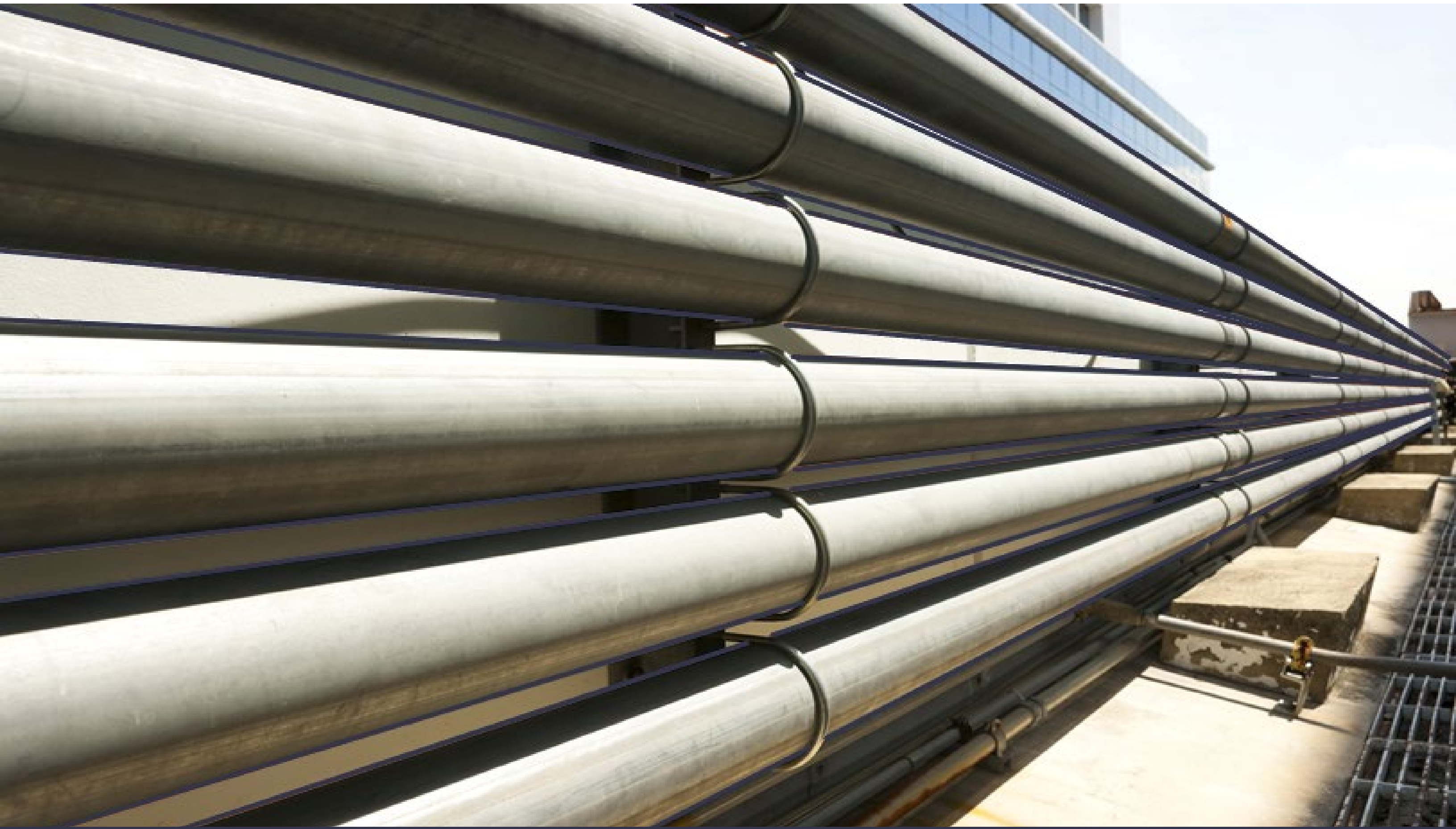
U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)
Final Report No. 25-30994-6000754R

Recommended Revisions in 49 CFR 192, ASME B31.8, and ASME B31.8S

Leslie Ward, Rick Sugden, and Michiel P. Brongers, PE,
September 9, 2025



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to

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

on

September 9, 2025

Prepared by

Leslie Ward
Senior Principal Engineer

Rick Sugden
Principal Engineer

Michiel P. Brongers, PE
Principal Engineer

Approved by

Dyke Hicks
Director of Operations

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

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Executive Summary

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

The objective of the Task 3 work was to recommend changes to 49 CFR 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, ASME B31.8 Gas Transmission and Distribution Piping Systems, and ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8). The recommended changes apply to the reassessment interval determination for defects in pipelines transporting hydrogen or hydrogen/natural gas blends as detected by in-line inspection (ILI).

Based on the analysis of Codes and Standards, review of publicly available literature, evaluation of the results of the analyses performed in Tasks 1 and 2 of this project, and the discussions included in this report, the following recommendations were formulated:

<u>For 49 CFR 192 Subpart A - General</u>

- Kiefner recommends that PHMSA remove the words "introductory text and " from Section 192.7(c)(7), because the introductory text in Section 192.907 no longer exists. Without this change, the text in 192(c)(7) is confusing.
- Kiefner recommends that PHMSA update 49 CFR 192 to incorporate by reference API STD 1163, 3rd edition for ILI systems qualification.
- Kiefner recommends that, until such additional requirements are provided in ASME B31.8S, PHMSA incorporate by reference API RP 1176, the industry-recommended practice for managing pipeline cracking, into 49 CFR 192.
- Kiefner recommends that PHMSA incorporate by reference API RP 1176 into 49 CFR 192 to require operators of hydrogen and hydrogen/natural gas blended pipelines to develop crack management plans and procedures within their integrity management programs (IMPs), based on industry-recommended practices.

<u>For 49 CFR 192 Subpart M - Maintenance</u>

- Kiefner recommends that PHMSA issue an advisory bulletin to remind operators to update their risk assessments for hydrogen considerations and perform ILI with tool technologies appropriate to detect indications susceptible to the effects of hydrogen degradation for pipelines being considered for hydrogen blending or transportation.
- Kiefner recommends that PHMSA issue an advisory bulletin to remind operators to consider the interaction of hydrogen's potentially detrimental microstructural effects on the material properties used in crack analysis models.

- Kiefner recommends that PHMSA explicitly include hydrogen effects to fatigue as a threat when determining reassessment intervals and require fatigue crack growth models to be considered within 49 CFR 192.
    - Alternatively, at a minimum, Kiefner recommends that PHMSA issue an advisory bulletin to reinforce the expectation for operators to consider the effect of hydrogen on the fatigue life in crack growth models used to determine reassessment intervals for anomalies previously considered non-susceptible to environmental effects.

<u>For 49 CFR 192 Subpart O - Gas Transmission Pipeline Integrity Management</u>

- Kiefner recommends that PHMSA issue an advisory bulletin highlighting the outcomes of recent research on hydrogen transport to remind operators of the applicable risk changes associated with hydrogen transportation in pipelines that are not purpose-built for that product.
- Kiefner recommends that PHMSA issue an advisory bulletin based on this report's findings to inform operators of their responsibility to consider the additional risks that hydrogen and hydrogen blends have on existing pipelines, including the effects of fatigue and crack growth rates, prior to converting a pipeline or transporting these products.
- Kiefner recommends that, given the additional risk imposed by hydrogen fatigue crack growth rates, the requirement should be updated to require operators to consider any change in pipeline operation or product that may change the basis of a prior analysis, perform a new cyclic fatigue analysis, and evaluate the effects of fatigue on existing anomalies within the pipeline.
- Kiefer recommends that PHMSA issue an advisory bulletin to remind operators to consider the embrittlement effects of hydrogen on crack-like anomalies and that tools capable of assessing a pipeline for cracks should be used on pipelines transporting hydrogen or hydrogen blends.
- Kiefner recommends that PHMSA update the incorporation by reference (IBR) in 192.933(d) to the 2022 edition of ASME B31.8S.

<u>For ASME B31.8 Gas Transmission and Distribution Piping Systems</u>

- Kiefner recommends supporting the balloting items being proposed and the review process being followed by the Hydrogen Task Group of ASME B31.8.

<u>For ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8)</u>

<u>*Review of Potential Threats to Integrity*</u>

- Kiefner recommends adding the following missing integrity threats applicable to any gas transmission pipeline to Paragraph 2.2 of future versions of ASME B31.8S:
    - "Time-Dependent – Fatigue Cracking"

- "(b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Low toughness seam"
    - "(b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Defect in or near an electric resistance welded (ERW) seam"
    - "(b) Resident (2) Welding/fabrication-related – At in-service/repair welds – Hydrogen stress cracking"
- Kiefner recommends adding the following missing integrity threats applicable to gas transmission pipelines in hydrogen and hydrogen blend service to the future ASME B31.8S hydrogen chapter:
    - "Time-Dependent – Hydrogen-induced cracking (HIC)"
    - "Time-Dependent – Fittings and sharp transitions"
    - "(b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body"
    - "(b) Resident (2) Welding/fabrication related – At welded sleeves and fittings – Type B sleeves and Puddle welds"
    - "(b) Resident (2) Equipment – Other material/equipment failure – Disbonded coating caused by hydrogen"
    - "(c) Random or Time Independent (3) Weather-related and outside force – At locations that may experience an electrical arc or fire – Fire damage"

Description of Hydrogen Effects

- Kiefner recommends using consistent terminology when describing hydrogen effects.
- Kiefner recommends that Table 5. Summary of Hydrogen Terminology of this Task 3 report be included in ASME B31.8S.
- Kiefner recommends adding the hydrogen terms that are not currently mentioned if they are going to be used within ASME B31.8 or ASME B31.8S (when Table 5 is added).

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

- Kiefner recommends introducing the concepts of remaining life (RL) and reinspection interval (RI) into the Code while maintaining the concept of response time (RT).
- Kiefner recommends revising ASME B31.8S-2018 Table 5.6.1-1 and Figure 7.2.1-1 with consistent application of predicted failure pressure (P_f) and factors related to the specified minimum yield strength (SMYS).
- Kiefner recommends that ILI anomalies be assessed with a more realistic corrosion rate (CR) while considering the possible variability in CRs to assess the risk of overestimating or underestimating current criticality and future RL.

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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
BHN	Brinell Hardness Number
BS	British Standard
CAR	Crack Area Ratio
CGR	Crack Growth Rate
CLR	Crack Length Ratio
CO_2	Carbon dioxide
CO&M	Corrosion, Operations, and Maintenance (Subgroup of ASME B31.8)
CP	Cathodic Protection
CR	Corrosion Rate
CSA	Canadian Standards Association
CSR	Crack Sensitivity Ratio
CTR	Crack Thickness Ratio
DG-ICDA	Dry Gas Internal Corrosion Direct Assessment
DSAW	Double Submerged Arc Welded
ECDA	External Corrosion Direct Assessment
EMAT	Electro-Magnetic Attenuation Testing
ERW	Electric Resistance Welded
FBE	Fusion Bonded Epoxy
FCGR	Fatigue Crack Growth Rate
FW	Flash Welded
GPS	Global Positioning System
GW	Girth Weld
H	Hydrogen (atom)
H_2	Hydrogen (molecule)
H_2S	Hydrogen sulfide
HAC	Hydrogen-Assisted Cracking
HAZ	Heat-Affected Zone
HBN	Brinell Hardness
HCA	High Consequence Area
HE	Hydrogen Embrittlement
HEC	Hydrogen-Enhanced Cracking
HIAD	European Hydrogen Incidents and Accidents Database
HIC	Hydrogen-Induced Cracking
HRB	Rockwell B Hardness
HRC	Rockwell C Hardness
HSC	Hydrogen Stress Cracking
HV	Vickers Hardness
IBR	Incorporated by Reference
ID	Inside Diameter
ILI	In-Line Inspection

IM	Integrity Management
IMP	Integrity Management Program
Kiefner	Kiefner and Associates, Inc.
LF-ERW	Low-Frequency Electric Resistance Weld
MAOP	Maximum Allowable Operating Pressure
MCA	Moderate Consequence Area
MFL	Magnetic Flux Leakage
NACE	(formerly) National Association of Corrosion Engineers (now Association for Materials Protection and Prevention (AMPP))
NDE	Non-Destructive Examination
OD	Outside Diameter
PHMSA	Pipeline and Hazardous Materials Safety Administration
PQR	Procedure Qualification Record
PRCI	Pipeline Research Council International
PWHT	Post-Weld Heat Treatment
QA	Quality Assurance
RI	Reinspection Interval
RL	Remaining Life
RP	Recommended Practice
RT	Response Time
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SMYS	Specified Minimum Yield Strength
SOHIC	Stress-Oriented Hydrogen Induced Cracking
SSAW	Single Submerged Arc Welded
SSC	Sulfide Stress Cracking
STD	Standard
USDOT	U.S. Department of Transportation
UTCD	Ultrasonic Testing Crack Detection
UTS	Ultimate Tensile Strength
WPS	Welding Procedure Specification
WT	Wall Thickness

List of Variables

J_H	Diffusion Flux of Hydrogen Atoms
D_{eff}	Effective Diffusivity
D_H	Diffusion Coefficient for Hydrogen Atoms
$d\varphi_H/dx$	Hydrogen Atom Concentration Gradient
H_f	Carbon Steel Pipeline Materials Performance Factor
J_{IC}	J-Fracture Toughness
M_f	Carbon Steel Piping Materials Performance Factor
P_f	Predicted Failure Pressure
S	Stress

1 INTRODUCTION

1.1 General

This Task 3 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.

In this task, the 'what if' methodology was applied to the review performed in Task 2, to develop recommendations to revise the requirements of Title 49 CFR 192[1] Subpart M or O, or elsewhere in the Code, and ASME B31.8S and ASME B31.12 Standards. For different threat types, recommendations for revisions were formulated based on the threat's unique characteristics. However, considering the basic premise that only if the presence of hydrogen or hydrogen-blended gas (for different percentages of hydrogen) makes it necessary, revisions should be required.

The current Code ASME B31.12 Hydrogen Piping and Pipelines is the 2023 edition[2]. ASME Standards Committees are working to incorporate the content of the ASME B31.12 standard into future editions of ASME B31.1 Power Piping, ASME B31.3 Process Piping, and ASME B31.8 Gas Transmission and Distribution Piping Systems. Depending on the timing of the publication of the content from ASME B31.12 into each of the other three documents, ASME B31.12 may be revised again. As of May 7, 2025, the Hydrogen Task Group of ASME B31.8 expects that ASME B31.12 will continue to exist through 2030.

A future edition, if any, will likely incorporate ASME B31 Code Case 218[3,4], which was approved on January 3, 2023. Code Case 218 specifies for ASME B31.12 what conditions must be met to permit the use of enhanced materials performance factors, H_f and M_f, in the construction of hydrogen piping and pipelines, respectively. In Task 2 of the present work, Kiefner proposed changes to ASME B31.8-2022[5] and ASME B31.8S-2018[6] Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8). Kiefner identified four changes regardless of whether hydrogen or hydrogen-blended gas is used in a system, and six changes for hydrogen and hydrogen/blended pipelines.

In the present work, Kiefner provides recommendations for changes to requirements within 49 CFR 192 — Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, which are intended to promote public safety. The suggested changes focus on Subpart M — Maintenance and Subpart O — Gas Transmission Pipeline Integrity Management, and recommendations for one or more possible PHMSA advisory bulletins.

> *"This part (49 CFR 192) prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act ([43 U.S.C. 1331](43 U.S.C. 1331))."* [1]

Kiefner further provides recommendations for changes to industry codes, ASME B31.8-2022 Gas Transmission and Distribution Piping Systems and ASME B31.8S-2018 Managing System Integrity of Gas Pipelines (Supplement to ASME B31.8). These are both ASME Codes for Pressure Piping, ASME B31. Per the ASME website, these documents are intended to

> *"help users comply with applicable regulations within their jurisdiction, while achieving the operational, cost and safety benefits to be gained from the many industry best-practices detailed within these volumes."*

1.2 Evolution of ASME B31.8 Gas Transmission and Distribution Piping Systems

The evolution of ASME B31.8 Gas Transmission and Distribution Piping Systems is given in its "Foreword."

