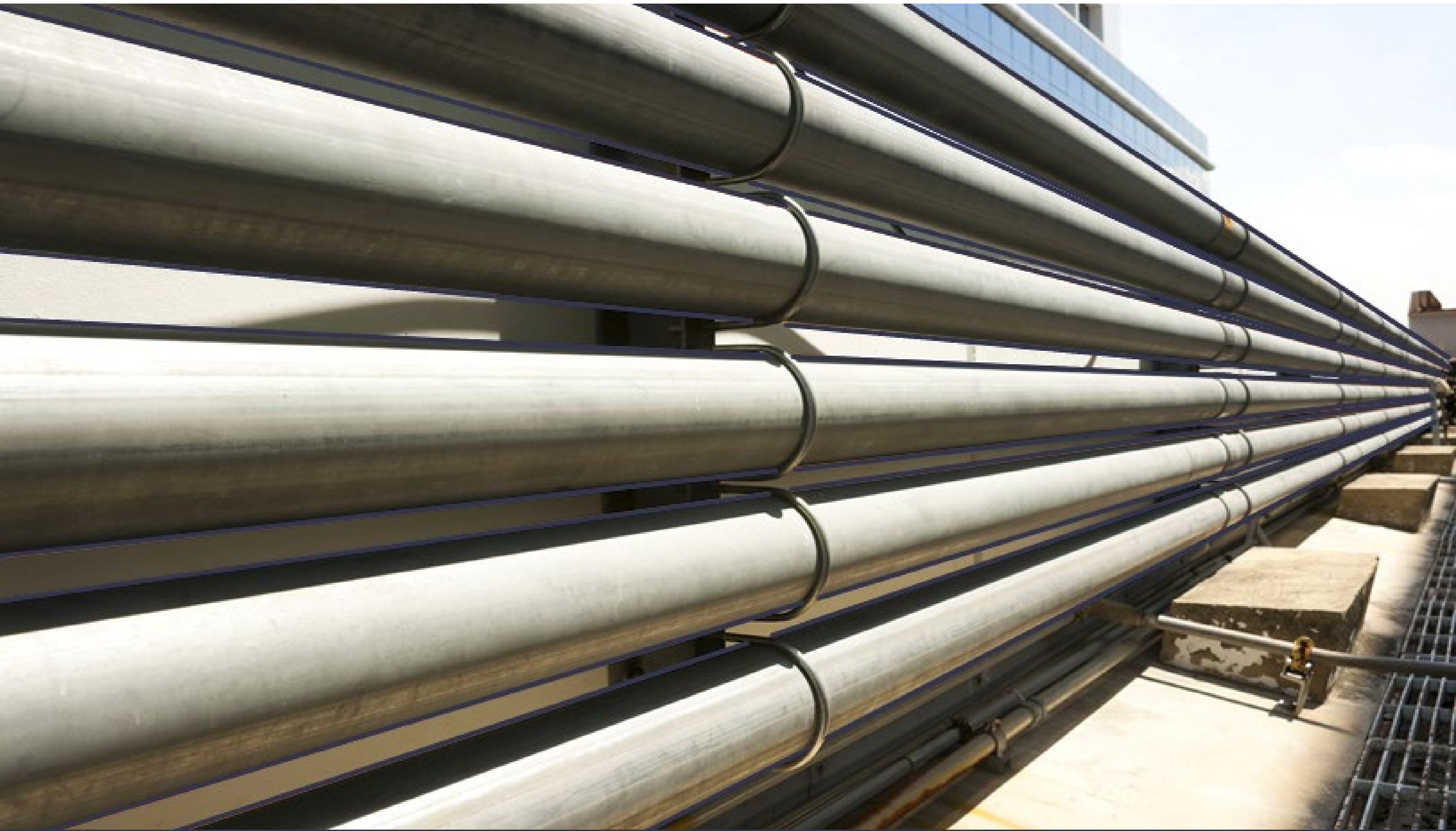
U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)
Final Report No. 24-30994-6000754R

Review of ASME B31.8S on Reinspection Intervals for Pipelines Carrying Hydrogen or Hydrogen/Natural Gas Blends

Michiel P. Brongers, PE, Leslie A. Ward, and Lucinda Smart
December 2, 2024



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to

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

on

December 2, 2024

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Executive Summary

The objective of Task 2 was to review ASME B31.8S-2018 Table 5.6.1-1 (Integrity Assessment Intervals) and other risk assessment tools and propose a technically sound basis for determining Predicted Failure Pressure (P_f) and Reinspection Interval (RI) for pipelines carrying hydrogen or hydrogen-blended gas. Additional work included an assessment of the limitations and possible improvements of Figure 7.2.1-1 (Timing for Scheduled Responses). These are described in Chapter 5 of this report.

Terminology related to ambient-temperature hydrogen effects on pipelines can be confusing. To alleviate this, Chapter 6 of this report provides a description of the effects of hydrogen.

There is an ongoing effort by the Hydrogen Task Group of ASME B31.8 (Gas Transmission and Distribution Piping Systems) to move content from ASME B31.12 (Hydrogen Piping and Pipelines) into new hydrogen chapters of ASME B31.8 and ASME B31.8S (Managing System Integrity of Gas Pipelines). To help this process, a review of the potential threats to pipeline integrity described in ASME B31.8S Paragraph 2.2 (Integrity Threat Classification) was performed. This is described in Chapter 7 of this report.

The following conclusions and recommendations were formulated based on the results from this Task 2 review.

Review of ASME B31.8S-2018 Table 5.6.1-1 Integrity Assessment Intervals and ASME B31.8S-2018 Figure 7.2.1-1 Response Time

ASME B31.8S-2018 uses the terminology for Integrity Assessment Interval and Response Time (RT) interchangeably, which is incorrect. RT should refer to the time to repair or mitigate a present condition. RT should be shorter than the (re-)assessment interval (RI), which in turn should be shorter than the remaining life (RL) to reach a future critical condition.

The Maximum Allowable Operating Pressure (MAOP) coefficients and Specified Minimum Yield Strength (SMYS) coefficients in ASME B31.8S-2018 are not consistently chosen. For In-Line Inspections (ILI), ASME B31.8S-2018 requires RTs of 10, 15, and 20 years to reach a P_f of 1.00 x SMYS for MAOPs up to 30%, between 30% and 50%, and above 50% of SMYS, respectively. The other SMYS-coefficients are also inconsistent: 0.50, 0.66, 0.70, 0.83, and 0.90 x SMYS.

A more technically sound methodology would be to: first calculate the RL to reach a P_f of "SMYS-coefficient x SMYS," then apply a Safety Factor to the RL to set an RI, and finally, set an RT for expedited mitigation of conditions with a short RI. This methodology is adopted in API 570-2023, as described in this report.

ASME B31.8S-2018 Figure 7.2.1-1 specifies the required RT for external and internal corrosion. However, the curves in the figure are independent of the pipe wall thickness and the corrosion rate (CR), which is a shortcoming for the threat of corrosion metal loss because the mechanism reduces wall thickness with time. Example calculations using the equations from

ASME B31G-2023 show that the RL for different wall thicknesses and diameters varies greatly. The RL can be much shorter than the RT for all but the thickest pipes.

It is recommended to (1) revise ASME B31.8S Table 5.6.1-1 and Figure 7.2.1-1 with consistent application of P_f and factors related to SMYS, and (2) introduce the concepts of RL and RI into the Code while maintaining the concept of RT.

Description of Hydrogen Effects

The terminology used for ambient-temperature hydrogen effects can be confusing. These effects can occur in the base metal, weld fusion metal, or weld heat-affected zone (HAZ). Some are named after their mechanism, and others after the source of hydrogen. This report describes and distinguishes each of the following terms:

- Hydrogen ingress — reversible; no cracks
- Hydrogen embrittlement (HE) — reversible; embrittles steel; no cracks
- Hydrogen-assisted cracking (HAC) — irreversible; H_2 gas micro-fissures the steel
- Hydrogen-induced cracking (HIC) — irreversible; no external stress; cracks grow
- Hydrogen stress cracking (HSC) — irreversible; with external stress; cracks grow
- Stress-oriented HIC (SOHIC) — irreversible; HSC parallel to external stress
- Sulfide stress cracking (SSC) — irreversible; source of H is wet H_2S corrosion
- Hydrogen-enhanced cracking (HEC) — H enhances SCC or fatigue crack growth rate

It is recommended to use consistent terminology when describing hydrogen effects.

Review of Potential Threats to Integrity

An analysis of the potential threats to pipeline integrity listed in ASME B31.8S-2018 showed four generally applicable and six hydrogen-applicable threats missing.

Integrity threats applicable to any gas transmission pipeline - add to ASME B31.8S Paragraph 2.2:

1. Y1 "Time-Dependent – Fatigue cracking"
2. Y4 "(b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Low-toughness seam"
3. Y5 "(b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Defect in or near an electric resistance welded (ERW) seam"
4. Y7 "(b) Resident (2) Welding/fabrication-related – At in-service/repair welds – (Delayed) Hydrogen Stress Cracking"

Integrity threats applicable to gas pipelines in hydrogen and blend service - add to future ASME B31.8S chapter on hydrogen:

1. Y2 "Time-Dependent – Hydrogen-Induced Cracking (HIC)"
2. Y3 "Time-Dependent – Fittings and sharp transitions"

3. Y6 "(b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body"
4. Y8 "(b) Resident (2) Welding/fabrication related – At welded sleeves and fittings – Type B sleeves and Puddle welds"
5. Y9 "(b) Resident (2) Equipment – Other material/equipment failure – Disbonded coating caused by hydrogen"
6. Y10 "(c) Random or Time Independent (3) Weather-related and outside force – At locations that may experience an electrical arc or fire – Fire Damage"

It is recommended to add these missing integrity threats to future versions of ASME B31.8S.

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Table of Contents

1 INTRODUCTION 1

2 BACKGROUND 1

3 OBJECTIVE 4

4 SCOPE OF WORK 4

5 ASME B31.8S REVIEW OF INTEGRITY ASSESSMENT INTERVALS 4

5.1 Review of ASME B31.8S-2018 Table 5.6.1-1 (Integrity Assessment Intervals) and Figure 7.2.1-1 (Timing for Scheduled Responses) 4

5.1.1 Example with Very Conservative CR per ANSI/NACE SP0502 9

5.1.2 Example with Conservative CR Determined from ILI 11

5.2 ASME B31.8S-2018 Integrity Assessment Intervals Compared with API 570-2023 Inspection Intervals 14

6 HYDROGEN EFFECTS 18

7 ASME B31.8S REVIEW OF POTENTIAL THREATS TO INTEGRITY 24

7.1 Review of Integrity Threat Classification 24

7.2 Updated Threats Mapped Versus Hydrogen Integrity Threats 26

7.2.1 Missing Threat Y1: Time-dependent – Fatigue cracking 30

7.2.2 Missing Threat Y2: Time-dependent – Hydrogen-Induced Cracking (HIC) 31

7.2.3 Missing Threat Y3 Time-dependent – Fittings and sharp transitions 32

7.2.4 Missing Threat Y4 (b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – At long-seam weld – Low-toughness seam 35

7.2.5 Missing Threat Y5 (b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – At long-seam weld – Defect in or near an ERW seam 37

7.2.5.1 Manufacturing-Caused Arc Burns 37
7.2.5.2 Hook Cracks 38

7.2.6 Missing Threat Y6 (b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body 40

7.2.6.1 Fabrication-Caused Arc Burns/Strike 40

7.2.7 Missing Threat Y7 (b) Resident (2) Welding/fabrication related – At in-service/repair welds – (Delayed) Hydrogen Stress Cracking 43

7.2.8 Missing Threat Y8 (b) Resident (2) Welding/fabrication related – At welded sleeves and fittings – Type B sleeves and Puddle welds 44

7.2.8.1 Type B Sleeves 45
7.2.8.2 Puddle Welds 46

7.2.9 Missing Threat Y9 (b) Resident (2) Equipment – Other material/equipment failure – Disbonded coating caused by hydrogen 47

7.2.9.1 Hydrogen Blisters in Coatings 47

7.2.10 Missing Threat Y10 (c) Random or Time Independent (3) Weather-related and outside force – At locations that may experience an electrical arc or fire – Fire Damage 48

7.2.10.1 Fire Damage 48

8 CONCLUSIONS AND RECOMMENDATIONS 49

9 REFERENCES (OR WORKS CITED) 52

List of Tables

Table 1. Integrity Assessment Intervals: Time-Dependent Threats, Internal and External Corrosion, Prescriptive Integrity Management Plan B31.8S-2018 [2] 3

Table 2. Values of % SMYS for Different Response Times, Compared with ASME B31.8S-2018 Table 5.6.1-1 6

Table 3. Corrosion Rates (CRs) for External and Internal Metal Loss (ML) on Gas Transmission Pipelines, as Determined Using Kiefner's CorroSure Software to Correlate Features from 26 Consecutive ILI Runs for Different Operators 12

Table 4. API 570-2023 Recommended Maximum Inspection Intervals [9] 17

Table 5. Summary of Hydrogen Terminology 23

Table 6. Hydrogen-Related Threats Mapped Versus Integrity Threats Defined in ASME B31.8S-2018 [2] . 27

Table 7. "Table 3" from Early Generation Seam Welds Report [33] 37

Table 8. "Table 2" from Holbrook and Cialone [35] 42

List of Figures

Figure 1. Figure 7.2.1-1Timing for Scheduled Responses – Time-Dependent Threats, Prescriptive Integrity Management Plan B31.8S-2018 [2] 7

Figure 2. Replot of B31.8S-2018 Figure 7.2.1-1 with Dependent Variable "Response Time" on the y-Axis. 8

Figure 3. Effect of Pipe Diameter and Wall Thickness on Calculated Remaining Life and Figure 7.2.1-1 Response Time per ASME B31.8S-2018 [2] for MAOP=30% SMYS, API 5L Grade X52 Steel, CR = 16 mpy (Growth with Constant Length) 10

Figure 4. Effect of Pipe Diameter and Wall Thickness on Calculated Remaining Life and Figure 7.2.1-1 Response Time per ASME B31.8S-2018 [2] for MAOP=30% SMYS, API 5L Grade X52 Steel, CR = 16 mpy (Growth with Constant Length) 11

Figure 5. Effect of Wall Thickness on Calculated Remaining Life and Figure 7.2.1-1 Response Time per ASME B31.8S-2018 [2] for MAOP=30%, 50%, and 72% SMYS, API 5L Grade X52 Steel, CR = 8.96 mpy (Growth with Constant Length) 14

Figure 6. API 570-2023 Corrosion Rate Determination [9] 16

Figure 7. API 570-2023 Remaining Life Calculations [9] 17

Figure 8. "Figure 8" from PRCI Report PR-276-241503-R01, Data Through 2021 [14] 25

Figure 9. "Figure 9" from PRCI Report PR-276-241503-R01; Data Through 2021 [14] 26

Figure 10. "Figure 11" from ANSI/NACE TM0284-2016 [29] 32

Figure 11. "Figure 2" from Krom [31] 34

Figure 12. "Table 5" from Krom [31] 34

Figure 13. Example of ERW with OD Arc Burns and Small Crack [32] 38

Figure 14. Examples of Hook Cracks [32] 39

Figure 15. Examples of Arc Burns/Strikes: (a) and (b) surface views, and (c) cross-section view [34] 41

Figure 16. "Figure 11" from Holbrook and Cialone [35]; for gas mixtures M = 100% CH_4, MH = CH_4/H_2, MHC = $CH_4/H_2/CO$, MHCC = $CH_4/H_2/CO/CO_2$ 42

Figure 17. "Figure 1" from TWI Website, Showing Possible Locations for HSC to Occur [36] 44

Figure 18. "Figure 2" from TWI Website, Showing HSC [36] 44

Figure 19. "Figure 16" from PRCI Pipeline Repair Manual, Showing Welding of Type B Sleeve [17] 46

Figure 20. Example of HIC in Weld HAZ [39] 47

Figure 21. Example of FBE Coating Blisters [40] 48

List of Acronyms and Abbreviations

AMPP	Association for Materials Protection and Prevention
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
CAR	Crack Area Ratio
CFR	Code of Federal Regulations
CLR	Crack Length Ratio
CML	Condition Monitoring Location
CP	Cathodic Protection
CR	Corrosion Rate
CSA	Canadian Standards Association
CSR	Crack Sensitivity Ratio
CTR	Crack Thickness Ratio
DOE	U.S. Department of Energy
DSAW	Double Submerged Arc Welded (pipe)
ERW	Electric Resistance Welded (pipe)
FBE	Fusion-Bonded Epoxy
FGCR	Fatigue Crack Growth Rate
FFS	Fitness for Service
FW	Flash Welded (pipe)
H_2S	Hydrogen Sulfide
HAC	Hydrogen-Assisted Cracking
HAZ	Heat-Affected Zone
HE	Hydrogen Embrittlement
HEC	Hydrogen-Enhanced Cracking
HIC	Hydrogen-Induced Cracking
HSC	Hydrogen Stress Cracking
ID	Inside Diameter
ILI	In-Line Inspection
IMP	Integrity Management Program
LF-ERW	Low-Frequency Electric Resistance Welded (pipe)
LT	Long-Term (corrosion rate)
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic Flux Leakage
ML	Metal Loss
NACE	(formerly) National Association of Corrosion Engineers (now AMPP)
NDE	Non-Destructive Evaluation
nnpH SCC	Near-Neutral pH Stress Corrosion Cracking
OD	Outside Diameter
PHMSA	Pipeline and Hazardous Materials Safety Administration
PRCI	Pipeline Research Council International
PWHT	Post-Weld Heat Treatment
RBI	Risk-Based Inspection
RI	Reinspection Interval

RL	Remaining Life
RT	Response Time
SCC	Stress Corrosion Cracking
SMYS	Specified Minimum Yield Strength
SOHIC	Stress Oriented Hydrogen-Induced Cracking
SSAW	Single Submerged Arc Welded (pipe)
SSC	Sulfide Stress Cracking
SSWC	Selective Seam Weld Corrosion
ST	Short-Term (corrosion rate)
SWC	Step-Wise Cracking
USDOT	United States Department of Transportation

List of Variables

a	Length dimension of HIC crack/crack colony per ANSI/NACE TM0284
b	Height dimension of HIC crack/crack colony per ANSI/NACE TM0284
$d\varphi_H/dx$	Concentration Gradient of Hydrogen Atoms
d	Flaw depth
D	Pipe Diameter
D_{eff}	Effective Diffusivity
D_H	Hydrogen Diffusivity
g(P)	Hydrogen Gas Pressure
J_H	Diffusion Flux of Hydrogen Atoms
ΔK	Stress Intensity Factor Range
L	Flaw (axial) length
M	Bulging Stress Magnification Factor
P	Gas Pressure
P_f	Predicted Failure Pressure
R	Loading Ratio
t	Pipe Wall Thickness
T	Specimen Thickness per ANSI/NACE TM0284
W	Specimen Width per ANSI/NACE TM0284
x	x-Direction

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1 INTRODUCTION

This Task 2 report was prepared by Kiefner and Associates, Inc. (Kiefner) as part of the research project titled "Investigate Damage Mechanisms for Hydrogen (H_2) and Hydrogen/Natural Gas Blends to Determine Inspection Intervals for In-Line Inspection (ILI) Tools" for the U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA), under Contract 693JK32310011POTA.

