



Inspectioneering Journal

ASSET INTEGRITY INTELLIGENCE

SPECIAL EDITION

2022 API Inspection & Mechanical Integrity Summit

Including 8 of Our Most Popular Articles
Since the 2019 Summit



2022
INSPECTION
AND MECHANICAL
INTEGRITY SUMMIT

AUGUST 9-11
SAN ANTONIO
TEXAS | USA



American
Petroleum
Institute

GET MORE FROM THE 2022 API INSPECTION SUMMIT



INSPECTION & ENGINEERING



OIL



GAS

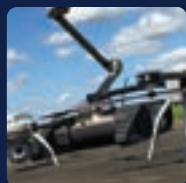
Services | Software | Consulting | Systems

- ✓ FIELD INSPECTIONS
- ✓ LABORATORY SERVICES
- ✓ MAINTENANCE
- ✓ CONSULTING
- ✓ ACCESS
- ✓ DATA MANAGEMENT
- ✓ MONITORING
- ✓ EQUIPMENT
- ✓ SPECIAL EMPHASIS PROGRAMS

VISIT US AT BOOTH #320 AND COME SEE OUR LIVE DEMOS



PCMS®



AIR, LAND & SEA DRONE
INSPECTION SERVICES



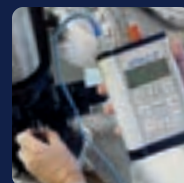
ONSTREAM INLINE
PIPE INSPECTION



AUTOMATED RT
CRAWLER SERVICES



LARGE STRUCTURE
INSPECTION (LSI™)



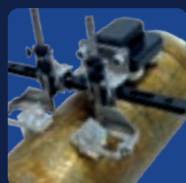
VPAC™II



CALIPERAY™ REMOTE
THICKNESS TRACKING



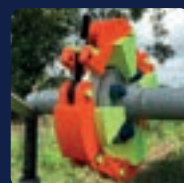
CORROSION UNDER
PIPE SUPPORTS



TOUCH POINT
CORROSION SERVICES



MISTRAS DIGITAL®



FLANGE CUFF™



ENGINEERING/AIMS/
MI SERVICES

AND MORE...

DEMONSTRATIONS ARE SUBJECT TO AVAILABILITY AND CHANGE

VISIT US AT

MISTRASGROUP.COM



MG
LISTED
NYSE

ONLINE

Subscribe online to gain exclusive access to the Journal archives, online articles, industry news and events, and other valuable resources.

inspectioneering.com/subscribe

INTEGRIPEDIA

A community-sourced encyclopedia of Asset Integrity Management terms and definitions. We need your help continuing to expand our library of terms.

inspectioneering.com/topics

THE INSPECTIONEER

A free weekly e-newsletter containing featured content, news recaps, industry updates, and upcoming events.

inspectioneering.com/newsletters

Neither this publication nor any part of it may be reproduced, stored in any retrieval system, or transmitted in any form or by any means, electronic, mechanical, photocopying, recording or otherwise, without the prior permission of Inspectioneering, LLC. Inspectioneering Journal (ISSN 1082-6955) is published bi-monthly, by Inspectioneering, LLC, 24900 Pitkin Road, Suite 325, Spring, TX 77386 USA. Inspectioneering Journal is a registered trademark of Inspectioneering, LLC.

Postmaster: Send address changes to Inspectioneering, LLC, 24900 Pitkin Road, Suite 325, Spring, TX 77386 USA.

Design and layout by Heather Cobb.
Printed by Alliance Graphics and Printing,
5225 Hollister, Houston, TX 77040 USA

Copyright © 2022 Inspectioneering, LLC.
All rights reserved.



SPECIAL EDITION

2022 API INSPECTION & MECHANICAL
INTEGRITY SUMMIT

TABLE OF CONTENTS

- 9 Moving Forward with Professional Development – API ICP Recertification Requirements**
Andri Orphanides, API
- 12 Lessons Learned from the Rupture of a Steam Superheater Header**
Peter Tait, Methanex
- 15 A Thousand Important Roles & Responsibilities of the Plant Fixed Equipment Inspection and Mechanical Integrity Group**
John T. Reynolds, Intertek AIM and Inspectioneering SME
- 23 Lessons from a Risk-Based Career**
Brent Ray, Marathon Petroleum Corporation
- 30 Management and Identification of Dead Legs**
Ashfaq Anwer, Sr. Integrity Engineer
Kaiser Alam, Inspection Engineer
- 33 Risk Based Management of Corrosion Under Insulation**
Frode Wiggen, DNV GL
- 40 Fitness-for-Service Forum: Updates to the New & Improved API 579 Standard**
Greg Garic, PE, Stress Engineering Services, Inc.
- 45 Damage Control: Wet H₂S Damage Detection**
Phillip E. Prueter, PE, The Equity Engineering Group, Inc.

OTHER FEATURES

- | | |
|-----------------------------|----------------------------------|
| 04 Floor Plan | 06 Corporate Members List |
| 05 Exhibitor Listing | 07 Publisher's Note |

EXHIBIT HALL FLOOR PLAN



Inspectioneering raffle participant

EXHIBITOR LISTING

COMPANY	BOOTH
Abyss Solutions	502
Acuren	200
Amerapex NDT LLC	531
American Society for Nondestructive Testing	414
Antea	304
Applus+	118
ARIX Technologies	623
AUT Solutions Group, LLC.	410
Becht	319
ClampOn, Inc.	109
Cognascent Consulting	112
Cokebusters USA	510
Collins Engineers, Inc.	621
Conco Services	101
Consulting and Field Services, LLC	121
Corrosion Radar Ltd	13
Creaform	9
Curran International	108
DÜRR NDT GmbH & Co. KG	625
E2G The Equity Engineering Group, Inc.	301
Eddyfi Technologies	620
Engineering & Inspection Services, LLC	218
Fixed Equipment Reliability – FER	630
FlawTech America, LLC	525
Foerster Instruments	11
FRONTICS AMERICA	411
G.C. Laser Systems Inc.	521
Gecko Robotics	306
Guided Ultrasonics Ltd.	512
Guided Wave Analysis LLC	313
HMT Tank	401
HUVRData	403
Inductosense	413
INGU	310
InPro	615
Integrity EPC	408
Intertek Asset Integrity Management	7
Ionix Advanced Technologies	309
IRET THERMAL GROUP LTD.	119
IRISNDT	520
JIREH	632
KNIGHTHAWK ENGINEERING	311
Lavender International NDT USA	307
Leica Geosystems	409
Lloyd's Register	305

COMPANY	BOOTH
Matrix Service Company	210
MFE Inspection Solutions	631
MI Solutions	209
MISTRAS Group	320
MMT	115
mPACT2WO (A Molex Business)	105
NDT SEALS, INC.	110
NDT SPOT, Inc.	506
NVI	404
Olivier International	1
Olympus/Evident	207
Oplii	514
Pinnacle	300
PK Technology	15
Pro-Surve Technical Services, LLC	418
PROtect, LLC	315
Provenance Consulting, A Trinity Consultants Company	406
Qi2 Elements	523
QSA Global, Inc.	212
Quasset LLC	214
Quest Integrity	614
ROSEN	308
ScanTech Instruments, Inc.	114
SciAps Inc	106
Screening Eagle Technologies	412
Sensor Networks	204
Sentinel Integrity Solutions, Inc.	419
Southern Services, Inc	111
Stress Engineering Services	515
Stronghold Inspection LTD	19
TesTex, Inc.	206
THE PHASED ARRAY COMPANY, LLC	617
Thermo Fisher Scientific	405
TLV CORPORATION	407
Turnaround Consulting Services	500
Turner Specialty Services	508
TUV Rheinland	205
UTComp	504
VERMON	619
VERSA INTEGRITY GROUP	201
VIEWTECH BORESCOPES	113
VMI	100
WAYGATE TECHNOLOGIES	519
WJE ASSOCIATES, INC.	211

ARTICLE SUBMISSION GUIDELINES

1. All articles must adhere to the Guidelines and Requirements listed on our website at inspectioneering.com/publish.
2. Authors must have/obtain authorized permission to print, with company and name byline, in this publication.
3. Send duplicates of all photos, illustrations, and visual aids with permission to reprint. Must be submitted with draft article.
4. Editor and contributing editors will make all final decisions regarding acceptance of article, judged by value and appropriateness, along with editing decisions.
5. Author is responsible for final review, following step 4, and authorization from his/her employer to release, as necessary.
6. All articles accepted by Inspectioneering Journal become property of Inspectioneering, LLC. No reprint is permitted without prior written authorization.

Submit all articles to

publish@inspectioneering.com

DISCLAIMER

Inspectioneering, LLC assumes no responsibilities or liabilities for the accuracy or application of methodologies, technologies, philosophies, references, case histories, or unauthorized release of company information in relation to any printed subject matter in Inspectioneering Journal. Inspectioneering, LLC, the editors and authors of Inspectioneering Journal, or anyone acting on their behalf, assume no responsibility or liability, without limitation, for the use of information published in Inspectioneering Journal.



CORPORATE MEMBERS

Inspectioneering would like to thank all of our subscribers for their trust and their commitment to a higher level of Asset Integrity Intelligence. The Journal is now read by thousands of integrity management professionals in nearly 160 countries, many of whom gained access through our Corporate Membership program. If your company is not yet a Corporate Member (listed below), please visit inspectioneering.com/subscribe or contact Josh Means at jmeans@inspectioneering.com to get started today.

ABB	HF Sinclair Corporation	Repsol
Abu Dhabi National Oil Company (ADNOC)	Houston Integrity Consultants	Rio Tinto
Air Liquide	Hunt LNG Operating Company	ROSEN Group
Air Products	Hunt Refining Company	Santos
Alberta Boilers Safety Association	Huntsman	SapuraOMV Upstream
American Petroleum Institute (API)	Imperial Oil	Sasol
Americas Styrenics	Incitec Pivot Limited (IPL)	SATORP (Saudi Aramco Total Refining & Petrochemical Co.)
Antea	INVISTA	Saudi Aramco
Ascend Performance Materials	IRISNDT	Shell plc
Aspen Aerogels	Irving Oil	Sipchem
Astron Energy	Keyera	Stress Engineering Services, Inc.
Atlantic LNG	Kinder Morgan	Suncor Energy
Badak LNG	Koch Industries	Syngenta Group
Bayer	Kraton	TEAM, Inc.
Becht	LyondellBasell	ThaiOil Group
BHP Billiton	Mangalore Refinery and Petrochemical Limited	TotalEnergies
Borealis Group	Marathon Petroleum Corporation	TSASK (Technical Safety Authority of Saskatchewan)
BP	Mercer International	Uganda National Oil Company (UNOC)
Braskem	Methanex Corporation	Unipetrol
Canadian Natural Resources Limited (CNRL)	MISTRAS Group	UPM
Cenovus Energy	Motiva Enterprises LLC	Valero Energy Corporation
Channel Infrastructure	Motor Oil (Hellas)	Varo Energy
Chevron	NewMarket Corporation	Veolia
Chevron Phillips Chemical	NOVA Chemicals	Westlake Chemical
CHS Inc.	Nutrien	Williams
CITGO Petroleum	Occidental Petroleum Corporation (Oxy)	WJE (Wiss, Janney, Elstner Associates, Inc.)
COMISA	Oceaneering	wood.
ConocoPhillips	Office of Technical Inspection (UDT)	XTO Energy
Covestro	Olympus	Yara International
Delek US	ONEOK	
DNV (Det Norske Veritas)	Orica	
Dolphin Energy	Origin Energy	
Dow Chemical	Pan American Energy	
DuPont	Parkland Corporation	
Ecopetrol	PBF Energy	
Enbridge	Petro Rabigh	
Enerplus	Petrobras	
Eni	Petrojam Limited	
Equinor	Petronas	
Equity Engineering Group (E2G)	Philadelphia Energy Solutions	
ExxonMobil	Phillips 66	
Federated Co-Operatives Limited (FCL)	Pinnacle	
Flint Hills Resources	PK Companies	
FM Global	Pro-Surve Technical Services LLC	
Gecko Robotics	PTT Global Chemical	
Grupa LOTOS	PTT Public Company Limited	
Gunvor	Qatar Fuel Additives Company (QAFAC)	
Haldor Topsoe	QatarEnergy	
Health and Safety Executive	Qenos	
Hellenic Petroleum	Quest Integrity Group	

