mechanisms can be affected by hydrogen effects, while others can be assumed to be the same for natural gas transmission pipelines. The most significant defects in the case of hydrogen are crack-like defects, which reduce the fatigue life of pipelines operating under pressure fluctuations. An existing crack-like defect will impact the MAOP and the number and amplitude of cycles.

5.9 Pre-Existing Defects

Certain defects may be acceptable under current integrity management criteria. However, those defects may become critical due to a material property change in hydrogen-containing environments. Accelerated fatigue CGRs are known to occur in hydrogen-exposed steels. This will contribute to reduced fatigue life of pre-existing defects in a pipeline, including long-seam weld defects, plain dents, dents combined with gouges or metal loss, and SCC.

5.10 Hydrogen Embrittlement Mechanisms

In DNV's 2023 white paper [45], one of the major gaps identified in the ASME B31.12 Code is that it does not consider the probability of HE mechanisms. The Code always assumes that hydrogen has entered the steel and caused degradation of properties. But this assumption is conservative. For HE or other hydrogen-related degradation mechanisms to occur, atomic hydrogen (H^+) must enter the metal matrix. Molecular hydrogen, H_2, does not directly cause material issues. It must dissociate into H atoms first and then diffuse into the steel to cause issues. This dissociation can be promoted by high temperatures, electrical arcs, or other high-energy phenomena, which are rarely encountered in transmission pipelines.

According to DNV, atomic hydrogen can also be generated at an actively growing fatigue crack, where the fresh metal surfaces catalyze the dissociation mechanism. In addition to H_2 interacting with surface-breaking flaws, one often-raised consideration is whether H^+ can enter the pipeline steel under typical operating conditions and interact with mid-wall or external defects associated with the pipeline.

DNV argued that, according to the latest industry understanding, the entry of atomic hydrogen through the oxide films of steel is kinetically limited under the typical operating temperatures of a pipeline, . However, limited work has been performed to ascertain whether H_2 dissociation and entry can occur over the lifetime of the pipe. It is important to determine with sufficient confidence whether H_2 dissociation and entry can occur, as this will have significant implications for structural analysis of mid-wall and outer diameter flaws.

In contrast, San Marchi et al. [65] in their December 2023 status report on the U.S. Department of Energy's HyBlend project, reported on the effects of hydrogen-assisted fatigue and fracture. These researchers have tested the uptake of hydrogen into steels and the effects on material properties. Their research has included a variety of linepipe steel materials ranging from vintages from the 1950s to now, various grades and hardnesses, and different base metal microstructures. They have executed comparative fatigue CGR testing in air, hydrogen gas, and hydrogen gas blends, to research the effects of gas pressure, hydrogen concentration, maximum load levels, loading ratios, and cyclic frequencies. They have unequivocally established that hydrogen uptake due to gas pressure at ambient temperatures will occur with time, even at low pressures.

The occurrence of hydrogen embrittlement in pipelines depends on three interrelated conditions: steel metallurgy, stress, and hydrogen concentration. The standards developed by organizations such as ASME, NACE, BS, and DNV can help decrease and minimize the possibility of hydrogen embrittlement occurrence. However, hydrogen embrittlement cannot be eliminated for pipelines exposed to high-pressure hydrogen gas environments. Research into hydrogen effects, along with industry standards, can help integrity specialists to better manage and control the problem.

An illustration of the effect on the fracture resistance of a linepipe steel is shown in Figure 19. San Marchi's [65] testing also showed the dependence of R-ratio (see Figure 20) and the dependence on pressure (see Figure 21). Hydrogen effects as a function of hardness and grade as found in research by Agnani et al. [66] were presented at the 2023 International Hydrogen Conference, see Figure 22 and Figure 23, respectively.

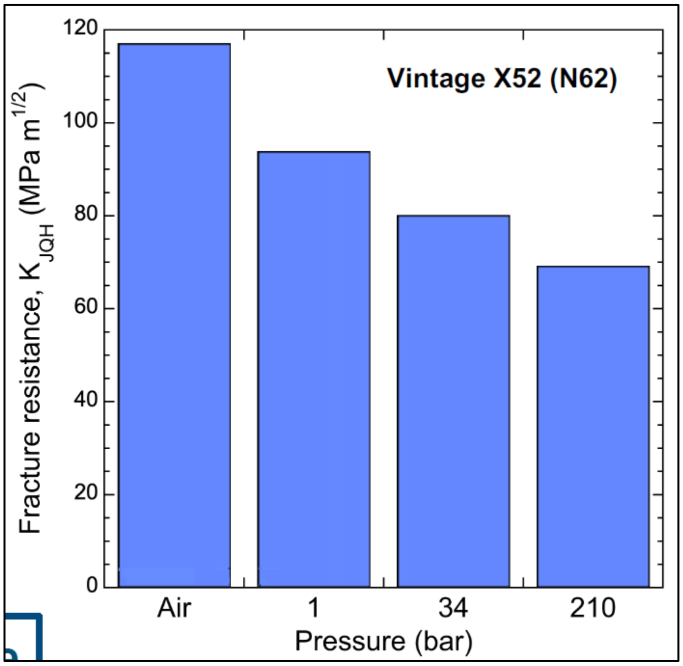


Figure 19. Effect of Pressure on Hydrogen-Assisted Fracture in Gaseous Hydrogen for Vintage X52 Steel [65]

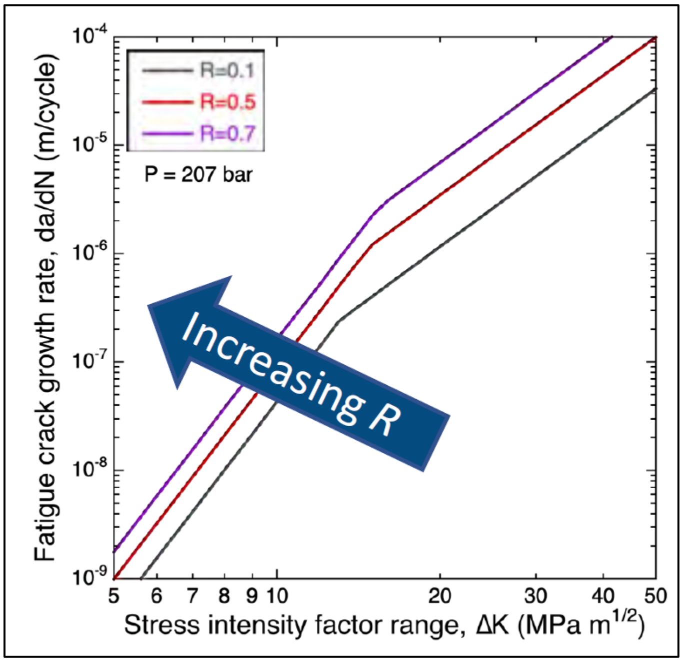


Figure 20. Effect of R-ratio on Fatigue CGR in Gaseous Hydrogen at 207 Bar [65]