> *"The need for a national code for pressure piping became increasingly evident from 1915 to 1925. …After several years of work by Sectional Committee ASME B31 and its subcommittees, a first edition was published in 1935 as an American Tentative Standard Code for Pressure Piping. …Following its reorganization in 1948, Standards Committee ASME B31 made an intensive review of the 1942 Code…*
>
> *…A revision was presented for letter ballot vote of Standards Committee ASME B31. Following approval by this body, the project was approved by the sponsor organization and by the American Standards Association. It was finally designated as an American Standard, with the designation ASME B31.1-1951, in February 1951.*
>
> *At its annual meeting on November 29, 1951, Standards Committee ASME B31 authorized the separate publication of a section of the Code for Pressure Piping addressing gas transmission and distribution piping systems, to be completed with the applicable parts of Section 2, Gas and Air Piping Systems; Section 6, Fabrication Details; and Section 7, Materials - Their Specifications and Identification. The purpose was to provide an integrated document for gas transmission and distribution piping that would not require cross-referencing to other sections of the Code. The first edition of this integrated document, known as American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems, was published in 1952 and consisted almost entirely of material taken from Sections 2, 6, and 7 of the 1951 edition of the Pressure Piping Code.*
>
> *…In December 1978, the American National Standards Committee ASME B31 was reorganized as the ASME Code for Pressure Piping, ASME B31 Committee. The code designation was also changed to ANSI/ASME B31."*[7]

Periodic revisions were produced between 1955 to 2022.

As of May 23, 2025, the current version of ASME B31.8 is 2022 and includes the following high-level contents:

- *General Provisions and Definitions*
- *Chapter I Materials and Equipment*
- *Chapter II Welding*
- *Chapter III Piping System Components and Fabrication Details.*
- *Chapter IV Design, Installation, and Testing*
- *Chapter V Operating and Maintenance Procedures*
- *Chapter VI Corrosion Control*
- *Chapter VII Intentionally Left Blank*
- *Chapter VIII Offshore Gas Transmission*
- *Chapter IX Sour Gas Service*
- *Mandatory Appendices*
- *Nonmandatory Appendices*

The objectives for ASME B31.8-2022 are given in the Scope and Intent section.

ASME B31.8-2022 *"802 SCOPE AND INTENT*
802.1 Scope

> *(a) This Code covers the design, fabrication, installation, inspection, examination, and testing of pipeline facilities used for the transportation of gas. This Code also covers safety aspects of the operation and maintenance of those facilities. (See Mandatory Appendix Q for scope diagrams.) This Code is concerned only with certain safety aspects of liquefied petroleum gases when they are vaporized and used as gaseous fuels. All of the requirements of NFPA 58 and NFPA 59 and of this Code concerning design, construction, and operation and maintenance of piping facilities shall apply to piping systems handling butane, propane, or mixtures of these gases.*

802.2 Intent
802.2.3 Safety. *This Code is concerned with*

> *(a) safety of the general public.*
>
> *(b) employee safety to the extent that it is affected by basic design, quality of materials and workmanship, and requirements for testing, operations, and maintenance of gas transmission and distribution facilities. Existing industrial safety procedures pertaining to work areas, safety devices, and safe work practices are not intended to be supplanted by this Code."*

1.3 Evolution of ASME B31.8S Managing System Integrity of Gas Pipelines (Supplement to ASME B31.8)

The evolution of ASME B31.8S Managing System Integrity of Gas Pipelines (Supplement to ASME B31.8) is given in its "Foreword."

> *"The gas pipeline industry needed to address many technical concerns before an integrity management standard could be written. A number of initiatives were undertaken by the industry to answer these questions; as a result of two years of intensive work by a number of technical experts in their fields, 21 reports were issued that provided the responses required to complete the 2001 edition of this Code. (The list of these reports is included in the reference section of this Code.)*
>
> *This Code is nonmandatory and is designed to supplement ASME B31.8, Gas Transmission and Distribution Piping Systems." This Code is a process code that describes the process an operator may use to develop an integrity management program. It also provides two approaches for developing an integrity management program: a prescriptive approach and a performance- or risk-based approach. Pipeline operators in a number of countries are currently using risk-based or risk-management principles to improve the safety of their systems.*
>
> *The intent of this Code is to provide a systematic, comprehensive, and integrated approach to managing the safety and integrity of pipeline systems*."

As of May 23, 2025, the current version of ASME B31.8S is 2022[7], which includes the following contents:

1. *Introduction*
2. *Integrity Management Program Overview*
3. *Consequences*
4. *Gathering, Reviewing, and Integrating Data*
5. *Risk Assessment*
6. *Integrity Assessment*
7. *Responses to Integrity Assessments and Mitigation (Repair and Prevention)*
8. *Integrity Management Plan*
9. *Performance Plan*
10. *Communications Plan*
11. *Management of Change Plan*
12. *Quality Control Plan*
13. *Terms, Definitions, and Acronyms*

14. References and Standards

Nonmandatory Appendices

The objectives for ASME B31.8S-2022[7] are stated in the Purpose and Objectives section.

ASME B31.8S-2022 "*1 INTRODUCTION*

1.1 Scope
This Code applies to onshore pipeline systems constructed with ferrous materials and that transport gas. The principles and processes embodied in integrity management are applicable to all pipeline systems. This Code is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes. The processes and approaches described within this Code are applicable to the entire pipeline.

1.2 Purpose and Objectives

Managing the integrity of a gas pipeline system is the primary goal of every pipeline system operator. Operators want to continue providing safe and reliable delivery of natural gas to their customers without adverse effects on employees, the public, customers, or the environment. Incident-free operation has been and continues to be the gas pipeline industry's goal. The use of this Code as a supplement to ASME B31.8 will allow pipeline operators to move closer to that goal."

1.4 Relationship between ASME B31.8 and ASME B31.8S

ASME B31.8 and ASME B31.8S are standards that the American Society of Mechanical Engineers (ASME) developed for the design, operation, and integrity management of gas transmission and distribution pipelines. Their relationship is as follows:

- **ASME B31.8 Gas Transmission and Distribution Piping Systems** is the primary code governing gas pipeline design, construction, operation, and maintenance. It provides detailed requirements related to materials, welding, testing, safety, and pressure considerations.
- **ASME B31.8S Managing System Integrity of Gas Pipelines** is a supplementary standard that provides specific guidance on integrity management programs (IMPs) for pipelines covered under ASME B31.8. It focuses on risk assessment, inspection, maintenance, and mitigation strategies to enhance the safety and reliability of gas pipeline systems.

Key Relationship:

1. **Supplementary Role**: ASME B31.8S complements ASME B31.8 by providing additional requirements and best practices for the integrity management of gas pipelines.

2. **Regulatory Influence**: ASME B31.8S is often referenced by regulatory bodies (e.g., PHMSA in the U.S.) to enforce integrity management program processes in high-consequence areas (HCAs).
3. **Risk-Based and Prescriptive Approaches**: While ASME B31.8 covers the technical aspects of pipeline construction and operation, ASME B31.8S emphasizes proactive risk assessment, continuous monitoring, and preventive maintenance during pipeline operation.

During the June 4, 2025, meeting of the ASME B31.8 Corrosion, Operations & Maintenance (CO&M) Subgroup, ASME reported that the publication of the next edition of ASME B31.8 is scheduled for this summer and will be designated as the 2025 edition.

The timing of incorporating ASME B31.12 into ASME B31.8 and ASME B31.8S is targeted for ASME B31-level committee approval by April 15, 2026. There have been two ballots for changes to ASME B31.8 regarding adding content from ASME B31.12. The ASME B31.8 Hydrogen Task Group is managing these changes and ballots. The second ballot for the exception (hydrogen) changes was closed on April 28, 2025, and did not pass. The Task Group circulated a third ballot, and at the time of writing this report, the results have not been made public.

ASME B31.8 establishes the fundamental engineering and operational requirements for gas pipelines, while ASME B31.8S enhances these requirements by focusing on integrity management and safety assurance. Work on revisions for ASME B31.8S will not start until summer 2025, after this report has been submitted to PHMSA.

1.5 Relationship between ASME B31.8, ASME B31.8S, and 49 CFR 192 – Incorporated by Reference

As of the writing of this report, both ASME B31.8 and ASME B31.8S were last published in 2022. On November 20, 2018, ASME B31.8-2018 Gas Transmission and Distribution Piping Systems, incorporated by reference (IBR) per § 192.7(c)(5), was approved for:

> §§ 192.112(b) "***Additional design requirement for steel piping using alternative maximum allowable operating pressure.*** *(b) Fracture Control"* and

> 192.619(a) "***Maximum allowable operating pressure: Steel or plastic pipelines*** *(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:…"*

Effective June 28, 2024, 49 CFR 192 was updated to reference ASME B31.8S-2018 (instead of ASME B31.8S-2004), but not 100%. On November 28, 2018, ASME B31.8S-2018 Managing System Integrity of Gas Pipelines, IBR per § 192.7(c)(7), was approved for:

> §§ 192.13(d). "***What general requirements apply to pipelines regulated under this part?*** *(d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment*

through a management of change process. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME B31.8S, section 11 (incorporated by reference, see § 192.7), that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. …"

192.714(c) "***Transmission lines: Repair criteria for onshore transmission pipelines.*** *(c) Schedule for evaluation and remediation.;"*

192.903 "***What definitions apply to this subpart?"*** note to Potential impact radius (factor);

192.907 "***What must an operator do to implement this subpart?"*** introductory text and "*(b) Implementation Standards;*"

192.911 "***What are the elements of an integrity management program?*** introductory text, *(i) A performance plan as outlined in ASME B31.8S, Section 9 that includes performance measures meeting the requirements of § 192.945., (k) A management of change process as required by § 192.13(d). (l) A quality assurance process as outlined in ASME B31.8S, Section 12. (m) A communication plan that includes the elements of ASME B31.8, Paragraph 850.9 (incorporated by reference, see § 192.7), and that includes procedures for addressing safety concerns raised by—(1) OPS; and (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.;"*

192.913 "***When may an operator deviate its program from certain requirements of this subpart?*** *(a) General, (b) Exceptional Performance (c) Deviation;"*

192.917(a) through (e); ***How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?*** *(a) Threat identification.*

An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME B31.8S (incorporated by reference, see § 192.7), Section 2, which are grouped under the following four threat categories: …

(b) … In performing data gathering and integration, an operator must follow the requirements in ASME B31.8S, Section 4.

(c) ***Risk assessment.***

An operator must conduct a risk assessment that follows ASME B31.8S, Section 5, and that analyzes the identified threats and potential consequences of an incident for each covered segment.

(e)(1) ***Third party damage.*** *An operator must utilize the data integration required in [paragraph (b)] of this section and ASME/ANSI ASME B31.8S, Appendix A-8 to determine the susceptibility of each covered segment to the threat of third party damage.*

(e)(4) ***Electric Resistance Welded (ERW) pipe****.*

If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME B31.8S, Appendices A-5.3 and A-5.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding 5 years (including abnormal operation as defined in § 192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies.

192.921(a)(2)… *An operator must use the test pressures specified in Table 5.6.1-1 of Section 5 of ASME B31.8S (incorporated by reference, see § 192.7) to justify an extended reassessment interval in accordance with § 192.939.*

192.923(b)(1); ***Primary method. (Not in scope of this report)***

192.925(b); ***What are the requirements for using External Corrosion Direct Assessment (ECDA)? (Not in scope of this report)***

192.933(c); ***Schedule for evaluation and remediation.***

An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME B31.8S (incorporated by reference, see § 192.7), Section 7, Figure 7.2.1-1.

192.935(b)(iv); … *An operator must excavate, and remediate, in accordance with ASME B31.8S and § 192.933 any indication of coating holidays or discontinuity warranting direct examination.*

192.937(c)(2); …*An operator must use the test pressures specified in Table 5.6.1-1 of Section 5 of ASME B31.8S (incorporated by reference,* see *§ 192.7) to justify an extended reassessment interval in accordance with § 192.939.*

192.939(a)(1); ***Pressure test or internal inspection or other equivalent technology.***

An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by - … (ii) *Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, see § 192.7), Table 5.6.1-1 of Section 5.*

(3) ***Internal Corrosion or SCC Direct Assessment (Not in Scope of this report)***

192.945 ***What methods must an operator use to measure program effectiveness?*** (a)… *These measures must include the four overall performance measures specified in ASME/ANSI ASME B31.8S (incorporated by reference, see § 192.7 of this part), Section 9.4, and the specific measures for each identified threat specified in ASME/ANSI ASME B31.8S, Appendix A.*

As of January 14, 2005, ASME/ANSI ASME B31.8S-2004 "Supplement to ASME B31.8 on Managing System Integrity of Gas Pipelines," IBR per § 192.7(c)(6), was approved for §§ 192.714(d); 192.933(d).

192.714(d)(1) ***Immediate repair conditions.*** *An operator's evaluation and remediation schedule for immediate repair conditions must follow Section 7 of ASME/ANSI ASME B31.8S-2004 (incorporated by reference,* see *§ 192.7). An operator must repair the following conditions immediately upon discovery:…*

(2) **Two-year conditions**… (iv)… *For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI ASME B31.8S-2004 (incorporated by reference,* see *§ 192.7), Section 7, Figure 4, as specified in paragraph (c) of this section.*

192.933(d) **Special requirements for scheduling remediation —**(1) ***Immediate repair conditions****.*

An operator's evaluation and remediation schedule must follow ASME/ANSI ASME B31.8S-2004, (incorporated by reference, see § 192.7), Section 7, in providing for immediate repair conditions.

(2) **Two-year conditions**… (iv)… *For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME B31.8S (incorporated by reference,* see *§ 192.7), Section 7, Figure 4, in accordance with paragraph (c) of this section.*

2 BACKGROUND

2.1 General

While hydrogen has been safely transported by purpose-built pipelines for decades, interest in using hydrogen as a fuel source has intensified in the United States. This interest has included blending significant amounts of hydrogen into the current natural gas pipeline networks within the United States and repurposing pipelines to transport either blended hydrogen or pure hydrogen in the existing pipeline systems. This interest has led to extensive research efforts to determine if this can be done safely.

This project, awarded by USDOT PHMSA, studies the effect of a gaseous hydrogen environment on integrity management and ILI intervals that have been well-established for over 20 years. These intervals need to be reviewed for when the transported gas includes hydrogen blends and pure hydrogen in pipeline systems that were not initially designed, constructed, or assessed for hydrogen transport.

Prior studies, including Tasks 1 and 2 of this project, have identified that the primary concern with transporting hydrogen is the deleterious impact on features within the pipeline that are susceptible to embrittlement or fatigue effects. In Task 3, the goal was to recommend changes to 49 CFR 192, ASME B31.12, and ASME B31.8S regarding the ILI of pipelines transporting hydrogen or hydrogen/natural gas blends.

The following sections are the conclusions for the first two tasks of this project.

2.2 Task 1 Literature Review on Reinspection Intervals for Pipelines Carrying Hydrogen or Hydrogen/Natural Gas Blends Final Report – Section 6. Conclusions

Key findings from Kiefner's Task 1 Literature Review - Final Report[8] of this project included:

- Global research performed over the past decades has yielded valuable insights, but the material property data originated from a relatively small number of research organizations. The data are relatively limited in scope as related to pipeline steels for gas.
    - For example, the data on accelerated fatigue crack growth rates (CGRs) are relatively limited, as they address only a few loading R-ratios (minimum stress divided by maximum stress) - typically, R=0.1 and R=0.5. However, gas pipelines typically operate with less severe pressure fluctuations (R=0.9).
    - Where material properties are evaluated, the studies primarily reported on yield or tensile strength. Fracture toughness data were scarce, and few data were reported on weld-related properties.