OFFICE

Please address all correspondence to:
24900 Pitkin Road, Suite 325
Spring, TX 77386 USA

JOURNAL STAFF

Chief Editor

Gregory Alvarado

VP and Technical Director

Nick Schmoyer

VP and General Counsel

Jeremiah Wooten

VP, Sales & Marketing

Christopher Levy

Business Development Manager

Josh Means

EDITORIAL BOARD

Senior Editor

John Reynolds

Technical Editors

Mark Geisenhoff

John Harville

Art Jensen

Lynne Kaley

John Nyholt

Dave Osage

Chad Patschke

Brent Ray

Shane Roysum

Clay White

Josh Yoakam

SUBSCRIPTION

For our latest subscription pricing visit
inspectioneering.com/subscribe

For subscription service, please
contact by telephone or email at
the details below:

Phone: +1 (281) 397-7075

Email: subscribe@inspectioneering.com

Subscription Prices

1-year print/online subscription: US\$220

1-year online subscription: US\$160

Inquire about Corporate Pricing

PUBLISHER'S NOTE



The Return of the Summit

After a three-and-a-half-year hiatus, the API Inspection and Mechanical Integrity Summit has finally returned. For those fortunate enough to join us in person in San Antonio, welcome. This marks the eighth biennial Summit, which had been previously held in Galveston every other year since 2007. Unfortunately, COVID forced the 2021 conference to be delayed until this point, but I believe I speak for everyone when saying how exciting it is to be returning to this event in person.

The Summit is a special event for many reasons. It is the only conference of its kind in the U.S. that focuses on inspection and mechanical integrity of equipment in the oil, gas, and chemical industry. And when that specific focus is combined with a network of the leading minds in our industry, you get an exceptional technical program that is truly unrivaled.

This year, there are nearly 300 technical sessions covering the upstream, midstream, and downstream sectors. Presentation topics include Engineering & Asset Integrity Management, Inspection/NDE/Monitoring, Metallurgy & Corrosion, Risk Based Inspection, Robotics & Unmanned Aerial Vehicles, and Storage Tanks. Moreover, there are 20+ panel discussions scheduled on "hot topics" in the industry with a diverse group of over 50 experienced, knowledgeable SMEs participating. On top of all that, on Monday before the conference begins, 20 different training courses are being offered by recognized industry experts covering a variety of important MI-related topics.

This is truly an incredible learning opportunity for all inspectioneers, regardless of facility type or experience level. But in addition to the training courses, presentations, and panel discussions, perhaps the greatest benefit to attendees is the opportunity to meet and network with your peers in the industry.

Mechanical Integrity SME and Inspectioneering Sr. Editor, John Reynolds, once said that "the personal relationships forged through networking at the Summit pay big dividends long after the conference is over." His personal network of colleagues he's met at the Summit is well over 100 people now, and over the years they've routinely shared their personal knowledge and experiences with one another to help improve inspection and mechanical integrity practices.

Brent Ray, Summit Downstream Sector Chair, put it pretty simply: "I tell anybody asking about attending the Summit that this is without a doubt the best opportunity in our industry to network and learn from each other."

I have been attending this event since 2013, and from what I've seen first-hand, and from the conversations I've had with countless attendees, John and Brent are spot on!

So, enjoy your time at the Summit, leverage the numerous learning opportunities, and take away at least a few "nuggets" that will make your job easier, make your facility more reliable, and make your company better. And if you have a free moment, stop by the Inspectioneering booth and say hello.

Jeremiah Wooten
VP and General Counsel



American
Petroleum
Institute



INVEST IN AN API CERTIFICATION

INVEST IN YOURSELF

API 510 Pressure Vessel Inspector
API 653 Aboveground Tank Inspector
API 570 Piping Inspector

**ULTRASONIC TESTING
PRACTICAL EXAMINATIONS**
Phased Array, Sizing,
Detection, Crack Sizing,
Thickness Measurement,
and Long Seam Pipeline
(NEW!)

API 1184 Pipeline Facility Construction
Inspector (NEW!)
API 1169 Pipeline Construction Inspector

To take the next step in your career visit:

www.API.org/ICP
icp@api.org

Moving Forward with Professional Development – API ICP Recertification Requirements

Andri Orphanides, Credentialing Specialist & Director, Individual Certification Programs at API

The author of this article, Andri Orphanides, will be speaking at a session called “ICP and CPDs: Nourishing Your Professional Growth” at the API Inspection & Mechanical Integrity Summit. The session is scheduled for August 9th at 1:30 PM CDT. Please refer to API’s program for more information.

Introduction

“Why is API instituting Continued Professional Development (CPD) requirements to the recertification process for API 510, 570 and 653?” – this has been the most common question asked with the newly updated Individual Certification Programs (ICP) recertification requirements. The idea of adding continuing professional development to certification programs is not a novel idea. Many professional credentials ranging from engineering, to the medical or teaching professions, have criteria for professional development as part of their programs. In fact, the certification task group had considered the option of including CPD requirements early on but could not find consensus on feasible requirements.

Market fluctuations in the industry require employers to seek out a multifaceted talent pool, and the role of the inspector must develop and expand accordingly. The modern inspector must understand ever-evolving inspection techniques, damage mechanisms, as well as the business environment that drives decisions and judgements.

The concept of certified versus qualified, or newly-certified versus senior inspector, have been tossed around and discussed among industry experts for years. There is a paradigm shift occurring in the industry in which inspectors are not thought of as simply craft labor, but rather they should be well-rounded professionals with diverse skillsets. As with other professions, inspectors must constantly sharpen and hone their knowledge and skills.

Why Professional Development?

Professional development is a catch-all phrase that encompasses courses, classes, training, and educational initiatives designed

to help an employee stay relevant and continue to be competent within their company or industry. Once in a job, many workers do not set aside time or get the opportunity to keep pace with changing technology or other demands. Through professional development, workers can hone and expand their skills to become better and more efficient workers. Investing in yourself is a beneficial way to help you meet career goals.

A 2021 ICP survey on member satisfaction shows that 82% of respondents believe the qualifications and corresponding exams for the programs are sufficient to gain entry, but the qualified inspector should hone skills and build knowledge over time.

How CPD Credits Were Established

ICP has worked with industry leaders to ensure that certified personnel are constantly meeting the demands that the industry expects. The concept of professional development reemerged as discussions were held around intensifying the initial qualifications for new inspectors. Instead, the focus shifted to the expectation that certificants, who are certified for three or more years, should develop and increase knowledge over time. This notion was discussed with the ICP Governance Board, and a motion was put forward in the November 20, 2019 ICP General Session to garner volunteers to create a strawman proposal for continuing professional development. The requirements were developed with input from owner/users, service organizations, contractors, and other industry personnel. Emphasis was placed on ensuring the requirements were as flexible as possible, with reasonable hour requirements, and would support certified individuals in enhancing and strengthening their knowledge, skill set, and overall value to industry operations.

The requirements were a year and half in the making from inception to implementation, including going through a consensus process before being implemented. The final strawman was presented to the ICP General Session on May 22, 2020, where it was approved, and thus unanimously supported by the ICP Governance Board and presented to the API Committee on Refining Equipment (CRE).

Phased In Approach

Under ICP’s new recertification requirements, the number of CPD hours will be phased in over a three-year period. For individuals whose certifications expire after January 1, 2023, eight CPD hours are required. For those expiring in January 2024, 16 CPD hours will be required, with the full 24 CPD requirements for those expiring on or after January 2025.

Since the start of 2022, ICP has implemented a communication

plan to ensure that inspectors are fully aware of and prepared for the recertification process. Announcements have been placed both in the application portal and on the [API.org](https://www.api.org) website, introductory emails have been sent to certificants directly, and follow up emails are being planned. To help ease any potential angst, ICP has been working to make certificants aware of free or low-cost events that would help inspectors earn their credits.

Program Overview

ICP also developed a CPD Guidance Document that explains, guides, and helps answer many questions for inspectors. CPD activities are made up of nine different categories to allow for depth and breadth of learning, and skill building [1]. To help inspectors understand what areas to focus efforts on, ICP staff worked with industry experts to develop over 40 different topic areas related to the industry.

Once an individual completes their activity, any documentation received (certificate, agenda, published paper, etc.) should be promptly uploaded to their ICP portal account. ICP has a specific option (under the Education tab) to upload continuing professional development activities. For any activity that does not provide documentation, ICP has developed a CPD Activity Form that should be downloaded completed and signed at the event by the host or their supervisor to receive credit [2].

It is recommended that certificants submit their CPD hours as they are completed. However, they may also be submitted at the time of their recertification application.

Please visit the recertification requirements for your program at www.api.org/icpprograms to review the guide.

Professional Development offers individuals an opportunity to invest in themselves and show their employers that they are committed to being a valuable addition to operations. Many fields require professionals to take part in some form of ongoing learning, continuing education, or skill building—the inspection field for Oil and Gas should be no different. ■

For more information on this subject or the author, please email us at inquiries@inspectioneering.com.

REFERENCES

1. https://www.api.org/-/media/Files/Certification/ICP/Examinations/ICP-PD-102_CPD_202203.pdf
2. <https://www.api.org/-/media/Files/Certification/ICP/Examinations/API%20CPD%20Activity%20Form.pdf>

COMPANY SPOTLIGHT / MISTRAS Group

MISTRAS Group is a leading "one source" multinational provider of integrated technology-enabled asset protection solutions, helping to maximize the safety and operational uptime for the Oil & Gas industry.

Backed by an innovative, data-driven asset protection portfolio, proprietary technologies, and a decades-long legacy of industry leadership, MISTRAS leads clients in the Oil & Gas industry towards achieving operational and environmental excellence.