Chapter 5 of this report presents a review of ASME B31.8S-2018 Table 5.6.1-1 (Integrity Assessment Intervals) and an assessment of the limitations and possible improvements of Figure 7.2.1-1 (Timing for Scheduled Responses). Chapter 6 provides a description of ambient-temperature hydrogen effects for pipelines. Chapter 7 presents the results of a review of the potential threats to pipeline integrity as described in ASME B31.8S Paragraph 2.2 (Integrity Threat Classification). Chapter 8 provides conclusions and recommendations.

2 BACKGROUND

On July 26, 2024, Kiefner issued Task 1 Final Report, "Literature Review on Reinspection Intervals for Pipelines Carrying Hydrogen or Hydrogen/Natural Gas Blends" [1]. The literature review critically examined the methodologies currently employed in the United States, Europe, and other countries to determine ILI reinspection intervals. It also provided an in-depth comparison and discussion of related Codes and Standards.

Of particular interest to the USDOT-PHMSA is the methodology in ASME B31.8S-2018, "Managing System Integrity of Pipelines" [2], which provides guidance on various risk assessment approaches covering design, construction, operational prevention, mitigation, and assessment, ensuring the safe operation of gas pipelines. ASME B31.8S is a supplement to ASME B31.8-2018 "Gas Transmission and Distribution Piping Systems" [3].

Since June 28, 2024, the ASME B31.8S-2018 and ASME B31.8-2018 versions have been incorporated by reference in the Code of Federal Regulations (CFR) Title 49 Part 192 "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards" [4]. Before incorporating the ASME B31.8S-2018 version, ASME B31.8S-2004 [5] had been incorporated by reference. ASME releases an updated version of B31.8S biannually. The current version is ASME B31.8S-2022 [6].

At the time of writing the proposal (May 2023) for the current research, USDOT-PHMSA requested that Table 3 of ASME B31.8S-2004 be reviewed and recommendations be provided on how to improve ASME B31.8S so future editions of 49 CFR 192 can be more technically sound. The ASME B31.8S-2004 "Table 3 Integrity Assessment Intervals: Time-Dependent Threats, Prescriptive Integrity Management Plan" has been renumbered and partially retitled in ASME B31.8S-2018 as "Table 5.6.1-1 Integrity Assessment Intervals: Time-Dependent Threats, Internal and External Corrosion, Prescriptive Management Plan."

This Task 2 report, "Review of ASME B31.8S on Reinspection Intervals for Pipelines Carrying Hydrogen or Hydrogen/Natural Gas Blends," provides commentary and discussion regarding the 2018 version.

ASME B31.8S-2018 Table 5.6.1-1, reproduced as Table 1 below, lists the (maximum allowable) integrity assessment intervals for the time-dependent external and internal corrosion threats for a prescriptive integrity management program (IMP). These two threats to pipeline integrity are classified in Paragraph 2.2 of ASME B31.8S-2018 as (a)(1) Time-Dependent – External Corrosion and (a)(2) Time-Dependent – Internal Corrosion. The same paragraph lists 20 other threats (22 threats total), but those threats are not addressed in Table 5.6.1-1.

> The authors of this report note that perhaps the words "metal loss" should be added to these threats because the external and internal corrosion mechanisms do not threaten a pipeline's mechanical integrity by themselves. Instead, the pipe wall thinning resulting from metal loss reduces the pipeline's pressure-carrying capacity. The corrosion mechanism and local environmental conditions result in a corrosion rate (CR), which determines the increase in a metal loss area's size (depth, length, and width). The remaining life (RL) is the time to grow a defect from its present size to a size that becomes critical and ruptures or through-wall and leaks.

Table 5.6.1-1 specifies an integrity assessment interval of 5, 10, 15, or 20 years based on the used inspection technique (hydrostatic testing, ILI, or direct assessment). Note 1 states that these intervals are maximums and may be less. For ILI, the lowest calculated failure pressure (P_f), as a percentage of the specified minimum yield strength (SMYS), determines the reinspection interval (RI). This approach uses a generic CR for any internal and external corrosion metal loss anomalies. The CR is assumed to be the same for all internal and external corrosion cases, which is unrealistic. The calculation to determine the RL is not shown. A safety factor applied to the RL to calculate the reinspection interval (RI) is not stated. As mentioned, the table only addresses corrosion metal loss and no other threats. In the case of pipelines carrying hydrogen gas, the failure mechanisms of the various threats may be affected, increasing the rate at which anomalies may grow and shorten the RL compared to natural gas service.

An improved approach first assesses the failure mechanism (threat) for a particular feature (anomaly/indication), then calculates the RL for each anomaly and ultimately determines an RI. A safety factor (for example, 50% or Factor 2) can be applied to calculate the maximum allowable reinspection interval as a fraction of the shortest calculated RL for a family of anomalies detected within a pipeline section.

ASME B31.8S-2018 is generic for gas assumed to be benign (dry natural gas) and does not consider the presence of pure hydrogen or hydrogen-blended gas in the pipeline. The problem is two-fold: (1) for integrity assessment of present flaws, P_f, calculations rely on material properties that are not corrected for hydrogen effects, including for different percentages of hydrogen in blended gas, and (2) for life evaluation of growing flaws, the RL of hydrogen-affected features can be dramatically shorter than the RL of those same features in a more benign environment.

Table 1. Integrity Assessment Intervals: Time-Dependent Threats, Internal and External Corrosion, Prescriptive Integrity Management Plan B31.8S-2018 [2]

ASME B31.8S-2018

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

Inspection Technique	Interval, yr [Note (1)]	Criteria: Operating Pressure Above 50% of SMYS	Criteria: Operating Pressure Above 30% But Not Exceeding 50% of SMYS	Criteria: 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.

3 OBJECTIVE

The objective of this Task 2 review of ASME B31.8S-2018 Table 5.6.1-1 and other risk assessment tools was to propose a technically sound basis for determining P_f and RI for pipelines carrying hydrogen or hydrogen-blended gas.

4 SCOPE OF WORK

In Task 2, ASME B31.8S-2018 Table 5.6.1-1 (Integrity Assessment Intervals), Figure 7.2.1-1 (Timing for Scheduled Responses), and Paragraph 2.2 (Integrity Threat Classification) were assessed for their limitations and possible improvements. In addition, threats presently missing from ASME B31.8S were identified, and the potential effects of hydrogen-affected material properties on different threat assessments were discussed. In support of this effort, other Codes and Standards related to risk, threats, and failure mechanisms associated with transporting gaseous hydrogen and hydrogen blends were reviewed.

5 ASME B31.8S REVIEW OF INTEGRITY ASSESSMENT INTERVALS

5.1 Review of ASME B31.8S-2018 Table 5.6.1-1 (Integrity Assessment Intervals) and Figure 7.2.1-1 (Timing for Scheduled Responses)

ASME B31.8S-2018 covers both a prescriptive-based and a performance-based IMP. The Code states that when followed explicitly, the prescriptive process will provide all the inspection, prevention, detection, and mitigation activities necessary to produce a satisfactory IMP. The performance-based IMP alternative utilizes more data and more extensive risk analyses, which enables the operator to achieve a greater degree of flexibility to meet or exceed the requirements of this Code, specifically in the areas of inspection intervals, tools used, and mitigation techniques employed.

Each section of the Code provides requirements for prescriptive-based and performance-based IMPs. In addition, Nonmandatory Appendix A provides specific activities by threat categories that an operator must follow to produce a satisfactory prescriptive IMP.

For prescriptive-based IMPs, the initial interval between construction and the first required reassessment of integrity is limited by the pipe's operating pressure and shall not exceed:

Pipe operating >60% of SMYS	10 years
Pipe operating >50% - 60% of SMYS	13 years
Pipe operating >30% - 50% of SMYS	15 years
Pipe operating <30% of SMYS	20 years

For ILI, ASME B31.8S-2018 Paragraph A-3.5 explains that the response depends on the severity of corrosion, as determined by calculating the P_f of indications and a "reasonably anticipated or scientifically proved rate of corrosion." ASME B31G Manual [7] or equivalent is referenced as the method to calculate P_f.

ASME B31G defines failure as a pipeline burst (in which the rupture deforms the pipe surface and a "fish mouth" opening forms) as opposed to a leak (in which a hole forms without extension beyond the immediate defect). Thus, perforation/leak is not considered a failure in this Code. The equations are valid only for corrosion depth of 80% or less of the wall thickness. Only ductile failure is considered in ASME B31G. Brittle fracture is not accounted for. This is clear from the calculation input values, which include yield strength, flaw axial length and depth, pipe wall thickness, and diameter, but there is no measure of fracture toughness. This methodology is not suitable for evaluating P_f if the material properties are affected by hydrogen embrittlement.

Subsequent assessment intervals are given in ASME B31.8S-2018 Table 5.6.1-1 (see Table 1). ASME B31.8S-2018 Table 5.6.1-1 addresses only the threats of internal and external corrosion. The required response times to threats other than internal and external corrosion are described in other paragraphs of ASME B31.8S-2018 Nonmandatory Appendix A.

Pipe operating > 50% of SMYS	P_f > 1.25 x MAOP = 0.90 x SMYS	5 years
(72% SMYS)	P_f > 1.39 x MAOP = 1.00 x SMYS	10 years
Pipe operating > 30% - 50% of SMYS	P_f > 1.39 x MAOP = 0.70 x SMYS	5 years
	P_f > 1.65 x MAOP = 0.83 x SMYS	10 years
(50% SMYS)	P_f > 2.00 x MAOP = 1.00 x SMYS	15 years
Pipe operating < 30% SMYS	P_f > 1.65 x MAOP = 0.50 x SMYS	5 years
	P_f > 2.20 x MAOP = 0.66 x SMYS	10 years
	P_f > 2.75 x MAOP = 0.83 x SMYS	15 years
(30% SMYS)	P_f > 3.33 x MAOP = 1.00 x SMYS	20 years

The maximum allowable operating pressure (MAOP) coefficients and SMYS-coefficients in ASME B31.8S-2018 are not consistently chosen, as can be seen from the P_f ratios versus MAOP and versus SMYS in Table 2. A more technically sound methodology would be to first calculate the RL to reach a P_f of "SMYS-coefficient x SMYS," then apply a Safety Factor to the RL to set an RI, and finally, set an RT for expedited mitigation of conditions with a short RI. This methodology is adopted in API 570-2023, as described in this report.

Instead, for ILI inspections, ASME B31.8S-2018 requires RTs of 10, 15, and 20 years to reach a P_f of 1.00 x SMYS for MAOPs up to 30%, between 30% and 50%, and above 50% of SMYS, respectively. The other SMYS-coefficients are also inconsistent: 0.50, 0.66, 0.70, 0.83, and 0.90 x SMYS.

The authors of this Task 2 report recommend (1) revising ASME B31.8S Table 5.6.1-1 and Figure 7.2.1-1 with consistent application of P_f and factors related to SMYS and (2) introducing the concepts of RL and RI into the Code while maintaining the concept of RT.

Table 2. Values of % SMYS for Different Response Times, Compared with ASME B31.8S-2018 Table 5.6.1-1.

Integrity Assessment Interval (Table 5.6.1-1), or Response Time (Figure 7.2.1-1)	Maximum Allowable Operating Pressure (MAOP)		
	72% SMYS	**50% SMYS**	**30% SMYS**
5 years	0.90 x SMYS (1.25 x MAOP)	0.70 x SMYS (1.39 x MAOP)	0.50 x SMYS (1.65 x MAOP)
10 years	1.00 x SMYS (1.39 x MAOP)	0.83 x SMYS (1.65 x MAOP)	0.66 x SMYS (2.20 x MAOP)
15 years	Not allowed	1.00 x SMYS (2.00 x MAOP)	0.83 x SMYS (2.75 x MAOP)
20 years	Not allowed	Not allowed	1.00 x SMYS (3.33 x MAOP)

These assessment intervals are shown graphically in ASME B31.8S-2018 Figure 7.2.1-1 (see Figure 1). Figure 7.2.1-1 provides "Response Time" to assess/repair a detected anomaly. This should not be confused with a calculated "Remaining Life" or selected "Reinspection Interval." This Figure is merely intended as a screening tool and is severely limited in its application because no distinction is made for pipelines of different diameters and wall thicknesses.

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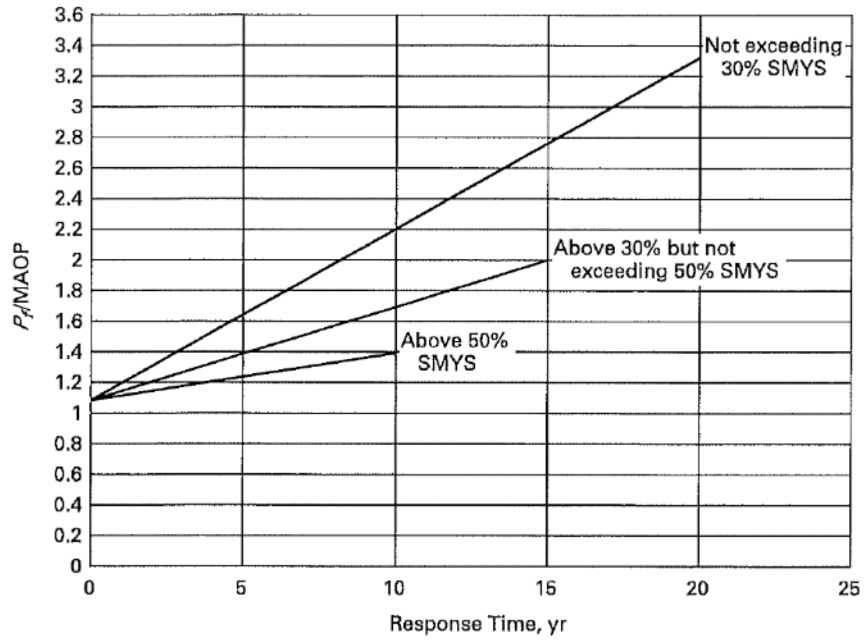
ASME B31.8S-2018

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 1. Figure 7.2.1-1Timing for Scheduled Responses – Time-Dependent Threats, Prescriptive Integrity Management Plan B31.8S-2018 [2]

Figure 1 represents the following linear relationships between RT and P_f/MAOP:

Pipe operating > 50% of SMYS	P_f / MAOP = 0.0290 x RT + 1.1	(1)
Pipe operating > 30% - 50% of SMYS	P_f / MAOP = 0.0600 x RT + 1.1	(2)
Pipe operating < 30% SMYS	P_f / MAOP = 0.1115 x RT + 1.1	(3)

To better understand the graphs, Figure 1 was replotted as Figure 2, with the independent variable "P_f/MAOP" on the x-axis, the dependent variable "Response Time" on the y-axis, and three linear curve fits showing the implied relationships between P_f/MAOP and RT. The equations are:

Pipe operating > 50% of SMYS	RT = 34.48 x P_f / MAOP – 37.96	(4)
Pipe operating > 30% - 50% of SMYS	RT = 16.67 x P_f / MAOP – 18.33	(5)
Pipe operating < 30% SMYS	RT = 8.97 x P_f / MAOP – 9.87	(6)

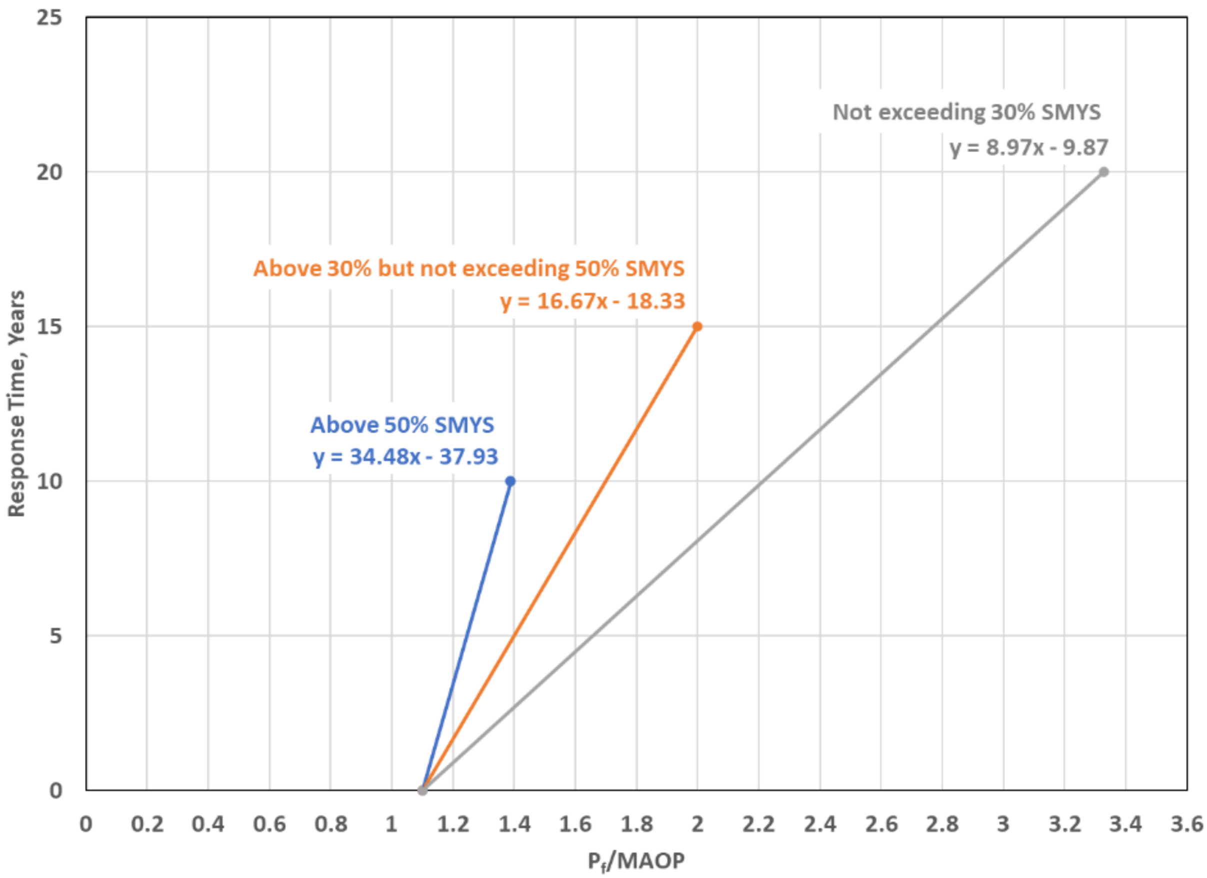


Figure 2. Replot of B31.8S-2018 Figure 7.2.1-1 with Dependent Variable "Response Time" on the y-Axis.