- Although integrity management was described in general terms, the specific connection between CGRs and inspection intervals was not included in most hydrogen-related Codes and Standards.
    - No documents were found that describe the methodologies for assessing hydrogen effects on specific defect types other than a general "crack-like" feature.
- The various Codes and Standards cross-reference one another, with most leading back to ASME B31.12 and BS 7910[9].
- There are several methodologies for fatigue CGR assessments included in hydrogen-related Codes and Standards.
    - ASME B31.12 Code Case 220[10] is the only method that formalizes fatigue design curves for gaseous hydrogen that account for the loading R-ratio, the stress intensity factor range, ΔK, and the hydrogen gas pressure, g(P), as a function of overall pressure, P.
- European (Germany, UK) Standards refer to American (ASME) and British (BS) Standards. American Standards do not reference European documents.
    - Considering the European Hydrogen Backbone program with 35,700 miles of planned hydrogen pipelines (58.6% repurposed) in the near future, the American program is currently much smaller, with 1,500 miles of existing hydrogen pipelines. Learning from the European experience would be beneficial for the United States.

2.3 Task 2 Review of ASME B31.8S on Reinspection Intervals for Pipelines Carrying Hydrogen or Hydrogen/Natural Gas Blends Final Report Section 8 Conclusions and Recommendations

The following conclusions and recommendations were formulated based on the results from the Task 2 review. A detailed discussion of these findings is given in Section 4.3 ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8) Review of Potential Integrity Threats.

<u>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</u>

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)inspection 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 ILI inspections, ASME B31.8S-2018 requires RTs of 10, 15, and 20 years to reach a predicted failure pressure (P_f) of 1.00 x SMYS for MAOPs up to 30 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 has been adopted in American Petroleum Institute (API) API 570-2023[11].

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 (WT) and the corrosion rate (CR), which is a shortcoming for the threat of corrosion metal loss as the mechanism reduces the WT with time. Example calculations using the equations from ASME B31G-2023[12] show that the RL for different WTs and diameters varies greatly. The RL can be much shorter than the RT for all but the thickest pipes.

- Kiefner recommends introducing the concepts of remaining life (RL) and reinspection interval (RI) into the Code while maintaining the concept of response time (RT).
- Kiefner recommends revising ASME B31.8S-2018 Table 5.6.1-1 and Figure 7.2.1-1 with consistent application of predicted failure pressure (P_f) and factors related to the specified minimum yield strength (SMYS).

<u>Description of Hydrogen Effects</u>

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 effects are named after their mechanism, and others after the source of hydrogen. The Task 2 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

- Kiefner recommends using consistent terminology when describing hydrogen effects.

<u>Review of Potential Threats to Integrity</u>

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 that should be added to ASME B31.8S Paragraph 2.2:

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

Integrity threats applicable to gas pipelines in hydrogen and hydrogen blend service that should be added to the future ASME B31.8S hydrogen chapter:

5. Time-Dependent – Hydrogen-induced cracking (HIC)
6. Time-Dependent – Fittings and sharp transitions
7. (b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body
8. (b) Resident (2) Welding/fabrication related – At welded sleeves and fittings – Type B sleeves and Puddle welds
9. (b) Resident (2) Equipment – Other material/equipment failure – Disbonded coating caused by hydrogen
10. (c) Random or Time Independent (3) Weather-related and outside force – At locations that may experience an electrical arc or fire – Fire damage

- Kiefner recommends adding these missing integrity threats to future versions of ASME B31.8S.

3 OBJECTIVES

The objective of the Task 3 work was to recommend changes to 49 CFR 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, ASME B31.8 Gas Transmission and Distribution Piping Systems, and ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8). The recommended changes apply to the reassessment interval determination for defects in pipelines transporting hydrogen or hydrogen/natural gas blends as detected by ILI.

4 RECOMMENDED CHANGES

4.1 49 CFR 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards

4.1.1 General

Kiefner reviewed all of the Subparts of 49 CFR 192 to identify sections of the regulation that would apply to pipelines with hydrogen as a major constituent and the associated changes in threats and reassessment intervals as previously identified and discussed in Tasks 1 and 2. The following is a discussion of the applicable sections of the regulations and recommendations to PHMSA on potential approaches to provide enhancements or advisories to the regulations and owners/operators.

4.1.2 Subpart A - General

> Section 192.7(c)(7) *ASME B31.8S-2018, Managing System Integrity of Gas Pipelines, Issued November 28, 2018, (ASME B31.8S); IBR approved for §§ 192.13(d); 192.714(c); 192.903 note to Potential impact radius; 192.907 introductory text and (b); 192.911 introductory text, (i), and (k) through (m); 192.913(a) through (c); 192.917(a) through (e); 192.921(a); 192.923(b); 192.925(b); 192.933(c); 192.935(b); 192.937(c); 192.939(a); 192.945(a).*

192.907 contains no introductory text and only references ASME B31.8S in paragraph (b).

- Kiefner recommends that PHMSA remove the words "introductory text and " from Section 192.7(c)(7), because the introductory text in Section 192.907 no longer exists. Without this change, the text in 192(c)(7) is confusing.

Section 192.7(b)(12) incorporates by reference API Standard (STD) 1163, 2nd edition[13] of 2013. API STD 1163, 3rd edition[14] of 2021, requires more robust feature analysis and validation of tool technology. The industry has improved API STD 1163 with specific sections applicable to hydrogen threats. These improvements are necessary, particularly with hydrogen and calculating appropriate reassessment intervals.

- Kiefner recommends that PHMSA update 49 CFR 192 to incorporate by reference API STD 1163, 3rd edition for ILI systems qualification.

Specific sections of API STD 1163, 3rd edition are improvements above API STD 1163, 2nd edition as follows:

> Section 4.2 of API STD 1163, 3rd edition requires that *"non-destructive examination (NDE) personnel used to generate data as part of the verification and validation process be trained, certified, and competent in the appropriate testing method."* No such requirement exists in the 2nd edition. This is an important requirement as the sizing of crack features is critical to the determination of RL for hydrogen pipelines due to the increased rate of fatigue and the decreased fracture toughness of the steel.

Section 5.4 of API STD 1163, 3rd edition requires a more extensive evaluation of the selection of an ILI system, with specific considerations of the identified and/or susceptible threats versus the available state-of-the-art technologies. In contrast, the 2nd edition only refers to selecting an appropriate ILI system that meets the operator's goals and objectives.

Section 6.2.1 of API STD 1163, 3rd edition requires that ILI service providers identify which parts of the performance specification are based on statistically valid methods and which are not, unless otherwise agreed to by the operator. API STD 1163, 3rd edition does not require this clarification. This is important because of the unique nature of hydrogen cracks (often very fine features). The methods/calculation tools selected by operators to assess for crack-like anomalies must "understand" how the ILI tool specifications affect what type of features can be detected and how those features are sized. The analyst needs to consider when ILI specifications are statistically valid and when specifications are not.

As an example, anomalies at and near girth welds (GWs) typically have poor performance in ILI detection and sizing. However, "(b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body" is one of the applicable threats identified by Task 2.

Section 6.3.4 of API STD 1163, 3rd edition requires that NDE measurements be performed by trained, qualified, and experienced technicians following well-established and recognized investigation protocols. The validation measuring methodologies shall be compatible with the type of defect to be evaluated. The validation measurements shall be detailed and well-documented and should include three-dimensional profiling. There is no requirement in API STD 1163, 2nd edition for technicians to be qualified or experienced, let alone in the type of defects that hydrogen cracking will involve.

Section 7.6.1 of API STD 1163, 3rd edition includes specific information that could be included in the quality assurance (QA) of ILI tool runs. For crack detection tools (ultrasonic testing crack detection [UTCD] and electromagnetic attenuation testing [EMAT]), such QA information is completely absent in API STD 1163, 2nd edition. QA by evaluation of velocity, data coverage, and signal losses is critical to understanding if cracks affected by hydrogen have been adequately detected and sized. For natural gas pipelines, EMAT tools will more likely be used than UTCD tools to detect cracks because EMAT tools do not need a liquid couplant. Guidance on QA checks for EMAT data is also absent in API STD 1163, 2nd edition.

Section 8 of API STD 1163, 3rd edition significantly expands the statistical analysis of ILI tool evaluation, including the probability of detection, identification, sizing, uncertainty, and agreement test requirements compared to the 2nd edition. With the implications of hydrogen effects on existing defects, it is critical to understand the certainty and probabilities of tool performance in detection, identification, sizing, and confidence of anomalies.

Section 9.2.2 of API STD 1163, 2nd edition lists two metadata (essential variables that may affect the quality and accuracy) as (1) tool speed and projection and vertical datum of global positioning system (GPS) coordinates, and (2) how these data are obtained. In contrast, Section 9.3.2.2 of API Standard 1163, 3rd edition adds an additional nine items, three of which are critical for the evaluation of defects when hydrogen is transported. These three are signal noise, protrusion of the GW into the inside diameter (ID), and protrusion of the longitudinal seam into the ID.

API STD 1163, 3rd edition recommends following Bulletin API BULL 1178 [1st edition[15], 2017] Integrity Data Management and Integration, in responding to new ILI surveys and integrating multiple integrity assessment data sets. In December 2024, API BULL 1178, 2nd edition[16] was published. API STD 1163, 2nd edition was published prior to the publication of the industry consensus on data management and integration.

Without incorporating the latest edition of API STD 1163, incorrect tools may be selected, feature sizing may not be validated by qualified technicians, and necessary guidance may be missed by an operator. This can lead to an incorrect evaluation of the effect and remaining life of features impacted by hydrogen effects, resulting in unexpected failures and reduced safety.

- Kiefner recommends that PHMSA update 49 CFR 192 to incorporate by reference API STD 1163, 3rd edition for ILI systems qualification.

Section 192.7 does not incorporate by reference any recommended crack management practices, and ASME B31.8S, Section 7 only contains a short paragraph on responding to crack tool indications for stress corrosion cracking (SCC).

API Recommended Practice (RP) 1176, 1st edition[17] for Assessment and Management of Cracking in Pipelines was published in June 2016. API RP 1176 presents the pipeline industry's understanding of pipeline cracking and has been widely adopted by pipeline operators to develop and implement crack management programs. Mechanisms that cause cracking are discussed, methods to estimate the failure pressure of cracks are reviewed, and methods to estimate crack growth are presented.

API RP 1176 also includes current knowledge about ILI and NDE technology. The document presents a methodology for responding to ILI indications and specific response criteria for when to respond to certain results. In comparison, PHMSA has issued response criteria within 49 CFR 192 (gas pipelines) but has not issued criteria within 49 CFR 195 (liquids pipelines). Both gas and liquid pipelines deal with crack management issues that API RP 1176 (crack management) considers, but ASME B31.S (integrity of gas pipelines) and API RP 1160[18] (integrity of liquid pipelines) do not.

For natural gas pipelines, ASME B31.8S and 49 CFR 192 do not consider fatigue crack growth rates specific to hydrogen or hydrogen/natural gas blends. These codes also do not include the considerations of gas pipeline operators developing crack management programs for hydrogen-carrying pipelines that were not purpose-built. API RP 1176, 2nd edition is currently in development and is expected to be published soon.

The current API RP 1176 (1st edition) notes in Section 5.2 that the pipeline industry has modeled threats to varying levels of detail as provided in ASME B31.8S and API RP 1160. Although pipeline integrity management entails addressing each of these threats, only a portion of the threats are related to cracking. For each pipeline segment where the threat of cracking has been identified, each element of a pipeline operator's IMP should contain provisions for managing crack threats. ASME B31.8S and 49 CFR 192 both lack guidance and requirements for developing a crack management program.

- Kiefner recommends that, until such additional requirements are provided in ASME B31.8S, PHMSA incorporate by reference API RP 1176 as the industry-recommended practice for managing pipeline cracking into 49 CFR 192.

Section 10 of API RP 1176 provides guidance on the selection of integrity assessment methods with more detail than is included in ASME B31.8S or 49 CFR 192. The same section also provides considerations for hydrotesting and ILI in combination with hydrotesting, which are technologies that could be considered for addressing hydrogen-related threats. Furthermore, Section 11 of API RP 1176 provides detailed guidance on the selection of ILI technologies for the assessment of cracking, which is important when evaluating hydrogen-related threats.

As long as API RP 1176 is not incorporated in 49 CFR 192, operators are not required to develop a crack management program using industry best practices. With virtually no guidance in ASME B31.8S on crack management for hydrogen, gas pipeline operators will likely experience unnecessary failures, particularly if they are not involved in using API practices and/or have little experience in managing the higher fatigue crack growth rates in hydrogen-embrittled steel.

- Kiefner recommends that PHMSA incorporate by reference API RP 1176 into 49 CFR 192 to require operators of hydrogen and hydrogen/natural gas blended pipelines to develop crack management plans and procedures within their IMPs, based on industry-recommended practices.

4.1.3 49 CFR 192 Subpart M - Maintenance

192.710(a) requires the assessment of transmission pipelines with an MAOP > 30% of SMYS located in a Class 3 or 4 location[i] or a moderate consequence area (MCA) if the pipeline can accommodate an ILI no later than July 3, 2034.

Assessments of pipelines being converted to or blended with hydrogen should not be deferred until 2034. Due to the rate at which crack-like defects can grow with hydrogen, these pipelines should be assessed with crack tools sooner rather than later. Older natural gas pipelines are known to contain hard spots, and hard spot failures have occurred regularly in the industry. In November 2024, PHMSA issued a hard spot advisory bulletin.[19] The transportation of hydrogen or hydrogen blends in pipelines that contain hard spots will exacerbate this issue, resulting in

[i] Per 49 CFR 195.2, a Class 3 location is (i) any class location unit that has 46 or more buildings intended for human occupancy or (ii) an area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area that is occupied by 20 or more persons on at least five days a week for 10 weeks in any 12-month period. A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

higher failure rates. ILI tools configured for hard spot detection should be used prior to the transportation of hydrogen to understand the potential threat that the introduction of hydrogen poses. Deferment of the transmission pipeline assessment until 2034 should not be permitted in this case. While this section of 49 CFR 192 is adequate for enforcement purposes, operators may benefit from a reminder of these requirements to reduce the likelihood of a failure.

- Kiefner recommends that PHMSA issue an advisory bulletin to remind operators to update their risk assessments for hydrogen considerations and perform ILI with tool technologies appropriate to detect indications susceptible to the effects of hydrogen degradation for pipelines being considered for hydrogen blending or transportation.

"192.712(d)(1) Crack analysis models. When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle, or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other)."

This section, while appropriate, does not explicitly state to consider the interactions of the material and material defects with the potentially detrimental microstructural effects of hydrogen and hydrogen blends on the steel. Traditionally, crack development and growth were a function of stress and fatigue cycling to failure. However, the influence of hydrogen is unique in that the critical flaw size decreases because the material's fracture toughness decreases due to hydrogen embrittlement. The fatigue crack growth rate is increased due to the interaction of the material and atomic hydrogen trapped in the microstructure. Therefore, the size at which a defect fails is smaller, and the time to reach the critical flaw size is shorter.

This phenomenon warrants additional consideration within the crack models to determine RL and RIs. While this section of 49 CFR 192 is adequate for enforcement purposes, operators may benefit from a reminder of these requirements to reduce the likelihood of a failure.

- Kiefner recommends that PHMSA issue an advisory bulletin to remind operators to consider the interaction of hydrogen's potentially detrimental microstructural effects on the material properties used in crack analysis models.

192.712(d)(2) requires that *"If the segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law or other technically appropriate engineering methodology."*

Prior operator experience has been that cyclic fatigue does not significantly affect natural gas pipelines. Due to this new requirement to assess for cyclic fatigue at least once every seven years, Kiefner has observed that some natural gas pipelines do experience moderate to aggressive fatigue in contrast to historical assumptions. While some may interpret "other loading conditions" to include hydrogen influence, this is not an explicit interpretation.