MISTRAS provides support across the downstream sector of the Oil & Gas industry, by helping drive productivity, improve safety, reduce downtime, optimize maintenance costs, provide quicker turnaround times, increase facility profitability, and meet regulatory



compliance. As a true asset protection industry leader for downstream refineries, MISTRAS delivers a range of integrated, value-added asset protection solutions, including:

- Advanced and Traditional Non-Destructive Testing (NDT) Services and Technologies
- Data collection, analysis, and management solutions, including the cloud-based reporting platform MISTRAS Digital® and Plant Condition Management Software (PCMS®)
- Engineering Consulting
- Rope and Drone Access Solutions
- Maintenance & Light Mechanical Services
- Inspection and Online Monitoring Equipment
- Lab Testing and Inspections
- Special Emphasis Programs

Visit www.mistrasgroup.com to see how MISTRAS can serve as your One Source for Asset Protection Solutions®. ■

Push your mechanical integrity program towards ~~baseline compliance~~ operational excellence.



Subscribe to Inspectioneering and join a community of experts who all share a common desire: to advance our industry through improved equipment integrity.

Individual and company-wide subscriptions available.

Visit inspectioneering.com/subscribe to get started.

Lessons Learned from the Rupture of a Steam Superheater Header

Peter Tait, Global Expert – Static Equipment at Methanex

Abstract

A 110 barg (1,595 psi) stainless steel superheated steam coil outlet header ruptured, producing an instantaneous release of high-pressure steam. The failure occurred at a methanol plant after eight years in service, and without any prior indications. The failure mechanism was determined to be stress relaxation cracking adjacent to the longitudinal seam weld, which resulted in a large “window” torn out of the side of the header. The initial investigation focused on the materials and fabrication of the header, but deeper analysis highlighted that **code compliance** does not always equate to **fit for service**. This article walks the reader through the header specification, design, fabrication, and inspection processes to identify where opportunities were available to question and act to proactively address the vulnerabilities that resulted in the header rupture.

Introduction

One of the biggest fears for any executive leader in the chemical and energy industry is a loss of primary containment event, which brings with it the potential for fatalities, significant equipment damage, and downtime.

Methanex experienced such an event in April 2019. Fortunately, the rupture occurred at shift change so all on-site personnel were in the control room and there were no injuries, but given the energy release associated with the event, there was potential for far greater consequences than what was experienced.

This case study suggests how the strategic, systematic approach to technical knowledge acquisition/assimilation, management, and utilization in the design, fabrication, maintenance, and operation of assets should evolve.

Incident Overview

On April 9, 2019 at roughly 5:35 am, the outlet header for a set of steam superheating coils abruptly ruptured. The header was operating under normal and stable conditions at 520°C (968°F) and 110 barg (1,595 psi) pressure at that time. The outlet header was fabricated from 48 mm (2 in) thick ASTM240 Grade 316H stainless steel plate, cold formed into a 610 mm (24 in) diameter cylinder with a long seam weld.

The rupture caused significant physical damage in the immediate area of the convection section of the reformer (refer to **Figure 1**), and large pieces of debris were hurled into other areas of the site, up to 100 m (330 ft) away.

Organizational Context

As with all organizations, continuous improvement is an ongoing process that has resulted in an evolution within the organization since the time of the original design and construction of the facility. The two relevant areas of the organization evolution are provided for background and context.



Figure 1. Ruptured superheated steam outlet header.

Corporate Technical Knowledge and Expertise

Structured global discipline teams were developed early in the history of the organization. These teams provide a way to link technical experts and management at each of the sites into a global network of peers to share best practices and lessons learned from and by the organization.

Static equipment management is a challenging area given the size of the portfolio and technical complexity associated with static equipment (including design, construction, inspection, maintenance, and operation).

Some key characteristics of the current global static equipment program include:

- The primary focus is on connections to the petrochemical industry (e.g., ASME, API, AIChE) with a lower degree of networking with other industries (e.g., power or nuclear industries).
- There is a large focus on specialty and critical static equipment

within the methanol process including the design, operation, and maintenance (e.g., conventional reformers, converters, auto thermal reformers) with the intent of continuously improving asset integrity and reliability.

- There is also a large focus on the development and implementation of risk-based inspection (RBI) management programs.

While this approach has allowed the organization to reach new levels of expertise around our specialty static equipment, unexpected vulnerabilities were brought to light because of this incident.

Corporate Project Management, Engineering, and Assurance

The construction project was executed as a lump sum Engineering, Procurement, and Construction (EPC) contract. The supplier of the reformer island is a recognized vendor with relevant history of manufacturing this type of equipment. They sublet the supply of the coil package to an experienced supplier, in another country, who in turn sublets the header fabrication to yet another reputable supplier in yet another country.

At the time of the project, the project management model and contracting strategy was comprised of a relatively small team of owners working in collaboration with the EPC contractor. The small number of technical experts were more involved in the upfront conceptual material selection and design review/input for specialty/critical equipment than the detailed design and quality control for industry standard equipment. The EPC contractor and equipment suppliers used industry codes and standards to direct appropriate design, fabrication, and construction.

Investigation and Root Causes

The incident investigation started immediately after the failure, but the complexities associated with the metallurgical and engineering analysis meant that determining the exact direct cause of the failure and underlying root causes took several weeks.

The investigation concluded that the direct cause of the rupture was stress relaxation cracking within the heat affected zone on either side of the longitudinal seam weld. This is a potential failure mode for austenitic stainless steels operating at higher temperatures. Threshold temperatures are not defined in the first edition of API 571, which was applicable during design. However, available published papers^[1,2,3] variously indicate 500°C or 550°C (932°F or 1,022°F). Stress relaxation cracking can be an in-service failure mechanism with indications of the mechanism appearing after a period of operating the equipment, and it may not be present upon initial fabrication.

The installed header was in service at a susceptible temperature and material, with underlying fabrication stresses and cold work; all of which contributed toward development of the damage mechanism and, ultimately, the incident.

Reliance on the Design Code

The design of the steam outlet header was compliant with the 2007 edition of the American Society of Mechanical Engineers

(ASME) BPVC Section I, *Rules for Construction of Power Boilers*.

However, as there are relatively fewer ASME BPVC Section I vessels compared to ASME BPVC Section VIII vessels in a methanol plant, the mechanical engineers are not quite as familiar with its requirements.

The nature of code revision cycles is that they may lag in new learnings and that “engineering judgement” is required. In this case, more in-depth knowledge of high energy systems is required than is usually available in a chemical plant.

The 2007 edition of the ASME BPVC Section I code used in design of the header is unclear on the need for post-fabrication heat treatment for this material with it being “neither required nor prohibited.” (Table PW-39 for P-No.8 material)

The 2007 edition of ASME BPVC Section II Part D is more direct around the PWHT of austenitic stainless steels, stating “in recognition of the controversial opinion relative to the effects of postweld heat treatment of austenitic stainless steels, mandatory requirements for such have been omitted.” (Paragraph A-350 Heat Treatment of Austenitic Chromium-Nickel Steels) It becomes apparent from the full paragraph that it is referring to the corrosion resistance of the stainless steel rather than addressing stress relaxation cracking, but it nonetheless leads the designer to not specifying heat treatment.

The net result was a code-compliant, thick-walled stainless steel, high pressure steam header fabricated with a large longitudinal seam weld.

Ambiguity Around Mechanism and Naming

Stress relaxation cracking is not a new phenomenon but has been described by different names; van Wortel reports more than ten with different threshold times and temperatures.^[1] For example, API RP 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry* describes “reheat cracking,” which occurs during fabrication and would be expected to be detected by nondestructive testing.^[4]

However, the amorphous nature of the descriptions has meant the lower bounds for at-risk fabrications is difficult to define with certainty. Even today this failure was reported as “atypical stress relaxation cracking” both from the extended time to failure (eight years) and the metallography of the cracked material.

Risk-Based Inspection Program

A full RBI program had been completed prior to the first plant turnaround. However, the review of this header did not identify that it contained a substantial amount of cold work and a significant submerged arc weld without any post-fabrication heat treatment. Consequently, there was no inspection specified for the longitudinal weld. The RBI system had no specific trigger to check how the header was fabricated, welded, or heat treated.

The RBI identified creep and creep fatigue as potential damage mechanisms and called for penetrant testing of the pipe to header dissimilar welds and a sample of the coil to header welds. Stress relaxation cracking was not identified as a possible mechanism.

The header was specified as 24 NB Schedule 120, which implies fabrication to a pipe specification that would have autogenous welds and solution annealing. However, it was actually designed to ASME BPVC Section 1 as a pressure vessel with the use of a large submerged-arc welded (SAW) longitudinal joint without annealing. This was only found post-event after some time looking in the MDR and it was not expected that the RBI study would go to this extent so there was no NDE for it in the Inspection and Test Plan (ITP).

Other Learnings

The static equipment portfolio is large and diverse and becomes more challenging as the plants age. Site Asset Engineers work on current issues and rely on RBI to cover long-term risks. The global technical engineers are expected to keep up with developments, but they too have to balance looking outwards with current site issues. There should be a more structured approach in determining who are the external sources of knowledge and how and when they are accessed. A strong network of site-based asset engineers, corporate subject matter experts, and external consultants is required to ensure complete coverage of all knowledge areas.

The ITP should only serve as a starting point and everyone should be empowered to be curious and challenging when working in the field. Strict adherence to the ITP and difficulty in adding NDE during a turnaround are barriers to improving the RBI process.

Corrective Actions

Immediate Actions

The immediate actions were to determine if there were any similar at-risk items of equipment in the other Methanex plants. The risk ranking was performed using the British Energy methodology 3, p.178.^[3] Fortunately, only one process header was at risk at the very low to low risk category and this component is due for replacement with seamless construction in an upcoming turnaround.

Long-Term Actions

This event, and the subsequent investigation, led to the implementation of the following items:

- The in-house Methanex technical standard for pressure vessels has been updated to require all stainless steel high temperature headers to be specified and supplied as pipe. The specification will be for either seamless pipe or pipe with a longitudinal seam welded without filler and with post-fabrication heat treatment.
- The RBI program will include specific triggers such as an internal radius to thickness ($r/T < 10$) confirmation for explicit data book review of suitable welding and heat treatment.
- The RBI assessment of critical equipment will be subject to an independent review by the global technical or third-party experts.
- An extra step will be added to the ITP for the first inspection of equipment to validate the RBI assessment basis.
- The Global Technical Experts team is being expanded to allow greater interaction and involvement with relevant non-petrochemical associations such as the Electric Power Research Institute (EPRI).
- Each site Lead Asset Engineer has been assigned a portfolio of standards to monitor for updates and evolving cautionary notes on behalf of the organization. For instance, the notes relating to stress relaxation cracking are now much more explicit in the ASME Section IID 2019 edition. When the system is embedded it is anticipated that it will be expanded to include other engineering disciplines such as process and rotating equipment.
- Site staff inspectors and asset engineers are enabled and expected to maintain a field presence in the plant during turnarounds.

Conclusions

Design codes require sound engineering judgment, as does the ongoing assessment of equipment condition and fitness for service. The processes for design, fabrication, and maintenance of pressure equipment need to assure that all relevant data is available and up to date.

An organization's structure and resourcing needs should never be considered "complete." Rather, they should undergo a process of continuous improvement and reassessment based on knowledge and experience. Furthermore, this knowledge and experience needs to be made available to the right people at the right time. ■

For more information on this subject or the author, please email us at inquiries@inspectioneering.com.