The ASME B31G-2023 equations to calculate P_f were used to derive an equation for P_f/MAOP:

$$\frac{Pf}{MAOP} = \frac{1}{\%SMYS}\left(\frac{2t}{D}\right)(SMYS + 10{,}000)(1 - 0.85\frac{d}{t})/(1 - 0.85\frac{d}{t}\frac{1}{M}) \tag{7}$$

with the bulging stress magnification factor, M, specified as:

$$M = (1 + 0.6275z - 0.00375\, z^2)^{0.5} \;\; \text{for z} \leq 50 \tag{8a}$$

$$M = 0.032\text{z} + 3.3 \;\; \text{for z} > 50 \tag{8b}$$

where z is defined as:

$$z = L^2/(Dt) \tag{9}$$

M is typically less than five and does not affect P_f much in equation (7). Therefore, it is ignored in further discussion.

Looking at the example for MAOP not exceeding 30% SMYS, substitute equation (3) and (7) are equal as follows:

$$0.1115\,RT + 1.1 = \frac{1}{30\%SMYS}\left(\frac{2t}{D}\right)(SMYS + 10{,}000)(1 - 0.85\frac{d}{t})/(1 - 0.85\frac{d}{t}\frac{1}{M}) \tag{10}$$

Equation (10), rewritten for the 30%, 50%, and 72% SMYS cases, shows that the dependent variable RT varies with the flaw depth (d), pipe wall thickness (t), pipe diameter (D), and the pipe's SMYS.

$$RT = (\left(\frac{\frac{1}{30\%SMYS}\left(\frac{2t}{D}\right)(SMYS+10{,}000)\left(1-0.85\frac{d}{t}\right)}{1-0.85\frac{d}{t}\frac{1}{M}}\right) - 1.1)/0.1115 \tag{11}$$

$$RT = (\left(\frac{\frac{1}{50\%SMYS}\left(\frac{2t}{D}\right)(SMYS+10{,}000)\left(1-0.85\frac{d}{t}\right)}{1-0.85\frac{d}{t}\frac{1}{M}}\right) - 1.1)/0.06 \tag{12}$$

$$RT = (\left(\frac{\frac{1}{72\%SMYS}\left(\frac{2t}{D}\right)(SMYS+10{,}000)\left(1-0.85\frac{d}{t}\right)}{1-0.85\frac{d}{t}\frac{1}{M}}\right) - 1.1)/0.029 \tag{13}$$

The coefficients produce relationships that are not linear, as implied in ASME B31.8S-2018 Table 5.6.1-1. Figure 7.2.1-1 specifies the required RT for external and internal corrosion. However, the curves in the figure are independent of the pipe wall thickness and the corrosion rate (CR), which is a shortcoming for the threat of corrosion metal loss because the mechanism reduces wall thickness with time. It is recommended that B31.8S Table 5.6.1-1 and Figure 7.2.1-1 should consistently apply P_f and factors related to SMYS.

To further elaborate on the conclusions, the following paragraphs provide examples of RI calculations using different CR assumptions. The calculations assume nominal dimensions for wall thicknesses, diameter, and a specified minimum yield strength (SMYS) of 52,000 psi (nominally API 5L Grade X52).

5.1.1 Example with Very Conservative CR per ANSI/NACE SP0502

A comparative "Level 0" assessment was made per ASME B31G-2023 to demonstrate the Code's limitations. As directed by ASME B31.8S-2018 to determine a conservative CR, reference was made to Standard Practice ANSI/NACE SP0502-2010 "Pipeline External Corrosion Direct Assessment Methodology" [8]. ANSI/NACE SP0502-1010 Paragraph C3.2 directs that as a Default Corrosion Rate, a pitting rate of 16 mpy (0.4mm/year) should be used to determine reinspection intervals when other data are unavailable. According to the Practice, this CR represents the upper 80% confidence level of maximum pitting rates for long-term (up to 17-years duration) underground corrosion tests of bare steel pipe coupons without cathodic protection (CP) in various soils, including native and nonnative backfill.

The RL of (corrosion) metal loss flaws was calculated as a function of P_f/MAOP using the Modified ASME B31G equations for the analysis. The results were plotted with the RT versus

P_f/MAOP curve. The following assumptions were made: MAOP = 30% of SMYS, API 5L Grade X52 Steel, and CR = 16 mpy.

The results displayed in Figure 3 show that the RL under these conditions is much shorter than the RT for all but the thickest pipes. In addition, any RI should be shorter than RL (for example, a Safety Factor of 2 for 50%). Thus, the ASME B31.8S-2018 Figure 7.2.1-1 screening curve is very non-conservative when a very conservative CR is assumed.

In addition, ASME B31.8S-2018 Figure 7.2.1-1 does not require wall thickness to be considered for the response time. This is a shortcoming for the threat of corrosion metal loss because the mechanism reduces wall thickness over time.

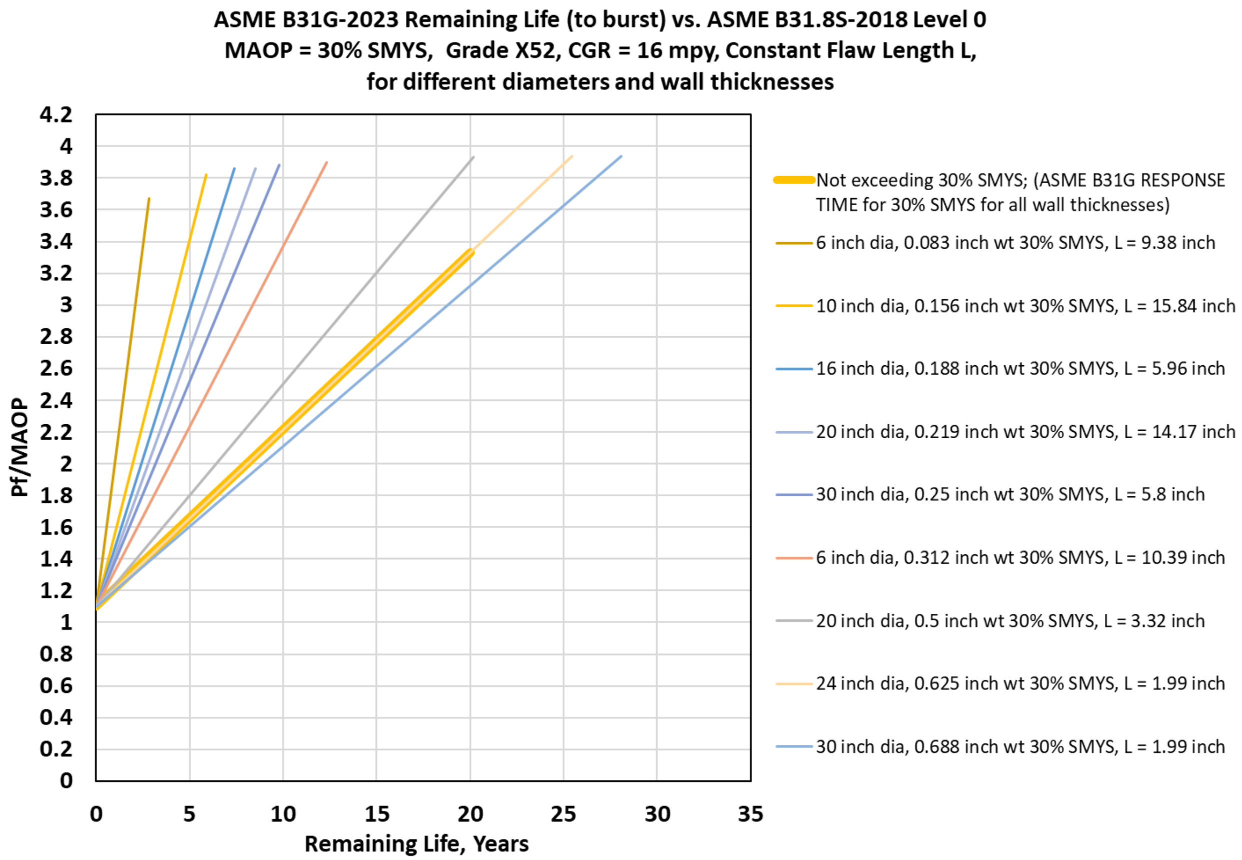


Figure 3. Effect of Pipe Diameter and Wall Thickness on Calculated Remaining Life and Figure 7.2.1-1 Response Time per ASME B31.8S-2018 [2] for MAOP=30% SMYS, API 5L Grade X52 Steel, CR = 16 mpy (Growth with Constant Length).

Further analysis was performed by evaluating the effects of pipe diameter (10-inch, 20-inch, and 30-inch) and wall thickness (0.218-inch and 0.500-inch). Figure 4 shows that the RL of a thicker pipe is longer than that of a thinner pipe, which is consistent with a CR that reduces the remaining pipe wall over time. The figure also shows that for the assumed conditions, the diameter does not have much effect on RL. As with the prior analysis, the very conservative CR of 16 mpy results in predicted RLs much shorter than the RTs, which is very non-conservative.

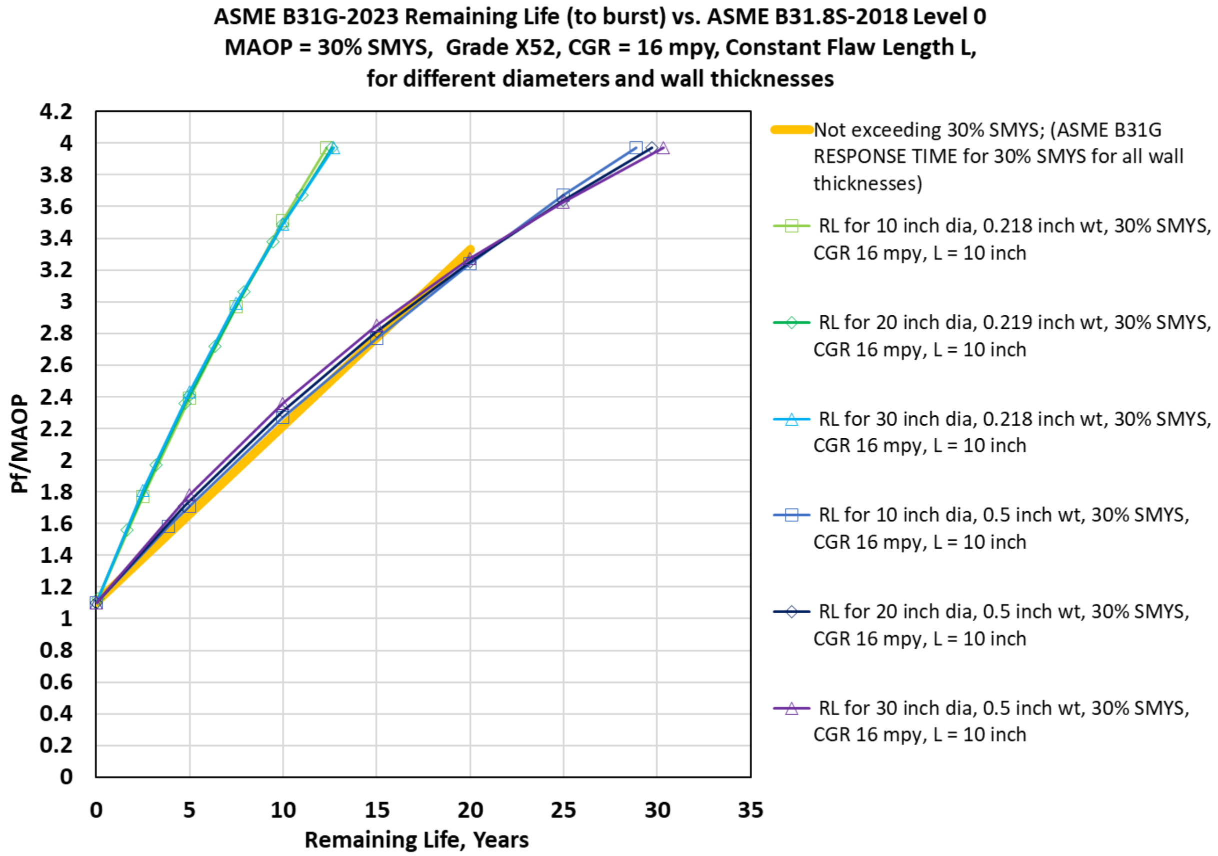


Figure 4. Effect of Pipe Diameter and Wall Thickness on Calculated Remaining Life and Figure 7.2.1-1 Response Time per ASME B31.8S-2018 [2] for MAOP=30% SMYS, API 5L Grade X52 Steel, CR = 16 mpy (Growth with Constant Length).

5.1.2 Example with Conservative CR Determined from ILI

The justification for a pipeline's reinspection interval depends on knowledge of the accuracy of corrosion defect measurements and having an accurate estimate of the CR. In the prior example, a CR of 16 mpy was used. This is overly conservative because the basis for this value came from buried steel samples with no external coating and no CP, which is uncommon for natural gas pipelines.

It would be better practice to obtain CRs by comparing the dimensions of corrosion features identified during successive ILIs. CRs obtained from comparing individual corrosion features in successive ILI inspections using various matching and data alignment processes have been widely accepted as an accurate method for estimating corrosion growth. CRs are essential in quantifying repairs necessary to maintain the Safe Operating Pressure of corroded pipe to a level not less than the established MAOP before scheduled reassessments and optimizing re-inspection intervals.

To determine a CR specific to natural gas transmission pipelines, Kiefner compiled historical data from its CorroSure software[1], which was used to determine CR from consecutive ILI runs for different clients. CorroSure correlates data from ILI Excel tabular feature listings using axial distance and circumferential orientation coordinates for ILI events (boxes or clusters) along with their respective depth, length, and width dimensions. The overall pattern for ILI features is aligned and correlated per individual joint, and the software identifies each data point. The results are then analyzed to obtain a statistically significant upper-bound CR value for application in the present study.

Each correlated ILI data set had a period of seven years in between each run. Kiefner used magnetic flux leakage (MFL) runs from 26 different pipeline segments with various diameters, wall thicknesses, and locations (different soil conditions) to obtain reasonable CRs for U.S. natural gas pipelines in operation. The results were divided into external and internal metal loss rates, with decidedly more data available for external rates. This analysis assumed that the CRs are linear (constant rate with time). However, there will always be variability for any given pipeline because CRs depend on the local corrosion mechanisms and variable environmental conditions.

Using an upper bound CR, defined as average CR plus three standard deviations, results in 99.7% of the population being within this value based on the sample data. This provides conservatism in the analysis without being overly unrealistic. The results of the assessment of 26 pipeline segments with 95,911 external metal loss features and 1,533 internal metal loss features are presented in Table 3.

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[1] CorruSure correlates two ILI data sets and is a function of Kiefner's LaserSure(TM) software.

Table 3. Corrosion Rates (CRs) for External and Internal Metal Loss (ML) on Gas Transmission Pipelines, as Determined Using Kiefner's CorroSure Software to Correlate Features from 26 Consecutive ILI Runs for Different Operators.