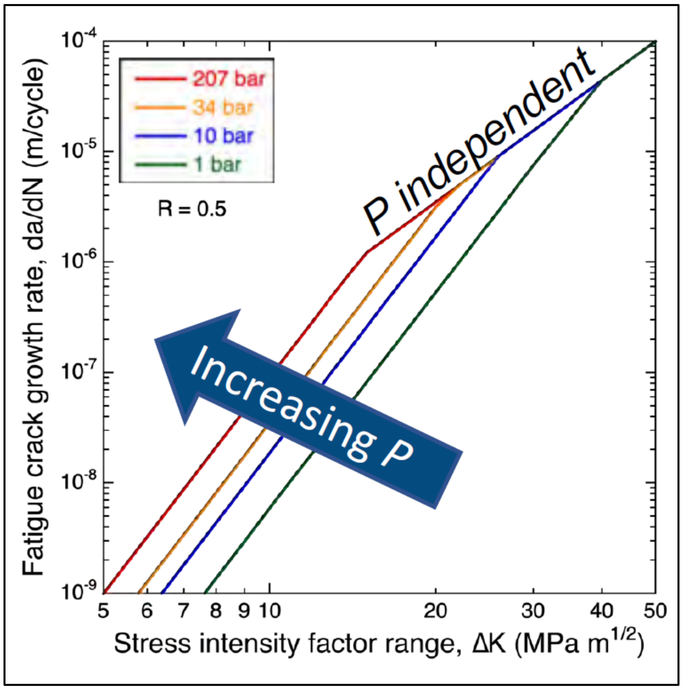


Figure 21. Effect of Pressure on Fatigue CGR in Gaseous Hydrogen at R-ratio = 0.5 [65]

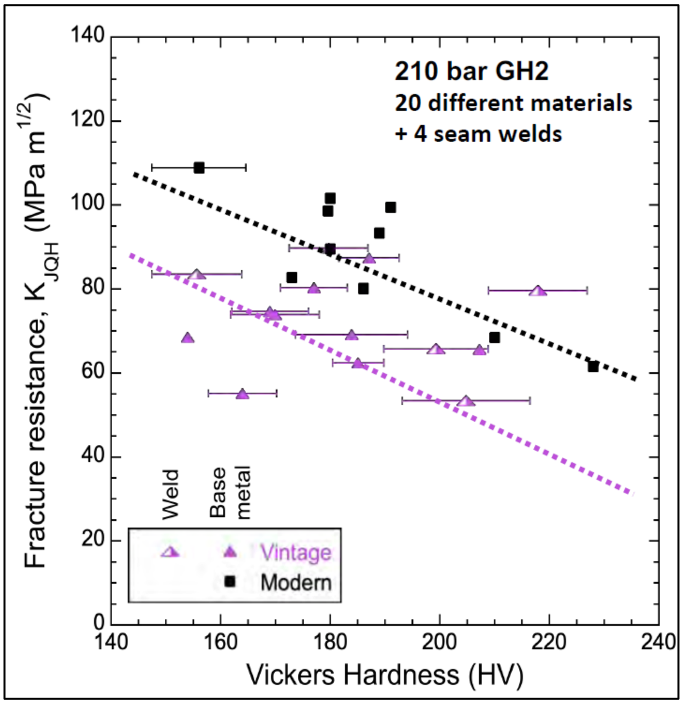


Figure 22. Effect of Hardness on Fracture Resistance in Gaseous Hydrogen at 210 Bar [66]

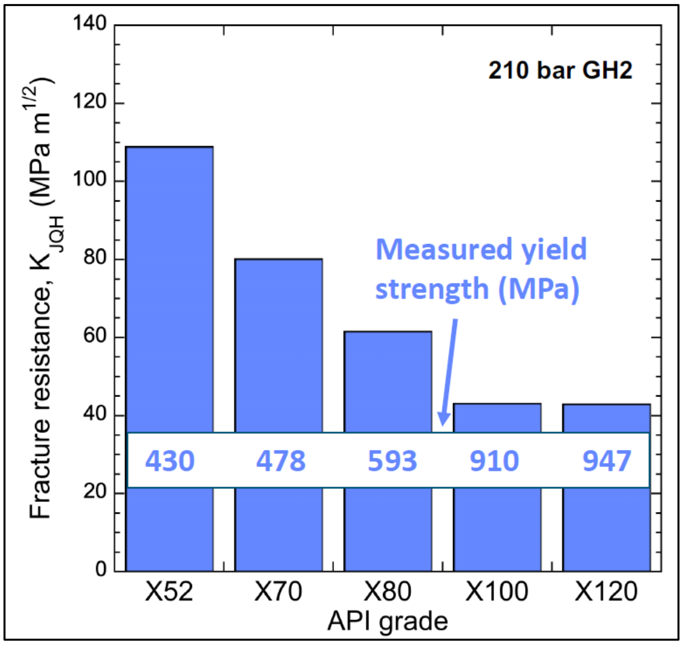


Figure 23. Effect of Steel Grade on Fracture Resistance in Gaseous Hydrogen at 210 Bar [66]

San Marchi et al. [65] developed probabilistic fracture mechanics software "HELPR" (Hydrogen Extremely Low Probability of Rupture) [67], which provides tools for the probabilistic analysis of hydrogen effects for different defect configurations. This software can be downloaded from Sandia National Laboratories' website.

In addition, they have contributed to the fatigue CGR equations in ASME B31.12 Code Case 220 [68], which formalized fatigue design curves for gaseous hydrogen. The equations, shown below as Equation (4), are captured in a conventional power law formulation and account for the loading R-ratio, the stress intensity factor range, ΔK, and the hydrogen gas pressure g(P) as a function of overall pressure, P.

- **At low ΔK** $$\frac{da}{dN} = 3.5x10^{-14}\left[\frac{1+0.4286R}{1-R}\right]\Delta K^{6.5}g(P)$$

- **At high ΔK** $$\frac{da}{dN} = 1.5x10^{-11}\left[\frac{1+2R}{1-R}\right]\Delta K^{3.66}$$

$$g(P) = 0.071P^{0.51}$$ In units of MPa for P < 210 bar (4)

5.11 European Standards Related to Hydrogen Gas Pipelines

The following section describes some European (Germany and United Kingdom) standards and guidelines that were identified as both allowing hydrogen and having defined materials requirements for gas pipelines.

5.11.1 DVGW Documents (Germany)

The German organization "Deutscher Verein des Gas- und Wasserfaches e.V." (DVGW) publishes the following documents:

- Forschungsbericht G202006 01/2023 [69] DVGW Project SyWeSt H2: Investigation of Steel Materials for Gas Pipelines and Plants for Assessment of their Suitability with Hydrogen.

- DIN CEN/TR 17797 09/2022 [70] Gas infrastructure - Consequences of Hydrogen in the Gas Infrastructure and Identification of Related Standardisation Need in the Scope of CEN/TC 234.

- DVGW G407(M) Technical Information - Guideline 08/2022 [71] Conversion of Gas Pipelines Made of Steel Pipes for the Distribution of Hydrogen-Containing High-Methane Gases and Hydrogen up to 16 bar Operating Pressure.

- DVGW G409(M) Technical Information - Guideline 09/2020 [72] Technical Information - Guideline - Conversion of High-Pressure Gas Steel Pipelines for a Design Pressure of More Than 16 Bar for Transportation of Hydrogen.