REFERENCES

1. Control of Relaxation Cracking in Austenitic High Temperature Components; Hans van Wortel, TNO Science and Industry. NACE Corrosion 2007 Paper number 07423
2. Relaxation cracking in the process industry, an underestimated problem; J.C. van Wortel. TNO Institute of Industrial Technology. (1998). Baltica IV, Plant Maintenance for Managing Life & Performance Vol.2 VTT Technical Research Centre of Finland
3. Reheat cracking and strategies to assure integrity of Type 316 welded components; Coleman M C, Miller D A & Stevens B A, British Energy, Barnwood, UK. (1998). International Conference on Integrity of High Temperature Welds. London, UK: Professional Engineering Publishing.
4. Damage Mechanisms Affecting Fixed Equipment in the Refining Industry, ANSI/API Recommended Practice 571, Third Edition, March 2020

A Thousand Important Roles & Responsibilities of the Plant Fixed Equipment Inspection and Mechanical Integrity Group

John T. Reynolds, *Inspectioneering SME and Principal Consultant at Intertek AIM*

Introduction

Alright, perhaps it isn't quite one thousand, but it's getting pretty close and seems to increase every year. Whatever the ultimate number is, there are at least many dozens of key roles in most fixed equipment inspection and mechanical integrity (FEMI) groups in any hydrocarbon processing facility. In the January/February 2017 issue of *Inspectioneering Journal*, I published an article on the **Fifty Important Roles and Responsibilities of the Plant Corrosion/Materials SME**. For those that may have missed that article, it is still available in the Journal archives.^[1] Continuing on the theme of that article, I have outlined herein the roles and responsibilities of the Plant FEMI Group. Why would I want to do that since most inspectors, chief inspectors, inspection SMEs, inspection supervisors, reliability engineers, etc. pretty much know all the issues that they are supposed to be doing on the job?

Here's why – several reasons. When I participate in the API/AFPM Process Safety Site Assessment Program (PSSAP) as a FEMI SME, one of the things I always ask for at each site is a copy of the roles and responsibilities for all members of the FEMI group at the site. Frequently I find those documents to be woefully lacking in detail and thoroughness. Too often I find that the documented roles and responsibilities are overly brief and very generic (i.e., not very useful and sometimes even non-existent). I remember visiting one site whose inspection supervisor had six bullet points on his roles and responsibilities. I asked him what he did for the rest of the week after lunch on Monday. Sometimes the roles and responsibilities are so vague and brief that they contain only a very few bullet points with a smattering of HR clichés such as “work safe,” “do what your boss wants you to do,” “go forth and do good” and other non-technical administrative duties. Herein, I've skipped all that other fluff that does not add to the FEMI needs of a process site and I've focused on the technical aspects of FEMI jobs.

Having detailed, thorough roles and responsibilities for our jobs typically doesn't get much priority relative to all the important activities in our FEMI community of practice, but that doesn't mean that they aren't important. But why are detailed, thorough roles and responsibilities important?

One of the big gaps I find at refining and petrochemical process sites is a huge lack of understanding (outside of the FEMI group) of what the entire FEMI group does for the site. I often find that the Site Leadership Team (SLT) typically only has a vague, high level idea of what the FEMI group is supposed to be doing. Sometimes the turnaround manager thinks the primary role of the FEMI group is to slow down turnaround work by finding problems that need to be fixed just before startup. And the maintenance manager thinks the role of the FEMI group is mostly just

a vast knowledge base ready and waiting to tell his foreman how to make repairs and “hold their hands” while doing their jobs. And the project manager thinks that the FEMI group is primarily there to slow down his projects and cause cost over-runs. And the technical manager doesn't have a clue since we don't have anything to do with increasing yield.

And sadly enough, too often, even the SLT member who has the FEMI group reporting directly to him/her doesn't know in any detail of all the activities in which the FEMI group is involved. Hence, when the SLT manager comes to his/her Inspection Manager/Supervisor with another sudden large need for additional work activity (often due to a major failure somewhere in the industry or a head office directive), he/she has no real idea what other work has to be displaced or “put on the back burner” to accommodate this new activity. So, when I was an inspection supervisor some 100 years ago and that sort of thing happened to me, I would pull out my detailed, three-page roles and responsibilities, put it in front of my manager, and ask, “what is it on this list that you would like me to put aside while we take on all this extra work without any increase in staff or resources?” Sometimes this tactic worked and I got extra staff for the new workload. Other times, all I got was sympathy or a comment like “John, if you can't get it done, I'll find someone who can.” But in the end, it always helped for my supervisor to know how large the workload was for which my group was responsible.

I realize that no site can just copy the list below and use it as the roles and responsibilities for the FEMI group at their site because a lot of work activities vary from site to site. But hopefully, the list below will provide ideas that will help you update and make your role and responsibility descriptions more detailed and more definitive for the different jobs in your FEMI work group, including inspectors, inspection support engineers, chief inspectors, inspection supervisors, NDE specialists, etc. Since the list below most closely describes the roles and responsibilities for the entire FEMI group at a plant, the list may be most closely applicable to the roles and responsibilities of the Inspection Manager or Supervisor, but then need to be modified to describe a more specific role that each individual member of the FEMI group has, with regard to the totality of each individual FEMI issue included below. For example: take the roles and responsibilities of Inspection Planning: the inspector may have the role of creating the inspection plan from the IDMS information; the inspection supervisor may have the role of approving the inspection plan created by the inspector; the corrosion/materials SME may have the role of reviewing the inspection plan for the need to help designate where to look for localized corrosion or when to look for

some less common damage mechanisms; and the NDE specialist may have a role in making sure the most appropriate, cost-effective NDE tools and techniques are included in the plan. Hence, the list below can be modified to include the actual responsibility of each person involved in each specific activity.

Hopefully each item on this list of FEMI roles and responsibilities below will fit on someone's work list at your site, so that managers on the SLT and other stakeholders in operations, maintenance, engineering, process safety, technical, etc. will come to know and appreciate the huge depth and breadth of the entire FEMI group at your site. Also, some of these roles and responsibilities may be shared with other people at the site that aren't assigned to the FEMI group; but from my perspective, someone at each site needs to be accountable for making sure all the FEMI issues listed below are adequately handled in order to avoid leaks, failures, and process safety incidents that may occur.

A Thousand (Give or Take) Key Roles and Responsibilities

So here we go. From my perspective, these are the key roles and responsibilities of a FEMI group. They are listed in no particular order.

Industry FEMI Codes and Standards (C/S) – Ensures that all members of the FEMI group are aware of, have ready access to and apply all the latest editions of API/ASME and other applicable FEMI industry C/S that can help to inspect, maintain and improve FEMI at the site.

Site FEMI Standards and Procedures – Has all the appropriate FEMI programs (preventative and reactive) in place with requirements and expectations documented which are kept up-to-date on a specified review interval, including all those covered in the *101 Essential Elements of Pressure Equipment Integrity Management in the Hydrocarbon Process Industry*.^[2] Ensures that the systems and procedures required by API 510 - 4.1.1 and API 570 - 4.3.1.1 are all documented in site procedures, kept up-to-date and implemented.

Special Emphasis Inspection (SEI) Programs – Implements appropriate SEIs for FEMI issues that have been discovered to be deficient in order to conduct “catch-up” inspections to bring the programs up to an adequate run-and-maintain status as required and/or expected by industry codes/standards as well as company/site standards/procedures.

Corrosion and Materials Engineering Support – ensures that all 50 of the roles and responsibilities outlined in the referenced article on Fifty Important Roles and Responsibilities of the Plant Corrosion/Materials SME are documented and fulfilled by an appropriately experienced and knowledgeable C/M SME whether that individual is an employee on site, another company C/M SME from off-site or a contractor.

Damage Mechanisms (DMs) – Ensures that all credible DMs are identified in accordance with API 510/570 - 5.4 that may afflict plant equipment/piping in order to help inspectors perform adequate inspection planning and develop inspection strategies for

each DM (with or without RBI). Is thoroughly familiar with the appropriate content of API RP 571 for inspection planning based on all credible DMs.

Failure Modes – Focuses increased attention on mitigation of identified DMs that could lead to catastrophic ruptures as opposed to just leaks (e.g., ammonium salts corrosion, high-temperature hydrogen attack, sulfidation, brittle fracture) and other DMs that can result in insidious localized corrosion, general thinning, cracking, metallurgical deterioration or other difficult to detect types of damage.

Failure Analysis – Ensures that appropriate failure analysis of equipment/piping is conducted by a recognized engineering support organization with experience in the API 571 type of damage mechanisms in order to support incident/leak failure investigations and shared learning opportunities with others who need to know.

Leaks, Failures and Near Leaks – Follows a documented procedure to involve appropriate members of the FEMI group to investigate all significant leaks, failures and surprise findings to understand what can be done to avoid them in the future and determine if the issue that caused the problem was adequately addressed in the CCD, IOW and Inspection Planning/RBI process. Applies the investigation methods contained in API RP 585 for all fixed equipment leaks, failures and near-misses.^[3]

Environmental Cracking Mechanisms – Ensures that all credible environmental cracking DMs are identified in conjunction with a C/M SME and that appropriate inspection practices and mitigation are in place to detect and/or prevent them. Makes sure that any equipment that could be exposed to environmental cracking DMs that could occur as a result of steam cleaning (e.g., caustic or amine cracking) is identified and the appropriate mitigation methods are in place to prevent inadvertent exposure to cracking.

High Temperature Equipment/Piping – Has a documented FEMI program in place for all equipment/piping that may be subject to the high temperature DMs (e.g., creep, embrittlement, stress rupture, oxidation, sulfidation (per API 939C), HTHA (per API 941)) and ensures that such equipment has the right type of FEMI programs in place. The program includes heater reliability efforts and remaining life analysis of tubulars in the more demanding heater services (e.g., API RP 530 or OMEGA analysis). Applies all the applicable recommendations and guidance contained in API 571 & 573.

Low Temperature Equipment/Piping – Makes sure that any older, brittle materials that were installed during times of outmoded design/construction practices are identified and appropriately mitigated or replaced (e.g., grey cast iron valves, flanges, pump cases and other fittings). Makes sure that Minimum Safe Operating Temperatures and Minimum Pressurization Temperatures are identified for all equipment that may be susceptible to brittle fracture during upset or abnormal operating conditions (e.g., auto-refrigeration, flashing of LHC, by-passing

and heating/cooling of heavy wall vessels) such that the lowest permissible metal temperature for a given material at a specified thickness is not exceeded.

Higher Pressure/Higher Risk Equipment/Piping – Has a documented FEMI program in place for all equipment/piping that may be subject to the higher pressures/risk and thereby would create a greater process safety hazard if a release were to occur due to undetected DMs. For example, implements API 932B to avoid releases in hydroprocessing units subject to ammonium bisulfide and provides assurance that LPG and other API 570 class 1 systems have all the right FEMI work processes in place to prevent potential big releases.

Corrosion Control Documents (CCDs) – Conducts a documented FEMI program that records all credible damage mechanisms (DM) and develops and implements thorough, comprehensive CCDs (including keeping them evergreen on a scheduled basis) for all process units in accordance with the work process described in API 970. Makes sure that all appropriate stakeholders have access to and awareness of the contents of all unit CCDs. Ensures that the CCD is reviewed and updated as necessary each time a leak, failure or near-miss occurs in fixed equipment/piping to avoid having repeat incidents.