Metal Loss Data from ILI	**External ML CR (mpy)**	**Internal ML CR (mpy)**
Average	1.58	1.71
Standard Deviation	2.46	2.76
3 Standard Deviations	7.38	8.28
Upper Bound CR	8.96	9.99
Number of Features (N)	**95,911**	**1,533**

An analysis with a realistic but conservative CR for external metal loss (8.96 mpy for 99.7% of the flaw population) was performed to further evaluate the effects of pipe wall thickness (0.218-inches and 0.500-inches). Previously, it was shown that the pipe diameter did not have a large effect, so one diameter was selected (20-inch). Scenarios were run for pipe operating at MAOP = 30%, 50%, and 72% SMYS. Figure 5 shows that the three RL curves of the thinner pipe (0.218-inch) coincided with the three RT curves. This is still non-conservative for integrity management purposes because the RT should be much shorter than the RL. For the thicker pipe (0.500 inches), the RL is conservatively much larger than the RT.

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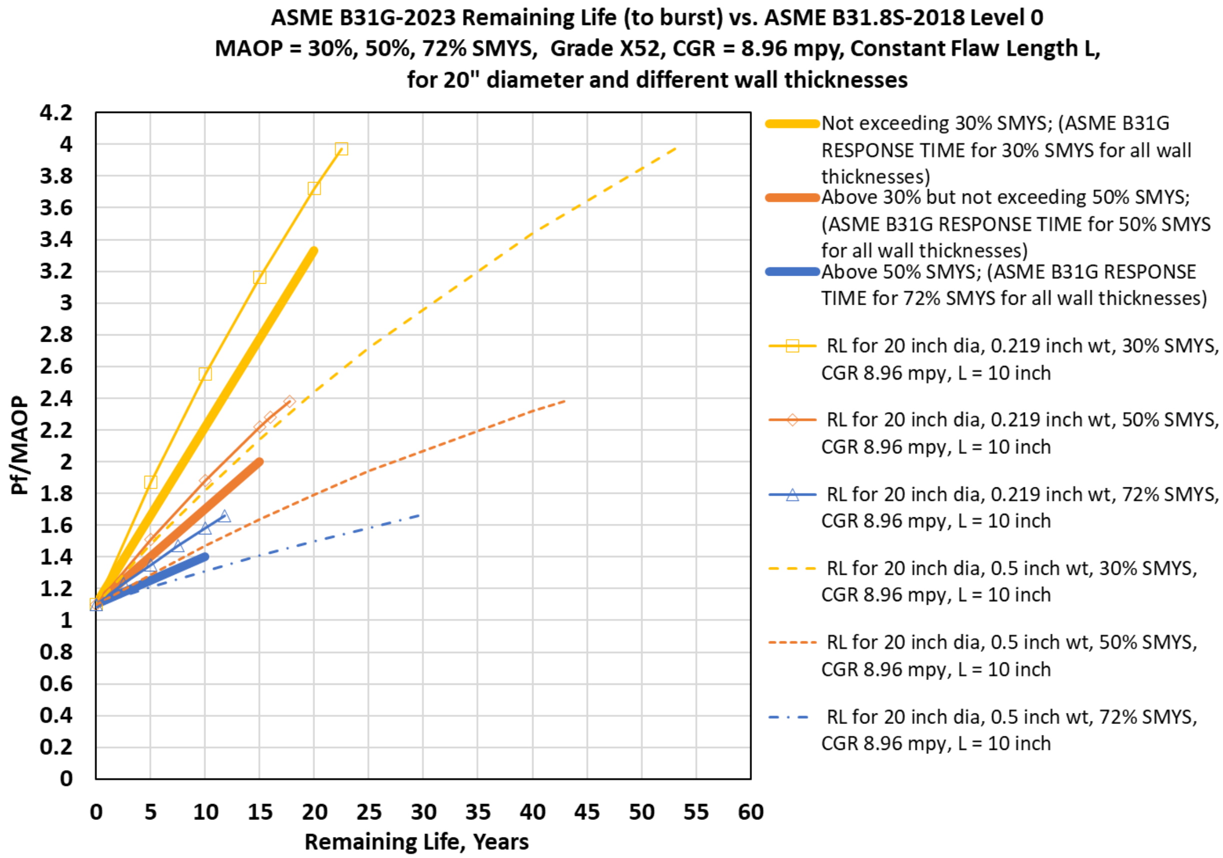

Figure 5. Effect of Wall Thickness on Calculated Remaining Life and Figure 7.2.1-1 Response Time per ASME B31.8S-2018 [2] for MAOP=30%, 50%, and 72% SMYS, API 5L Grade X52 Steel, CR = 8.96 mpy (Growth with Constant Length).

The implications of using an unrealistic CR in ILI analysis can be significant. On the one hand, anomalies assessed with a "too high" CR may appear near failure and be marked as candidates for excavation and response. On the other hand, those same anomalies assessed with a "too low" CR may appear to be far from failure and be discarded as non-critical until the next reinspection/reassessment. One technique to determine CRs for the specific pipeline being analyzed is ILI run-to-run comparison to determine its average CR and standard deviation for the recent period. It is recommended that ILI anomalies be assessed with a most realistic CR while considering the possible variability in CRs to assess the risk of overestimating or underestimating current criticality and future remaining life.

5.2 ASME B31.8S-2018 Integrity Assessment Intervals Compared with API 570-2023 Inspection Intervals

The integrity assessment intervals ASME B31.8S-2018 Table 5.6.1-1 are based on the P_f/MAOP ratio for a presently existing metal loss flaw but do not explicitly consider CR. It is helpful to compare this with the approach taken in the API 570-2023 Piping Inspection Code [9]. API 570-2023 is based on monitoring a representative sampling of inspection locations on selected piping with the specific intent to reveal a reasonably accurate assessment of the condition of the piping. This approach is similar to running and rerunning ILI inspections to reveal the condition of a pipeline.

API 570-2023 requires that scheduled inspections be conducted on or before their due date[2] or be considered overdue for inspection. The date may be established by rule-based inspection methodologies (e.g., fixed intervals, retirement half-life interval, or retirement date), risk-based methodologies (e.g., RBI target date), Fitness-For-Service (FFS) analysis results, owner-operator inspection agency practices/procedures/guidelines, or any combination thereof.

API 570-2023 Section 6.3.3 requires that for programs not using Risk Based Inspection (RBI)[3] concepts, the interval between piping inspections should be established and maintained by using the following criteria:

(a) the corrosion rate and remaining life calculations;

(b) the piping service classification;

   a. Classes 1 through 4, where Class 1 has the highest potential consequences if failure or loss of containment should occur. On-site hydrogen, fuel gas, and natural gas are included with Class 2 services.

   b. Generally, the higher classified systems require more extensive inspection at shorter intervals to affirm their integrity for continued safe operation.

   c. Classifications should be based on potential safety and environmental effects should a leak occur.

(c) and the judgment of the inspector, the piping engineer, the piping engineer supervisor, or a corrosion specialist based on operating conditions, previous inspection history, current inspection results, and conditions that may warrant supplemental inspections.

To determine the next inspection interval, a combination of conditions is used based on a corrosion rate determination (API 570 Section 7.1), a remaining life calculation (API 570 Section 7.2), and a recommended maximum inspection interval (API 570 Section 6.3.3).

[2] API 570-2023 defines the due date as the date established by the owner-operator and in accordance with this code, whereby an inspection, test, examination, or inspection recommendation falls due or is to be completed.
[3] API 570-2023 defines RBI as a risk assessment and management process that considers both the probability of failure and the consequence of failure due to material deterioration.

The relevant paragraphs for CR determination, RL calculations, and recommended RI intervals are reproduced below as Figure 6, Figure 7, and Table 4, respectively.

7 Inspection Data Evaluation, Analysis, and Recording

7.1 Corrosion Rate Determination

7.1.1 General

The owner-operator may use either the point-to-point analysis method or a statistical analysis method, or a combination of both, to determine the LT or short-term (ST) corrosion rates.

7.1.2 Point-to-Point Method

The LT corrosion rate of an individual CML shall be calculated from the following formula:

$$\text{Corrosion rate (LT)} = \frac{t_{\text{initial}} - t_{\text{actual}}}{\text{time (years) between } t_{\text{initial}} \text{ and } t_{\text{actual}}}$$

The ST corrosion rate of an individual CML shall be calculated from the following formula:

$$\text{Corrosion rate (ST)} = \frac{t_{\text{previous}} - t_{\text{actual}}}{\text{time (years) between } t_{\text{previous}} \text{ and } t_{\text{actual}}}$$

where

t_{initial} is the thickness, in inches (millimeters), at the same location as tactual measured at initial installation or at the commencement of a new corrosion rate environment;

t_{previous} is the thickness, in inches (millimeters), at the same location as tactual measured during one or more previous inspections.

Figure 6. API 570-2023 Corrosion Rate Determination [9]

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7.2 Remaining Life Calculations

The remaining life shall be calculated from the following formula:

$$\text{Remaining life (years)} = \frac{t_{\text{actual}} - t_{\text{required}}}{\text{corrosion rate [inches (mm) per year]}}$$

where

t_{actual} is the actual thickness, in inches (millimeters), measured at the time of inspection for a given location or component as specified in 5.7.

t_{required} is the required thickness, in inches (millimeters), at the same location or component as the actual measurement computed by the design formulas (e.g. pressure and structural) before corrosion allowance and manufacturer's tolerance are added.

Figure 7. API 570-2023 Remaining Life Calculations [9]

Table 4. API 570-2023 Recommended Maximum Inspection Intervals [9]

Table 1—Recommended Maximum Inspection Intervals [c]

Type of Circuit	Thickness Measurements	Visual External
Class 1	5 years	5 years
Class 2	10 years	5 years
Class 3	10 years	10 years
Class 4	Optional	Optional
Injection points [a]	3 years	By class
SAIs [b]	—	By class

NOTE Thickness measurements apply to systems for which CMLs have been established in accordance with 5.6.

[a] Inspection intervals or due dates for potentially corrosive injection/mix points can also be established by a valid RBI analysis in accordance with API 580. Injection and mix points can be extended beyond 3 years if deemed relatively noncorrosive after review from a corrosion specialist.

[b] See API 574 for more information on SAIs.

[c] The maximum inspection intervals can be modified by the owner-operator with the application of RBI that meets the requirements contained in API 580.

As an example of determining the RI using the API 570 method, a case with low long-term (LT) and short-term (ST) CRs is considered. The RL will be more than 20 years, and ½ RL (half-life concept) will be greater than 10 years. Based on Table 4 (API 570-2023 Table 1) above, the next visual inspection and the next thickness measurement inspection shall be completed no later than 10 years from the date of each of the last inspections. They may be done sooner or be completed at the same time.

The point is that the determination of the RI is based on CRs. This assumes at least two data sets are available for the same condition monitoring location (CML) to calculate a CR. Similarly, for ILI, it would be assumed that a metal loss (ML) flaw was detected in two consecutive runs.

This example is for a corrosion metal loss flaw. For anomalies caused by other integrity threats, there may be different methods to determine a growth rate. Possible cracking mechanisms should be considered for anomalies in hydrogen-carrying pipelines.

6 HYDROGEN EFFECTS

A short explanation of the terminology used for ambient-temperature hydrogen effects for pipelines is provided here to facilitate the discussion of cracking effects in hydrogen. These effects can occur in the base metal, weld fusion metal, or weld heat-affected zone (HAZ). Some are named after their mechanism, and others after the source of hydrogen.

- Hydrogen ingress:
    - Occurs when hydrogen atoms available at a metal surface diffuse into a metal lattice structure.
    - The availability of hydrogen atoms at the surface depends on the kinetics of the dissociative adsorption process, in which hydrogen atoms separate from hydrogen-containing molecules and adsorb to the surface.
    - Once hydrogen atoms are produced and become adsorbed on the steel surface, the ingress of hydrogen is a function of the concentration gradient of hydrogen atoms and the diffusivity of hydrogen in the metal.
    - Hydrogen ingress is a diffusion process influenced by several factors, such as temperature, pressure, material composition, and surface conditions.
    - Hydrogen atoms can readily occupy the interstitial spaces in metal lattices and settle into octahedral or tetrahedral sites, causing lattice expansion as it gets absorbed.
    - Once inside the metal, hydrogen atoms diffuse through the material, often settling in areas of high stress/high strain which have "free volume," such as grain boundaries, dislocations, or voids in the metal's lattice structure.
    - Hydrogen preferentially diffuses to and concentrates in areas with elevated stress/strain.
    - The presence of hydrogen atoms in a metal matrix does not necessarily affect the material properties, nor does it necessarily cause cracking.
    - Different metals and alloys have varying susceptibilities to hydrogen ingress.

- Hydrogen embrittlement (HE):
    - Hydrogen atoms within the steel matrix can cause a reduction in the intrinsic fracture resistance of the material.
    - The reduction of intrinsic fracture resistance (embrittlement) by itself does not cause the formation of cracks.

- Reduction of intrinsic fracture resistance is not a visible phenomenon in the metal microstructure. It only becomes apparent in the stress/strain response when the material is plastically deformed, i.e., the stress/strain to cause crack formation is reduced.
    - Hydrogen ingress is reversible with heat treatment (outgassing) and/or time, leaving no permanent damage.
    - The term "hydrogen embrittlement" is often used as a general indication of hydrogen-affected materials. However, this may lead to confusion. Using more precise terminology would help clarify which hydrogen effect is being described.

- Hydrogen-assisted cracking (HAC):

    - Within metals, hydrogen atoms naturally concentrate at locations with "free volume" (trapping sites) in the metal microstructure. Examples of trapping sites include vacancies, dislocations, voids, grain boundaries, precipitates and their interfaces, grain boundary triple points, phase boundaries, and crack tips either inside the metal or surface-connected.
    - At high hydrogen atom concentrations within steels, hydrogen atoms weaken the metallic bonds between iron atoms, and when those bonds are broken, micro-fissures initiate. With time, these fissures can grow and coalesce to form larger cracks.
    - HAC requires the contribution of external stress (e.g., from pressurized pipe) or internal stress (microscopic strains within the atomic lattice) to initiate and propagate cracks.
    - Static loading can cause stable crack growth to occur.
    - HAC (in which H-atoms weaken the metallic bonds between iron atoms) is a precursor to HIC (in which H-atoms recombine to H_2 at microscopic sites within the metal lattice), but HIC does not require external stress.

- Hydrogen-induced cracking (HIC):

    - When hydrogen atoms within a metal recombine, the newly formed hydrogen gas molecules occupy more space. The partial pressure within small trapping sites and narrow cracks can be exceedingly large. This results in large, localized stresses that cause those features to open and grow.
    - Although external stress may accelerate the process, HIC does not require external stress. Rather, the internal stresses from the formation of hydrogen molecules within the metal are sufficient to cause HIC.
    - HIC cracks are generally oriented parallel to the rolling direction of (pipeline) steels, which is parallel to the pipe outside diameter (OD) / inside diameter (ID) surfaces.
    - When multiple HIC cracks connect, they do so in a step-wise morphology, also known as step-wise cracking (SWC).

- HAC (in which H-atoms weaken the metallic bonds between iron atoms) is a precursor to HIC (in which H-atoms recombine to H2 at microscopic sites within the metal lattice).

- Hydrogen blistering (of steel)

    - Hydrogen blistering refers to the phenomenon that hydrogen gas molecules form due to recombination of hydrogen atoms within steels.
    - Hydrogen blistering is an advanced stage of HIC, which can occur when a large amount of hydrogen gas forms within cracks, voids, or at laminations. This increases the local pressure within the crack/void/lamination and in ductile steels this can result in the faces separating and hydrogen blisters forming.
    - No external stress is required for hydrogen blistering to occur.
    - Blisters split the metal along the rolling direction and are physically apparent as bulges on the ID or OD steel surface.
    - Blisters can initiate at mid-wall, or closer to the ID or OD of the pipe.
    - Hydrogen blistering is not reversible

- Hydrogen Stress Cracking (HSC):

    - HSC is a form of HIC where external tensile stress exacerbates the mechanism and where cracks form in the direction perpendicular to the stress.
    - For pipelines, the largest tensile stress is normally the hoop stress. Thus, HSC cracks are generally perpendicular to the pipe OD/ID surfaces.

- Stress-Oriented HIC (SOHIC):

    - SOHIC is a form of HIC where external tensile stress exacerbates the mechanism.
    - SOHIC has been observed in spiral-welded and longitudinally welded line pipe materials.
    - For pipelines, the largest tensile stress is normally the hoop stress. Thus, SOHIC cracks are generally oriented parallel to the pipe OD/ID surfaces. In spiral-welded pipe, SOHIC can be oriented diagonally to the pipe cylinder axis.

- Sulfide Stress Cracking (SSC):

    - A combination of the above-described HAC, HIC, and/or SOHIC, but with the distinction that the source of hydrogen is corrosion in a wet hydrogen sulfide (H_2S) environment.
    - The manifestation of SSC is crack extension under static loading.

- Hydrogen-Enhanced Cracking (HEC):

    - An accelerated crack growth rate for a cracking mechanism otherwise not associated with hydrogen.

- Steels can be **<u>susceptible to crack extension under static loading</u>** in a hydrogen environment, where no crack extension would occur in a benign (natural gas) environment.
- It is known that **<u>fatigue crack growth rates (FCGRs) can be accelerated</u>** in the presence of hydrogen. This has been codified in ASME B31.12-2023 [10].
  - Susceptibility to accelerated FCGR can occur even at low partial pressures of hydrogen [11].
- It is suspected that certain forms of **<u>stress corrosion cracking (SCC) can be accelerated</u>** in the presence of hydrogen.
  - The influence of hydrogen on SCC, as an essential step in the corrosion process or as a contributing factor to an accelerated growth rate, is often inferred but is challenging to prove.
  - Hydrogen atoms from the pipe's ID surface can migrate through the metal and concentrate around the tips of external cracks, such as external SCC from water trapped under disbonded coatings.
- Specifically for pipelines, in the case of near-neutral-pH SCC (nnpH SCC) and high-pH SCC, the key to understanding is that the interactions between hydrogen gas (H_2), carbon dioxide gas (CO_2) and water (H_2O) give rise to the chemical reactions involving their intermediates carbonic acid (H_2CO_3), bicarbonate (HCO_3^-) and carbonate (CO_3^{2-}) [12]. Note the difference in the number of hydrogen atoms. If additional hydrogen atoms are supplied from an external source, it may influence SCC growth rates.