- DVGW G464(M) Technical Information - Guideline 03/2023 [73] Fracture-Mechanical Assessment Concept for Steel Pipelines with a Design Pressure of More Than 16 Bar for the Transport of Hydrogen.

These documents are discussed next.

5.11.1.1 Forschungsbericht G202006 01/2023 [69]

Forschungsbericht G202006 is an extensive document that covers many aspects of hydrogen pipelines, including multiple materials and different components. That said, Paragraph 6.12.3.1 on pipeline integrity management states only two degradation mechanisms that apply to steels in hydrogen (mixtures):

- Cracks due to hydrogen embrittlement, materials, and welds; and
- Fatigue.

A general statement is included related to life: "If a design life has been determined for the pipeline system, this needs to be revised, if necessary."

An excerpt of "Table 3" from this Forschungsbericht G202006, with a focus only on unalloyed carbon steel as a material of construction, is reproduced here as Table 15.

Table 15. Excerpt from "Table 3" from Forschungsbericht G202006 01/2023, Showing Hydrogen Tolerance of Steel Used in Natural Gas Infrastructure [69]

Pressure (bar g)	≤ 2 Vol.%	≤ 5 Vol.%	≤ 10 Vol.%	Up to 100 Vol.%
<5,0	✓	✓	✓	✓
<8,0	✓	✓	✓	–
<10,0	✓	✓	✓	
<60,0				

Where ✓ = No effect expected, – = No short-term effect expected, and Empty box = Not part of the study findings at the time of drafting Forschungsbericht G202006.

Forschungsbericht G202006 gives a few examples of changes in the mechanical behavior of (pipeline) steels, by showing figures and referencing some of the often-cited references related to hydrogen effects. These include: Briottet et al. [74] for the reduction in fracture strain, Ronevich and San Marchi [75] for the reduction in fracture resistance, San Marchi and Somerday [76] and Solin and De Miguel [77] for the increase in fatigue CGRs, and Van Wortel [78] for fatigue threshold stress intensity factors and crack growth rates.

Forschungsbericht G202006 refers to ASME B31.12 [4] for the approach to designing hydrogen pipelines, as well as for the approach to fit-for-purpose assessments with respect to hydrogen.

Forschungsbericht G202006 refers to Appendix H of EIGA IGC Doc 121/14 [79] for requalifying existing pipelines for hydrogen service. The latter provides the following commentary on ILI:

> ***EIGA IGC Doc 121/14 Appendix H Paragraph 6 "Internal pipeline inspection"***
>
> *ILI is suggested:*
>
> - *if CP records are missing, or if they indicate that protection has been inadequate*
> - *if the previous service history of the pipeline is unknown, or if it has carried fluids such as crude oil or wet natural gas which are known to increase the likelihood of internal corrosion*
> - *if original material data reports for the pipeline are missing, internal inspection is required to supplement data obtained from samples …*
>
> *ILI may be waived if an internal inspection has already been made within 5 years of the evaluation, assuming that satisfactory records are available.*
>
> *The ILI device shall be capable of locating internal and external corrosion, buckles and dents, and actual wall thickness.*
>
> *If corrosion is found either the areas of corrosion will be cut out and replaced with new pipeline or the working pressure will be limited to the values calculated according to the applicable design standard.*

5.11.1.2 DIN CEN/TR 17797 09/2022 [70]

The content of Technical Report (TR) DIN CEN/TR 17797 is similar to the content of Forschungsbericht G202006. Both documents provide a technical basis for the Guidelines described in the paragraphs below. The DIN CEN/TR 17797 Paragraph 6.4.3.2 includes instructions on how to calculate the design life/lifetime of a pipeline subject to pressure cycles but has no discussion on the topic of remaining life and reassessment or reinspection intervals.

5.11.1.3 DVGW G407(M) Technical Information - Guideline 08/2022 [71]

DVGW G407 applies to conversion of steel pipelines up to 16 barg (232 psig) pressure of hydrogen and hydrogen/natural gas blends. At these relatively low pressures, the pipeline would typically be part of a gas distribution system. The guideline states:

> *"Pipes and fittings made from steel are in general suitable for the conversion of networks handling pressures lower than 16 bar to hydrogen-containing, methane-rich gases …"*

> *"In principle, the design pressure (DP) remains unchanged after the conversion of the pipeline. If, after conversion, the supply capacity is not sufficient, pressure uprating can be carried out …"*
>
> *"In general, based on experiences with the operation of gas pipelines up to 16 bar, it can be assumed that gas networks can be pressurised with up to 20% hydrogen content. …"*
>
> *"The inspection intervals for a gas inspection network of pipelines for up to 16 bar are specified by DVGW Code of Practice G465-1."*

Depending on the percentage of hydrogen in the gas, the DVGW G407 Guideline recommends doing operational evaluations, analysis of damage statistics, individual evaluations for noticeable faults, taking CP into account, performing a network survey shortly after injection, pressure testing, and material testing. In-line inspection and/or reinspection are not mentioned.

5.11.1.4 DVGW G409(M) Technical Information - Guideline 09/2020 [72]

DVGW G407 applies to conversion of steel pipelines of more than 16 barg (232 psig) pressure of hydrogen and hydrogen/natural gas blends. At these relatively high pressures, the pipeline would typically be part of a gas transmission system. The DVGW G409 Guideline is notably more stringent than DVGW G407, in that it requires extensive documentation.

> ***Paragraph 4.2 Documentation of Construction, Operation, and Maintenance***
>
> *The operator's documentation on the construction of the gas pipeline, including all changes, on the hitherto mode of operation, and on safety-relevant events shall be examined for completeness and compliance with the technical rules applicable at the time of conversion. Throughout that process, it shall be determined whether the previous mode of operation has in any way impaired the gas pipeline with regard to the planned conversion. Specific attention shall be paid to:*
>
> - *current pipeline documentation (routing maps, as-built drawings, pipe book, pipe order list etc.)*
> - *certifications on material tests*
> - *certifications from technical experts*
> - *documentation on gas quality*
> - *external influences (e.g., mining activity, corrosive soil, built-up areas)*
> - *documentation and properties of other fluids, including concomitant substances, that were transported*
> - *pressure test certificates*
> - *operation and maintenance (monitoring and repair)*
> - *internal and external corrosion (condition of cathodic protection)*
> - *proof of CP effectiveness (insofar prescribed by a technical rule)*

- *current condition analysis / integrity assessment in accordance with DVGW Code of Practice G466-1 (ILI and intensive measurement processes)*
- *pressure recordings including corresponding analyses*
- *results of NDT*

If the pipeline documentation on pipeline construction is incomplete, reference is made to DVGW Code of Practice G453.

Note that in the above list, ILI was clearly mentioned, but only for current condition assessment. There is no requirement for life assessment; neither as a remaining life, nor as a reinspection interval.