Corrosion Control Programs – Works closely with the site C/M SME to ensure that documented corrosion control programs are being implemented appropriately to avoid unanticipated or

accelerated deterioration e.g. cathodic protection systems, coatings and linings programs, corrosion inhibitors, materials selection, corrosion monitoring devices, etc.

Materials Selection – Makes sure that knowledgeable C/M SMEs are involved in recommending the most economic choice of construction materials and fabrication methods based on risk assessment for new construction and proposed replacement-in-kind equipment/piping.

Metallic and Non-Metallic Coatings and Linings – Conducts a documented program to apply the most cost-effective coatings and linings and ensure that they are properly applied to provide the maximum service life under all anticipated process conditions. This effort includes ensuring that rigorous QA/QC is applied during surface preparation and application which includes utilizing qualified coatings inspectors (e.g., NACE certified) and qualified refractory inspectors (e.g., API 936 certified) for higher risk applications.

Corrosion and Process Monitoring – Works with a C/M SME to apply appropriate corrosion monitoring devices (e.g., hydrogen probes, electric resistance probes and linear polarization measurements, as well as permanently mounted UT sensors) where needed to understand changing or uncertain corrosion/damage rates.

Integrity Operating Windows (IOWs) – Conducts a documented program to develop, implement and evergreen the IOW

COMPANY SPOTLIGHT / Pinnacle

Pinnacle's goal is to help facilities build programs that increase availability and production, reduce leaks, optimize total lifecycle spend, and ensure regulatory mechanical integrity compliance.

What We Help Our Customers Do:

We help our customers collect and organize the right data to fuel the right models so they can make the right decisions, helping them:

- Collect and organize the right data:
 - Photogrammetry and Image Analytics for visual inspection
 - Connected Worker Solutions
 - Optimized Sensor Deployment for real time data capture
 - Equipment Hierarchy Definition and Piping Circuitization



- Data Mining and upkeep for data quality
- System Integration and Data Contextualization between systems
- Reliability Modeling to Drive the Right Asset Strategies and Improvements:
 - Damage and Corrosion Modeling
 - Risk-Based Inspection
 - Reliability-Centered Maintenance
- Reliability Availability Maintainability Modeling
 - CML/TML Optimization
 - Reliability Operating Windows
- Quantitative Reliability Optimization
- Various Data Science Modeling for Reliability: Natural Language Processing, Neural Networks, Bayesian, and more.
- Build Reliability Foundations:
 - Reliability Software Selection and Architecture
 - Reliability and Integrity Education
 - Workflows and Procedures
 - Organizational Structure, Health, and Incentives
 - Dashboarding and Business Intelligence

info@pinnaclereliability.com

pinnaclereliability.com

DIGITAL RADIOGRAPHY SYSTEMS

THE BEST OF TWO TECHNOLOGIES FOR EVERY APPLICATION

COMPUTED RADIOGRAPHY SCANNERS

HD-CR 35 NDT / CR 35 NDT



FLAT PANEL DETECTORS

DRC 1024 NDT / DRC 2430 NDT / DRC 3643 NDT



Whether you decide for a Computed Radiography scanner with flexible imaging plates or a flat panel detector with the fastest imaging, or even combine the advantages of both technologies, DÜRR NDT's innovative systems offer high reliability and the best image quality. Across all your inspection tasks, the 'D-Tect X' X-ray imaging and analysis software supports you with helpful tools to make your daily work easier. **Call to arrange a free demonstration and convince yourself today!**

Digital Intelligence - Ready to Change.

www.duerr-ndt.com / info@duerr-ndt.com / Atlanta +1 516 448 1692 / Boston +1 508 333 2840



process in accordance with API 584 in order to identify and implement all necessary IOWs to minimize surprise changes in DMs and rates of deterioration from operations outside of designated IOW limits. Ensures that appropriate members of the FEMI group are notified of IOW exceedances and that they participate in investigations of exceedances to determine if any changes in inspection planning are needed. Ensures that IOWs are reviewed and revised as necessary each time a leak, failure or near-miss occurs in fixed equipment/piping.

Management of Change (MOC) – Ensures that the MOC work process (or documented MOC alternative work process) is followed wherever needed for all process and IOW changes, as well as physical changes. Ensures that the appropriate members of the FEMI group are involved in the MOC work process whenever FEMI may be affected by the proposed change.

Mechanical Engineering Support for Inspection – Manages the interface between inspection and engineering support to ensure that inspectors receive sufficient assistance where needed e.g. FFS issues, stress analysis, repairs (temporary and permanent), T-min analysis, rerating, alterations, cyclic service, vibration analysis, etc.

Outside FEMI Support/Advice – Knows when and where to consult with outside FEMI SMEs when confronted with difficult FEMI issues beyond his/her area of expertise or as workload requires more FEMI resources. Provides guidance to management as necessary on unusual, different or higher risk FEMI issues that may need specialized or more experienced input.

FEMI Contractors – Contracts with and oversees the work of qualified FEMI service contractors hired to provide additional FEMI resources and specialty services as needed to supplement/complement existing company resources at the site.

Inspection Planning – Creates appropriate inspection plans in accordance with API 510–5.1 and API 570–6.3 for all credible DMs (e.g., environmental cracking, embrittlement, localized and general corrosion, fatigue, etc.) included in the CCDs or equivalent damage mechanism reviews for all types of inspection (internal, external, on-stream, CUI, etc.). Ensures that inspection plans are reviewed and revised as necessary each time a leak, failure or near-miss occurs in fixed equipment/piping. Ensures appropriate inspection strategy and NDE techniques are planned for each location of an expected DM.

Risk-Based Inspection (RBI) – Where RBI is in use for inspection planning, ensures that the application of RBI at the site is in accordance with the requirements and expectations of API 510/570 – 5.2 and API 580, including appropriate NDE methods for each DM. Promotes the need for common sense from knowledgeable, experienced FEMI members is applied where it is obvious that the RBI software may not be providing the best guidance for each individual inspection planning issue. Ensures that RBI planning is reviewed and revised as necessary each time a leak, failure or near-miss occurs in fixed equipment/piping.

Turnaround Planning – Supports unit turnaround planning by developing cost-effective turnaround scopes using risk analysis

and keeps management informed of the risks associated with eliminating some work from turnaround scopes.

Inspection Recommendation Work Process – Maintains an effective, documented inspection recommendation categorization and tracking system independent of the site CMMS, so that work that is vital to maintaining equipment/piping integrity and reliability is accomplished in a timely, cost-effective manner.^[7]

Deferrals of Inspections and Repairs – Follows documented procedures in accordance with API 510–6.7 & 6.8 and API 570–7.13 whenever an inspection or repair needs to be deferred from a scheduled due date.

Piping Inspection Program – Manages all aspects of the documented piping inspection program in accordance with API 570 & 574.

Injection Points, Mixing Points and Deadlegs – Ensures that all IPs, MPs, and DLs that may be susceptible to higher damage rates due to corrosion, turbulence, temperature gradients, thermal fatigue and/or stagnation are identified and included in the site piping inspection program and IDMS for monitoring on the specified frequency in site standards and API 570–5.9, 5.10 & 6.6.2.

Pipe Rack Inspections – Manages the documented piperack inspection program in order to minimize piperack leaks with a focus on preventing contact point corrosion where piping sits flat (line-contact) on support beams.

Small Bore Piping (SBP), Threaded Connections and Auxiliary Piping – Ensures that all SBP, threaded connections, and auxiliary piping get the necessary FEMI attention in accordance with API 570–6.6.

Piping Service Classification and Circuitization – Ensures that all piping systems are classified for inspection purposes using the piping classification system in API 570–6.3.4 and that all process piping is properly circuitized per API 570–5.1.1, 7.9.5 & 7.9.6.

Inspection Execution – Conducts all scheduled inspections (internal, external, on-stream, thickness, CUI, special inspections, etc.) as required and expected by API 510/570 – 5.5 and company needs using appropriately detailed inspection plans.

NDE Optimization – Makes sure that the proper inspection/NDE methods and techniques are applied depending upon the DMs of concern (e.g., when profile RT or UT scanning may be needed to find localized corrosion DMs). Utilizes the expertise of an NDE SME to specify, apply and interpret results of specialty NDE methods for unique inspection applications (e.g. HTHA, on-stream inspections, deterioration of metallurgical properties) that may be beyond the routine day-to-day use of NDE such as UT, RT, PT, MT and the like.

Heat Exchanger Tubular Inspections – Conducts appropriate FEMI programs for all types of heat exchangers in accordance with API 510, and Annex A of API 572 in order to maximize reliability and minimize any process safety risks associated with tubular leaks.

Top Ten FEMI Risk List – Compiles, stewards and evergreens a list of the “top ten” FEMI risks (e.g. those identified in API 571) at the site and spearheads the work process to make sure all the issues are understood and adequately mitigated by appropriate stakeholders including site management.

10/10 FEMI Bad Actor List – Develops and tracks a list of equipment/piping circuits with higher corrosion rates and/or limited remaining life (e.g. over 10 MPY or less than 10 years remaining life = 10/10 list). Keeps track of actual corrosion rates being measured above a specified level (e.g., 10+ mpy) in order to address mitigation that may be needed. Also provides oversight to the list of short interval inspections (e.g., equal to or less than 12 months) to assess the risks and understand if short interval inspections are the most appropriate mitigation under the circumstances. Keeps management informed of equipment/piping on such a list and mitigation steps planned to get them off the list.

Pressure Relief Devices – Ensures that the PRD program is conducted in accordance with documented site procedures as well as API 510/570/576 requirements and expectations and is kept up-to-date (i.e., data entry and timely analysis of data) for future inspection planning for PRDs.

Inspection Data Management Systems (IDMS) – Ensures that the site IDMS and associated record-keeping systems are kept up-to-date with all the information and data needed to maximize the effectiveness and efficiency of the FEMI program, including timely data entry, evaluation and analysis. Ensures that all inspectors and other users of the IDMS have adequate training to use all the features of the software in order to minimize errors and maximize efficiency of record keeping. Endeavors to maximize digital record-keeping and minimize or eliminate hard copy records.

External Corrosion Programs – Manages the external corrosion programs and makes sure that CMLs are properly placed for CUI and other atmospheric corrosion degradation following the guidance in API 510/570/571/572/ 574/583. Identifies and conducts inspection programs for all buried vessels and piping systems in accordance with API 510/570 that could result in process safety or environmental incidents if leaks should occur. Conducts a CUF program for all fire-resistant coatings that may cause structural supports associated with fixed equipment to deteriorate. Specifies cost-effective external corrosion control methods for issues like: buried piping, vessels and canned pumps, tank bottoms and equipment exposed to CWT outfall.

Temporary Repairs – Ensures that temporary repairs are designed and installed per documented requirements including those included in API 510/570 and applicable ASME PCC-2 articles.

Temporary Equipment and Piping – Ensures that any fixed equipment and piping that are installed for temporary site process or turnaround needs is covered by MOC and that the FEMI group has a role in ensuring that it meets all documented requirements, is inspected if needed during the temporary installation period and is removed from service on the designated date of retirement.

Inspection Checklists – Provides and utilizes detailed inspection checklists to guide inspectors in conducting inspections of different specific types of equipment (e.g. internal and external inspections) to ensure that all credible issues are covered during the scheduled inspections.