Based on the findings documented in Task 1 and Task 2, and the results from a 2022 Pipeline Research Council International (PRCI) study[20] into the causes of crack failures in pipelines, operators should not continue to assume that defects in gas pipelines are not or are rarely susceptible to fatigue. Conversely, the introduction of hydrogen does not automatically mean that the pipeline is highly susceptible to fatigue of existing anomalies. Possible fatigue effects simply need to be evaluated for their impact.

Many gas operators assume that cyclic (pressure fluctuations) fatigue is not a factor in their natural gas systems. However, failures have occurred in gas systems due to cyclic fatigue, which resulted in PHMSA including this requirement in 49 CFR 192. The threat of hydrogen effects on cracking is so significant that without either an explicit change in the regulatory language or an advisory bulletin on this issue, operators may not consider the effect that hydrogen has on cycling, resulting in more frequent catastrophic failures.

- Kiefner recommends that PHMSA explicitly include hydrogen effects to fatigue as a threat when determining reassessment intervals and require fatigue crack growth models to be considered within 49 CFR 192.
    - Alternatively, at a minimum, Kiefner recommends that PHMSA issue an advisory bulletin to reinforce the expectation for operators to consider the effect of hydrogen on the fatigue life in crack growth models used to determine reassessment intervals for anomalies previously considered non-susceptible to environmental effects.

4.1.4 49 CFR 192 Subpart O - Gas Transmission Pipeline Integrity Management

192.917(b)(4) requires operators to *"analyze pipeline integrity data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the consequences of incidents."*

This paragraph adequately contains the requirements to consider cyclic fatigue and reduced toughness caused by hydrogen as applicable risk factors that are interrelated. While this section of 49 CFR 192 is adequate for enforcement purposes, operators may benefit from a reminder of these requirements to reduce the likelihood of a failure.

- Kiefner recommends that PHMSA issue an advisory bulletin highlighting the outcomes of recent research on hydrogen transport to remind operators of the applicable risk changes associated with hydrogen transportation in pipelines that are not purpose-built for that product.

192.917(c) requires a risk assessment that follows ASME B31.8S, Section 5, and that analyzes and identifies the threats and potential consequences for each covered segment.

This paragraph adequately contains the requirements for operators to consider the risks that hydrogen and hydrogen-blended natural gas pipelines pose. Hydrogen and hydrogen blends have similar but also different threat mechanisms and effects from natural gas alone. Operators considering transporting these products must consider the additional effects of fatigue on the existing attributes of the pipeline. ASME B31.8S is being updated to provide additional guidance for hydrogen pipelines, but it may be some time until publication. While this section of 49 CFR 192 is adequate for enforcement purposes, operators may benefit from a reminder of these requirements to reduce the likelihood of a failure.

- Kiefner recommends that PHMSA issue an advisory bulletin based on this report's findings to inform operators of their responsibility to consider the additional risks that hydrogen and hydrogen blends have on existing pipelines, including the effects of fatigue and crack growth rates, prior to converting a pipeline or transporting these products.

192.917(e)(2) requires the analysis of cyclic fatigue at least once every seven years.

This requirement is a critical component of the pipeline feature fatigue analysis. This requirement was recently added to the federal code requirements after several notable failures due to the cyclical fatigue of gas pipeline long seams. There is no explicit requirement to consider a renewed analysis prior to the seven calendar years. If hydrogen is blended into a pipeline, an operator may continue to assume that cyclic fatigue is not an issue. However, the increased fatigue crack growth rates in hydrogen can result in a much more rapid decline of a feature's RL and a shorter resultant pipeline time to failure.

- Kiefner recommends that, given the additional risk imposed by hydrogen fatigue crack growth rates, the requirement should be updated to require operators to consider any change in pipeline operation or product that may change the basis of a prior analysis, perform a new cyclic fatigue analysis, and evaluate the effects of fatigue on existing anomalies within the pipeline.

192.921(a)(1) requires the selection of an internal inspection tool capable of detecting those threats to which the pipeline is susceptible.

This requirement is appropriate for hydrogen and hydrogen-blended pipelines. While this section of 49 CFR 192 is adequate for enforcement purposes, operators may benefit from a reminder of these requirements to reduce the likelihood of a failure.

- Kiefer recommends that PHMSA issue an advisory bulletin to remind operators to consider the embrittlement effects of hydrogen on crack-like anomalies and that tools capable of assessing a pipeline for cracks should be used on pipelines transporting hydrogen or hydrogen blends.

192.933(d) requires an operator to evaluate and remediate conditions following ASME B31.8S-2004, Section 7. This section contains many outdated requirements and should be updated, considering the threats and reassessment interval considerations for hydrogen and hydrogen blends.

PHMSA should update 49 CFR 192 with all the requirements of ASME B31.8S to the 2022 edition based on the recommendations in Section 4.3 ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8) Review of Potential Integrity Threats. ASME B31.8S-2004, Section 7.2.2 only discusses the crack detection tool response for SCC. It is a short paragraph that does not include many of the issues described and recommendations provided in this report.

- Kiefner recommends that PHMSA update the IBR in 192.933(d) to ASME B31.8S-2022 based on recommendations in Section 4.3 ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8) Review of Potential Integrity Threats.

4.2 ASME B31.8 Gas Transmission and Distribution Piping Systems

The Hydrogen Task Group of the ASME B31.8 committee is working to incorporate the pipeline-related content for hydrogen into a hydrogen chapter of the ASME B31.8 Code. Voting members, contributing members, and guests representing more than 20 different pipeline companies and consultants actively attend the task group meetings.

The following sections provide details about some of the items being discussed. None of the items are finalized until they are fully balloted, approved, and published by ASME as a new edition of ASME B31.8. Since the 2nd ballot was sent out on April 2, 2025, and closed on April 28, 2025, items have already been discussed for further consideration and changes.

- Kiefner recommends supporting the balloting items being proposed and the review process being followed by the Hydrogen Task Group of ASME B31.8.

4.2.1 Hydrogen Piping and Pipelines Chapter Ballot

A hydrogen chapter for ASME B31.8 that is being created by the ASME B31.8 Hydrogen Task Group based on the content of ASME B31.12 will be balloted at the ASME B31.8 subgroup level in Quarter 4, 2025. The ASME B31.8 Hydrogen Task Group has proposed that Chapter XI Gaseous Hydrogen and Hydrogen Blend Pipelines be targeted for approval at the ASME B31 committee level by Quarter 2, 2026.

The following are some of the items that were included in the 2nd ballot, dated April 2, 2025, and these should be noted as key items:

1. Hardness Requirements,
2. Fracture Control Requirements,
3. Fatigue Requirements, and
4. Fracture Toughness Requirements.

The following are the portions of the suggested new content, as of April 28, 2025, regarding the four key items above.

"805.2.4 Construction, Operation, and Maintenance Terms and Definitions

Hardness: resistance of metal to plastic deformation, usually by indentation. For carbon steels, hardness can be related to the ultimate tensile strength.

Brinell Hardness Number (BHN): a value to express the hardness of metals obtained by forcing a hard steel ball of specified diameter into the metal under a specified load. For the standard 3000 kg load, numbers range from 81 to 945.

Rockwell Hardness: a series of hardness scales for metals.

(a) The Rockwell "C" (HRC) scale uses a cone diamond indenter and a load of 150 kg. The scale starts at 20 for soft steels and reaches a maximum of about 67 for very hard alloys.

(b) The Rockwell "B" (HRB) scale uses a hard metal ball indenter and starts at zero for extremely soft metals and reaches a maximum of 100 for soft steels and alloys. HRB 100 = HRC 20.

Vickers Hardness (HV): a value achieved by use of a diamond pyramid indenter. The load applied to the indenter is defined by a suffix after the HV; for example, HV_{10} specifies a load of 10 kgf.

H811.4 Qualification of Materials and Equipment for Gaseous Hydrogen and Hydrogen Blends

Paragraphs H811.4(a) – (e) apply to all hydrogen and hydrogen blend pipelines. If an engineering assessment (EA) is required by the paras. H841.1.4, H841.1.6, H841.1.9, or H855.6.4(b), then the requirements of paras. H811.4 (f) – (g) also apply.

(a) Line pipe material properties shall meet the material properties and chemical composition requirements of API Spec 5L PSL2 or equivalent.

(b) For fracture control and arrest, para. H841.1.2 applies.

(c) The maximum allowable hardness in the line pipe body and weld zones of the seam weld, including weld metal and HAZ, shall be 275 HV_{10} (or equivalent Brinnel Hardness (HBN) or HRC values). The user can specify a lower value of maximum hardness as required.

(d) For new-build pipelines, the testing shall be performed as part of a manufacturing procedure qualification as defined in API Spec 5L, Annex B. The use of equivalence (see H811.5) is at the user's discretion; see Nonmandatory Appendix S-3 for additional guidance. Properties based on published data from testing in gaseous hydrogen may be used, provided that the engineering critical assessment (ECA) remains conservative.

(e) For new-build pipelines, properties of construction GWs and associated HAZ (including GWs produced in the pipe mill if applicable) shall be characterized as part of weld qualification per para. H823.

(f) A fracture toughness value or the J-R curve shall be established in a representative gaseous hydrogen environment in accordance with ANSI CSA CHMC1 "Test methods for evaluating material compatibility in compressed hydrogen applications – Metals". Crack stability shall be assured.

(g) For an EA, testing shall be performed in a representative gaseous hydrogen environment. See para. H811.6.

H821.7 Cathodic Protection Leads and Attachments

(a) Procedures and personnel for temporary or permanent attachments welded, brazed, or thermite welded shall be qualified.

(b) Multipass procedures and single pass procedures shall be qualified separately.

(c) The hardness limit for welds is 275 HV_{10} (or equivalent HBN or HRC values) in accordance with para. H823.2.4.

H822 PREPARATION FOR WELDING

H822.3 Seal Welds

(a) A qualified seal welding procedure shall be used to seal threaded joints.

(b) The hardness limit for welds is 275 HV_{10} (or equivalent HBN or HRC values) in accordance with para. H811.4(c).

H823.2.4 Hardness Control

(a) The maximum allowable hardness in any of the weld zones, including weld metal and HAZ, is 275 HV_{10} (or equivalent HBN or HRC values).

(b) Hardness testing shall be performed in accordance with API STD 1104. The hardness indents shall be placed in accordance with Figure 2 of ISO 15156-2 for the GW, API STD 1104, Section 10.3.6.4 Girth Weld Repair, and Section B.2.5.4 Branch Groove Welds and Fillet Welds. The HAZ hardness impressions shall be entirely within the HAZ and located as close as possible to the fusion boundary.

H823.2.5 Testing Requirements

(a) Charpy testing is required during qualification. The weld and HAZ shall be tested per API STD 1104, Annex A. The weld and HAZ shall meet the requirements for the seam weld and HAZ of pipes in API 5L PSL2 or equivalent. The notch locations shall be in accordance with API STD 1104 Figure A.2.

(b) When an EA is required for design or product change according to para. H855.6.4, the testing in para. H811.4 is required.

(c) The notch locations shall be in accordance with the guidance in API STD 1104, Figure A.6.

H851 PIPELINE MAINTENANCE

H851.4 Repair Procedures for Steel Pipelines

In addition to the requirements of 851.4, for gaseous hydrogen and hydrogen blend pipelines the following requirements apply for repairs:

(a) Temporary bolted clamps are acceptable. Temporary clamps shall prevent the leakage of hydrogen and be monitored to ensure effectiveness.

(b) For nonmetallic composite repair, the qualification criteria in ASME PCC-2 or ISO 24817 shall be reviewed to consider any change in the properties of composite materials in the presence of hydrogen.

(c) For all repair systems, the combination of defect type and repair system shall be reviewed for the applicable static and fatigue loading. The effect of hydrogen on the material properties in the pipe, weld and HAZ of both the carrier pipe and sleeve material shall be considered.

(d) Before opening any pipe to the atmosphere, the system shall be purged so that the concentration of flammable gas is less than the lower flammability limit in air. Before reintroducing flammable gas into a system, the concentration of air in the piping shall be reduced to a level that prevents a combustible mixture by purging with nitrogen or another suitable inert gas.

(e) The materials used for full encirclement sleeves shall be made from the same or higher wall thickness and grade, unless it is confirmed through an analysis that the pressure carrying capacity is equal to or greater than the maximum allowable operating pressure (MAOP).

(f) The materials used for full encirclement sleeves shall be API Spec 5L PSL2 or material in its final manufactured state that is suitable for hydrogen service.

(g) The welding procedures used for welded full encirclement sleeves, including any seal welds used, shall be qualified, performed, and examined per the requirements of para. H823.

(h) For any process that requires in-service welding on gaseous hydrogen or hydrogen blend pipelines, the following applies:

> *(1) In-service welding procedures shall be qualified and performed in accordance with API Standard 1104, Annex B. The effect of hydrogen on the procedure, weld quality, and material properties of the weld and HAZ shall be considered.*
>
> *(2) The cooling rate during qualification testing shall be representative of gaseous hydrogen and hydrogen blend service or higher.*
>
> *(3) The maximum allowable hardness limit shall be 275 HV_{10} (or equivalent HBN or HRC values).*
>
> *(4) Low hydrogen welding electrodes classified to meet a diffusible hydrogen content of 5ml/100g or lower shall be used.*

(5) There should be a minimum of 3 in. (75 mm) distance from the end of the toe of the in-service weld to an adjacent girth weld.

(6) Procedures qualified under API STD 1104, Appendix B are suitable for weld deposition repair, provided the procedure is appropriate for the remaining wall thickness to which it is being applied.

(7) The areas of the pipe body that will be welded shall be examined using UT methods to confirm the wall thickness and that the area is free of laminations.

(i) One-hundred percent of in-service welds require inspection per API STD 1104, para. B.5. It is recommended that particular attention is paid to detecting cracks. When possible, RT or UT, or both, shall be used to examine the full volume of the weld and HAZ.

S-3 MATERIALS EQUIVALENCE AND USE OF REPRESENTATIVE OR CONSERVATIVE LOWER BOUND PROPERTIES

Representative test data in gaseous hydrogen may be used in an EA if it can be demonstrated that the referenced dataset is 'equivalent' to the material used in construction (including welds). There are no industry-acknowledged standard criteria to define materials equivalence in gaseous hydrogen and hydrogen blend service. The requirement is to ensure that the materials intended for service have the same or better properties than materials included in the equivalent data set. The user should consider variables that affect material properties such as, but not limited to the following:

- *a) Vintage or age*
- *b) Plate, strip or billet feedstock material*
- *c) Pipe type (inc. seam welding process)*
- *d) Manufacturer*
- *e) Manufacturing process*
- *f) Heat treatment*
- *g) Dimensions*
- *h) Chemistry*
- *i) Microstructure*
- *j) In air mechanical properties (strength, toughness, hardness)*
- *k) Applicable line pipe specifications*
- *l) Applicable construction specifications*
- *m) WPS and procedure qualification (PQR)*
- *n) Repairs*

The user should consult industry literature to help support the definition of conservative properties in hydrogen from test data if equivalence with the dataset is appropriate

S-8 WELDING

S-8.1 Undermatching Welds and HAZ Softening

In addition to the requirements of Section 828, the following guidance should be considered:

(a) The cross-weld tensile testing performed during qualification should fail in the pipe body and not in the weld or HAZ.

(b) Overmatching consumables should be selected to ensure that weld failure occurs in the base metal and not the HAZ and weld.

(c) The maximum weld heat input should be controlled to minimize the width of the HAZ and to increase the strength of the weld. This is often practically achieved by limiting the minimum number of weld passes on the WPS based on the number of weld passes used on the Procedure Qualification Record (PQR) weld of the same wall thickness. For hardness control, it may also be necessary to limit the maximum number of weld passes.