5.11.1.5 DVGW G464(M) Technical Information - Guideline 03/2023 [73]

DVGW G464 provides the parameters for assessing pressure fluctuations in pipelines, which are based on a fracture-mechanics approach, specifically for steel pipelines carrying hydrogen at pressures of more than 16 barg (232 psig). The guideline describes it as follows:

> *"High pressure gas pipelines usually are designed for predominantly static loads since barely any significant changes in operating pressure (load cycles) occur and even sharp-edged defects that might occur under such conditions exhibit a negligible growth rate. When operating the pipeline with the medium of hydrogen, the potential crack growth for steel is larger, compared to natural gas, and the fracture toughness lower. Consequently, the operation with hydrogen … usually requires a fracture mechanical assessment based on conservatively predicted number of changes of operating pressure. This specifically applies if the pipeline is meant to be operated with significant changes in operating pressure."*

The guideline provides instructions on how to perform the assessment for sharp-edged, crack-like defects with regards to static stress and fatigue crack growth rate. The guideline requires that this crack may not exceed the size of the allowable crack under static load at MAOP. Figure 1 from the Guideline, reproduced here as Figure 24, shows schematically how crack depth may develop as a function of the number of load cycles.

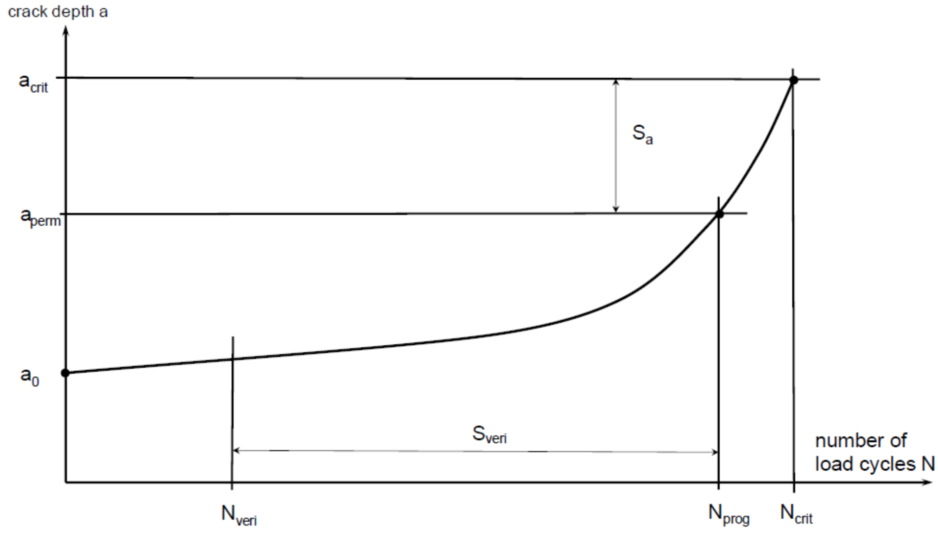


Figure 1: Schematic of Fracture Mechanical Assessment

Figure 24. "Figure 1" from DVGW G464(M) Technical Information - Guideline 03/2023 [73]

Some of the input parameters to the calculations include initial crack size (measured or postulated), pressure fluctuation prognosis, fracture toughness (measured or assumed), and CGR data. The Guideline requires that safety factors and constraints be taken into account. If no material properties are available, the Guideline recommends values to be used. Annex A of the Guideline provides an example calculation.

5.11.2 IGEM Documents (United Kingdom)

The British organization "Institution of Gas Engineers and Managers" (IGEM) publishes the following documents, which are discussed next:

- IGEM/TD/1 Edition 6 [80] Supplement 2 [81] Steel Pipelines for High Pressure Gas Transmission; Supplement 2 - High Pressure Hydrogen Pipelines.
- IGEM/TD/3 Edition 5 Supplement 1 [82] Repurposing of Natural Gas (NG) Pipelines with MOP Not Exceeding 7 bar for NG/Hydrogen Blends.
- IGEM/TD/21 [83] Reference Standard for Hydrogen Distribution for New Steel and PE Mains and Services.
- IGEM/TD/22 [84] Reference Standard for Repurposing Natural Gas Distribution Mains and Services for Hydrogen.

5.11.2.1 IGEM/TD/1 Edition 6 [80] with Supplement 2 [81] High Pressure Hydrogen Pipelines

Transmission and distribution (TD) Standard IGEM/TD/1 Edition 6 [80] "Steel Pipelines for High Pressure Gas Transmission" applies to the design, construction, inspection, testing, operation, and maintenance of pipelines designed after the date of publication. This edition applies to all new pipelines and diversions, as well as modifications of existing pipelines. This standard is extensive (249 pages).

For purposes of this present literature review that focuses on ILI-reinspection intervals for hydrogen pipelines, a schematic for the reassessment of design life, as shown in Figure 15 in the Standard, is reproduced here as Figure 25. Paragraph 12.8.3.3 of the Standard includes Table 15, reproduced here as Table 16, stating that the maximum interval between internal "monitoring" inspections shall not exceed 10 years.

> *Paragraph 12.8.4.1*
>
> *Provided that appropriate data is available, then, as a first preference, (inspection and maintenance) frequencies should be determined by a risk-based approach and the use of software tools where appropriate. Frequencies that have been determined using a risk-based approach should be reviewed periodically. Such a review should take account of the results of previous inspection results.*