QA/QC – Conducts the documented FEMI QA/QC programs including developing and execution of the QA/QC requirements for all new construction, repairs and replacements of fixed equipment at the site. Ensures that inspection and QA/QC for shop inspections are conducted in accordance with documented site and equipment-specific specifications as well as API RP 588.^[8]

Approved Suppliers – Ensures that only approved suppliers/vendors for new and replacement fixed equipment/piping are utilized to lower the risk of receiving inferior work products as well as fraudulent or counterfeit materials.

FEMI Program Auditing – Conducts appropriate FEMI audits in accordance with site documents and API 510–4.2.7 to ensure that work practices continue to be in accordance with QA/QC requirements and expectations, e.g. welding, PRV repairs, NDE, shop inspections, etc.

CML Management and Optimization – Ensures that CMLs are properly placed and are adequate in numbers in order to provide the best chances of finding the DMs that have been identified for piping and equipment, especially for process services subject to localized corrosion, CUI, and environmental cracking.

On-Stream Inspections (OSI) in Lieu of Internal Inspections – Conducts OSI in lieu of internal inspections of vessels only in accordance with the requirements of API 510–6.5.2.

Pressure Testing – Ensures that any pressure testing is conducted in accordance with site documentation, API 510–5.8, API 570–5.11 and the appropriate articles in ASME PCC-2, with special attention for situations that could result in potential brittle fracture (e.g., pneumatic and/or heavy wall pressure vessel testing) where material toughness may not be adequate. Ensures that vessels and piping that may have suffered potential metallurgical embrittlement in service is identified in the IDMS so that any inspection planning, pressure testing and repairs takes that condition into consideration.

Fitness for Service (FFS) Analysis – Conducts a documented program to determine when inspection findings may need immediate attention or can possibly wait until a more appropriate time for mitigation, depending upon risk and likelihood of imminent failure (i.e., continue to safely operate or need to shut-down ASAP). Seeks the application of API 579-1 FFS techniques from appropriate FFS SMEs for damaged equipment and piping. Ensures that inspectors know and understand the difference between flaws, imperfections and defects and thereby know when to seek engineering assistance for further evaluation.

Repairs and Alterations – Makes recommendations for repairs and alterations for conducting cost-effective methods of maintenance/modifications and/or need for replacement in accordance with applicable articles in ASME PCC-2 as well as API 510/570.

Welding – Ensures that the welding requirements and guidance contained in API 510, 570, 577 and 582 are followed as appropriate in accordance with site documents for the welding QA/QC program. Provides guidance in the application of non-standard methods and procedures for applications such as hot taps, low heat input applications, weld repairs, controlled deposition welding, weld overlays, hydrogen bake-outs, as well as when to apply preheating and various forms of heat treatment to optimize avoidance of fabrication and in-service DMs. Conducts audits of contactors, shops and maintenance groups responsible for making welding repairs.

Dissimilar Metal Welds (DMWs) – Has all DMWs in the plant documented and makes sure that appropriate inspection procedures are being applied and that any new DMWs being contemplated have the appropriate WPS/PQRs to avoid the potential for DMW failure in-service.

Material Spec Changes – Has all the locations of material spec changes that could be affected by process creep and/or process upsets that may expose a construction material to process conditions for which it was not designed (e.g., exchanger bypass piping experiencing higher temperatures and being exposed to HTHA conditions or acidic materials flowing downstream where construction materials may not be fully resistant to corrosion).

Bolting and Gasketing – Conducts the documented program for bolting and gasketing program in accordance with ASME PCC-1 in order to achieve leak free startups after all maintenance activities, including documented procedures for QA/QC of bolted joint assemblies after maintenance has completed their assigned QC. Inspects and repairs deficient flange joints in accordance with API 510/570.

PHAs/HAZOPs – Provides ad hoc resources as needed for teams conducting PHA/HAZOP revalidations/redo's to make sure that the team considers the potential for FEMI and C/M hazards as well as other process safety hazards.

Materials Verification Programs (MVP) – Conducts the documented MVP (including appropriate PMI) in accordance with the guidance in API 510 – 5.9, API 570 – 5.12 and API RP 578 in order to ensure that the materials of construction installed in the process units are in accordance with specification. The MVP will have appropriate strategies/tactics for new material receipt as well as retro-PMI.

Training on FEMI Issues – Plans and/or provides appropriate levels of training for all FEMI group members in order to improve FEMI competency as needed.^[4] Also has a program for appropriate knowledge transfer of FEMI issues to operators, craftsmen, engineers, etc. on what they need to know about FEMI issues so that others can be the added “eyes and ears” for symptoms of FEMI issues. Documents on-going FEMI training and knowledge transfer programs.

Certified Inspectors and NDE Technicians – Ensures that all inspectors (contract and company) and NDE examiners are properly certified and/or have passed the appropriate performance

demonstrations conducted by the appropriate standards organizations and that these requirements are properly documented.^[4]

Documented Mission, Vision, and Values – Creates and documented statements of the Mission, Vision, and Values of the FEMI group so that all appropriate stakeholders at the site know why the FEMI group exists, what the FEMI group wants to accomplish, and the value they bring to the organization.^[5]

FEMI Human Resources – Plans for the necessary, qualified human resources (company and contract) necessary for the site to meet their FEMI needs, goals and Mission, Vision, and Values.^[6]

Continuous Improvement – Involved in selecting and reporting FEMI KPIs to provide the necessary management focus on important FEMI issues that need to be tracked and trended to improve reliability and process safety. Sets goals to make improvements in any of the FEMI programs needed or desired.

Networking – Participates in internal FEMI communities of practice with other company sites and appropriate external (industry) FEMI networks (e.g. API, ASME, ASNT, NACE) to share knowledge and learn from other FEMI SMEs for the benefit of his/her knowledge base, especially learning from industry incidents caused by preventable FEMI failures.

Tank Farms and Offsite Equipment – Manages assigned tank farm and offsites equipment/piping inspection programs to ensure FEMI reliability and minimize leakage that could cause environmental contamination as well as process safety incidents.

Regulated Equipment and Facilities – Ensures that all laws and regulations are met for equipment and piping that may be covered by various jurisdictions, including local, national, federal, DOT, Coast Guard, etc.

Non-Pressure Boundary Inspection – Ensures that there is a clear understanding about who has responsibility for inspection and maintenance of components of vessels that do not contain the process pressure, e.g. trays, tray rings, distribution piping, baffles, thermowells, non-stiffening insulation support rings, clips, davits, etc. If it's the FEMI group, then there will be documentation of that responsibility.

Hydrofluoric Acid Alkylation (HFA) Units – Ensures that the FEMI program for HFA units on site (where applicable) is in accordance with the requirements and expectations documented in the latest edition of API 751 Section 3 (soon to be Section 6 in the pending 5th edition).

Conclusion

So there you have it: my idea of what would be contained in a detailed description of the roles and responsibilities of a FEMI work group at a hydrocarbon processing site. It's a big job, but somebody has to do it in order to avoid reliability impacts and/or process safety incidents due to leaks or failures associated with fixed equipment. Once again, I recognize that the FEMI group may consist of inspectors, chief inspectors, inspection SMEs, inspection supervisors, corrosion/materials SMEs, reliability engineers, FFS engineers, and personnel with other titles related to FEMI.

Each of the FEMI issues covered above should be in someone's detailed roles and responsibilities and perhaps even on the roles and responsibilities for multiple people in the FEMI group. Of course, I realize that not all FEMI groups will have responsibilities in every one of these FEMI issues, but someone (perhaps in other groups at each site) should have the appropriate responsibility for each FEMI issue mentioned above. For those sites where the FEMI group does not have primary roles and responsibilities for some of the FEMI issues listed above, then the FEMI group may have a partial responsibility and/or audit responsibility for the issue which should also be included in the documented FEMI group's roles and responsibilities.

Do all the other stakeholders in management, operations, maintenance, turnarounds, engineering and technical at your site know what the key roles are for your FEMI group? Does your FEMI group handle all these issues or have some responsibility for each of them? What else does your FEMI group cover that I may have overlooked? Which of these roles and responsibilities don't you agree belong to your group? Your comments and feedback are welcomed. ■

For more information on this subject or the author, please email us at inquiries@inspectioneering.com.

REFERENCES

1. Fifty Important Roles and Responsibilities of the Plant Corrosion/Materials SME, John Reynolds, Inspectioneering Journal, January/February, 2017.
2. 101 Essential Elements of Pressure Equipment Integrity Management in the Hydrocarbon Process Industry, John Reynolds, Inspectioneering Publication, second edition, 2015.
3. Piping Leaks and Failures Can Be Substantially Eliminated – Here's How, John Reynolds, Inspectioneering Journal, September/October, 2019.
4. What Does It Take to Become a Capable FEMI Inspector – Certified vs. Qualified? John Reynolds, Inspectioneering Journal, July/August, 2018.
5. Does Everyone at Your Operating Site Know Everything You Do for Them?, John Reynolds, Inspectioneering Journal, March/April, 2018.
6. Fixed Equipment Mechanical Integrity (FEMI) Resources – Past vs. the Present, John Reynolds, Inspectioneering Journal, May/June, 2017.
7. Creating an Effective Inspection Recommendation Management System, John Reynolds and Mark Bell, Inspectioneering Journal, January/February, 2016.
8. The Role of the Source Inspector in the QA Process, John Reynolds, Inspectioneering Journal, September/October, 2017.

COMPANY SPOTLIGHT / E²G | The Equity Engineering Group, Inc.

E2G | The Equity Engineering Group, Inc. is a consulting, training, and software firm that is focused on delivering practical and innovative solutions to solve your asset challenges. We are united in delivering knowledge, excellence, and technology to extend the safe operating life of your new and aging equipment.

Knowledge is...

Delivering high-quality consulting services to maximize the efficiency and productivity of your facility by managing risk and controlling equipment costs. Our team's areas of expertise include:

- Fitness-for-Service (FFS)



- Instrumentation
- Materials & Corrosion
- Mechanical & Structural Engineering
- Mechanical Integrity
- Piping Thickness Analysis & Optimization
- Pressure Relieving Systems
- Process Technologies
- Risk-based Inspection (RBI)
- Rotating Equipment & Vibration

Excellence is...

Teaching and mentoring the next generation of engineers to support safer and more reliable facilities. We offer specialized industry training courses in fundamentals of asset lifecycle management, pressure equipment, materials and corrosion, and risk management.

Technology is...

Our industry-leading, proprietary software products and corporate standards help you maintain your assets safely and reliably.

- Our software combines the latest API and ASME codes and standards with the depth of E2G's engineering experience.
- The Equity Engineering Practices are a collection of detailed and customizable best practices that satisfy process safety management (PSM) requirements and are the industry's most comprehensive corporate standards.

We help you prevent future failures, increase efficiencies, reduce downtime, maximize reliability, and minimize damage. Shift your perspective and call us today. ■

www.E2G.com | sales@E2G.com | 216.283.9519



Orange FFA Mighty Pirm
Auction & Scholarship Awards

HASC HBR Safety Excellence Awards '22

Five Lunch '21

Honor Golf

We find our true selves by volunteering in the service of others; by participating in activities that contribute positively to the places where we live and work. We give back to the communities that have given so much to us. The joy this brings far outweighs our time and efforts spent in service.