  - H_2O (liquid) + CO_2 (gas) ⇌ H_2CO_3 (carbonic acid)
    - pH < 4.3
    - At pH 4.3, only dissolved carbon dioxide (gas) or carbonic acid is present.

  - 2 H_2CO_3 (carbonic acid) ⇌ 2 HCO_3^- (bicarbonate ion) + 2 H^+
    - pH 4.3 to 8.3
    - Between pH 4.3 and 8.3, only carbonic acid and bicarbonate ions are present, with the proportion of each species dependent on the pH.
    - At pH 6.3, the concentrations of each are equal (at pH 6.3, a buffer is formed).
    - ***Near-neutral pH SCC susceptibility of carbon steel***
    - At pH 8.3, only bicarbonate ions are present.

  - 2 HCO_3^- (bicarbonate ion) ⇌ 2 CO_3^{2-} (carbonate) + 2 H^+
    - pH 8.3 to 12.3
    - Between pH 8.3 and 12.3, only bicarbonate and carbonate ions are present, with the proportion of each species dependent on the pH.
    - At pH 10.3, the concentrations of bicarbonate and carbonate ions are equal (at pH 10.3, a buffer is formed).
    - ***High-pH SCC susceptibility of carbon steel***

- At pH 12.3, only carbonate ions are present

- CO_3^{2-} (carbonate) in water
  - pH >12.3
  - The pH of a carbonate solution (i.e., sodium carbonate) is approximately 12.3.

A summary of the hydrogen terminology is given in Table 5.

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Table 5. Summary of Hydrogen Terminology

Terminology	External Environment	External Stress Required?	Cracks	Visible in Microstructure?	Reversible
Hydrogen ingress	H_2-containing gas	Not Needed	NO	NO - Ingress is Invisible	YES
Hydrogen embrittlement (HE)	H_2-containing gas	Not Needed	NO	NO - Embrittlement is Invisible	YES
Hydrogen-assisted cracking (HAC)	H_2-containing gas	YES, Either External or Internal Stress	YES	YES - Buried Cracks Inside Metal, or Surface Cracks	NO
Hydrogen-induced cracking (HIC)	H_2-containing gas	NO, but HIC may Accelerate if YES	YES	YES - Buried Cracks Inside Metal	NO
Hydrogen blistering	H_2-containing gas	NO	YES	YES – As Blisters	NO
Hydrogen stress cracking (HSC)	H_2-containing gas	YES, or Residual Stress	YES	YES - Buried Cracks Inside Metal, Can be Associated to Weld	NO
Stress-oriented HIC (SOHIC)	H_2-containing gas	YES	YES	YES - Buried Cracks Inside Metal, Parallel to Stress	NO
Sulfide stress cracking (SSC)	H_2S and water	YES	YES	YES - Surface Cracks	NO
Hydrogen-enhanced cracking (HEC)	H_2-containing gas	YES, Cyclic (Fatigue) or Static (SCC)	YES	YES - Surface Cracks	NO

7 ASME B31.8S REVIEW OF POTENTIAL THREATS TO INTEGRITY

7.1 Review of Integrity Threat Classification

ASME B31.8S-2018 states that the first step in managing integrity is identifying potential threats to integrity, and all threats shall be considered. The ASME B31.8S-2018 Paragraph 2.2 identifies a total of 22 threats, of which one is "unknown." The remaining 21 threats are grouped into nine related failure types according to their nature and growth characteristics. This is further delineated by three time-related defect types.

The list of threats was based on research by the Pipeline Research Committee International (PRCI)[4]. Except for minor tweaks, the list has not changed much since the original issue of the Code Supplement, ASME B31.8S-2001 [13]. Two different words are used, and more specificity is provided for girth welds and weather-related and outside force threats. The differences include:

- Use of the word "resident" instead of "stable" threat:
    - Revised description: (b) Resident (2) Welding/ fabrication related (a) "defective pipe girth weld (circumferential) including branch and T-joints" instead of "defective pipe girth weld".
- Use of the words "random or time independent" instead of "time independent":
    - Revised description: (c) Random or Time Independent (3) Weather-related and outside force (a) "excessive hot or cold weather (outside the design range)" instead of "cold weather".
    - Added description: (c) Random or Time Independent (3) Weather-related and outside force (b) "high wind".
    - Revised description: (c) Random or Time Independent (3) Weather-related and outside force (c) "hydrotechnical: water-related threats" instead of "heavy rains or floods".
    - Revised description: (c) Random or Time Independent (3) Weather-related and outside force (d) "geotechnical: earth movement threats" instead of "earth movements".

[4] Current name: Pipeline Research Council International (PRCI). Previously known as the Pipeline Research Committee of the American Gas Association (AGA).

- Renumbered: (c) Random or Time Independent (3) Weather-related and outside force "(e) lightning" instead of "(b) lightning".

To further analyze the threats, an analysis was performed based on recent research (2022) on the causes of crack failures in pipelines published in the PRCI Report PR-276-241503-R01 [14]. These data included failures from the 1960s through 2021. 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 8 and the distribution of mechanical root causes is shown in Figure 9.

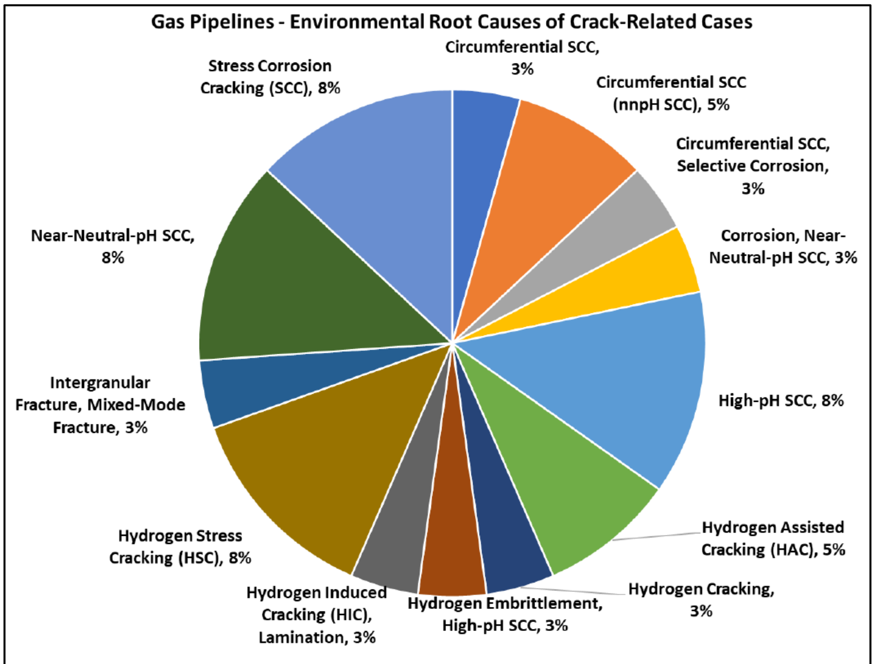

Figure 8 Distribution environmental root causes of crack-related cases for gas pipelines

Figure 8. "Figure 8" from PRCI Report PR-276-241503-R01, Data Through 2021 [14]

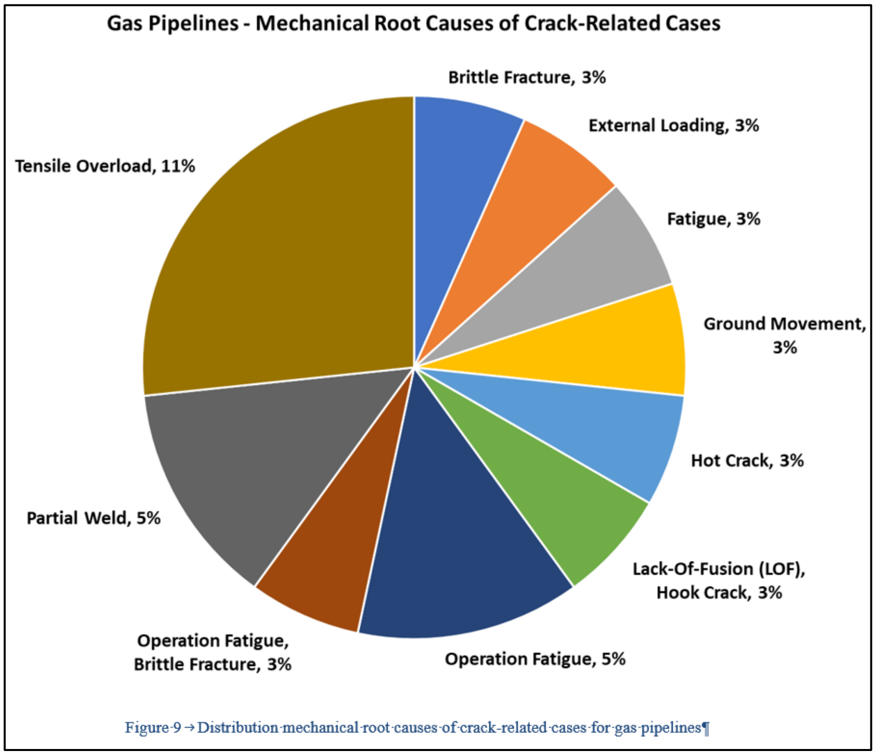

Figure 9. "Figure 9" from PRCI Report PR-276-241503-R01; Data Through 2021 [14]

7.2 Updated Threats Mapped Versus Hydrogen Integrity Threats

The PRCI report analyzed gas pipeline failure causes, which can be related to generally applicable threats to pipeline integrity. In the present project's Task 1 Final Report [1], various industry documents were cited. The following is a list of the documents reviewed in relation to threat identification, and the versions used are noted:

- NACE SP0102 In-Line Inspection of Pipelines (2017) [15]
- API RP 1176 Assessment and Management of Cracking in Pipelines (2016) [16]
- PRCI Pipeline Repair Manual (2021) [17]
- API 579-1/ASME FFS-1 Fitness-For-Service (2021) [18]
- BS7910 Guide to Methods for Assessing the Acceptability of Flaws in Metallic Structures (2019) [19]
- API RP 1183 Assessment and Management of Pipeline Dents (2020) [20]
- API 5L Line Pipe (46th Ed April 2018 incl. Errata 1 May 2018) [21]
- ASME B31.8 Gas Transmission and Distribution Piping Systems (2018) [3] and (2022) [22]
- ASME B31G Manual for Determining the Remaining Strength of Corroded Pipelines (2023) [7]
- API STD 620, Design and Construction of Large, Welded, Low Pressure Storage Tanks (2013 includes Addendum 1 dated 2014, Addendum 2 dated 2018) [23]

- API 1104 Welding of Pipelines and Related Facilities (2021) [24]
- ANSI/NACE MR0175/ISO 15156-2 Petroleum and Natural Gas Industries — Materials for use in H_2S-Containing Environments in Oil and Gas Production (2021) [25]
- API 2201 Safe Hot Tapping Practices in the Petroleum and Petrochemical Industries (2003 Reaffirmed: 2010 and 2-Year Extension: 2015) [26]

Kiefner's Task 1 Final Report [1] introduced some of the integrity threats missing from ASME B31.8-2004. Since the publication of the Task 1 report, Task 2 work has identified additional missing integrity threats in ASME B31.8-2018. The currently included threats, missing threats, and their relation to hydrogen-related threats are listed in Table 6. The reasoning for each of the missing threats is provided below. These missing threats were identified by evaluating possible hydrogen effects, but several are also generally applicable.

The authors of this Task 2 report recommend that the missing threats be included in a future edition of ASME B31.8S. The ASME committee should consider whether each threat should be included as a general threat or as a hydrogen-specific threat.

Table 6. Hydrogen-Related Threats Mapped Versus Integrity Threats Defined in ASME B31.8S-2018 [2]

<table>
<tr><th>#</th><th colspan="2">Integrity Threats per
ASME B31.8S-2018 Paragraph 2.2</th><th>Hydrogen-Related Threats
To Transmission Pipelines</th></tr>
<tr><td>1</td><td rowspan="3">(a) Time-Dependent</td><td>(1) External corrosion</td><td>• At external corrosion metal loss areas:
○ High stress in local thin areas
○ Selective seam weld corrosion (SSWC)</td></tr>
<tr><td>2</td><td>(2) Internal corrosion</td><td>• At internal corrosion metal loss areas:
○ High stress in local thin areas
○ Selective seam weld corrosion (SSWC)</td></tr>
<tr><td>3</td><td>(3) Stress corrosion cracking</td><td>• At service-induced cracks:
○ Stress corrosion cracking (SCC)</td></tr>
<tr><td>Y1</td><td colspan="2">NOT LISTED IN ASME B31.8S-2018
Time-Dependent – Fatigue cracking</td><td>• At service-induced cracks:
○ Pressure fluctuations/cyclic fatigue</td></tr>
<tr><td>Y2</td><td colspan="2">NOT LISTED IN ASME B31.8S-2018
Time-Dependent – Hydrogen-Induced Cracking (HIC)</td><td>• At service-induced cracks:
○ Hydrogen-Induced Cracking (HIC)</td></tr>
<tr><td>Y3</td><td colspan="2">NOT LISTED IN ASME B31.8S-2018
Time-Dependent – Fittings and sharp transitions</td><td>• At fittings and sharp transitions susceptible to crack initiation:
○ Threaded or welded fittings
○ Valves
○ Diameter transitions
○ Geometric constraints</td></tr>
</table>

#	Integrity Threats per ASME B31.8S-2018 Paragraph 2.2		Hydrogen-Related Threats To Transmission Pipelines
4	(b) Resident (1) Manufacturing related defects	(a) Defective pipe seam	• At welds: ○ Lack of fusion ○ Lack of penetration ○ Undercut ○ Under-trim/over-trim[5] ○ Porosity ○ Cold welds
Y4		***NOT LISTED IN ASME B31.8S-2018*** Low-toughness pipe seam	• At long-seam weld: ○ Low toughness
Y5		***NOT LISTED IN ASME B31.8S-2018*** Defect in or near an electric resistance welded (ERW) seam	• At long-seam weld: ○ Defect in or near an ERW seam
5		(b) Defective pipe	• At pre-existing manufacturing defects: ○ Laminations ○ Hook cracks ○ Inclusions ○ Hard spots ○ Scabs ○ Slivers ○ Blisters
6	(b) Resident (2) Welding/ fabrication related	(a) Defective pipe girth weld (circumferential) including branch and T-joints	• At welds: ○ Girth welds
7		(b) Defective fabrication weld	• At areas of elevated stress: ○ Weld residual stresses ○ Low toughness girth welds ○ Pipe manufacturing stresses
8		(c) Wrinkle bend or buckle	• At areas of elevated stress: ○ Pipeline field bends ○ Wrinkle bends
9		(d) Stripped threads/ broken pipe/coupling failure	• At areas of elevated stress: ○ Coupling
Y6		***NOT LISTED IN ASME B31.8S-2018*** Arc Burn/Strike on Pipe Body	• At areas of elevated stress: ○ Arc Burn/Strike on Pipe Body
Y7		***NOT LISTED IN ASME B31.8S-2018*** Hydrogen Cracking	• In-Service Welding: ○ Hydrogen Stress Cracking

[5] API RP 1176 Assessment and Management of Cracking in Pipelines [16] explains that many ERW welds are trimmed flush to the pipe circumference. When there is excess material (under-trim) or when extra material is removed (over-trim), it may interfere with ultrasonic ILI signals. Analysis rules are used to identify cracks in poorly trimmed pipe while not calling a trim variation a crack.

#	Integrity Threats per ASME B31.8S-2018 Paragraph 2.2		Hydrogen-Related Threats To Transmission Pipelines
Y8		***NOT LISTED IN ASME B31.8S-2018*** Repair sleeves and welded fittings	• At welded sleeves and fittings: ○ Type B sleeves ○ Puddle welds
10	(b) Resident (3) Equipment	(a) Gasket O-ring failure	• Other Material/Equipment Failure: ○ Gasket O-ring failure ○ Control/relief equipment malfunction ○ Seal/pump packing failure ○ Miscellaneous
11		(b) Control/relief equipment malfunction	
12		(c) Seal/pump packing failure	
13		(d) Miscellaneous	
Y9		***NOT LISTED IN ASME B31.8S-2018*** Disbonded coating caused by hydrogen	• Other Material/Equipment Failure: ○ Disbonded coating caused by hydrogen
14	(c) Random or Time Independent (1) Third-party/ mechanical damage	(a) Damage inflicted by first, second, or third parties (instantaneous/immediate failure)	• At locations that may experience an impact
15		(b) Previously damaged pipe (delayed failure mode)	• At mechanical/third-party damage: ○ Plain (Smooth) Dent ○ Dent with Stress Concentrator ○ Dent with Corrosion ○ Multiple Dents ○ Dents in Girth or Seam Weld ○ Gouges ○ Scratches/Scrapes ○ Buckles ○ Ovalities
16		(c) Vandalism	N/A
17	(c) Random or Time Independent (2) Incorrect operational procedure	(2) Incorrect operational procedure	N/A
18	(c) Random or Time Independent (3) Weather-related and outside force	(a) Excessive hot or cold weather (outside the design range)	• At locations that may experience an impact
19		(b) High wind	N/A
20		(c) Hydro-technical: water-related threats including, but not limited to, liquefactions, floodings, channeling, scouring, erosions, floatations, breaches, surges, inundations, tsunamis, ice jams, frost heaves, and avalanches	N/A

#	Integrity Threats per ASME B31.8S-2018 Paragraph 2.2		Hydrogen-Related Threats To Transmission Pipelines
21		(d) Geotechnical: earth movement threats including, but not limited to, subsidences, extreme surface loads, seismicity, earthquakes, fault movements, mining, and mud and landslides	• At areas of elevated stress: o Earth movement
22		(e) Lightning	• At locations that may experience an electrical arc or fire: o Lightning Damage
Y10		*NOT LISTED IN ASME B31.8S-2018* Fire Damage	• At locations that may experience an electrical arc or fire: o Fire Damage

7.2.1 Missing Threat Y1: Time-dependent – Fatigue cracking

Fatigue failure refers to the weakening of a material caused by repetitive or cyclic loading, resulting in progressive and localized structural damage caused by the formation and propagation of cracks. Fatigue cracking is currently not listed. The only currently listed type of time-dependent crack growth is stress corrosion cracking (SCC).