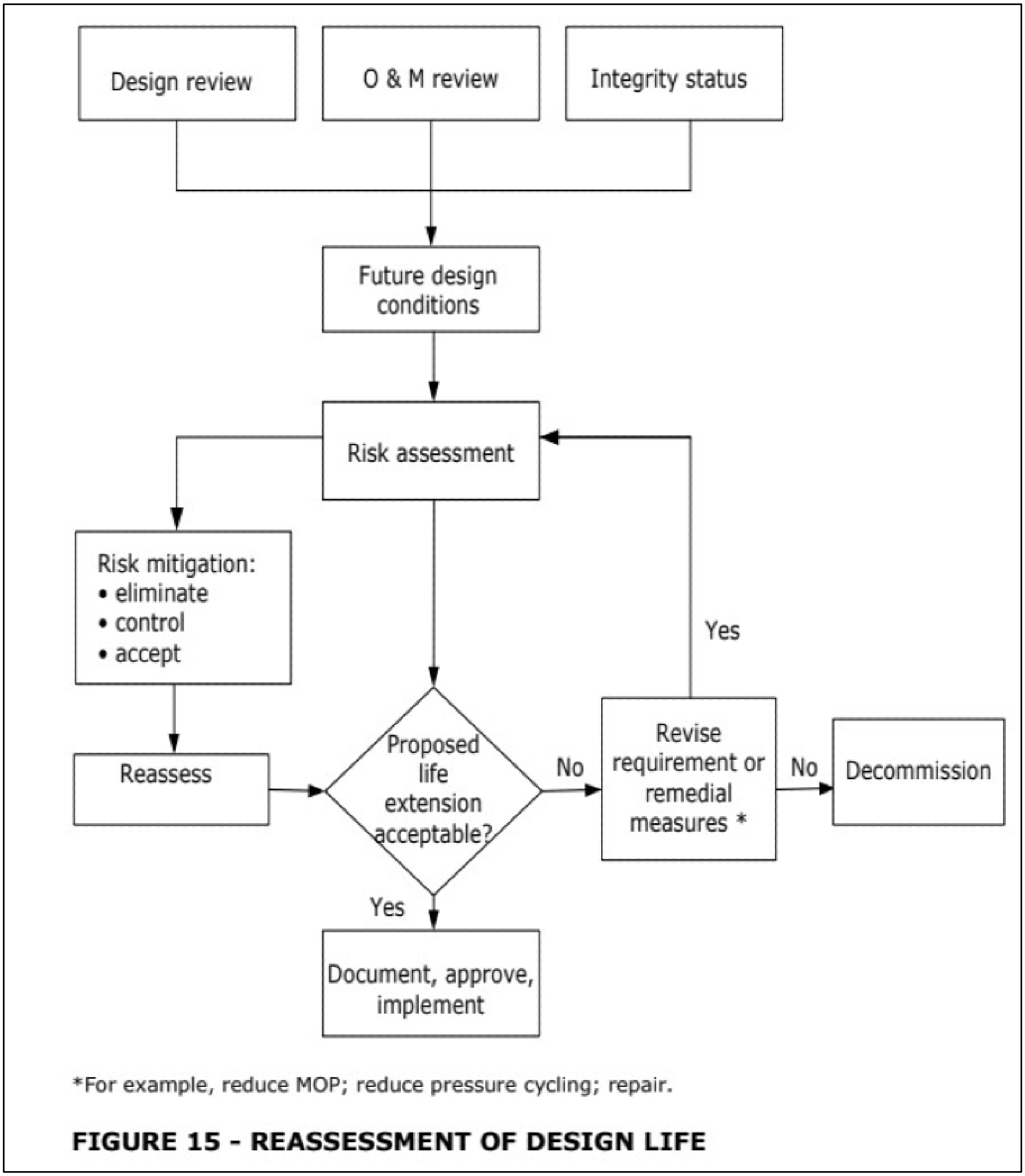


Figure 25. "Figure 15" from IGEM/TD/1 Edition 6 [80]

Table 16. "Table 14" from IGEM/TD/1 Edition 6 [80]

TYPE OF MONITORING	MAXIMUM INTERVAL BETWEEN MONITORING
Internal	Not to exceed 10 years
Above-ground a. For pipelines subject to internal inspection b. For pipelines not subject to internal inspection	Not to exceed 10 years to be carried out mid-way between internal inspections. Not to exceed 5 years
Hydrostatic test	Not to exceed 20 years

TABLE 14 - FREQUENCY OF CONDITION MONITORING WHERE RISK ASSESSMENT IS NOT CARRIED OUT IN ACCORDANCE WITH CLAUSE 12.2.4

Supplement 2 [81] (Communication 1849) "High Pressure Hydrogen Pipelines" to Standard IGEM/TD/1 Edition 6 is a 28-page document that gives additional requirements and qualifications for the transmission of hydrogen, including natural gas/hydrogen blended mixtures, and for the repurposing of natural gas pipelines to hydrogen service.

Supplement 2 Paragraph S2.9 states:

The design factor of pipelines in hydrogen services is limited to 0.5 (as compared to 0.72/0.8 for natural gas service).

A material performance reduction factors, as defined in ASME B31.12 is applied to reduce the allowable design factor for grades higher than L360 (X52).

Materials may be qualified to operate in hydrogen service at higher design factors through testing (see clause S5.8).

Supplement 2 Paragraph S3.5 "Integrity Management" states:

The IM system shall address the impact of hydrogen on steel properties and the probability of failure, including:

- *HE at ambient and operating temperature*
- *Increased rate of fatigue crack growth*
- *HIC*
- *SCC*

Supplement 2 Paragraph S6.6 “Fatigue” provides the same simplified approach, and a detailed fracture mechanics approach for fatigue assessments as the main Standard IGEM/TD/1 Edition 6. However, the fatigue CGR coefficients are adjusted to account for hydrogen service. Supplement 2 notes that the fatigue CGR in hydrogen service might be at least 10 to 100 times higher than that in air.

For the simplified approach – Constant Daily Pressure Cycling, Equation (4) is provided,

$$S^3 N = 2.93 \times 10^9 \tag{4}$$

where S = constant amplitude stress range (N/mm^2) and N = number of cycles.

For the detailed fracture mechanics approach – Variable Pressure Cycling, the recommended methods for calculation are given in BS 7910-2019 [27]. The recommended fatigue crack growth coefficients for steel pipelines in hydrogen service are given in Table 2, reproduced here as Table 17.

Table 17. “Table 2” from IGEM/TD/1 Edition 6 Supplement 2 [81]

The recommended fatigue crack growth threshold is 63 N mm$^{-3/2}$ (2 MPa m$^{0.5}$).

R	**STAGE A**		**STAGE B**		**STAGE C**		**STAGE D**		**STAGE A/ STAGE B Transition point Δk, N mm$^{-3/2}$**	**STAGE B/ STAGE C transition point Δk, N mm$^{-3/2}$**	**STAGE C/ STAGE D transition point Δk, N mm$^{-3/2}$**
	A	*m*	*A*	*m*	*A*	*m*	*A*	*m*			
<0.5	4.37×10^{-26}	8.16			5.18×10^{-24}	7.82	1.48×10^{-12}	3.37	203	203	375
≥0.5	2.10×10^{-17}	5.10	1.29×10^{-12}	2.88	1.68×10^{-23}	7.82	4.81×10^{-12}	3.37	144	203	375

TABLE 2 - RECOMMENDED FATIGUE CRACK GROWTH LAWS FOR STEELS IN HYDROGEN SERVICE

Note 1: R ≥ 0.5 values recommended for assessing welded joints.

Note 2: Stage A and B, for ΔK not exceeding 203 N mm$^{-3/2}$, are equal to the recommended values for steels in air given in BS 7910.

5.11.2.2 IGEM/TD/3 Edition 5 Supplement 1 [82] Repurposing Pipelines with MOP < 7 bar for Natural Gas/Hydrogen Blends

This 26-page Supplement to Standard IGEM/TD/3 does not include commentary on inspection intervals. This Standard focuses on relatively low-pressure distribution pipelines. The only material failure issue that is mentioned is the potential for leakage at mechanical joints in pipelines.

5.11.2.3 IGEM/TD/21 [83] Repurposing Natural Gas Distribution Mains and Services for Hydrogen

This 79-page Standard applies to repurposing pipelines for hydrogen. It mentions internal inspections only once in the category "Special Surveys." No reference is made to inspection intervals.