PRO SURVE TECHNICAL SERVICES, LLC

Visual Inspection (API, AWS, ASNT, NACE)
Conventional & Advanced NDE
Turnkey MI Services
Turnaround & Project Staffing Services
NACE Coatings & Corrosion Inspection
QA/QC & Vendor Surveillance
DMR, S&C, CML, ITP, CCD, FFS, IOW
Rope Access Services

PRO SURVE ENGINEERING SERVICES

Inspection & MI Planning
Process Safety Management
Professional Engineering (PE, PMP)
Materials & Corrosion Engineering
Similar Service Studies
Rerates, Service Suitability Studies
IDMS Inspection Data Management
ASME Appendix 47 Certifying Engineers

PRO SOURCE RADIOGRAPHY SERVICES, LLC

Conventional Radiography
Digital Radiography
Real Time Radiography
Computed Radiography
Conventional MT, PT, UT, VT, ET
Pressure Testing
Hardness Testing
Film Digitizing Services
Positive Material Identification

PRO VISION ACTIVITY STATUS SOFTWARE

Transparent, Real Time, Wireless for Projects & Turnarounds
Digital Wall Charts
IWR Logs
Weld Mapping
Flange Tracking
Virtual Log
Digital QC Packages
Customizable Cloud Reporting
Pay For Use Only
No Subscription or Maintenance Fees

Integrating engineering and inspection... because we said that we would.

Lessons from a Risk-Based Career

Brent Ray, *Inspection Engineering Specialist at Marathon Petroleum Corporation*

Have You Seen the Risk Panorama?

I have been involved with risk-based inspection and risk-based work process development for much of my career. The one thing I have learned as I've walked this path is that the concept of 'risk' extends far beyond the industry in which we work. Risk impacts every facet of our lives. Whether or not we're aware of it, there is some subconscious part of us that is analyzing the risks we take every day. We regularly try to make "better choices" by limiting negative consequences to ourselves and others.

An example is when we ask ourselves questions such as, "should I take a left turn or a right turn?" One might get me to work 10 minutes quicker, but there is a higher chance of hitting stop lights and traffic which would actually take longer. In a career filled with risk-based decision making, the one thing I've learned is that when you think about it, we are always analyzing; always assessing the risks we see in front of us.

"We made too many wrong mistakes."

~ Yogi Berra

That's what we are trying to avoid, too many 'wrong' mistakes. And that's when we realize, risks of all sorts surround us. In my mind, risk itself has many layers. There are many options with commensurate probabilities for winning; there are many options for losing. Each option is subject to the risks of concern and these can be described in many ways. This is described as the 'Risk Panorama' - the width and breadth of risk that surrounds us and our environment. The risk panorama surrounds us when we wake up, when we look in the mirror, and when we go out into the world. But, in reality, it's what we do with it that makes a difference.

Within our industry, it is important to remember three things about risk:

- **Risk Assessment** is the methodology used to determine the probability and consequence of operations, and how to plan for mitigating risk.
- **Risk-Based Inspection** is a tool for prioritizing inspections, through plans that include selecting the correct NDE for the anticipated damage mechanism, in order to minimize risk.
- **Risk Management** is the culmination of these two items, and how we use them to understand and manage the condition of our equipment.

So, let's back up a moment to consider these statements in relation to waking up in the morning. At that first moment of wakefulness, we go into risk assessment mode. We may ask ourselves "What do I need to be aware of that will make sure that I get through this day?" Then we look in the mirror and inspect ourselves. We may ask, "What's wrong with me today and how do I fix it?" (Your hair may be a frightful mess, so you may need hairspray to hold it in

It's a continuous cycle, in life and on the job. Risks never go away, and risk management never stops.

place and not scare other people!) So if looking presentable is an outcome you care about then that's a risk-based inspection every morning, right? And as you continue moving, up and out the door, you're not only looking at yourself, but your mind is looking out in the world and trying to rationalize risk management in your life. Will my car work? Will I make the meeting on time? And so on. Each of which requires us to assess, inspect, and manage the risk associated with making a decision as we put one foot in front of the other.

It's a continuous cycle, in life and on the job. Risks never go away, and risk management never stops. You have to continue looking forward at what the next step is so you can keep getting better and hopefully stay at least one step ahead of an equipment failure or process safety incident. The job is never finished.

"Nothing in this world is worth having or worth doing unless it means effort, pain, difficulty..."

~Theodore Roosevelt

But this discussion isn't about the risk in your life, it's about some important lessons I've learned in establishing risk-based thinking in the industry in which we work. So let me share some of the lessons in my career where understanding "risk" means more about how you engage in the process and learn, how you present yourself and listen to others, and how you plan for the success of your risk-based program.

Be Careful What You Volunteer For

I'll begin by stating that risk-based thinking isn't for everyone; it requires a certain mentality. A natural curiosity and desire to understand and solve problems is crucial. You just can't read a book and expect to be an expert. And you can't build a program from a 'cookie cutter' design. You must understand the work process and your company's level of risk acceptance, and be willing to adapt and adopt as will be required for success.

"Keep trying. Stay humble, Trust your instincts.

Most importantly, act. When you come to a fork in the road, take it."

~Yogi Berra

So, when you decide to get into the risk-based arena, be prepared. You may be asked by your company to take on this task. And the first order of business should be a good foundation! You must build the procedures, and implement the methodologies to make the effort sustainable and successful. You may ask, “But how can I build this if I’m just starting out and know very little?” Not a simple answer, but one we’ll develop in this discussion.

Building a program, and even a career, requires study of not only the requirements, but listening to those with experience. You will need to seek out opportunities that can help you gain experience. This can come from industry group participation which will provide opportunities for sharing knowledge and experiences. I would encourage participation (and volunteerism) in conferences, committees, and meetings, both internally in your company and externally. You can learn quite a bit when you engage with others dealing with similar challenges.

You should always be asking questions and gathering answers. At some point you want to be ‘the guy’, the subject matter expert. Asking questions and gathering answers will help you provide answers later to your company and your immediate peers. You need to absorb as much knowledge from colleagues, peers, industry publications, and educational conferences as possible.

In all of this though, it is important to remember not to bite off more than you can chew. You may think you can do something, volunteer somewhere, or build something, but don’t forget that you can overstep your abilities and resources. To be successful, you need to be able to recognize that moment and restart, rethink, and even ask for help.

The building of knowledge and positive use of that knowledge should help you become successful in risk management and this can lead to new opportunities and increase your professional value. Volunteering also shows a commitment to becoming better and leading. In truth, this is all part of building leadership potential. In my opinion, success and positive influence often indicates that you have more leadership potential, and that potential can always grow and be rewarded. For example, as stated earlier, you should want to become the subject matter expert at some point in your career. You should want to be someone people turn to for an opinion, an answer, or just a mentoring discussion. If you commit to volunteering your time and genuinely want to (and will) learn from others, that’s a strong indication you’re already headed down the right path.

Summing it up, it is my opinion that if you want to become successful in risk-based topics, you’ve got to think outside of the box and explore things outside of your current wheelhouse. Grow. Learn. And then give back.

**“When you are asked if you can do a job,
tell them ‘Certainly I can!’ Then get busy and
figure out how to do it.”
~Theodore Roosevelt**

Remember that Management Often Knows Little about RBI

RBI is not just a buzzword that should be thrown around cavalierly. Successful risk-based managers must be able to properly communicate what it is and what it can do for the organization, especially to management. This requires the ability to speak in terms that resonate with management. You need to learn how to speak on the progress of your program and successes, and you can’t get “lost in the weeds.” For example, when management hears RBI, they (sometimes) tend to immediately think you’re going to measure things in terms of money, of cost, or of savings. But when RBI successes on those terms cannot be explained, the concept and outcome can become lost to them. This must not happen.

Some people try to put cost savings up front with RBI and they can be successful. Others aren’t. What most do not see is the shortsightedness of putting money in front of the goal with a broader and deeper payback, successful risk management. Just looking at cost savings from risk management may obscure the true successes of the program and overlook areas of opportunity and vulnerability. As RBI practitioners, we look at areas of probability and consequence. We look at how inspections are prioritized, effectively planned, and efficiently implemented. We look at how risk is minimized through understanding our equipment and its environment. For example, RBI may not allow the movement of a turnaround, but it should allow you at least to streamline inspections to make the time more effective and efficiently used. For example, RBI may not initially reduce inspections, but in the long run the intervals should increase, allowing inspections to be balanced out over time. Cost can be associated with these aspects and more, but you must be careful on what you convey to management. It should also make operators more effective at establishing priorities and identifying and eliminating non-value adding activities.

Still stuck on the cost vs RBI issue? Just remember, risk-based planning will help you prioritize where you spend your money. It helps you prioritize how the turnaround is run. It helps you prioritize the efficiency of an inspection. For example, instead of inspecting a whole tower that is 100 feet tall and 15 feet in diameter, you may end up only having to do the top 20 feet of that tower to find out what you need to know about the damage that could potentially occur there. In the end, you save time, you save money, you just need to convey the outcome in management terms. The process the RBI team follows results in a deeper organizational knowledge and appreciation of how they design, run and maintain the equipment and how those behaviors affect risk, a part of which is probability of failure. In other words, they have a deeper appreciation for the risk drivers.

Further, as an RBI specialist, you will need to be able to educate management (and others) on how RBI truly helps you from the ground up and from the top down. Yes, money is part of the game and yes, the bigger picture is prioritizing the work, understanding the areas of risk, and knowing where and when you need to go inspect, or if inspection is the best way to mitigate the risk/s.

However, the most important single ingredient in the formula for success is knowing how to get along with people; how to communicate what you know and want them to know and how they open up to you with information that is vital for an effective program. For example, don't give management a diatribe through rose-colored glasses but provide them with the information they want and need in terms they can understand. If people ask questions, answer the questions. Don't beat around the bush; don't run circles around them. Give them the answers. (Which is sometimes "I don't know right now, but I'll get back to you.") Always be honest. This ensures everybody is on a level playing field, and you teach them a little bit more about what you're doing and provide the opportunity to buy in, and organizational engagement is important to have an effective sustainable program.

"The most important single ingredient in the formula of success is knowing how to get along with people."

~ Theodore Roosevelt

Lastly, it's important to remember that RBI is merely one tool in the mechanical integrity toolbox. It is the RBI specialist's responsibility to educate key stakeholders on the benefits and limitations of the methodology and help lead the RBI implementation initiative. In most cases you are the single most knowledgeable risk-based expert in a meeting or in your company. How you communicate your knowledge, in terms that the others in the room can understand and accept, is entirely up to you. Will you 'win' every discussion? No. Will you get everyone to understand the true benefits of risk-based planning? No. But these 'losses' do not lose the 'battle' you fight mitigating risk. Rather, these provide an opportunity to improve and progress forward. Learn from the conversations and make the necessary adjustments to achieve success.

**"Losing is a learning experience.
It teaches you humility. It teaches you to work harder.
It's also a powerful motivator."**

~ Yogi Berra

How to Stay Afloat in Risky Waters

First things first, you need to set a clear direction and establish a solid foundation when taking on any RBI initiative. As one example, it's important to have a documented program summarizing what you want to accomplish and the processes and procedures in place to get you there. If you don't implement a risk program, if you just say, "We're going to follow 580 and 581," you've already lost the game because you don't understand that you need a foundation specific to your company and culture. Create a vision. Communicate the vision. Establish a foundation and an achievable path forward.