The threat of fatigue crack growth is well-known in the pipeline industry. Cyclic pressure fatigue analysis is commonly performed for liquid pipelines that experience severe pressure cycling. Gas pipelines generally operate with less severe pressure cycles than liquid pipelines, and thus fatigue has been considered a lesser concern. However, fatigue cracking is not impossible (four reported failures in gas pipelines versus 21 reported failures in liquids lines), per the PRCI report PR-276-241503-R01 [14]. In the case of hydrogen, FCGRs can be accelerated by approximately an order of magnitude, increasing the risk of fatigue failure.

For gas pipelines, fatigue cracking was identified in 11% (4 of 36 failures) of crack-related cases as the mechanical root cause of failures. Referring to Figure 9: 8% (three failures) of fatigue crack failures were related to operational fatigue (i.e., from internal gas pressure cycling), and 3% (one failure) was caused by external loading (i.e., external force being exerted on the pipe). Within the 8% operational fatigue failures, 3% (one failure) with brittle fracture was also reported, which is evidence that the material's fracture toughness played a role.

Much research has shown hydrogen's deleterious effects on the FCGR of pipeline steels. For example, San Marchi et al. [27], in their December 2023 status report on the U.S. Department of Energy's (DOE's) HyBlend project, reported on the effects of hydrogen-assisted fatigue and fracture. They have contributed to the FCGR equations in ASME B31.12 Code Case 220 [28], which formalized fatigue design curves for gaseous hydrogen. The equations, shown below as equation (14) through equation (16), are captured in a conventional power law formulation and account for the loading ratio (R), the stress intensity factor range (ΔK), and the hydrogen gas pressure (g(P)) as a function of overall gas pressure (P).

Fatigue cracks can initiate from a sharp geometry in the pipe, such as at a weld, at a dent or gouge, at a fitting, or at a discontinuity such as a surface-breaking inclusion in the material microstructure. The FCGR depends on the severity of the pressure fluctuations and the material's susceptibility to fatigue. Accelerated FGCRs are expected for pipelines carrying gaseous hydrogen because hydrogen naturally diffuses to and concentrates in areas of elevated strain/stress, such as those occurring at a crack tip.

Thus, it is recommended to add "Time-Dependent – Fatigue cracking" as a threat in ASME B31.8S. This threat is generally applicable (not exclusive to pipelines carrying hydrogen).

7.2.2 Missing Threat Y2: Time-dependent – Hydrogen-Induced Cracking (HIC)

For pipeline operators, it will be impractical/impossible to distinguish between the precursor HAC (in which H-atoms weaken the metallic bonds between iron atoms) and the subsequent HIC (in which H-atoms recombine to H_2 at microscopic sites within the metal lattice). Suffice it to say that the result will be a risk of cracks inside the steel. HIC cracks are generally oriented parallel to the rolling direction of steels, which is also parallel to the pipe OD/ID surfaces

As described in Chapter 6, HIC does not require external stress. The internal stresses from forming hydrogen (gas) molecules within the metal are sufficient to cause HIC. This phenomenon is well-known in the oil and gas industry, traditionally for HIC caused by hydrogen absorption from aqueous sulfide corrosion (in a wet H_2S environment). However, the source of hydrogen atoms is not exclusive to a corrosion mechanism with H_2S. In gas pipelines, hydrogen atoms can originate from the dissociation of gaseous hydrogen at the pipe ID surface and ingress into the steel by diffusion.

Test Method ANSI/NACE TM0248 [29] has been developed as an accelerated test to evaluate a material's resistance to HIC. This test exposes machined steel specimens to a pH-adjusted liquid environment purged with H_2S or an H_2S/CO_2 gas mixture. The specimens are not externally stressed while they are exposed. Once the test duration has passed, the specimens are sectioned and metallographically prepared for viewing with a microscope.

Based on measurements of the visible cracks, the crack sensitivity ratio (CSR), crack length ratio (CLR), and crack thickness ratio (CTR) are then calculated (see Figure 10).

$$CSR = \frac{\Sigma\,(a \times b)}{(W \times T)} \times 100\% \tag{14}$$

$$CLR = \frac{\Sigma\,a}{W} \times 100\% \tag{15}$$

$$CTR = \frac{\Sigma\,b}{T} \times 100\% \tag{16}$$

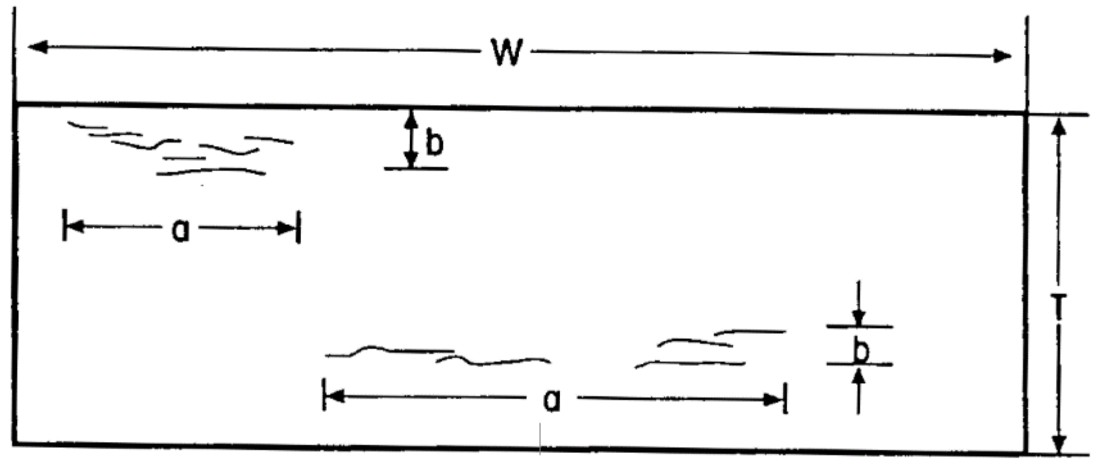

Figure 11: Test Specimen and Crack Dimensions to Be Used in Calculating CSR, CLR, and CTR

Figure 10. "Figure 11" from ANSI/NACE TM0284-2016 [29]

In ANSI/NACE TM0284-2016, it is noted that the presence or absence of HIC in the exposed specimens may be evaluated by automated ultrasonic testing prior to metallographic sectioning and examination. A procedure is provided in the test method's Nonmandatory Appendix A "Evaluation of Hydrogen Induced Cracking by Ultrasonic Testing." The procedure provides a method for determining the Crack Area Ratio (CAR) percentage as follows:

CAR % = Total Area of Indications x 100 / Area of Specimen Surface

where "Area of Specimen Surface" is the surface area of the scanned face only. For ILI applications, a measurement like the above-described CAR may be useful for characterizing the severity of possible detected HIC.

The integrity threat of HIC is self-enhancing. First, HIC cracks are initiated, but then those same HIC cracks will be susceptible to further growth by HEC.

Thus, it is recommended to add "Time-Dependent – Hydrogen-Induced Cracking (HIC)" as a threat in ASME B31.8S. This threat is applicable to pipelines carrying hydrogen.

7.2.3 Missing Threat Y3 Time-dependent – Fittings and sharp transitions

The diffusion of atomic hydrogen in steel occurs in the direction from high to low concentrations, as described by Fick's law of diffusion:

$$J_H = -D_H \frac{d\varphi_H}{dx} \tag{17}$$

Where J_H is the diffusion flux of hydrogen atoms (amount per area per time), D_H is the diffusion coefficient for hydrogen atoms in steel (area per time), and $d\varphi_H/dx$ is the hydrogen atoms concentration gradient (change in concentration per distance). This equation relates the amount of hydrogen moving through a surface area (i.e., the pipe ID surface) into the x-direction (i.e., through the pipe wall thickness).

The value of D_H differs per steel microstructure and is temperature-dependent and strain-dependent. The driving force of available hydrogen atoms at the ID surface will be continuously present in hydrogen transmission pipelines. Mohtadi-Bonab and Masoumi [30] measured the effective diffusivity D_{eff} for hydrogen in two different pipeline steels between 0.86 x 10^{-10} m^2/s and 1.84 x 10^{-10} m^2/s at ambient conditions. With hydrogen gas, pipelines are always exposed, so even at a slow absorption rate, a notable hydrogen concentration in the steel will occur over time.

Krom [31] provided calculations of hydrogen concentrations/equivalent hydrogen pressure in steel. He demonstrated that:

- For a carbon steel at 68 ^oF (20 ^oC) after only one minute of exposure, with a 0.012 inch (0.3 mm) depth, the hydrogen concentration is 95% of the concentration at the surface.
- For a 48-inch (1,219 mm) diameter pipeline, with 0.625 inch (15.9 mm) wall thickness and 1,160 psig (81 bar(a)) of hydrogen gas, the steady state hydrogen flux or permeation through the wall (if there is no oxide layer present) will be approximately 0.0019%, which is insignificant.
- Up to 2,176 psig (150 bar), the difference between the fugacity[6] and pressure of hydrogen is less than 10%. Therefore, making a pressure correction is not considered necessary (see Figure 11).
- Under steady-state conditions, steel at 68 ^oF (20 ^oC) exposed to 1,160 psig (81 bar(a)) hydrogen gas, will have a calculated equivalent hydrogen pressure of 0.25 ppm. The value of 0.25 ppm hydrogen means one hydrogen atom per one million iron atoms.
    - The equivalent hydrogen pressures for different hydrogen sources were compared (see Figure 12). Krom concluded that such high pressures in steel can result in cracking.

[6] If hydrogen gas behaves like an ideal gas, the pressure can be used. However, under frequently occurring conditions, hydrogen does not behave ideally. When the temperature is high, or pressure is low, the theoretically correct property "fugacity" should be used, which is a temperature- and pressure-corrected measure of the effective pressure.

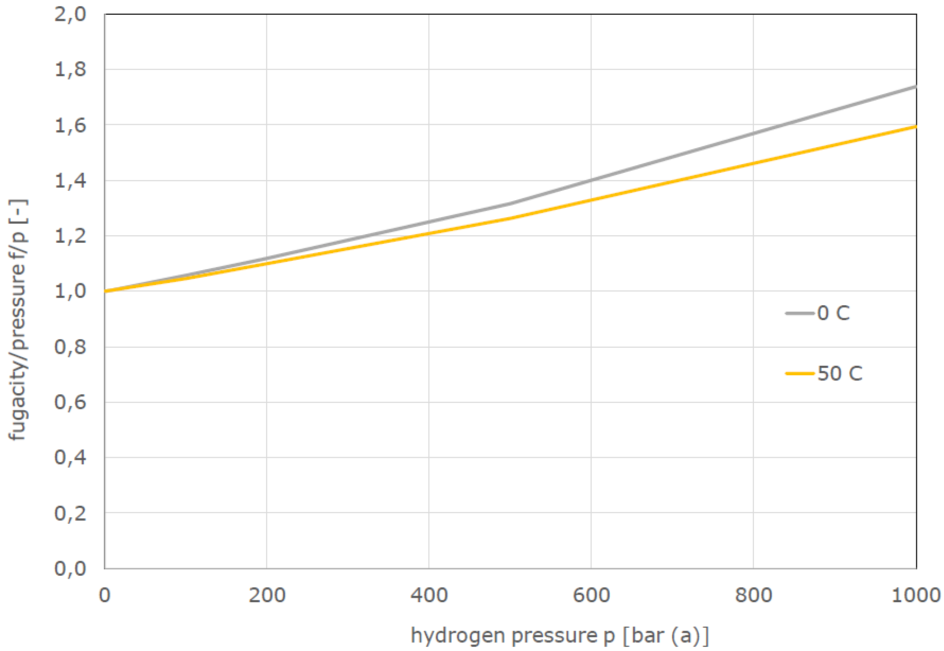

Figure 2 Relation between the fugacity and pressure of hydrogen at two temperatures

Figure 11. "Figure 2" from Krom [31]

Table 5 Examples of hydrogen concentrations in steel from different sources and calculated equivalent hydrogen pressures in a steady state (at 20 °C)

Hydrogen source	C_H [at ppm]*	equivalent hydrogen pressure [bar (a)]
81 bar H_2	0,25	81
0,01 bar H_2S [8], 0,25 wt ppm	14	7062
active cathodic protection [9] 1 wt ppm	56	11438
3 ml H_2 / 100 g welding electrode	150	14519
1 bar H_2S [10] 3,3 wt ppm	185	15493
cathodic charging [10] 11,6 wt ppm	650	19897

* 0,25 ppm H means 1 hydrogen atom per 1 million iron atoms

Figure 12. "Table 5" from Krom [31]

In addition to concentration-based diffusion, hydrogen preferentially diffuses to and concentrates in areas of elevated tensile stresses and associated tensile strains. Such areas can occur where fittings are present in the pipeline or where sharp transitions occur in the geometry. Examples include welded tees, elbows, diameter reducers, valves, threaded fittings for instrumentation, and sharp transitions (i.e., a weld toe, a gouge, or a wrinkle bend.)

Elastic strain causes the atomic lattice spacing between iron atoms to be larger, leaving more space for hydrogen to move through the interstitial spaces. In pipelines, elastic strain is primarily caused by the pipe's hoop stress from the internal gas pressure. Higher pressures produce higher strains and, accordingly, higher hydrogen mobility.

Plastic strain at a microscopic level is associated with the formation and movement of dislocations, which are various forms of stacking faults in the atomic lattice. The intricate network of entangled dislocations and the pile-up of dislocations at grain boundaries create space in the atomic lattice. In pipelines, normal operating conditions are at pressures that do not exceed the yield strength of the material. Although pipeline steels are not grossly plastically (permanently) deformed under normal operating conditions, at a microscopic scale, plastic deformations around inclusions, different metallurgical phases, or micro-fissures in the microstructure can occur. Another example is local plastic zone formation and growth around a crack tip.

Dislocation movement is also possible in the elastic loading regime, and this can cause fatigue cracks to initiate and grow. The presence of atomic hydrogen in steel enhances its FCGR. Therefore, fittings and sharp transitions become more susceptible to fatigue crack initiation and growth in pipelines transporting hydrogen gas than in pipelines carrying natural gas.

Thus, it is recommended to add "Time-Dependent – Fittings and sharp transitions" as a threat in ASME B31.8S. This threat is applicable to pipelines carrying hydrogen.

7.2.4 Missing Threat Y4 (b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – At long-seam weld – Low-toughness seam

In ASME B31.8S-2018, the threat classification of resident manufacturing-related defects has (b)(1)(a) defective pipe seam and (b)(1)(b) defective pipe. PRCI/DOT-sponsored research published in March 2004 [32] and January 2005 [33] on early-generation seam welds showed that typical weld-related anomalies include:

- Hook crack
- Alloy segregation
- Misalignment
- Mid-wall void
- Undertrim/overtrim
- Contact mark
- Lack of fusion
- Lack of penetration
- Undercut

- Porosity
- Cold weld

The Early Generation Seam Welds PRCI/DOT report [33] included a count of anomalies per seam weld type (see Table 7). The data were sourced from integrity analysis reports from 1995-2003. All these anomalies were physically detectable, either visibly in the microstructure, on fracture surfaces, or by non-destructive means using ILI or other non-destructive evaluation (NDE).

The "invisible" mechanical properties of welds are missing from this list: low toughness and low ductility. The pipeline industry is aware of the low fracture toughness that can occur in pre-1970s vintage line pipe seam welds. Direct current low-frequency electric resistance welded (LF-ERW) seam welds are of particular concern. Pipe with other weld types, such as flash welded (FW), single submerged arc welded (SSAW), and double submerged arc welded (DSAW) may be less susceptible, but those welds can also experience low toughness. While it may be argued that this is not necessarily a defective pipe seam, the fact is that a condition of low toughness is an integrity threat. As discussed earlier, atomic hydrogen in the steel microstructure is known to negatively affect the toughness further.

Thus, it is recommended to add "(b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Low-toughness seam" as a threat in ASME B31.8S. This threat is generally applicable (not exclusive to pipelines carrying hydrogen).

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Table 7. "Table 3" from Early Generation Seam Welds Report [33]

Table 3. List of Seam Welds and Number of Anomalies of Certain Type Found.

	ERW	FW	Lap Weld	SSAW	DSAW	TOTAL
ID or OD Hook Crack	28	33				61
Alloy Segregation	21					21
Misalignment	17					17
Other Crack	10	7		2	1	20
Mid-Wall Void	9			1		10
Over-Trim / Under-Trim	8	7				15
Repair Weld	8	1				9
Notch / Dent / Scab	5	1				6
Contact Mark(s)	5					5
Pit	4					4
Lack of Fusion	3	9	3	7		22
Roll-In Anomaly	2	3				5
Outbent Fiber	2	1				3
Seam Corrosion	1					1
Inclusion		1		2		3
Split				2		2

7.2.5 Missing Threat Y5 (b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – At long-seam weld – Defect in or near an ERW seam

Some line pipe seam weld defects are typical for resistance-welded long seams. Arc burns/contact marks and hook cracks are discussed here.