5.11.2.4 IGEM/TD/22 [84] Hydrogen Distribution for New Steel and PE Mains and Services.

This 43-page Standard applies to new pipelines for hydrogen. Materials of construction can be steel or polyethylene (PE). This standard mostly provides general information about integrity management. It recommends (should-statements) that:

> *For service with MOP ≤ 2 bar (29 psig) and diameter ≤ 63 mm (2.5 inches), a group design and integrity study of similar services should be carried out.*
>
> *For services with 2 bar (29 psig) < MOP ≤ 7 bar (102 psig) and any diameter, or MOP ≤ 2 bar (29 psig) and diameter > 63 mm (2.5 inches), individual design and integrity study shall be carried out for each service.*

6 CONCLUSIONS

Key findings from this literature review include:

- Global research performed over the past decades has yielded valuable insights, but the material property data originate from a relatively small number of research organizations, and the data are relatively limited in scope as related to pipeline steels for gas.
    - The data of accelerated fatigue CGRs, for example, are relatively limited in that they address only a few loading R-ratios (minimum stress divided by maximum stress). Typically, R=1.0 and R=0.5, while gas pipelines typically operate with less severe pressure fluctuations (R=0.9).
    - Where material properties are evaluated, the studies primarily report on yield or tensile strength. Fracture toughness data are scarce, and few data are reported on weld-related properties.
- Although integrity management is described in general terms, the specific connection between CGRs and inspection intervals is not included in most hydrogen-related Codes and Standards.
    - No documents were found that describe the methodologies for assessing hydrogen effects on specific defect types other than a general "crack-like" feature.
- The various Codes and Standards cross-reference each other, with most leading back to ASME B31.12 and BS7910.
- There are several methodologies for fatigue CGR assessments included in hydrogen-related Codes and Standards.
    - ASME B31.12 Code Case 220 is the only method that formalizes fatigue design curves for gaseous hydrogen that account for the loading R-ratio, the stress intensity factor range, ΔK, and the hydrogen gas pressure $g(P)$ as a function of overall pressure, P.
- European (Germany, UK) Standards refer to American (ASME) and British (BS) Standards. American Standards do not reference the European documents.
    - Considering the European Hydrogen Backbone program with 35,700 miles of planned hydrogen pipelines (58.6% repurposed) in the near future, the American program is currently much smaller, with 1,500 miles of existing hydrogen pipelines. Learning from the European experience would be beneficial for the U.S.

7 REFERENCES (OR WORKS CITED)

[1] PHMSA Project #985, Review of Integrity Threat Characterization Resulting from Hydrogen Gas Pipeline Service, K. Bagnoli, L. Hill, G. Wilkowski, Contractor: Engineering Mechanics Corporation of Columbus (Emc2), for U.S. Department of Transportation (DOT) Pipeline Hazardous Materials Safety Administration (PHMSA), Washington, DC, Contract 693JK32210013POTA, Performance Period: 09/30/2022 – 09/29/2024.

[2] CFR Title 49 Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Code of Federal Regulations, U.S. Department of Transportation (DOT).

[3] ASME B31.8S-2022, Managing System Integrity of Gas Pipelines, ASME Code for Pressure Piping, B31, Supplement to ASME B31.8, American Society of Mechanical Engineers (ASME), New York, NY, 2022.

[4] ASME B31.12-2019, Code for Hydrogen Piping and Pipelines, ASME Code for Pressure Piping, B31, American Society of Mechanical Engineers (ASME), New York, NY, 2019.

[5] DOT/PHMSA Data and Statistics Website [Online], U.S. Department of Transportation (DOT), https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids, 2022.

[6] PVP2018-84658, Influence of Hydrogen and Oxygen Impurity Content in a Natural Gas/Hydrogen Blend on the Toughness of an API X70 Steel, L. Briottet, H. Ez-Zaki, American Society of Mechanical Engineers (ASME), Prague, Czech Republic, ASME 2018 Pressure Vessels and Piping Conference, 15-20 July, 2018.

[7] ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, ASME Code for Pressure Piping, B31, Supplement to ASME B31.8, American Society of Mechanical Engineers (ASME), New York, NY, 2004.

[8] API RP 1176-2016, Recommended Practice for Assessment and Management of Cracking in Pipelines, American Petroleum Institute (API), First Edition, June, 2016.

[9] API 579-1/ASME FFS-1-2021, Fitness-For-Service, 2021 Edition, American Petroleum Institute (API) / American Society of Mechanical Engineers (ASME), December, 2021.

[10] L52047, PRCI Pipeline Repair Manual, 6th Edition, Pipeline Research Council International (PRCI), 2006.

[11] 10 - In-Line Inspection (ILI) Methods for Detecting Corrosion in Underground Pipelines, S. Brockhaus, M. Ginten, S. Klein, M. Teckert, O. Stawicki, D. Oevermann, S. Meyer, D. Storey, Woodhead Publishing, Underground Pipeline Corrosion, Ed. Mark E. Orazem, https://doi.org/10.1533/9780857099266.2.255, pp. 255-285, 2014.

[12] Ultrasonic In Line Crack Detection - SCC Inspection, ndt-global.com, Accessed 3 April, 2024.

[13] Ultrasonic Inspection (UT), Pipeline Inspection Services PIPECARE, pipecaregroup.com, Accessed 3 April, 2024.

[14] Theory and Application of Magnetic Flux Leakage Pipeline Detection, Y. Shi, C. Zhang, R. Li, M. Cai, G. Jia, Sensors, https://doi.org/10.3390/s151229845, Vol. 15 No. 12, pp. 31036-31055, 10 December, 2015.

[15] Circumferential MFL In-Line Inspection for Cracks in Pipelines, J.B. Nestleroth, Department of Energy (DOE), National Engineering Technology Laboratory (NETL), June, 2003.

[16] Grant/Cooperative Agreement No. DE-FC25-01NT41159, The Detection and Sizing of Circumferentially Oriented Stress Corrosion Cracking Using Axially Oriented Magnetic Flux Leakage Inspection, R. Thompson, J. Hare, R. Gardner, K. Dwyer, Novitech, Inc., Xcel Energy, Houston, TX, Pipeline Pigging and Integrity Management Conference (PPIM) 2019, 18-22 February, 2019.

[17] Integrity Management of Off-Axis SCC Through an ILI System and Engineering Assessment, R. Thompson, A. Corbett, G. Solano, R. Kania, Houston, TX, Pipeline Pigging and Integrity Management Conference (PPIM) 2024, 12-16 February, 2024.

[18] IPC2006-10156, Pipeline Inspection with the High Resolution EMAT ILI-Tool: Report on Full-Scale Testing and Field Trials, M. Klan, T. Beuker, American Society of Mechanical Engineers (ASME), Calgary, Alberta, Canada, ASME 2006 International Pipeline Conference (IPC), https://doi.org/10.1115/IPC2006-10156, 25-29 September, 2006.