(d) A minimum weld cap reinforcement height and width should be specified in the WPS unless the cross weld tensile fails in the base metal with the reinforcement removed in the cross weld tensile.

The current guidance for hardness testing of welds per API STD 1104 and ISO 15156-2 states the HAZ indents shall be positioned as close to the fusion line as possible. This is done to increase the probability of catching the highest hardness, that may not capture any effect of HAZ softening. This may occur away from the fusion line. If HAZ softening is considered a threat, additional indentations should be conducted across the HAZ.

S-8.2 In-Service Welding

The guidance included in para. H851.4 related to in-service welding is based on controlling hardness and requiring low hydrogen consumables classified to meet a diffusible hydrogen content of 5 ml/100 g or lower. SI units are used throughout industry for reference to diffusible hydrogen levels in welding. The work referenced International Pipeline Conference paper IPC2022-87202 also provides an approach for limiting the pipe internal surface temperature as a control against cracking if the requirements for hardness and diffusible content cannot be met.

H841.1.4 Limitations on Specified Minimum Yield Strength, S, in Para 841.1.1

(d) Low stress option: For gaseous hydrogen and hydrogen blend pipelines, the value of S used in para. 841.1.1 shall be limited as follows.

1) *If the material has an SMYS less than or equal to 52,200 psi (360 MPa), then S shall be equal to the SMYS of the material.*

2) *If the material has an SMYS greater than 52,200 psi (360 MPa) then S shall be equal to 52,200 psi (360 MPa)."*

4.3 ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8) Review of Potential Integrity Threats

4.3.1 Integrity Threats - Regardless of Hydrogen

The Task 2 report identified four items that should be considered for change regardless of whether the system has hydrogen or hydrogen-blended gas. They are integrity threats applicable to any gas transmission pipeline, which should be added to ASME B31.8S Paragraph 2.2:

(a)Time-Dependent

(1) External corrosion

(2) Internal corrosion

(3) Stress corrosion cracking

(4) Fatigue cracking[ii]

(b) Resident

(1) Manufacturing-related defects

(-a) Defective pipe seam

(i) Low-toughness seam[iii]

(ii) Defect in or near an electric resistance welded (ERW) seam[iv]

(-b) Defective pipe

(b) Resident

(2) Welding/fabrication-related

(-a) Defective pipe girth weld (circumferential) including branch and T-joints

(-b) Defective fabrication weld

(-c) Wrinkle bend or buckle

(-d) Stripped threads/broken pipe/coupling failure

(-e) At in-service/repair welds

(i) Hydrogen stress cracking[v]

More information about each of the four missing threats is provided next.

4.3.1.1 Fatigue Cracking

Some organizations consider fatigue or fatigue cracking as the cause of accelerated cracking, but not as a damage mechanism or threat on its own. API RP 571[21] Damage Mechanisms

[ii] See Paragraph 4.3.1.1 of this report.
[iii] See Paragraph 4.3.1.2 of this report.
[iv] See Paragraph 4.3.1.3 of this report.
[v] See Paragraph 4.3.1.4 of this report.

Affecting Fixed Equipment in the Refining Industry, 3rd edition of March 2020, identifies Mechanical Fatigue (Including Vibration-Induced Fatigue) as a damage mechanism.

> *"3.43 Mechanical Fatigue (Including Vibration Induced Fatigue)*
>
> *3.43.1 Description of Damage*
>
> *a) Fatigue cracking is a mechanical form of degradation that occurs when a component is exposed to cyclic stresses for an extended period, e.g., from dynamic loading due to vibration, water hammer, or unstable fluid flow, often resulting in sudden, unexpected thru-wall cracking.*
>
> *b) These stresses can arise from either mechanical loading or thermal cycling and are typically well below the yield strength of the material. This section focuses on mechanical loading, while the effects of thermal cycling are covered in 3.64 on thermal fatigue."*

The justification for adding fatigue cracking comes from the current project's Task 2 Final Report Section 7.2.1 Missing Threat: 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 in ASME B31.8S-2018. The only currently listed type of time-dependent crack growth is stress corrosion cracking.

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. 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 liquid lines), per the PRCI report PR-276-241503-R01[20]. In the case of hydrogen, fatigue crack growth rates (FCGRs) can be accelerated by approximately an order of magnitude, increasing the risk of fatigue failure.

Fatigue cracks can initiate from a sharp geometry in the pipe, such as at a weld, a dent or gouge, a fitting, or 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 elevated strain/stress areas, such as at a crack tip.

- Kiefner recommends adding "Time-Dependent Fatigue Cracking " as a threat in ASME B31.8S. This threat is generally applicable (not exclusive to pipelines carrying hydrogen).

4.3.1.2 Low-Toughness Pipe Seam

The justification for adding "low-toughness seam" comes from Task 2 Final Report, Section 7.2.4, Missing Threat: (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/USDOT-sponsored research published in March 2004[22] and January 2005[23] 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 "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 affects the toughness negatively.

- Kiefner recommends adding "(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).

4.3.1.3 Defect In or Near an ERW Seam

The justification for adding a defect in or near an ERW seam comes from Task 2 Final Report, Section 7.2.5, Missing Threat: (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. Manufacturing-caused arc burns/contact marks and hook cracks are discussed here.

Manufacturing-Caused Arc Burns/Contact Marks

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.

After removing the coating and cleaning the surface, manufacturing-caused arc burns can be visually recognized as shallow (~5-10%) metal loss on the pipe. Arc burns from manufacturing can appear on the pipe surface as lines of localized metal loss along either side of the weld center line.

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. ILI technologies to evaluate seam welds do not separately report manufacturing-caused arc burns.

Hook Cracks

Hook cracks are another defect in or near an ERW seam. Youngstown Sheet & Tube ERW and AO Smith FW pipes are particularly susceptible. Hook cracks typically start from the pipe's ID or outside diameter (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/WT 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 twofold: (1) the hook crack reduces the pressure-carrying WT 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 occur in different portions of the weld HAZ.

- Kiefner recommends adding "(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).

4.3.1.4 Hydrogen Stress Cracking

The justification for adding hydrogen stress cracking comes from Task 2 Final Report, Section 7.2.7, Missing Threat: (b) Resident (2) Welding/fabrication related – At in-service/repair welds – Hydrogen Stress Cracking.

ASME B31.8-2018[24] provides repair procedures for steel pipelines. This section describes the missing threat of 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[25].

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 of the Task 2 Report, 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 and interact 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 1 and Figure 2, respectively[25].

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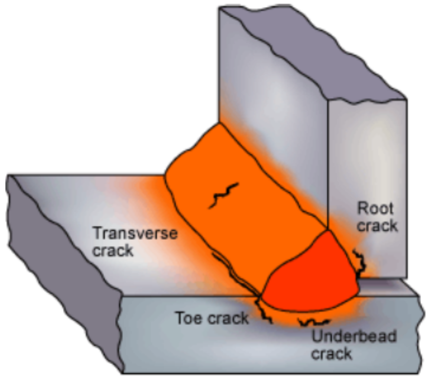

Fig. 1 Hydrogen cracks originating in the HAZ and weld metal. (Note that the type of cracks shown would not be expected to form in the same weldment.)

Figure 1. "Figure 1" from the TWI Website, Showing Possible Locations for HSC to Occur[25]

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

Figure 2. "Figure 2" from the TWI Website, Showing HSC[25]

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

4.3.1.5 ASME B31.8S CO&M Subgroup - Action Item 22-179

Action Item 22-179 in the ASME B31.8S CO&M Subgroup addresses the issue of missing integrity threats. Action Item 22-179 aims to revise ASME B31.8S, Section 2.2 to address the discrepancy in the number of root causes/threats listed as 21 and 22 in this section. As of February 5, 2025, any previously proposed changes were disapproved at the B31.8 CO&M committee level.

Cliff Maier, TC Energy, is the project manager on this action item. He will update and focus on integrity threats applicable to any transmission pipeline and send the ballot to the subcommittee. On March 13, 2025, Kiefner met with Mr. Maier to discuss the findings of the current PHMSA project in relation to Action Item 22-179. He agreed that "fatigue cracking," "low toughness seam," and "hydrogen stress cracking" should be included, and will propose those missing threats for consideration by the committee. He did not agree that "defect in or near an electric resistance welded (ERW) seam" should be called out separately from the higher category "defective pipe seam," and he will therefore not propose it as a missing threat.

As of April 11, 2025, the listing portion of the balloted text with markups was as follows:

"*(a) Time Dependent*

(1) External corrosion

(2) Internal corrosion

(3) Stress corrosion cracking

(4) Fatigue cracking

(b) Resident

(1) Manufacturing-related ~~defects~~ ***threats***

(-a) Defective pipe seam

(-b) Low-toughness pipe seam

(-~~b~~c) Defective pipe

(2) Welding/fabrication related

(-a) Defective pipe girth weld (circumferential), including branch and T-joints

(-b) Defective fabrication weld

(-c) Wrinkle bend or buckle

(-d) Stripped threads/broken pipe/coupling failure

(-e) Hydrogen stress cracking

(3) equipment

(-a) Gasket O-ring failure

(-b) Control/relief equipment malfunction

(-c) Seal/pump packing failure

(-d) Miscellaneous

(c) Random or Time Independent

(1) Third-party/mechanical damage

(-a) Damage inflicted by first, second, or third parties (instantaneous/immediate failure)

(-b) Previously damaged pipe (such as dents and/or gouges) (delayed failure mode)

(-c) Vandalism

(2) Incorrect operational procedure

(3) Incorrect operation

(~~3~~4) Weather-related and outside force

(-a) ~~Excessive hot or cold weather (outside the design range)~~ Geologic hazards: seismic events, geotechnical events, hydrotechnical events, meteorological events, and wildfire

(-b) ~~High wind~~ Surface transportation hazards: mechanical and fire damage events associated with surface transportation vehicles

~~(-c) Hydrotechnical: water-related threats including, but not limited to, liquefactions, floodings, channeling, scouring, erosions, floatations, breaches, surges, inundations, tsunamis, ice jams, frost heaves, and avalanches~~

~~(-d) Geotechnical: earth movement threats including, but not limited to, subsidences, extreme surface loads, seismicity, earthquakes, fault movements, mining, and mud and landslides~~

~~(-e) Lightning~~"

4.3.2 Integrity Threats – In the Presence of Hydrogen

The ASME B31.8 committee will formulate revisions based on the threat's unique characteristics. However, considering the basic premise that only if the presence of hydrogen or hydrogen-blended gas (for different percentages of hydrogen) makes it necessary, revisions should be required. In the process of formulating hydrogen-related revisions, Kiefner identified recommendations regardless of whether there is hydrogen or hydrogen-blended gas in the system.

Integrity threats applicable to gas pipelines in hydrogen and hydrogen blend service should be added to the future ASME B31.8S hydrogen chapter:

(a)Time-Dependent

(1) External corrosion

(2) Internal corrosion

(3) Stress corrosion cracking

(4) Fatigue cracking (recommended to be added from above)

(5) Hydrogen-induced cracking (HIC)[vi]

(6) Fittings and sharp transitions[vii]

(b) Resident

(1) Manufacturing-related defects

(-a) Defective pipe seam

(i) Low-toughness seam (recommended to be added from above)

(ii) Defect in or near an electric resistance welded (ERW) seam (recommended to be added from above)

(-b) Defective pipe

2) Welding/fabrication related

(-a) Defective pipe girth weld (circumferential) including branch and T-joints

(-b) Defective fabrication weld

(-c) Wrinkle bend or buckle

(-d) Stripped threads/broken pipe/coupling

(-e) At in-service/repair welds (recommended to be added from above)

(i) Hydrogen Stress Cracking (recommended to be added from above)

(-f) Near girth welds, and

(i) Arc burn/strike on pipe body[viii]

(-g) Near in-service/repair welds

(i) Arc burn/strike on pipe body[ix]

(-h) At welded sleeves and fittings[x]

(i) Type B sleeves

(ii) Puddle Welds

(3) Equipment

(-a) Gasket O-ring failure

(-b) Control/relief equipment malfunction

(-c) Seal/pump packing failure

(-d) Other material/equipment failure

(i) Disbonded coating caused by hydrogen[xi]

(-e) Miscellaneous. **(changed from -d to -e)**

[vi] See Paragraph 4.3.2.1 of this report, and Table 5. Summary of Hydrogen Terminology.
[vii] See Paragraph 4.3.2.2 of this report.
[viii] See Paragraph 4.3.2.3 of this report.
[ix] See Paragraph 4.3.2.3 of this report.
[x] See Paragraph 4.3.2.4 of this report.
[xi] See Paragraph 4.3.2.5 of this report.

(c) Random or Time Independent

(3) Weather-related and outside force

(-a) Excessive hot or cold weather (outside the design range)

(-b) High wind

(-c) Hydrotechnical: water-related threats

(-d) At locations that may experience an electrical arc or fire[xii]

(i) Fire Damage

4.3.2.1 From Task 2 Final Report, Section 7.2.2, Missing Threat: 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 molecules at microscopic sites within the metal lattice). This result will be a risk for 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 of the Task 2 Final Report, 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 hydrogen sulfide (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.

The occurrence of HIC without stress is usually subject to two conditions: (1) a high hydrogen concentration within the steel, and/or (2) a high strength of the steel. Testing has shown that in gaseous environments, hydrogen dissociation at the pipe ID surface and entry of H-atom diffusion into steels may be limited at relatively low pressure and at ambient temperature. However, it is not absent and does occur, even at low hydrogen concentrations. Therefore, the threat of hydrogen-induced cracking (HIC) does exist. In the presence of stress, the mechanism of hydrogen-assisted cracking (HAC) will become dominant over HIC. Irrespective of the cause (HIC or HAC), it is the threat of the cracks forming in the metal that affects pipeline integrity.

Test Method ANSI/NACE TM0248,[26] developed by the American National Standards Institute (ANSI) / National Association of Corrosion Engineers (NACE) and currently administered by the Association for Materials Protection and Prevention (AMPP), 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/carbon dioxide (CO_2) gas mixture. The specimens are not externally stressed while they are exposed. Once the test

[xii] See Paragraph 4.3.2.6 of this report.

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 3).

$$CSR = \frac{\Sigma\,(a \times b)}{(W \times T)} \times 100\% \quad (1)$$

$$CLR = \frac{\Sigma\,a}{W} \times 100\% \quad (2)$$

$$CTR = \frac{\Sigma\,b}{T} \times 100\% \quad (3)$$

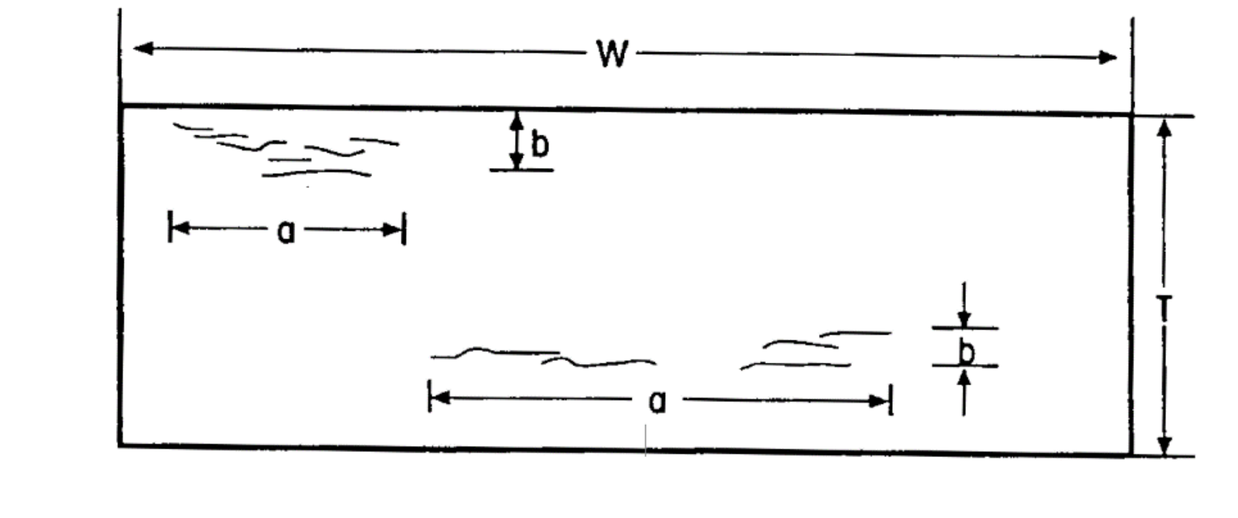

Figure 11: Test Specimen and Crack Dimensions to Be Used in Calculating CSR, CLR, and CTR

Figure 3. "Figure 11" from ANSI/NACE TM0284-2016[26]

ANSI/NACE TM0284-2016[26] notes that the presence or absence of HIC in the exposed specimens may be evaluated by automated UT 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.