7.2.5.1 Manufacturing-Caused Arc Burns

Defects in or near an ERW seam include arc burns or contact marks from the metal rollers used to position the pipe and apply electrical current during welding in the factory. Manufacturing-caused arc burns are linear surface features parallel to the weld seam.

Manufacturing-caused arc burns can be visually recognized as shallow (~5-10%) metal loss on the pipe after removing the coating and cleaning the surface. Arc burns from manufacturing can appear on the pipe surface as lines of localized metal loss along either side of the weld center line. When metallographically cross-sectioned and etched, arc burns can be seen in the microstructure as areas of fine-grained metal connected to the pipe surface, with a texture like a HAZ and with or without metal loss. Manufacturing-caused arc burns generally do not have surface melting.

In natural gas pipelines, manufacturing-caused arc burns are not a significant integrity risk because other weld defects dominate. However, in hydrogen service, there is an increased threat of cracking at arc burns because the locally changed microstructure may have created a hard spot. Currently, ILI technologies to evaluate seam welds do not separately report manufacturing-caused arc burns. An example of an arc burn with a small crack is shown in Figure 13 [32].

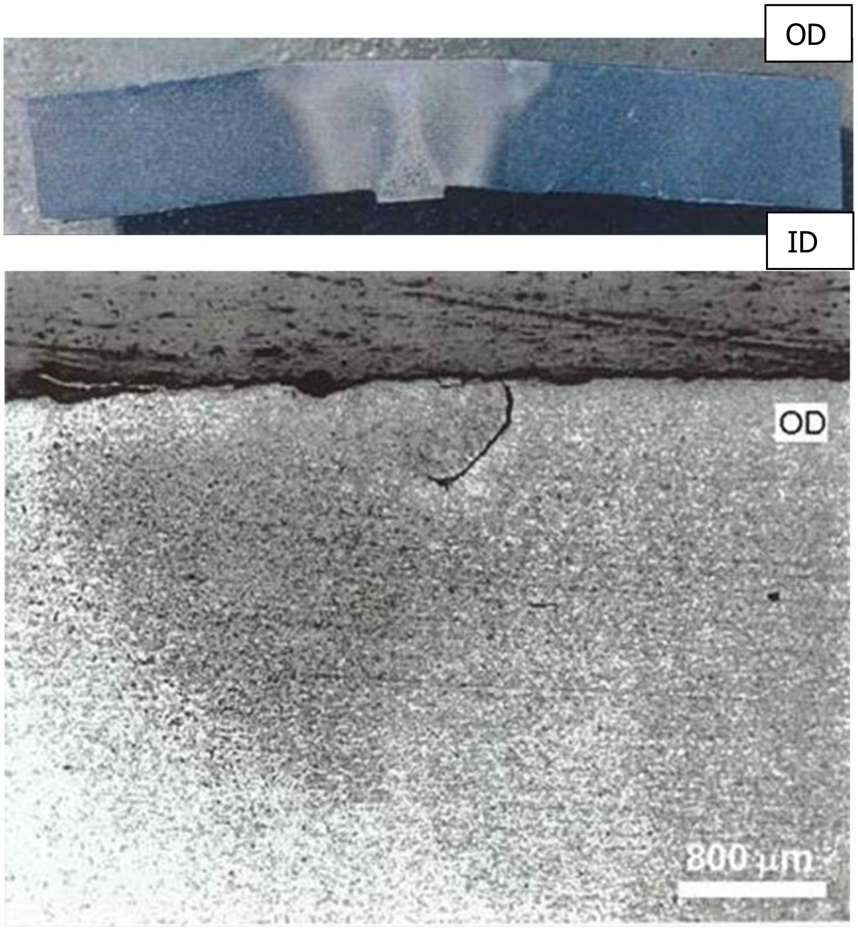

Figure 13. Example of ERW with OD Arc Burns and Small Crack [32]

7.2.5.2 Hook Cracks

Hook cracks are another example of a defect in or near an ERW seam. Youngstown Sheet & Tube ERW and AO Smith flash welded (FW) pipes are particularly susceptible. Hook cracks typically start from the pipe's ID or OD surface near the fusion line, progress on an angle into the wall following the weld flow lines, and then turn parallel to the ID/OD surface. Hook cracks usually have a depth/wall thickness ratio of 0.5 or less because they follow the flow lines formed when both sides of the pipe are pressed together during seam welding. Hook cracks form during and/or immediately after manufacturing.

The integrity threat posed by a hook crack is two-fold: (1) the hook crack reduces the pressure-carrying wall thickness and creates a lower failure pressure than the remainder of the pipe, and (2) a fatigue crack can initiate from a hook crack. A complication for the integrity assessment of hook cracks is their curved shape because most stress analysis models assume cracks are straight and oriented perpendicular to the pipe surface. In addition, the material properties at the crack tip are challenging to determine because hook cracks are located in different portions of the weld HAZ.

There have been hook crack-related failures, but those are sometimes categorized and reported as operation-fatigue failures (see Figure 9). Meanwhile, many pipelines containing hook cracks have been in service successfully. The challenge is to identify hook cracks that pose an integrity concern. ILI crack detection tools can find linear indications in seam welds. When operators choose to remove these, metallographic sectioning often confirms that these indications were hook cracks. However, in many cases, the sectioned hook cracks do not reveal visible evidence of fatigue crack growth. For the FW pipe, the extra "flash" wall thickness on the ID and OD of the pipe provides additional resistance to crack growth.

Examples of hook cracks are shown in Figure 14 [32].

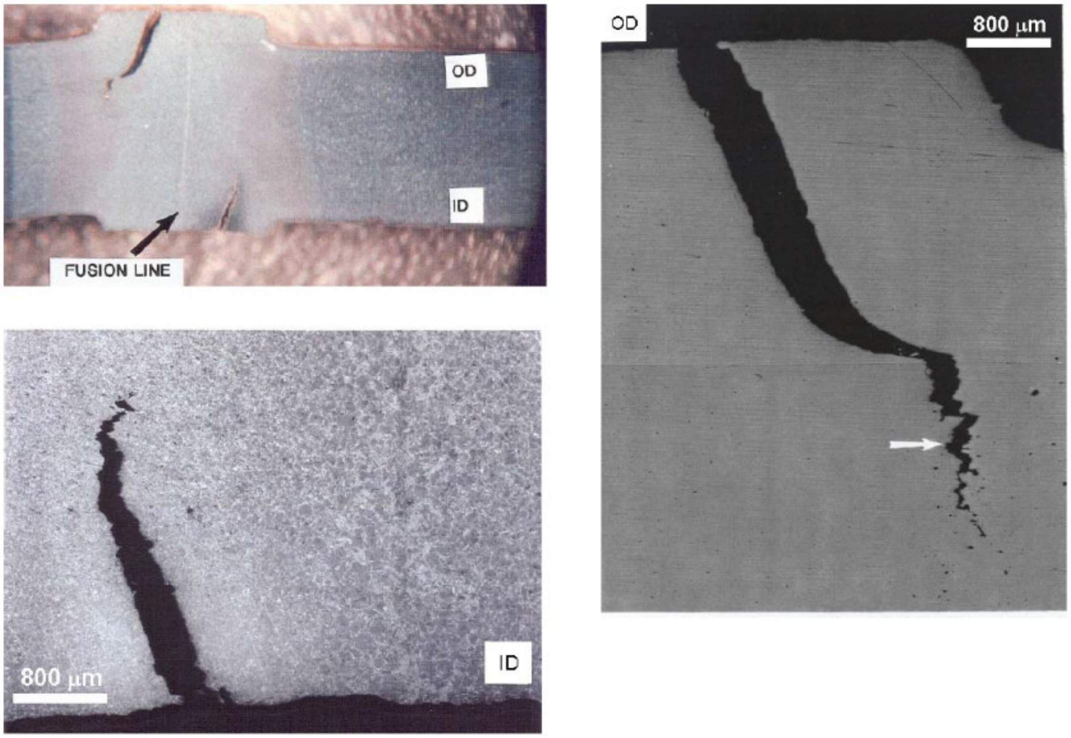

Figure 14. Examples of Hook Cracks [32]

Thus, it is recommended to add "(b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Defect in or near an ERW seam" as a threat in ASME B31.8S. This threat is generally applicable (not exclusive to pipelines carrying hydrogen).

7.2.6 Missing Threat Y6 (b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body

7.2.6.1 Fabrication-Caused Arc Burns/Strike

Arc burns/strikes can be caused during the manual fabrication of welds when the welder strikes an electrode to the pipe body. Fabrication-caused arc burns are distinct circular or oval surface features on the pipe surface.

Fabrication-caused arc burns can be visually recognized as moderately deep (~10%-30%) metal loss on the pipe after removing the coating and cleaning the surface. Arc burns from fabrication can appear on the pipe surface as a localized metal loss "pit" area, usually within a few inches of a manual weld. Some "puddle" resolidified metal may also be present around the arc burn. When metallographically cross-sectioned, arc burns can be seen in the microstructure as areas of fine-grained metal connected to the pipe surface, with a texture like a HAZ and with or without metal loss. Fabrication-caused arc burns can also be associated with localized surface melting.

In natural gas pipelines, fabrication-caused arc burns are not a significant integrity risk because of their relatively small size. However, in hydrogen service, there is an increased threat of cracking at an arc burn because the locally changed microstructure may have created a local hard spot. Magnetic flux leakage (MFL) based ILI technologies are being used to detect hard spots. Arc burns can be recognized by some ILI tools using a characteristic signature for the shape and location of such defects. Examples of arc burns/strikes are shown in Figure 15 [34].

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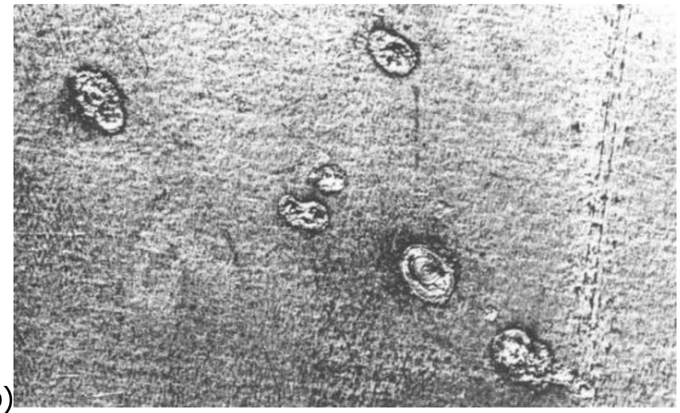
(a)  (b) 

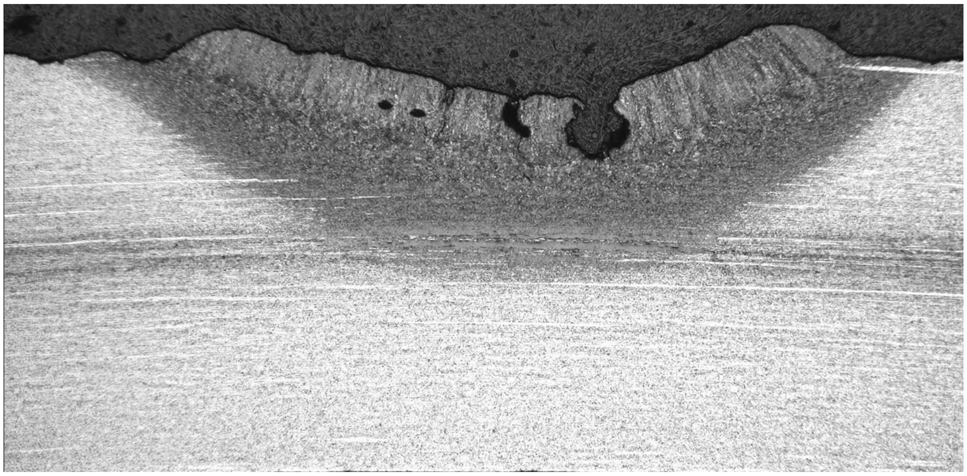
(c) 

Figure 15. Examples of Arc Burns/Strikes: (a) and (b) surface views, and (c) cross-section view [34]

Holbrook and Cialone [35] showed that a Grade X42 steel with simulated hard spots exposed to a blend of 40% hydrogen/60% methane exhibited reduced fracture resistance (both the fracture toughness, J_{IC}, [intersection of J-resistance curve and blunting line] and the tearing resistance [slope of the J-resistance curve]) compared with pure methane. The test conditions are summarized in Table 8 and Figure 16.

Table 8. "Table 2" from Holbrook and Cialone [35]

TABLE 2. SNG/HYDROGEN REFERENCE TEST GASES

	Content, volume percent				
	Methane	Hydrogen	Carbon Monoxide	Carbon Dioxide	Relative Humidity, percent
M	100				
MH	40	60			
MHC	16	60	24		
MHCC	6	60	24	10	100

All tests performed at 1000 psi.

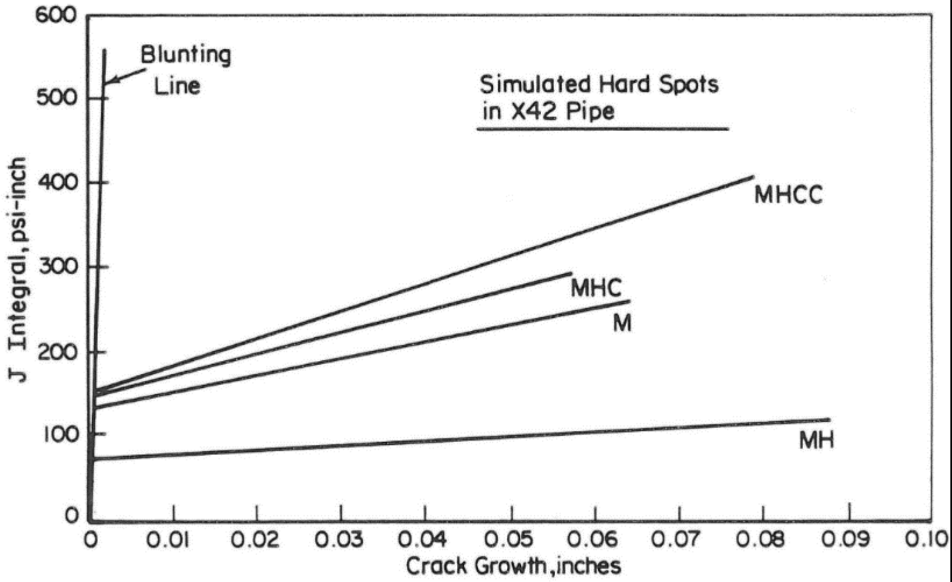


FIGURE 11. J-RESISTANCE CURVES FOR SPECIMENS FROM HARDENED X42 PIPE TESTED IN M, MH, MHC, AND MHCC ENVIRONMENTS

Figure 16. "Figure 11" from Holbrook and Cialone [35]; for gas mixtures M = 100% CH_4, MH = CH_4/H_2, MHC = $CH_4/H_2/CO$, MHCC = $CH_4/H_2/CO/CO_2$

Thus, it is recommended to add "(b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body" as a threat in ASME B31.8S. This threat is applicable to pipelines carrying hydrogen.

7.2.7 Missing Threat Y7 (b) Resident (2) Welding/fabrication related – At in-service/repair welds – (Delayed) Hydrogen Stress Cracking

ASME B31.8-2018 [3] provides repair procedures for steel pipelines. This section describes the missing threat of hydrogen stress cracking (HSC) of welds, also referred to as "cold cracking" or "delayed cracking." The principal distinguishing feature of this type of cracking is that it occurs in ferritic steels, most often immediately after welding or a short time after welding. Three factors combine to cause HSC: hydrogen generated by the welding process, a hard, brittle structure susceptible to cracking, and tensile stresses acting on the welded joints [36].

ASME B31.8-2018 Paragraph 851.4.5 allows for permanent field repair of HSC in hard spots and SCC, provided all performed repairs are tested and inspected. The standard allows repair by (a) the preferred method of cutting out and replacing with pipe of equal or greater design pressure and (b) installing a full-encirclement welded split sleeve. In the case of SCC, the fillet welds are optional. If the fillet welds are made, pressurization of the sleeve is optional. The same applies to HSC in hard spots, except that a flat hard spot shall be protected with a hardenable filler or by pressurizing a fillet-welded sleeve. SCC may also be repaired per Paragraph 851.4.2(c)(4), which describes repairs for SCC in dents.

Consistent with the description of HSC provided in Chapter 6 above, ASME B31.8-2018 defines HSC as:

> *Hydrogen Stress Cracking: cracking that results from the presence of hydrogen in a metal in combination with tensile stress. It occurs most frequently with high-strength alloys.*

Hydrogen can be introduced from water interacting with the fusion metal during welding. This can occur if wet or moist electrodes are used or welding occurs in challenging weather conditions (e.g., rain, high humidity). It can also be introduced when low-hydrogen electrodes are not used or when electrodes are not appropriately baked out before use.

When hydrogen is present in weld fusion metal, there is a high risk of HSC occurring immediately during weld cooling because of the strains from the constrained shrinking metal or at a delayed time due to the continued residual stresses in the weld. The missing threat in ASME B31.8S-2018 is the possible formation of HSC. Modern welds will have a low risk of HSC because of improved welding procedures. Older pipeline repair welds may be undocumented and have an unknown quality assurance history. Therefore, existing repair welds in vintage pipelines should be considered high risk.

Possible locations where HSC can occur and a photomicrograph showing HSC are shown in Figure 17 and Figure 18, respectively [36].

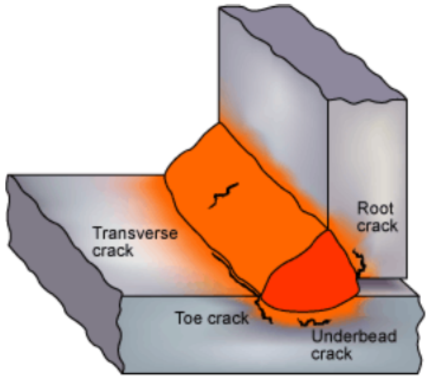


Fig. 1 Hydrogen cracks originating in the HAZ and weld metal. (Note that the type of cracks shown would not be expected to form in the same weldment.)