[19] IPC2012-90240, Validation of EMAT Technology for Gas Pipeline Crack Inspection, R. Kania, S. Klein, J. Marr, G. Rosca, E.S. Riverol, R. Ruda, N. Jansing, T. Beuker, N.D. Ronsky, R. Weber, American Society of Mechanical Engineers (ASME), Calgary, Alberta, Canada, ASME 2012 International Pipeline Conference (IPC), https://doi.org/10.1115/IPC2012-90240, 24–28 September, 2012.
[20] IPC2022-87663, Inline-Inspection Crack Detection for Gas Pipelines Using a Novel Technology, M. Aanes, M. Haas, K.K. Andersen, A.S. Talberg, American Society of Mechanical Engineers (ASME), Calgary, Alberta, Canada, ASME 2022 International Pipeline Conference (IPC), https://doi.org/10.1115/IPC2022-87663, 26-30 September, 2022.
[21] IPC2022-87668, Utilization of a Probabilistic Function to Describe the Performance of In-Line Crack Inspection Systems and a Possible Application in Hydrogen Service, T. Moritz, M. Baumeister, T. Beuker, American Society of Mechanical Engineers (ASME), Calgary, Alberta, Canada, ASME 2022 International Pipeline Conference (IPC), https://doi.org/10.1115/IPC2022-87668, 26-30 September, 2022.
[22] IPC2020-9494, Overcoming Challenges of EMAT Inline Inspection Validation for SCC Management in Natural Gas Pipelines: A Practical Approach, J. Philpot, K. Spencer, American Society of Mechanical Engineers (ASME), Calgary, Alberta, Canada, ASME 2020 International Pipeline Conference (IPC) - Virtual, https://doi.org/10.1115/IPC2020-9494, 28-30 September, 2020.
[23] ART – A Unique Technology for Unique Pipelines, B. Bergius, G. Dye, NDT Global AS, Pigging Products & Services Association Seminar 2021, 2021.
[24] GAT2004-GKP-2013.01, Pipeline Pigging Part 1: Cleaning Pigs & Pigging Strategy, Gibson Applied Technology and Engineering, Inc., January, 2013.
[25] NACE SP0102-2017, In-Line Inspection of Pipelines, NACE International, Item No. 21094, 10 March, 2017.
[26] Q5 Report, PHMSA Project 985 - Reviewing of Integrity Threat Characterization from Hydrogen Gas Pipeline Service, G. Wilkowski, K. Bagnoli, Contractor: Engineering Mechanics Corporation of Columbus (Emc^2), for U.S. DOT PHMSA, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=985, Quarterly Report, 31 December, 2023.
[27] BS7910:2019, Guide to Methods for Assessing the Acceptability of Flaws in Metallic Structures, 2019 Edition, British Standards Institution (BSI), 31 December, 2019.
[28] ANSI/NACE SP 0502-2010 (formerly RP0502), Standard Practice - Pipeline External Corrosion Direct Assessment Methodology, NACE International / American National Standards Institute (ANSI), 2010.
[29] API 570-2016, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, American Petroleum Institute (API), Fourth Edition, February, 2016.
[30] CFR Title 49 Part 195, Transportation of Hazardous Liquids by Pipeline, U.S. Department of Transportation (DOT).
[31] ASME B31.8-2022, Gas Transmission and Distribution Piping Systems, American Society of Mechanical Engineers (ASME), December, 2022.
[32] NACE SP0204-2015, Standard Practice - Stress Corrosion Cracking (SCC) Direct Assessment Methodology, NACE International, 2015.
[33] NACE SP0206-2016, Standard Practice - Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA), NACE International, 2016.
[34] CEPA SCC RP, Stress Corrosion Cracking - Recommended Practices, 2nd Edition - An Industry Leading Document Detailing the Management of Transgranular SCC, Canadian Energy Pipeline Association (CEPA), December, 2007.
[35] STP-PT-011, Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas, R.R. Fessler, A.D. Batte, M. Hereth, ASME Standards Technology, LLC, 31 October, 2008.
[36] ASME BPVC Section VIII, Boiler and Pressure Vessel Code, Section VIII: Rules for Construction of Pressure Vessels, American Society of Mechanical Engineers (ASME).
[37] PVT-17-1065, Fatigue Measurement of Pipeline Steels for Application of Transporting Gaseous Hydrogen, A.J. Slifka, E.S. Drexler, R.L. Amero, L.E. Hayden, D.G. Stalheim, D.S. Lauria, N.W. Hrabe, Journal of Pressure Vessel Technology, https://doi.org/10.1115/1.4038594, Vol. 140, Issue 1, pp. 011407-011407-12, 5 February, 2018.

[38] PVT-17-1066, Development of a Model for Hydrogen-Assisted Fatigue Crack Growth in Pipeline Steel, R.L. Amaro, R.M. White, C.P. Looney, E.S. Drexler, A.J. Slifka, Journal of Pressure Vessel Technology, https://doi.org/10.1115/1.4038824, Vol. 140, Issue 2, pp. 021403, April, 2018.
[39] ASME Code Case 2938, Hydrogen crack growth rate constants, threshold stress intensity factor KIH, and critical crack size requirements for SA-372 and SA-723 Steels Section VIII, Division 3, ASME International, Approved 18 December, 2018, 2019.
[40] PVP2019-93907, Technical Basis for Master Curve for Fatigue Crack Growth of Ferritic Steels in High Pressure Gaseous Hydrogen in ASME VIII-3 Code, C. San Marchi, J. Ronevich, P. Bortot, Y. Wada, J. Felbaum, M. Rana, American Society of Mechanical Engineers (ASME), San Antonio, TX, ASME 2019 Pressure Vessels and Piping Conference, 14-19 July, 2019.
[41] ANSI/NACE MR0175-2021 / ISO 15156:2020, Petroleum and Natural Gas Industries-Materials for Use in H_2S-Containing Environments in Oil and Gas Production. Parts 1, 2, and 3., American National Standards Institute (ANSI) / National Association of Corrosion Engineers (NACE) / International Organization for Standardization (ISO), 2021.
[42] API Specification 5L, Specification for Line Pipe, American Petroleum Institute (API), Washington, DC.
[43] F2002-50435, Integrity Characteristics of Vintage Pipelines, E.B. Clark, B.N. Leis, R.J. Eiber, Contactor: Batelle Memorial Institute, for Interstate Natural Gas Association of America (INGAA) Foundation, Final Report, October, 2004.
[44] API RP 1160 (2019), Recommended Practice - Managing System Integrity for Hazardous Liquid Pipelines, American Petroleum Institute (API), Third Edition, February, 2019.
[45] Repurposing Pipelines for Hydrogen Transportation: Guiding Operators Through the Re-Evaluation Process, V. Monsma, T. Illson, R. Thodla, A. Hussain, DNV, White Paper, April, 2023.
[46] 693JK32150004CAAP, Knowledge-Guided Automation for Integrity Management of Aging Pipelines (KAI-MAP) for Hydrogen Transport - 2nd Annual Report, K. Kathamukkala, S. Feng, L. Pend, Y. Liu, H. Yan, Y. Deng, Contractor: Arizona State University, for U.S. DOT PHMSA, 30 September, 2023.
[47] EPRI Report # 3002025050, Transitioning Line Pipe to Hydrogen Service - Integrity Management, D. Dinata, S. Finneran, N.G. Thompson, Contractor: DNV, for Electric Power Research Institute (EPRI), 31 October, 2022.
[48] ASME B31G-2023, Manual for Determining the Remaining Strength of Corroded Pipelines, Supplement to ASME B31 Code for Pressure Piping, American Society of Mechanical Engineers (ASME), New York, NY, 2023.
[49] DNV-ST-F101, Standard - Submarine Pipeline Systems, DNV, Edition 2021-08 Amended 2021-12, August, 2021.
[50] Challenges of Converting Existing Natural Gas Pipelines to Hydrogen Service, Including High-Grade Steels, V. Monsma, DNV, Pipeline Technology Conference (PTC) 2022, 2022.
[51] https://ehb.eu/
[52] Five Hydrogen Supply Corridors for Europe in 2030 – Full Version - European Hydrogen Backbone, Guidehouse, https://ehb.eu/files/downloads/EHB-Supply-corridor-presentation-Full-version.pdf, Presentation, May, 2022.
[53] https://www.south2corridor.net/
[54] https://h2medproject.com/the-h2med-project/
[55] https://www.whitehouse.gov/build/guidebook/
[56] https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving
[57] The GRHYD Demonstration Project, ENGIE, https://www.engie.com/en/businesses/gas/hydrogen/power-to-gas/the-grhyd-demonstration-project.
[58] GRHYD: A Successful Demonstration of the new Gas H2NG, I. Alliat, H. Pierre, ENGIE Lab CRIGEN, https://www.calameo.com/read/006449568db3c3c51b740, Presentation, 2020.
[59] HyDeploy: The UK's First Hydrogen Blending Deployment Project, T. Isaac, Progressive Energy, Ltd., Gloucestershire, UK, Clean Energy, Vol. 3, Issue 2, pp. 114-125, June, 2019.
[60] HYREADY, Joint Industry Project, DNV, https://www.dnv.com/article/hyready-219355.