Draft 2 of TM0284, which is currently under re-ballot by AMPP’s Committee SC-08 Metallic Material Selection & Testing, contains the following clarification on terminology:

> **The terms stepwise cracking (SWC), hydrogen pressure cracking, blister cracking, and hydrogen-induced stepwise cracking have been used in the past to describe cracking of this type in pipeline and pressure vessel steels, but are now considered obsolete. The term hydrogen-induced cracking (HIC) has been widely used for describing cracking of this type, and has been adopted by AMPP. Therefore, it is used throughout this standard test method. It is defined in NACE/ASTM G193 as “brittle cracking in metals caused by the presence of hydrogen in the structure.”**

- Kiefner recommends adding “Time-Dependent – Hydrogen-Induced Cracking (HIC)” as a threat in ASME B31.8S. This threat is applicable to pipelines carrying hydrogen.

4.3.2.2 From Task 2 Final Report, Section 7.2.4, Missing Threat: 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:

$$J_H = -D_H \frac{d\varphi_H}{dx} \tag{4}$$

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 atom 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 WT).

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[27] 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[28] provided calculations of hydrogen concentrations/equivalent hydrogen pressure in steel. He demonstrated that:

- For a carbon steel at 68°F (20°C) after only one minute of exposure, at 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) WT 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[xiii] and the pressure of hydrogen is less than 10%. Therefore, making a pressure correction is not considered necessary (see Figure 4).
- Under steady-state conditions, in steel at 68°F (20°C) 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 Table 1). Krom concluded that such high pressures in steel can result in cracking.

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[xiii] 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.

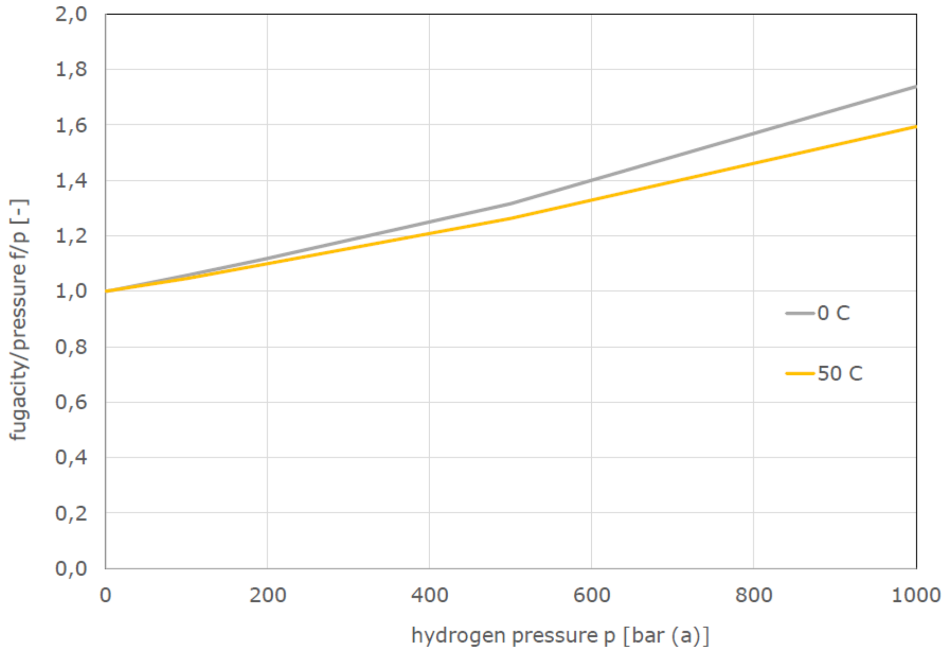

Figure 2 Relation between the fugacity and pressure of hydrogen at two temperatures

Figure 4. "Figure 2" from Krom[28]

Table 1. "Table 5" from Krom[28]

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

Krom compared the hydrogen concentration within steel under various hydrogen conditions (sources). While the metallurgical effects may not depend on the hydrogen source, there are implications for researchers performing tests in hydrogen environments. Of particular concern are the accuracy and reliability of the relationship between electrochemical charging conditions and equivalent hydrogen gas pressure. For conformity in testing, researchers should charge steel specimens in hydrogen gas and ensure that the gas composition is of known purity. If the intention is to test in pure hydrogen, special care needs to be taken to exclude contaminants such as oxygen and carbon monoxide.

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.

- Kiefner recommends adding "Time-Dependent – Fittings and sharp transitions" as a threat in ASME B31.8S. This threat is applicable to pipelines carrying hydrogen.

4.3.2.3 From Task 2 Final Report, Section 7.2.6, Missing Threat: (b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body

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 5[29].

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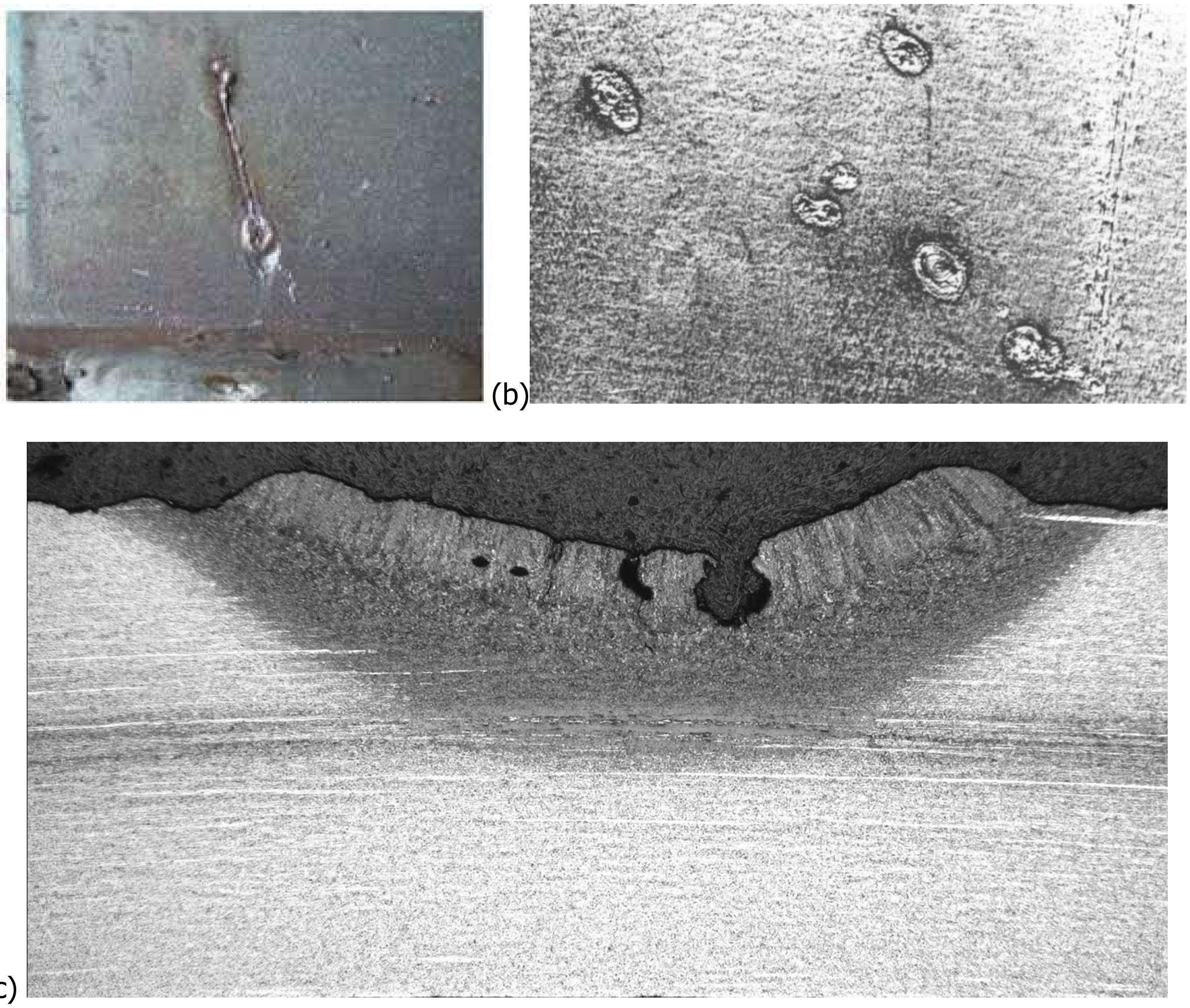
(a) (b)



(c)

Figure 5. Examples of Arc Burns/Strikes: (a) and (b) surface views, and (c) cross-section view[29]

Holbrook and Cialone[30] 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 J-fracture toughness J_{IC} [intersection of J-resistance curve and blunting line]) and the tearing resistance dJ/da [slope of the J-resistance curve]) compared with pure methane. The test conditions are summarized in Table 2 and Figure 6.

Table 2. "Table 2" from Holbrook and Cialone[30]

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.

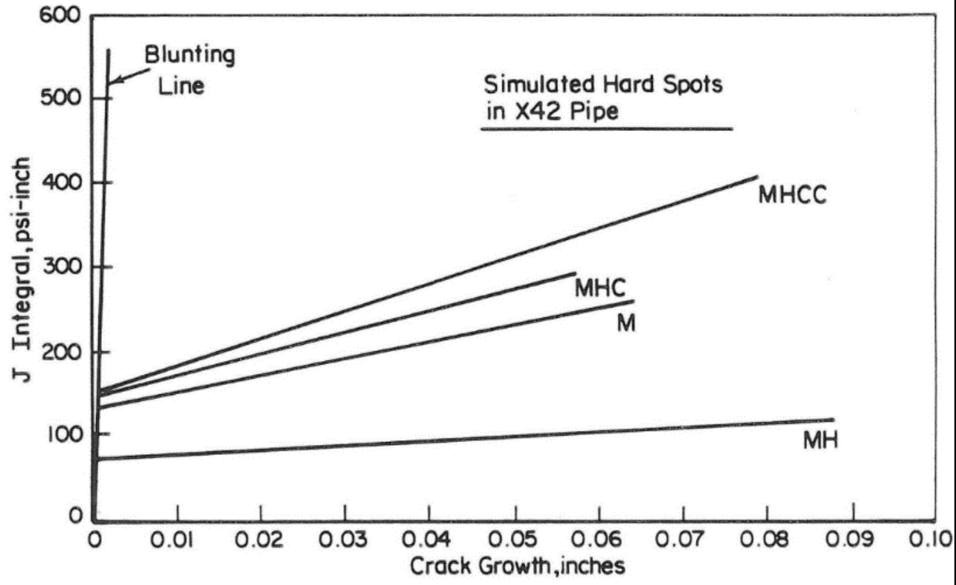


FIGURE 11. J-RESISTANCE CURVES FOR SPECIMENS FROM HARDENED X42 PIPE TESTED IN M, MH, MHC, AND MHCC ENVIRONMENTS

Figure 6. "Figure 11" from Holbrook and Cialone[30]; for gas mixtures M = 100% CH_4, MH = CH_4/H_2, MHC = $CH_4/H_2/CO$, MHCC = $CH_4/H_2/CO/CO_2$

- Kiefner recommends adding "(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.

4.3.2.4 From Task 2 Final Report, Section 7.2.8, Missing Threat: (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.

Type B Sleeves

Type B sleeves are an acceptable repair method. None of the welding/fabrication-related threat classifications in ASME B31.8S-2018 address Type B sleeves, although 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". This ignores essential differences between the fillet welds on Type B sleeve ends and the full-thickness butt welds used for GWs, 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 7).

The PRCI Pipeline Repair Manual 2021 edition[31] 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 weld fusion metal and HAZs 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 7. "Figure 16" from PRCI Pipeline Repair Manual, Showing Welding of Type B Sleeve[31]

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 PRCI Pipeline Repair Manual 2021 edition[31] 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[32], and subsequently added to API STD 1104, 21st edition released in 2013[33].

To illustrate the possibility of hydrogen cracking at puddle welds, an example of HIC in a weld HAZ is shown in Figure 8[34].

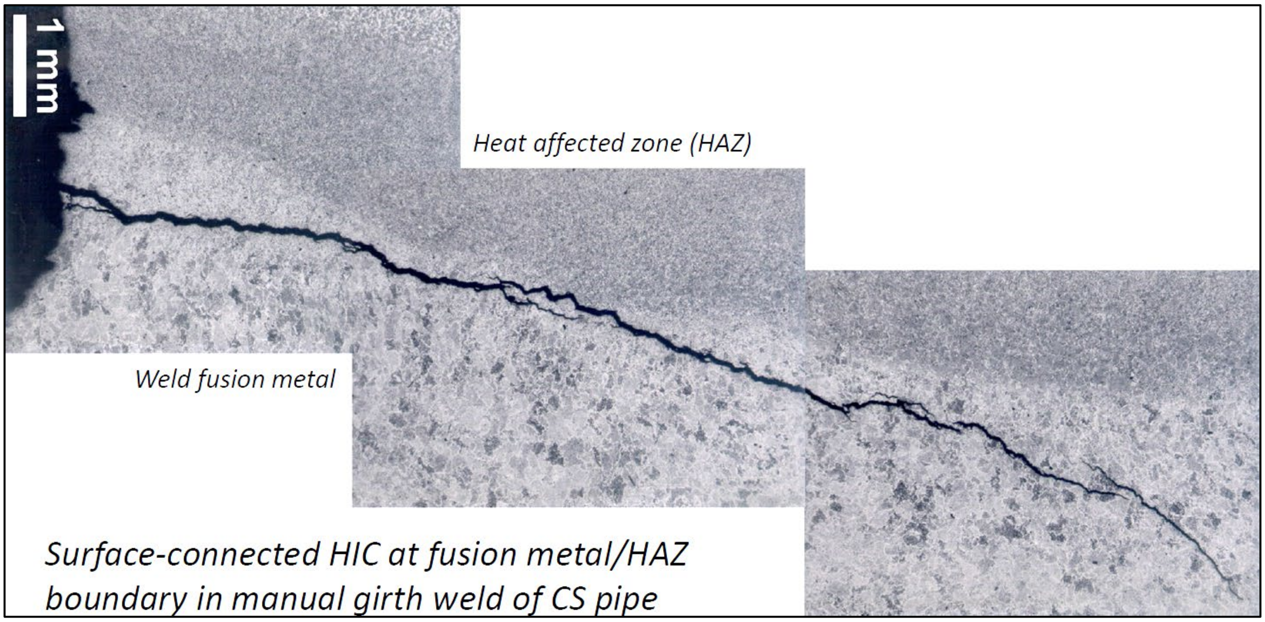


Figure 8. Example of HIC in Weld HAZ[34]

- Kiefner recommends adding "(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.

4.3.2.5 From Task 2 Final Report, Section 7.2.9, Missing Threat: (b) Resident (2) Equipment – Other material/equipment failure – Disbonded coating caused by hydrogen

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 9)[35].