Figure 17. "Figure 1" from TWI Website, Showing Possible Locations for HSC to Occur [36]

Fig. 2 Crack along the coarse grain structure in the HAZ

Figure 18. "Figure 2" from TWI Website, Showing HSC [36]

Thus, it is recommended to add "(b) Resident (2) Welding/fabrication-related – At in-service/repair welds – (Delayed) Hydrogen Stress Cracking" as a threat in ASME B31.8S. This threat is generally applicable (not exclusive to pipelines carrying hydrogen).

7.2.8 Missing Threat Y8 (b) Resident (2) Welding/fabrication related – At welded sleeves and fittings – Type B sleeves and Puddle welds

ASME B31.8-2018 Paragraph 851.4.4 allows for permanent field repair of leaks and nonleaking corroded areas, provided all repairs are tested and inspected. The standard allows repair techniques for specific conditions, including (a) the preferred method of cutting out and replacing with pipe of equal or greater design pressure, (b) installation of a full-encirclement welded split sleeve, (c) a bolt-on leak clamp for a leaking corrosion pit, (d) a welded nipple and fitting for a small leak, (e) deposited weld metal from low-hydrogen electrodes for small corroded areas, and (f) a steel plate patch with rounded corners for leaking or nonleaking corroded areas.

7.2.8.1 Type B Sleeves

Type B sleeves are an acceptable repair method. None of the welding/fabrication-related threat classifications in ASME B31.8S-2018 addresses Type B sleeves, while Type B sleeves involve welding to the carrier pipe. The closest classification would be "(b) Resident (2) Welding/fabrication related (a) defective pipe girth weld (circumferential) including branch and T-joints". However, this ignores essential differences between the fillet welds on Type B sleeve ends and the full-thickness butt welds used for girth welds, branches, and T-joints. Fillet welds are not made with full penetration. A sharp weld geometry exists at the crevice between the pipe and sleeve. The Type B sleeve end welds are necessary to contain pressurized gas, as this type of sleeve is allowed to repair leaks (see Figure 19).

The 2021 Edition of the PRCI Pipeline Repair Manual [17] states that Type B sleeves should be designed to carry the full pressure of the carrier pipe and that they should be carefully fabricated and inspected to ensure integrity.

In the case of hydrogen pipelines, atomic hydrogen diffuses preferentially to and concentrates in areas of high stress/high strain which have "free volume," such as grain boundaries, dislocations, or voids in the metal's lattice structure. Such microstructural features are often even more prevalent in welds fusion metal and heat affected zones than in the surrounding base metal. In addition, Type B sleeves are allowed for leak repair. Therefore, it is conceivable that the annular space (crevice) between the carrier pipe and the repair sleeve will contain pressurized hydrogen gas like the inside of the pipe. Thus, the fillet welds will be exposed to hydrogen atoms from diffusion through the pipe wall and from the dissociation of hydrogen gas in the sleeve's annular space.

Due to the heat sink that internally flowing gas provides, it is impractical to apply post-weld heat treatment (PWHT) on in-service pipelines for welds, such as those at Type B sleeve ends. Therefore, the as-welded microstructure, residual stresses, and possibly elevated hardness will be present in the fillet welds. All these are factors in the integrity threat assessment for pipelines in hydrogen service.

Figure 16. Installation of a Type B repair sleeve.

Figure 19. "Figure 16" from PRCI Pipeline Repair Manual, Showing Welding of Type B Sleeve [17]

7.2.8.2 Puddle Welds

Different methods involving puddle welds are acceptable as repair methods. These methods include welded nipples, deposited weld metal, and steel plate patch repairs. The term "puddle" refers to a surface melting weld without through-wall penetration. Like fillet welds made to the pipe's OD surface, puddle welds will experience elevated hydrogen concentrations.

It is impractical to apply PWHT to puddle welds on in-service pipelines. Therefore, the as-welded microstructure, residual stresses, and possibly elevated hardness will be present at the puddle welds. All these are factors in the integrity threat assessment for pipelines in hydrogen service.

The 2021 Edition of the PRCI Pipeline Repair Manual [17] comments that repairing a pipeline employing deposited weld metal is not a new method. Ample evidence exists that corrosion pits in old bare pipelines were often filled with weld metal via "puddle welding." Despite early research establishing the effectiveness of weld deposition repair, this technique did not initially become widespread. Weld deposition repair appears to have been displaced in favor of using full-encirclement repair sleeves. Requirements for weld deposition repairs (referred to as "direct deposition welding") were added to Canadian Standards Association (CSA) Group CSA Z662 in the 2003 edition [37], and subsequently added to American Petroleum Institute (API) Standard API 1104 in the 21st Edition, released in 2013 [38].

To illustrate the possibility of hydrogen cracking at puddle welds, an example of HIC in a weld HAZ is shown in Figure 20 [39].

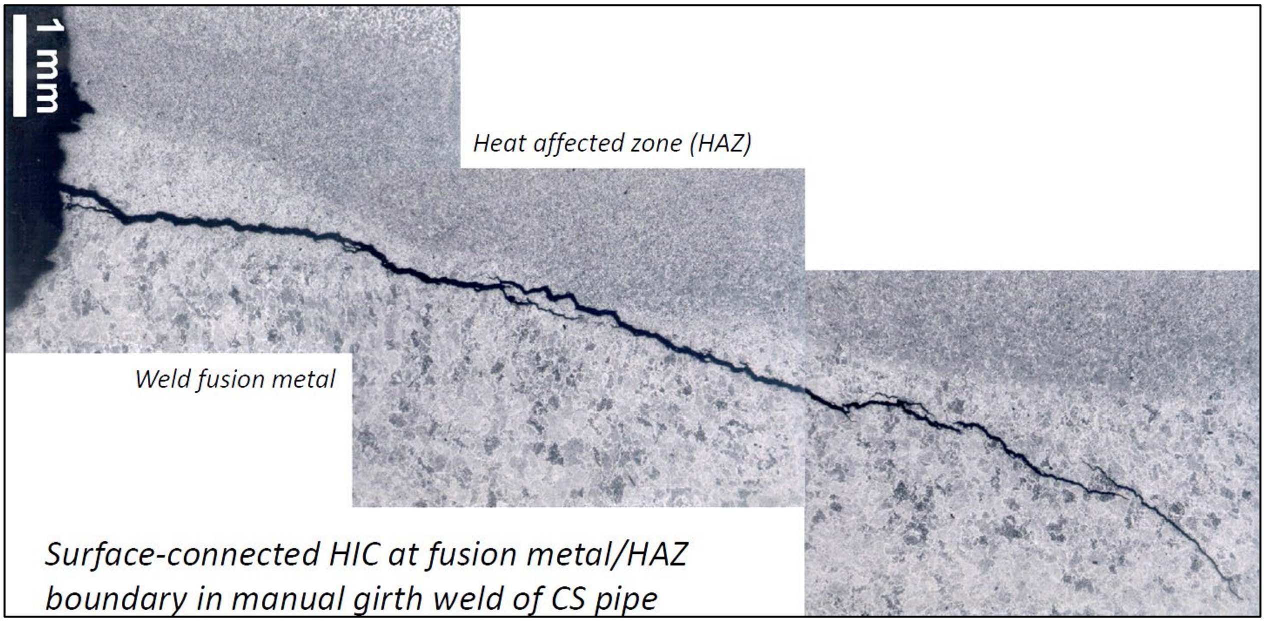


Figure 20. Example of HIC in Weld HAZ [39]

Thus, it is recommended to add "(b) Resident (2) Welding/fabrication related – At welded sleeves and fittings – Type B sleeves and Puddle welds" as a threat in ASME B31.8S. This threat is applicable to pipelines carrying hydrogen.

7.2.9 Missing Threat Y9 (b) Resident (2) Equipment – Other material/equipment failure – Disbonded coating caused by hydrogen

7.2.9.1 Hydrogen Blisters in Coatings

Hydrogen blistering of fusion-bonded epoxy (FBE) coatings is a known phenomenon in cases where hydrogen gas is trapped under the coating. The disbonded coating threat on the pipe's OD is caused by the recombination of hydrogen atoms (in the metal) to hydrogen molecules (H_2 gas) at the pipe/coating interface. The H_2 cannot diffuse through the coating, causing trapped gas to build up pressure at the interface. To accommodate the pressure, the coating locally disbonds and forms blister bubbles (see Figure 21) [40].

A pipeline not exposed to hydrogen will have a near-zero concentration of hydrogen atoms across its wall thickness. Upon exposure to hydrogen from the internal gas pressurization, molecular hydrogen on the pipe ID surface will dissociate to form atomic hydrogen. A portion of the atomic hydrogen will diffuse into the metal, creating a diffusion flux of hydrogen atoms through the wall thickness. The driving force for diffusion is the hydrogen concentration difference between the ID (high concentration) and OD (low concentration) pipe surfaces. Over time, the concentration profile through the wall thickness will equilibrate. Once the hydrogen atoms reach the pipe OD, they can recombine to form hydrogen gas molecules at the pipe/coating interface.

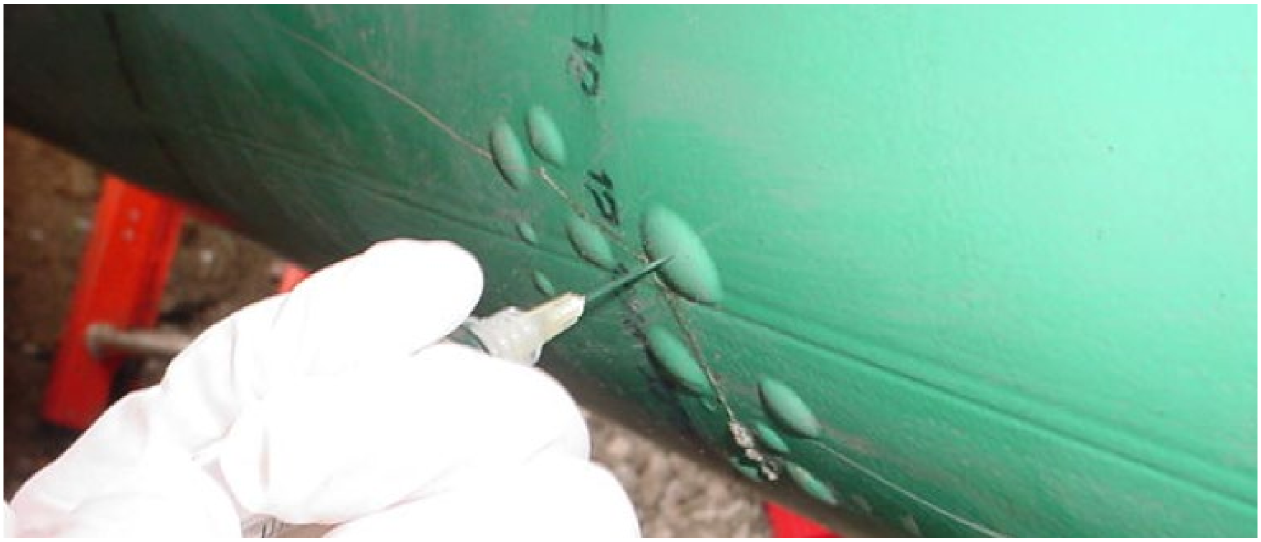


Figure 21. Example of FBE Coating Blisters [40]

Thus, it is recommended to add "(b) Resident (2) Equipment – Other material/equipment failure – Disbonded coating caused by hydrogen" as a threat in ASME B31.8S. This threat is applicable to pipelines carrying hydrogen.

7.2.10 Missing Threat Y10 (c) Random or Time Independent (3) Weather-related and outside force – At locations that may experience an electrical arc or fire – Fire Damage

7.2.10.1 Fire Damage

The mechanical strength of a line pipe steel is primarily determined by its carbon content and thermal history during manufacturing and fabrication. The pipe mill controls the microstructures of the base metal and seam welds during manufacturing, and the microstructures of girth welds result from on-site fabrication processes.

Should a pipeline experience a fire, the microstructure and mechanical properties may change from the heating and cooling. The time held above the austenite transformation temperature of 1,333 ^{o}F (723 ^{o}C) and the cooling rate will determine which phase transformations may occur. Rapid cooling (e.g., by fire water) can result in undesirable microstructures, and hard spots may result.

High temperatures can accelerate the diffusion of hydrogen into the pipeline walls. To ensure safe pipeline operation, post-fire inspections must focus on structural integrity, corrosion, and potential embrittlement. When loss-of-containment incidents occur on hydrogen-carrying infrastructure, fire is a common occurrence. Examples of more than 20 fires related to pipelines and piping are available in the European Hydrogen Incidents and Accidents Database (HIAD) [41], maintained by the HySafe International Association for Hydrogen Safety.

Fire damage is not a very large risk for natural gas pipelines because steel maintains much of its strength even after a thermal cycle. However, there may be an increased risk in hydrogen service because the rate of hydrogen diffusion through steel and the mechanical properties depend on the metal microstructure. Hydrogen decreases the overall ductility of the steel, specifically at hard spots, and hydrogen also increases crack growth rates.

Thus, it is recommended to add "(c) Random or Time Independent (3) Weather-related and outside force – At locations that may experience an electrical arc or fire – Fire Damage" as a threat in ASME B31.8S. This threat is applicable to pipelines carrying hydrogen.

8 CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations were formulated based on the results from this Task 2 review.

Review of ASME B31.8S-2018 Table 5.6.1-1 Integrity Assessment Intervals and ASME B31.8S-2018 Figure 7.2.1-1 Response Time

ASME B31.8S-2018 uses the terminology for Integrity Assessment Interval and RT interchangeably, which is incorrect. RT should refer to the time to repair or mitigate a present condition. RT should be shorter than the (re-)assessment interval (RI), which in turn should be shorter than the remaining life (RL) to reach a future critical condition.

The MAOP-coefficients and SMYS-coefficients in ASME B31.8S-2018 are not consistently chosen. For ILI inspections, ASME B31.8S-2018 requires RTs of 10, 15, and 20 years to reach a P_f of 1.00 x SMYS for MAOPs up to 30%, up to 50%, and above 50% of SMYS, respectively. The other SMYS-coefficients are also inconsistent: 0.50, 0.66, 0.70, 0.83, and 0.90 x SMYS.

A more technically sound methodology would be to: first calculate the RL to reach a P_f of "SMYS-coefficient x SMYS," then apply a Safety Factor to the RL to set an RI, and finally, set an RT for expedited mitigation of conditions with a short RI. This methodology is adopted in API 570-2023, as described in this report.

ASME B31.8S-2018 Figure 7.2.1-1 specifies the required RT for external and internal corrosion. However, the curves in the figure are independent of the pipe wall thickness and the CR, which is a shortcoming for the threat of corrosion metal loss because the mechanism reduces wall thickness with time. Example calculations using the equations from ASME B31G-2023 show that the RL for different wall thicknesses and diameters varies greatly. The RL can be much shorter than the RT for all but the thickest pipes.

It is recommended to (1) revise ASME B31.8S Table 5.6.1-1 and Figure 7.2.1-1 with consistent application of P_f and factors related to SMYS, and (2) introduce the concepts of RL and RI into the Code while maintaining the concept of RT.

Description of Hydrogen Effects

The terminology used for ambient-temperature hydrogen effects can be confusing. These effects can occur in the base metal, weld fusion metal, or weld HAZ. Some are named after their mechanism, and others after the source of hydrogen. This report describes and distinguishes each of the following terms:

• Hydrogen ingress	reversible; no cracks
• Hydrogen embrittlement (HE)	reversible; embrittles steel; no cracks
• Hydrogen-assisted cracking (HAC)	irreversible; H_2 gas micro-fissures the steel
• Hydrogen-induced cracking (HIC)	irreversible; no external stress; cracks grow
• Hydrogen stress cracking (HSC)	irreversible; with external stress; cracks grow
• Stress-oriented HIC (SOHIC)	irreversible; HSC parallel to external stress
• Sulfide stress cracking (SSC)	irreversible; source of H is wet H_2S corrosion
• Hydrogen-enhanced cracking (HEC)	H enhances SCC or fatigue crack growth rate

It is recommended to use consistent terminology when describing hydrogen effects.

Review of Potential Threats to Integrity

An analysis of the potential threats to pipeline integrity listed in ASME B31.8S-2018 showed four generally applicable and six hydrogen-applicable threats missing.

Integrity threats applicable to any gas transmission pipeline - add to ASME B31.8S Paragraph 2.2:

1. Y1 "Time-Dependent – Fatigue cracking"
2. Y4 "(b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Low-toughness seam"
3. Y5 "(b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Defect in or near an electric resistance welded (ERW) seam"
4. Y7 "(b) Resident (2) Welding/fabrication-related – At in-service/repair welds – (Delayed) Hydrogen Stress Cracking"

Integrity threats applicable to gas pipelines in hydrogen and blend service - add to future ASME B31.8S chapter on hydrogen:

5. Y2 "Time-Dependent – Hydrogen-Induced Cracking (HIC)"
6. Y3 "Time-Dependent – Fittings and sharp transitions"
7. Y6 "(b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body"
8. Y8 "(b) Resident (2) Welding/fabrication related – At welded sleeves and fittings – Type B sleeves and Puddle welds"
9. Y9 "(b) Resident (2) Equipment – Other material/equipment failure – Disbonded coating caused by hydrogen"

10. Y10 "(c) Random or Time Independent (3) Weather-related and outside force – At locations that may experience an electrical arc or fire – Fire Damage"

It is recommended to add these missing integrity threats to future versions of ASME B31.8S.

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