[61] H2Pipe, Joint Industry Project, DNV, https://www.dnv.com/article/transportation-of-hydrogen-gas-in-offshore-pipelines-h2pipe-213006.
[62] DNV-RP-F104, Recommended Practice - Design and Operation of Carbon Dioxide Pipelines, DNV, Edition 2021-02 Amended 2021-09, February, 2021.
[63] In-Service Welding of Methane/Hydrogen Mixture Pipelines, Joint Industry Project, DNV, https://www.dnv.com/article/in-service-welding-of-methane-hydrogen-mixture-pipelines-219708.
[64] PR-276-241503-R01, Causes of Crack Failures in Pipelines and Research Gap Analysis, Project Number MAT-8-3, M.P. Brongers, M. Rosenfeld, C. Macrory, G.M. Wilkowski, Contractor: Engineering Mechanics Corporation of Columbus (Emc2), for Pipeline Research Council International (PRCI), Final Report, 25 February, 2022.
[65] SAND2023-14266PE, HyBlend - Overview: Hydrogen-Assisted Fatigue and Fracture of Line Pipe Steels, C. San Marchi, J. Ronevich, B. Schroeder, M. Devin, B. Davis, M. Agnani, Sandia National Laboratories (SNL), Pipeline Blending CRADA, Phase II - a HyBlend(TM) Project, 6 December, 2023.
[66] Microstructural Effects on Fracture Resistance of Vintage Pipeline Steels in Gaseous Hydrogen, M. Agnani, J. Ronevich, C. San Marchi, Sandia National Laboratories (SNL), Park City, Utah, 2023 International Hydrogen Conference, 17-21 September, 2023.
[67] Download at: https://helpr.sandia.gov
[68] ASME Code Case 220, Fatigue Crack Growth Rate Properties in Hydrogen for B31.12 Pipeline Materials, ASME International, Approved: 10 July, 2023, 2023.
[69] Forschungsbericht G202006 01/2023, DVGW Project SyWeSt H2: Investigation of Steel Materials for Gas Pipelines and Plants for Assessment of their Suitability with Hydrogen, M. Steiner, U. Marewski, H. Silcher, Contractors: Open Grid Europ GmbH Essen and University of Stuttgart, for Deutscher Verein des Gas- und Wasserfaches e.V. (DVGW), Final Report, January, 2023.
[70] DIN CEN/TR 17797 09/2022, Gas infrastructure - Consequences of Hydrogen in the Gas Infrastructure and Identification of Related Standardisation Need in the Scope of CEN/TC 234, Deutscher Verein des Gas- und Wasserfaches e.V. (DVGW), Bonn, Germany, September, 2022.
[71] DVGW G407(M) Technical Information - Guideline 08/2022, Conversion of Gas Pipelines Made of Steel Pipes for the Distribution of Hydrogen-Containing High-Methane Gases and Hydrogen up to 16 bar Operating Pressure, Deutscher Verein des Gas- und Wasserfaches e.V. (DVGW), Bonn, Germany, August, 2022.
[72] DVGW G409(M) Technical Information - Guideline 09/2020, Technical Information - Guideline - Conversion of High-Pressure Gas Steel Pipelines for a Design Pressure of More Than 16 Bar for Transportation of Hydrogen, Deutscher Verein des Gas- und Wasserfaches e.V. (DVGW), Bonn, Germany, September, 2020.
[73] DVGW G464(M) Technical Information - Guideline 03/2023, Fracture-Mechanical Assessment Concept for Steel Pipelines with a Design Pressure of More Than 16 bar for the Transport of Hydrogen, Deutscher Verein des Gas- und Wasserfaches e.V. (DVGW), Bonn, Germany, March, 2023.
[74] Quantifying the Hydrogen Embrittlement of Pipeline Steels for Safety Considerations, L. Briottet, I. Moro, P. Lemoine, CEA-Liten, Grenoble, France, International Journal of Hydrogen Energy (Elsevier), https://doi.org/10.1016/j.ijhydene.2012.05.143, Vol. 37, Issue 22, pp. 17616-17623, November, 2012.
[75] Compatibility and Suitability of Existing Steel Pipelines for Transport of Hydrogen-Natural Gas Blends, J.A. Ronevich, C. San Marchi, Korea Research Institute of Standards and Science (KRISS), Sandia National Laboratories (SNL), Hamburg, Germany, 2017 International Conference on Hydrogen Safety, Presentation, 13 September, 2017.
[76] SAND2012-7321, Technical Reference for Hydrogen Compatibility of Materials, C. San Marchi, B.P. Somerday, Sandia National Laboratories (SNL), Albuquerque, NM and Livermore, CA, September, 2012.
[77] Full Scale Experimental Comparison - Mechanisms, Modeling, Experiments and pressure Vessel Design, J. Solin, N. De Miguel, Mathryce Dissemination Workshop, 18 September, 2015.
[78] Effect of Hydrogen on Fatigue Performance of Natural Gas Transmission Pipelines (EET + Naturalhy), J. Van Wortel, Netherlands Organisation for Applied Scientific Research (TNO), Final Report, April, 2008.

[79] IGC Doc 121/14 Appendix H, Hydrogen Pipeline Systems - Requalification of Existing Pipelines for Hydrogen Service, European Industrial Gases Association (EIGA), 2014.
[80] IGEM/TD/1 Edition 6, Steel Pipelines for High Pressure Gas Transmission, Institution of Gas Engineers and Managers (IGEM), United Kingdom, November, 2021.
[81] IGEM/TD/1 Edition 6 Supplement 2, Steel Pipelines for High Pressure Gas Transmission; Supplement 2 - High Pressure Hydrogen Pipelines, Institution of Gas Engineers and Managers (IGEM), United Kingdom, Communication 1849, December, 2021.
[82] IGEM/TD/3 Edition 5 Supplement 1, Repurposing of Natural Gas (NG) Pipelines with MOP Not Exceeding 7 bar for NG/Hydrogen Blends, Institution of Gas Engineers and Managers (IGEM), United Kingdom, December, 2022.
[83] IGEM/TD/21, Reference Standard for Hydrogen Distribution for New Steel and PE Mains and Services, Institution of Gas Engineers and Managers (IGEM), United Kingdom, August, 2023.
[84] IGEM/TD/22, Reference Standard for Repurposing Natural Gas Distribution Mains and Services for Hydrogen, Institution of Gas Engineers and Managers (IGEM), United Kingdom, November, 2023.