Traditionally, the phenomenon of coating blistering due to hydrogen has been observed when cathodic over-protection occurs. In this case, hydrogen molecules are formed through water electrolysis at the metal surface underneath the coating. However, in the case of a pipeline carrying hydrogen gas or a gas blend containing hydrogen, dissociation of hydrogen molecules at the ID can supply hydrogen atoms for diffusion from the pipe's ID to the OD surface.

A pipeline not exposed to hydrogen will have a near-zero concentration of hydrogen atoms across its WT. Upon exposure to hydrogen from the internal gas pressurization, molecular hydrogen on the pipe's 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 WT. 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 WT will equilibrate. Once the hydrogen atoms reach the pipe's OD, they can recombine to form hydrogen gas molecules at the pipe/coating interface.

Some exploratory testing to determine the effects of hydrogen gas formation is currently being conducted at Sandia National Laboratories[36]. In those tests, a simulated lamination was created by machining away a rectangular area of steel from a pipe's OD surface. An equally sized solid piece of steel was then welded into the machined area to create an artificial pipe lamination. It is anticipated that H-atoms diffuse into the simulated lamination, recombine to hydrogen gas, which creates internal pressure. The concept of hydrogen blisters forming under a pipeline coating is the same, and this can be caused by hydrogen diffusion from the pipe's ID.

While pipeline integrity professionals are primarily concerned with the load-bearing capacity of the pipeline steel, a disbonded exterior coating that was supposed to be protective is an integrity threat. For that reason, it is included in this report.

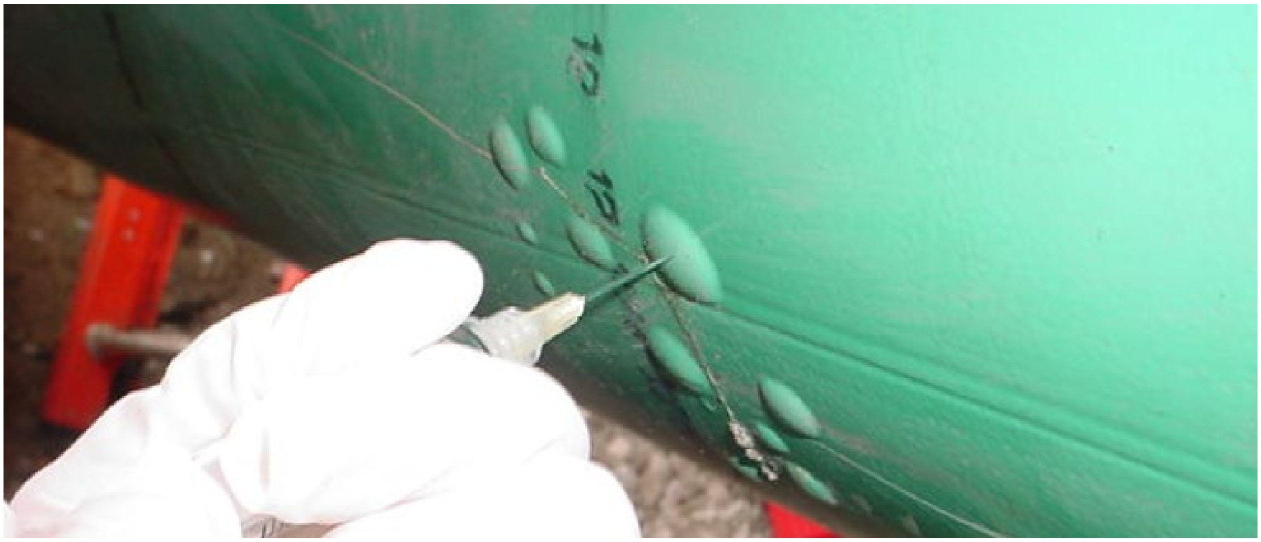


Figure 9. Example of FBE Coating Blisters[35]

- Kiefner recommends adding "(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.

4.3.2.6 From Task 2 Final Report, Section 7.2.10, Missing Threat (c) Random or Time Independent (3) Weather-related and outside force – At locations that may experience an electrical arc or fire – Fire Damage

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 GWs result from on-site fabrication processes.

Should a pipeline experience a fire, the microstructure and mechanical properties may change due to heating and cooling. The time held above the austenite transformation temperature of 1,333°F (723°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)[37], maintained by the HySafe International Association for Hydrogen Safety.

Fire damage is not a large risk for natural gas pipelines, as 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 its mechanical properties depend on the metal microstructure. Hydrogen decreases the overall ductility of the steel, specifically at hard spots. It also increases crack growth rates.

- Kiefner recommends adding "(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.

4.3.2.7 Task 1 Commentary on Reinspection Intervals in Codes and Standards ASME B31.8S-2022[7] versus ASME B31.8S-2004[38] Managing System Integrity of Gas Pipelines

As mentioned earlier, 49 CFR 192[1] incorporates by reference ASME B31.8S-2004[38]. The current version is ASME B31.8S-2022[7]. Some differences exist related to integrity assessment intervals. Specifically, the tables for prescriptive integrity management (IM) plans, which are reproduced below as Table 3 and Table 4, will be discussed next.

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

- The title of the 2022 version is "Integrity Assessment Intervals: Time-Dependent Treats, Internal and External Corrosion, Prescriptive Integrity Management Plan." The words "Internal and External Corrosion" were not included in the 2004 version.
- All factors are provided with two decimals in the 2022 version. Most were one decimal place in the 2004 version.
- Factors 1.65 and 2.75 are provided in the 2022 version. Those were 1.7 and 2.8, respectively, in the 2004 version.

The notes for the direct assessment process were updated with references to NACE SP0204[39] Stress Corrosion Cracking Direct Assessment (SCCDA) Methodology, NACE SP0206[40] Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA), and NACE SP0502[41] Pipeline External Corrosion Direct Assessment (ECDA).

The following discusses ILI reinspection intervals. Both versions of ASME B31.8S use P_f and compare the P_f value to the MAOP. The maximum allowable integrity assessment interval is specified based on the MAOP as a percentage of SMYS. For ILI, the interval can vary from as little as five years (P_f above 1.25 x MAOP, and MAOP above 50% SMYS) to as much as 20 years (P_f above 3.33 x MAOP, and MAOP below 30% SMYS) per ASME B31.8S-2022.

Figure 7.2.1-1 in ASME B31.8S-2022 (same as Figure 4 in ASME B31.8S-2004), reproduced here as Figure 10, graphically shows the timing for scheduled responses for time-dependent threats.

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

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

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

NOTES:
(1) Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time-dependent failure requires immediate reassessment of the interval.
(2) TP is test pressure.
(3) P_f is predicted failure pressure as determined from ASME B31G or equivalent.
(4) For the Direct Assessment Process, the intervals for direct examination of indications are contained within the process. These intervals provide for sampling of indications based on their severity and the results of previous examinations. Unless all indications are examined and repaired, the maximum interval for reinspection is 5 years for pipe operating at or above 50% SMYS and 10 years for pipe operating below 50% of SMYS.

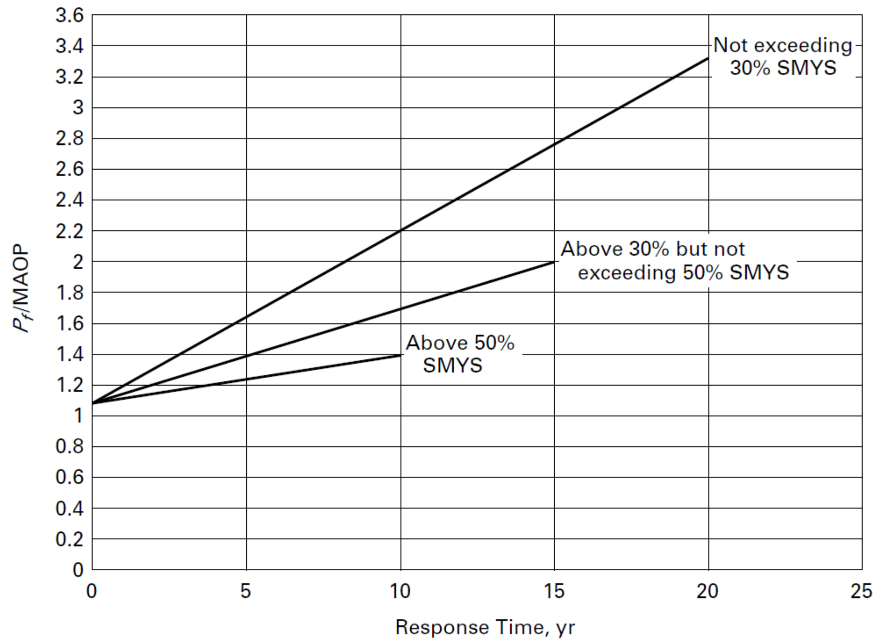
Table 4. “Table 5.6.1-1” from ASME B31.8S-2022

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

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.

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

4.4 ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8) Terminology

4.4.1 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 effects are named after their mechanism, and others after the source of hydrogen.

Table 5 (same as Table 5 of Kiefner's Task 2 Final Report of this project) summarizes the hydrogen terminology. The following terms are currently defined in the ASME B31.8 2022 edition:

- Hydrogen embrittlement (HE)
- Hydrogen-induced cracking (HIC)
- Hydrogen blistering
- Hydrogen stress cracking (HSC)
- Stress-oriented HIC (SOHIC)
- Sulfide stress cracking (SSC)

Kiefner recommends that Table 5 of this Task 3 report be included in ASME B31.8S.

The following terms are not currently defined in the ASME B31.8 2022 edition.

- Hydrogen ingress: A constant hydrogen concentration at the component surfaces exposed to the hydrogen-containing environment.
- Hydrogen-assisted cracking (HAC): Requires external stress to H-atoms to weaken the metallic bonds between iron atoms.
- Hydrogen-enhanced cracking (HEC): Steels susceptible to crack extension under static loading in a hydrogen environment, where no crack extension would occur in a benign (natural gas) environment.

Kiefner recommends adding the hydrogen terms that are not currently mentioned if they are going to be used within ASME B31.8 or ASME B31.8S (when Table 5 is added).

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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 with 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

*Note 1: The two items that are reversible are phenomena that can be reversed. Damage cannot be reversed.

4.4.2 Integrity Assessment Interval, Response Time (RT), Reassessment Interval (RI), and Remaining Life (RL)

ASME B31.8S-2018[6] 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 RI, and RI should be shorter than the RL to reach a future critical condition. The relation between these various times is described by Lotfian and Brongers in a 2025 paper[42] titled "Remaining Life Assessment of Hydrogen Pipelines for Flaw Sizes Below ILI and NDE Detection Limits".

Theoretically, a pipeline's life can be infinite if maintained adequately. However, pipeline integrity is threatened by various causes that must be managed to ensure safe operations. Codes such as ASME B31.8S-2018 list specific integrity threats, usually associated with the pipe's physical features and metallurgical conditions. IMPs rely on ILI to find those features.

Once the locations, identity, current dimensions, and a likely future growth rate are known for features, their anticipated RL can be estimated, and appropriate responses can be executed. These activities must be done on a schedule, with reinspection/reassessment before the feature becomes critical. Thus, to avoid failure, the RI should be set shorter (for example, half) than the RL.

Operators should evaluate all detected features and estimate their individual RLs. The feature with the shortest life will be "the weakest link" that dominates the life of the entire pipeline. The operator should repair or remove/cut out all features with an RL shorter than the desired RI (for example, five years).

In addition to the parameters mentioned above, the following is a non-exhaustive list of things that should be considered in the RL determination:

- Basic pipeline design, steel properties, and operational details - through data integration;
- Diameter, WT, SMYS, and ultimate tensile strength (UTS), assumptions on material properties;
- Seam weld type, vintage, coating type, cathodic protection (CP) or no CP;
- MAOP, pressure fluctuations, temperature, known history, threat identification, and interaction;
- Properties of sub-critical size features;
- Characteristics at time of inspection (probability of detection, identification, sizing);
- Estimated growth rates;
- Assumptions on growth mechanism;
- Assumptions on rate with time (constant or changing rate);
- Properties of critical size features;

- Definition of failure (depth-through-wall percentage, flow strength, fracture toughness);
- Uncertainty in all parameters;
- Decision on RI;
- If half of the RL is sufficient; and
- The length of the desired interval.

The process of establishing an RI is illustrated in Figure 11 through Figure 16. The period of interest is operations, which can last many decades. Periodic maintenance should be planned. Operators typically have a system to ensure these standard activities are accomplished. If maintenance is performed such that anomalies never reach critical dimensions, the pipeline's life can be infinite, as illustrated in Figure 11.

Features other than pipe manufacturing defects initiate sometime after the pipeline is placed into service. For example, it takes time before a coating disbonds, and corrosion metal loss can occur on the metal surface. From the moment a feature is initiated, it can grow at a rate determined by the growth mechanism and environmental and operational conditions. Failure is usually defined as the instant that a feature has grown to a critical size, causing the pipe to leak or rupture. Thus, the total feature life from initiation to a critical size is shown in Figure 12.

Features cannot be identified at the time of initiation because they are too small. Sometime later, during the feature’s subcritical life, it can be detected by an inspection. The time between the moment that a feature is detected/identified and the time that it grows to critical size is the RL of the feature, refer to Figure 13.

The RI should be set well before a feature becomes critical. A typical value engineers use is a Factor 2, signifying the RI should not exceed half of the RL, refer to Figure 14. For a collection of features, such as the entire collection of anomalies detected in an ILI run, the shortest RL of a feature dominates and limits the pipeline's RL. The desired RI can be reached by repairing/removing those features with the shortest RL. The non-repaired features should be monitored until the next inspection/assessment, refer to Figure 16.

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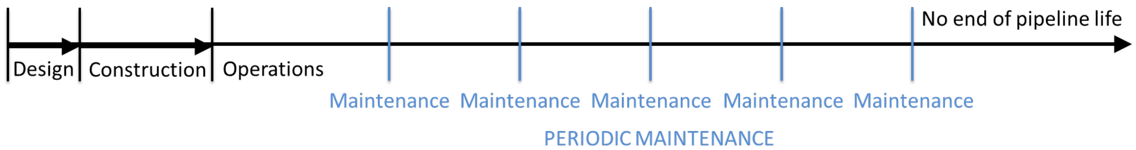


Figure 11. Timeline Showing Periodic Maintenance at Regular Intervals During Pipeline Operation.

Figure 12. Timeline Showing Feature Life from Time of First Initiation with Feature Growth Until the Feature's Critical Size is Reached.

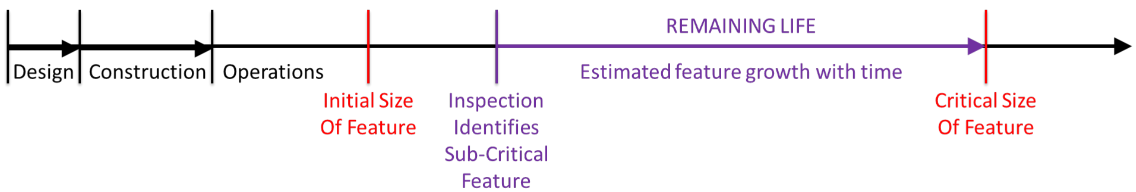


Figure 13. Timeline Showing Remaining Life is Shorter Than the Total Feature Life.

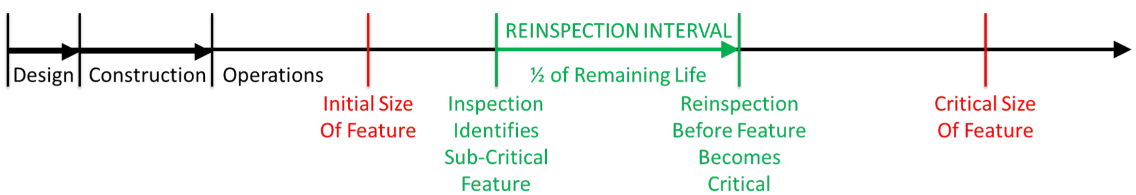


Figure 14. Timeline Showing a Reinspection Interval of a Single Feature as Half of the Feature's Remaining Life."

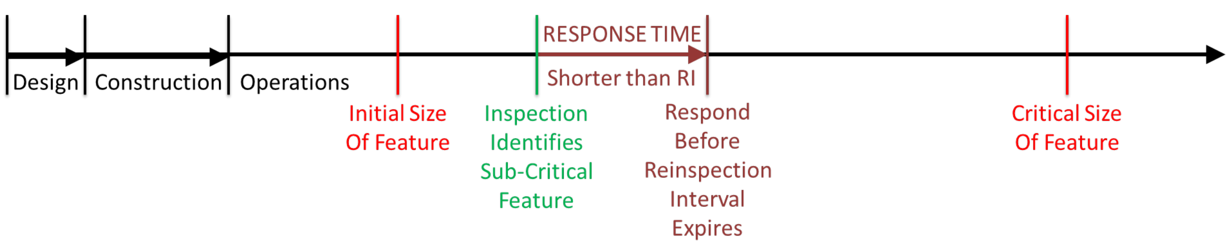


Figure 15. Timeline Showing that the Response Time Should be Shorter Than the Reinspection Interval for Any Single Feature.

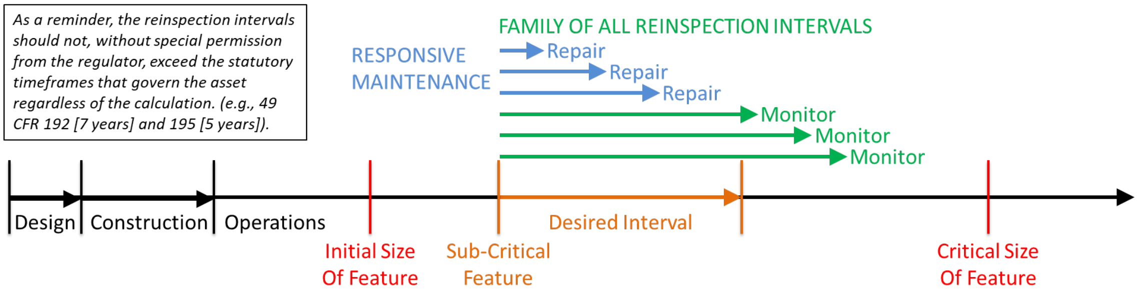


Figure 16. Timeline Showing that the Desired (Reinspection) Interval of a Collection of Features is Determined by the Shortest Remaining Life of Any Single Feature That Is Not Repaired.

4.5 Task 2 Commentary on Review of ASME B31.8S-2018 Table 5.6.1-1 (Integrity Assessment Intervals) and Figure 7.2.1-1 (Timing for Scheduled Responses)

Kiefner reviewed Table 5.6.1-1 (Integrity Assessment Intervals) and Figure 7.2.1-1 (Timing for Scheduled Responses) in Task 2. The findings are presented below.

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

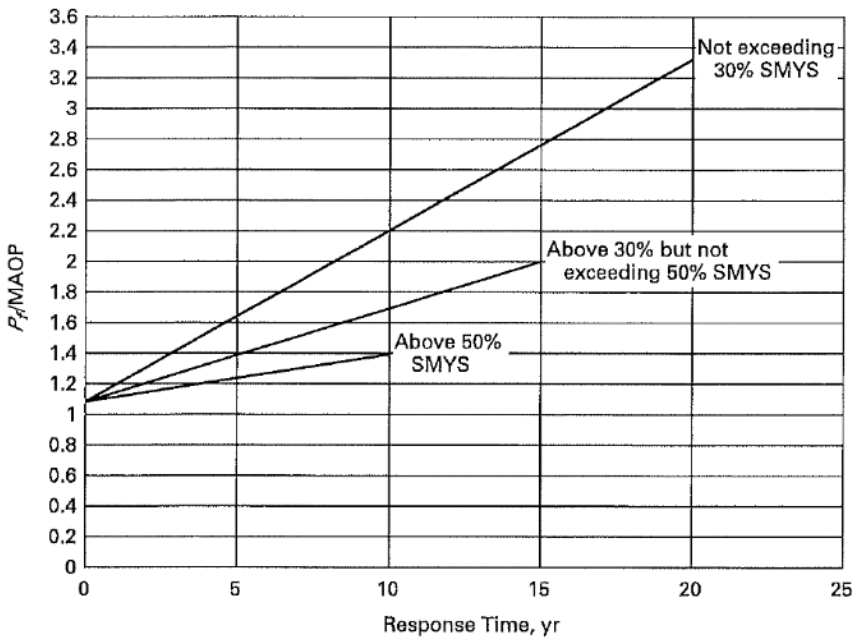
Integrity Assessment Interval (Table 5.6.1-1), or Response Time (Figure 7.2.1-1)	Maximum Allowable Operating Pressure (MAOP)		
	>50% SMYS	>30%-≤50% SMYS	≤30% SMYS
5 years	0.90 x SMYS (1.25 x MAOP)	0.70 x SMYS (1.39 x MAOP)	0.50 x SMYS (1.65 x MAOP)
10 years	1.00 x SMYS (1.39 x MAOP)	0.83 x SMYS (1.65 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 17. 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 WTs.

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 17. Figure 7.2.1-1 Timing for Scheduled Responses – Time-Dependent Threats, Prescriptive Integrity Management Plan from ASME B31.8S-2018[6]

Figure 17 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	(5)
Pipe operating > 30% - 50% of SMYS	P_f / MAOP = 0.0600 x RT + 1.1	(6)
Pipe operating < 30% SMYS	P_f / MAOP = 0.1115 x RT + 1.1	(7)

To better understand the graph, Figure 17 was replotted as Figure 18, 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	(8)
Pipe operating > 30% - 50% of SMYS	RT = 16.67 x P_f / MAOP – 18.33	(9)
Pipe operating < 30% SMYS	RT = 8.97 x P_f / MAOP – 9.87	(10)

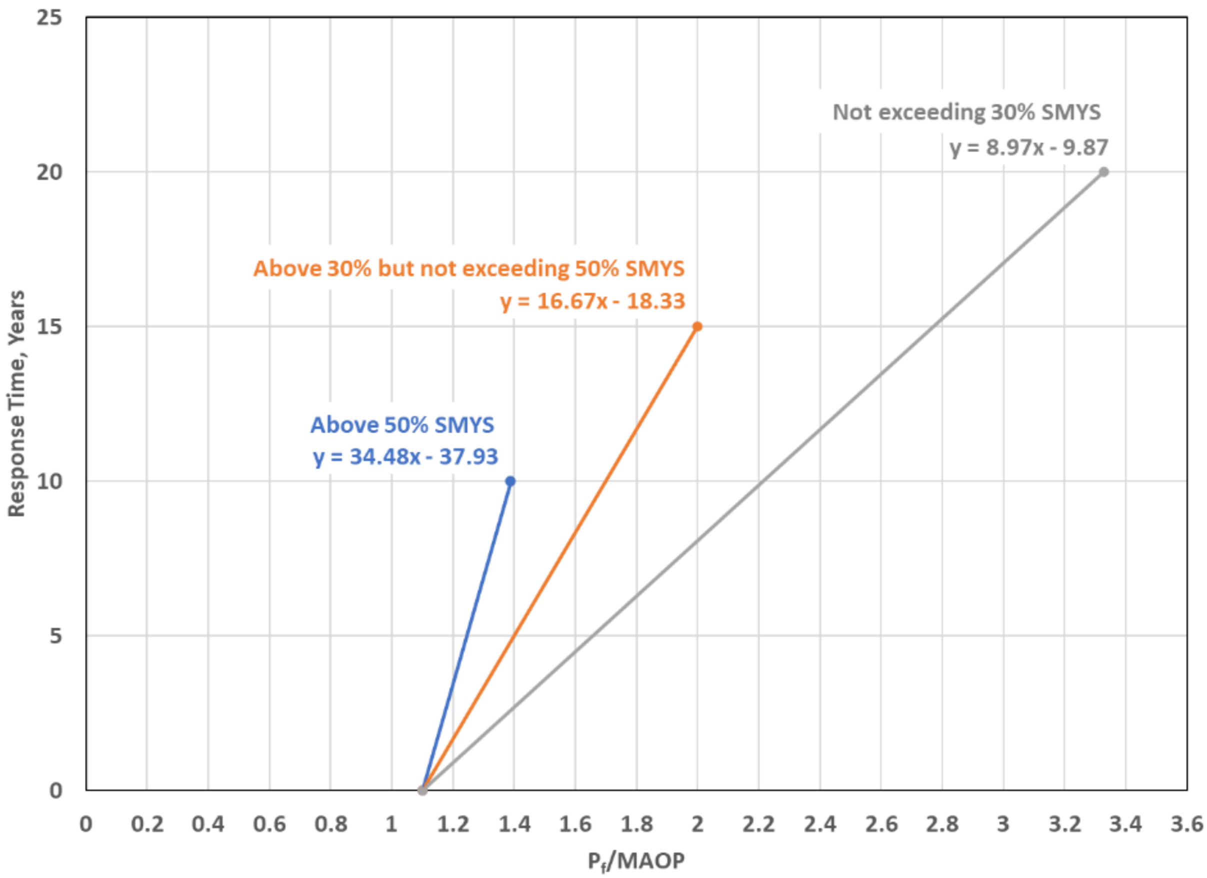


Figure 18. Replot of ASME B31.8S-2018 Figure 7.2.1-1 with Dependent Variable "Response Time" on the y-Axis.

Based on the analysis presented in this project's Task 2 Final Report:

- Kiefner recommends introducing the concepts of remaining life (RL) and reinspection interval (RI) into the Code while maintaining the concept of response time (RT).
- Kiefner recommends revising ASME B31.8S-2018 Table 5.6.1-1 and Figure 7.2.1-1 with consistent application of predicted failure pressure (P_f) and factors related to the specified minimum yield strength (SMYS).
- Kiefner recommends that ILI anomalies be assessed with a more realistic corrosion rate (CR) while considering the possible variability in CRs to assess the risk of overestimating or underestimating current criticality and future RL.

5 RECOMMENDATIONS

Based on the analysis of the various Codes and Standards, review of publicly available literature, evaluation of the results of the analyses performed in Tasks 1 and 2 of this project, and the discussions included in this report, the following recommendations were formulated:

For 49 CFR 192 Subpart A - General

- Kiefner recommends that PHMSA remove the words "introductory text and " from Section 192.7(c)(7), because the introductory text in Section 192.907 no longer exists. Without this change, the text in 192(c)(7) is confusing.
- Kiefner recommends that PHMSA update 49 CFR 192 to incorporate by reference API STD 1163, 3rd edition for ILI systems qualification.
- Kiefner recommends that, until such additional requirements are provided in ASME B31.8S, PHMSA incorporate by reference API RP 1176, the industry-recommended practice for managing pipeline cracking, into 49 CFR 192.
- Kiefner recommends that PHMSA incorporate by reference API RP 1176 into 49 CFR 192 to require operators of hydrogen and hydrogen/natural gas blended pipelines to develop crack management plans and procedures within their IMPs, based on industry-recommended practices.

For 49 CFR 192 Subpart M - Maintenance

- Kiefner recommends that PHMSA issue an advisory bulletin to remind operators to update their risk assessments for hydrogen considerations and perform ILI with tool technologies appropriate to detect indications susceptible to the effects of hydrogen degradation for pipelines being considered for hydrogen blending or transportation.
- Kiefner recommends that PHMSA issue an advisory bulletin to remind operators to consider the interaction of hydrogen's potentially detrimental microstructural effects on the material properties used in crack analysis models.
- Kiefner recommends that PHMSA explicitly include hydrogen effects to fatigue as a threat when determining reassessment intervals and require fatigue crack growth models to be considered within 49 CFR 192.
    - Alternatively, at a minimum, Kiefner recommends that PHMSA issue an advisory bulletin to reinforce the expectation for operators to consider the effect of hydrogen on the fatigue life in crack growth models used to determine reassessment intervals for anomalies previously considered non-susceptible to environmental effects.

For 49 CFR 192 Subpart O - Gas Transmission Pipeline Integrity Management

- Kiefner recommends that PHMSA issue an advisory bulletin highlighting the outcomes of recent research on hydrogen transport to remind operators of the applicable risk changes associated with hydrogen transportation in pipelines that are not purpose-built for that product.

- Kiefner recommends that PHMSA issue an advisory bulletin based on this report's findings to inform operators of their responsibility to consider the additional risks that hydrogen and hydrogen blends have on existing pipelines, including the effects of fatigue and crack growth rates, prior to converting a pipeline or transporting these products.
- Kiefner recommends that, given the additional risk imposed by hydrogen fatigue crack growth rates, the requirement should be updated to require operators to consider any change in pipeline operation or product that may change the basis of a prior analysis, perform a new cyclic fatigue analysis, and evaluate the effects of fatigue on existing anomalies within the pipeline.
- Kiefer recommends that PHMSA issue an advisory bulletin to remind operators to consider the embrittlement effects of hydrogen on crack-like anomalies and that tools capable of assessing a pipeline for cracks should be used on pipelines transporting hydrogen or hydrogen blends.
- Kiefner recommends that PHMSA update the IBR in 192.933(d) to ASME B31.8S-2022 based on recommendations in Section 4.3 ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8) Review of Potential Integrity Threats.

<u>For ASME B31.8 Gas Transmission and Distribution Piping Systems</u>

- Kiefner recommends supporting the balloting items being proposed and the review process being followed by the Hydrogen Task Group of ASME B31.8.

<u>For ASME B31.8S Managing Systems of Integrity of Gas Pipelines (Supplement to ASME B31.8)</u>

<u>Review of Potential Threats to Integrity</u>

- Kiefner recommends adding the following missing integrity threats applicable to any gas transmission pipeline to Paragraph 2.2 of future versions of ASME B31.8S:
    - Time-Dependent – Fatigue cracking
    - (b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Low-toughness seam
    - (b) Resident (1) Manufacturing-related defects (a) Defective pipe seam – Defect in or near an electric resistance welded (ERW) seam
    - (b) Resident (2) Welding/fabrication-related – At in-service/repair welds – Hydrogen Stress Cracking
- Kiefner recommends adding the following missing integrity threats applicable to gas transmission pipelines in hydrogen and hydrogen blend service to the future ASME B31.8S hydrogen chapter:
    - Time-Dependent – Hydrogen-Induced Cracking (HIC)
    - Time-Dependent – Fittings and sharp transitions
    - (b) Resident (2) Welding/fabrication-related – Near girth welds, and near in-service/repair welds – Arc burn/strike on pipe body

- (b) Resident (2) Welding/fabrication related – At welded sleeves and fittings – Type B sleeves and Puddle welds
- (b) Resident (2) Equipment – Other material/equipment failure – Disbonded coating caused by hydrogen
- (c) Random or Time Independent (3) Weather-related and outside force – At locations that may experience an electrical arc or fire – Fire damage

Description of Hydrogen Effects

- Kiefner recommends using consistent terminology when describing hydrogen effects.
- Kiefner recommends that Table 5. Summary of Hydrogen Terminology of this Task 3 report be included in ASME B31.8S.
- Kiefner recommends adding the hydrogen terms that are not currently mentioned if they are going to be used within ASME B31.8 or ASME B31.8S (when Table 5 is added).

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

- Kiefner recommends introducing the concepts of remaining life (RL) and reinspection interval (RI) into the Code while maintaining the concept of response time (RT).
- Kiefner recommends revising ASME B31.8S-2018 Table 5.6.1-1 and Figure 7.2.1-1 with consistent application of predicted failure pressure (P_f) and factors related to the specified minimum yield strength (SMYS).
- Kiefner recommends that ILI anomalies be assessed with a more realistic corrosion rate (CR) while considering the possible variability in CRs to assess the risk of overestimating or underestimating current criticality and future RL.

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