**"Make a game plan and stick to it.
Unless it's not working."**

~ Yogi Berra

Create a vision. Communicate the vision. Establish a foundation and an achievable path forward.

Once you set that clear direction, then you can establish peer groups. Initially, you may have to find those groups externally because it is unlikely you will have them internally. Once you find those people outside the company, and you gain experience and knowledge, then spread it internally. I have found the establishment of communication amongst internal persons is a game changer. Use this to teach, foster, mentor, and discuss the vision and its implementation so you can get better buy in and understanding from your peers (and management) within your company. It also helps with the long term sustainability of the program.

Determine the best places to start that will show early successes. You may initially start by organizing smaller projects and completing them. These successes can help 'get the ball rolling.' However, a common problem we face is a lack of follow-through on projects. Anybody can start projects, but the real challenge is seeing them through to completion. So it's important to set realistic goals and establish projects that are feasible. If it's not a feasible goal, it may be because it doesn't have the right timeline or resources. Design your project for success by understanding the resources (time, money, effort, etc.) that are needed. Build upon these small projects (and successes) to gain support for the bigger picture of risk-based management.

As your program matures, you will need to establish key performance indicators (KPIs) that are both leading (predicting forward) and lagging (measuring the past). These should include measures that lead you to make changes that are positive but could identify items you have missed and spur improvement opportunities. Don't be afraid to report both sides, and make sure you report the facts. When you provide the information to management, don't be afraid to say, "Hey, we have a problem" or "Look at this success." Brag on the successes and provide achievable solutions for any problems.

"Performance should be made square with promise."

~ Theodore Roosevelt

Let's remember that KPIs are necessary to tell you whether you're going in the right or wrong direction, or if a correction in course is needed to get better. It is important to assess the direction and the path you're taking regularly. Changes have to be made at times for opportunities to provide the best probabilities for success. If you just keep moving forward and throwing RBI at people without measuring the progress (or lack of progress), there's a good chance you're going to fail or stagnate.

Another way to stay afloat as your program matures is to implement an effective training strategy. You can train others in a classroom setting, but you must let them learn and share by experience just as much. Training is constant because people move jobs in or between companies. While effective training is a necessity, it does not replace sharing knowledge and experience. That part needs fostering as part of your culture. As mentioned before, using peer groups for knowledge sharing purposes is one way. But you also must let people go out on their own and make mistakes. Identifying and reviewing mistakes is a necessary building block of learning, but shouldn't include harsh criticism. Define the error, adjust toward a success, and move on. Just like a lost sheep, you may have just stepped off the path and all you need is to be brought back into the fold. Consistent and persistent training will reinforce going in the right direction. Corrections keep you on the good path.

**"You don't have to swing hard to hit a home run.
If you got the timing, it'll go."
~ Yogi Berra**

Plan for the Next Phase in Life

You have done a lot. Your program may be hitting on all cylinders and be very successful. Or you may just be getting started and in need of change. Regardless, it is important to plan for the next phase. For your program, this is where people leave, people move on, and people retire. Things happen that cause us to move on in our career and in our lives. If you're that person getting ready to move, and you've been the subject matter expert, you need to have a succession plan to leave a shepherd in your place - someone who can take over for you when you decide to take that next step. First, you must share your vision and experiences with them. Hopefully you've been mentoring them for a while. And for you, it's important to remember the job is never done; it just continues with someone else, so you need to prepare them well. You have a duty to train the replacement and leave good instructions, which means you need a documented and successful program in place to help guide their decision making.

**"If you don't know where you are going,
you might wind up someplace else."
~ Yogi Berra**

When you do leave, leave with a smile. Nothing is perfect, and you have to continually improve things. It's all part of the lifecycle and the process, and you should leave on a high note and in high regard. You don't want to burn bridges. You should know when to move on, but we know that's difficult for some of us.

Don't be afraid to leave. Remember, when you started out, all the work was probably not always right, but you made it right and you should be proud of that. And when you are at the end, you should take enough steps to make sure what you leave is on the right path. Don't let your pride obscure knowing when you need

to step onto another path. Leave that shepherd there to help cultivate what you started and continue on a good path. And smile as you know you've done your best and it is time for the next person to carry the torch.

**"Let us rather run the risk of wearing out
than rusting out."
~ Theodore Roosevelt**

Conclusion

Truth be told, RBI was never the biggest challenge in my life, or in my career. It enhanced both. It gave me opportunities where I didn't know opportunities existed. It gave me chances to develop philosophies, principles, and procedures, and ways of thinking I never thought about. It has provided me with peers, colleagues, and friends that have enhanced my career and life.

The takeaway should be an understanding that we can progress. We can set programs up for success. We can establish a common language. We can train and mentor others for sustainability of effective initiatives. And in the end, we can make a difference. That difference is the consequence if the probabilities have been weighted toward success, you understand the risk drivers, and you're willing to take the measured risk each step of the way.

**"Don't wait until everything is just right.
It will never be perfect. There will always be challenges,
obstacles and less than perfect conditions. So what.
Get started now. With each step you take, you will
grow stronger and stronger, more and more
skilled, more and more self-confident and
more and more successful."
~ Mark Victor Hansen (Author & Motivational Speaker)**

I'm not ready for that next phase in life or career myself, but I'm not afraid. It's not about me, but what I can pass along. I hope that you have read this and found some humor, some truth, and maybe a nugget or two that helps build your risk-based career and life. In the end, remember that it's not just about equipment, it's also about the risks you take, the risks you wake up with, the risks you will encounter each day and how much you improve in managing those risks throughout your career and life. ■

For more information on this subject or the author, please email us at inquiries@inspectioneering.com.



As I reflect on E²G's first 20 years, I am struck by how far the industry has progressed towards safer and more reliable facilities. In those early days, the industry was faced with process safety management (PSM) legislation, shrinking oil prices, and a need to safely evaluate aging equipment to extend life. The greatest challenge was to develop this technology and obtain jurisdictional acceptance. The method used to create what is now known as API 579/ASME FFS-1 and obtain jurisdictional acceptance as an international code was carefully choreographed and innovative. We were at the forefront of innovation.

At E²G, we have continued to innovate, our focus is unwavering, and our pillars of success are unchanged. We are united and focused on creating and delivering knowledge, excellence, and technology.

I CHALLENGE YOU TO

SHIFT

YOUR

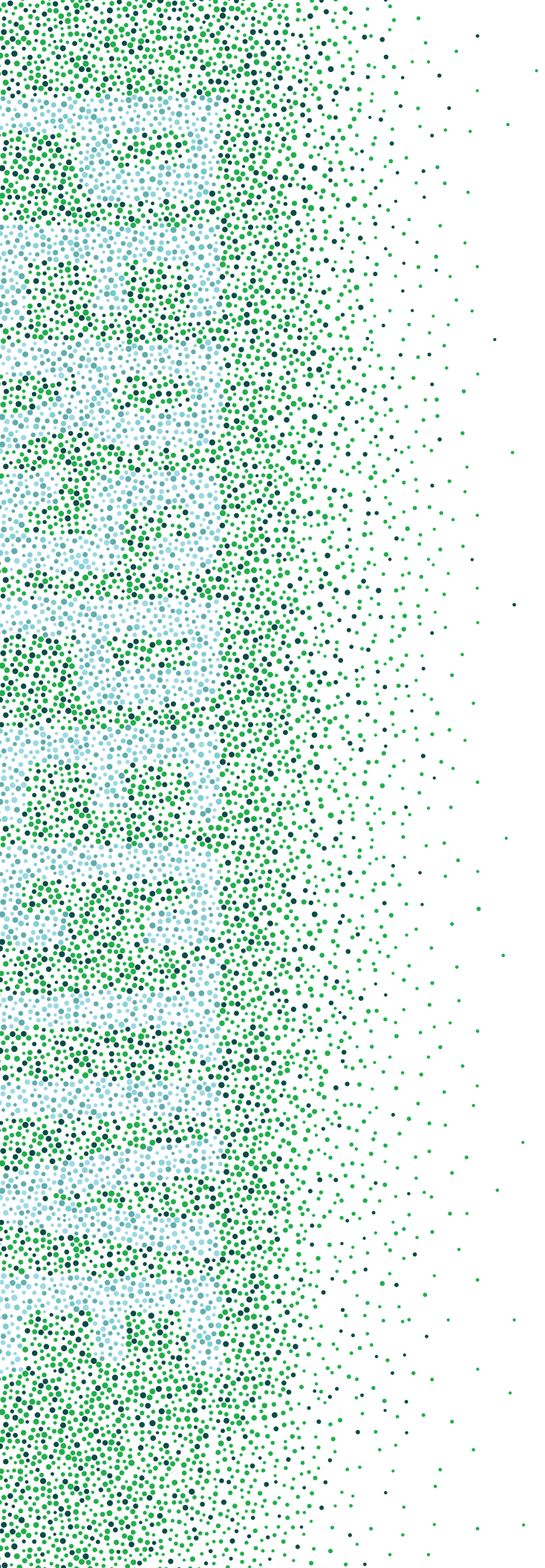
PERSPECTIVE.



ANSWERS FOR TODAY. INSIGHTS FOR TOMORROW.

216.283.9519 // Sales@E2G.com // www.E2G.com

© 2022 E²G | The Equity Engineering Group, Inc.



KNOWLEDGE IS...

- Analyzing and assessing aging equipment to deliver safer and more reliable facilities
- Offering the most comprehensive corporate standards and delivery platform available in the world
- Researching new technologies and processes to push the boundaries of asset lifecycle management
- Participating on API, ASME, and other committees to guide industry best practices and advancements

EXCELLENCE IS...

- Integrating our clients' legacy documents into the Equity Engineering Practices
- Training the next generation of engineers with mentoring and guided knowledge sharing
- Educating and empowering our clients with industry-relevant training courses
- Working with a team of all-stars who are 100% dedicated to E²G and its future growth

TECHNOLOGY IS...

- Providing the most advanced fitness-for-service software for our clients and E²G's consulting team
- Assessing corrosion behavior using a patented thickness analysis methodology
- Innovating new inspection techniques that use consequence of failure and vibration data
- Using Bayesian networks to develop inspection plans for equipment subject to corrosion and pitting

We are a consulting, training, and software firm that is focused on creating and delivering practical and innovative solutions to solve your asset challenges. We are as strong as ever, and we will continue to shift your perspective.

Sincerely,



David A. Osage, P.E., ASME Fellow
President & CEO

Management and Identification of Dead Legs

Ashfaq Anwer, Sr. Integrity Engineer
Kaiser Alam, Inspection Engineer

Introduction

Hydrocarbon processing facilities encounter numerous damage mechanisms threatening the asset integrity. However, many of those damage mechanisms become even more detrimental when the flow is stagnant and the process parameters are unlike the ones in the normal operating circuits. For instance, in piping with hydrofluoric acid service, segments with stagnant flow are more prone to damage due to higher corrosion rates compared to segments where the flow is normal. Similar observations are also evident in process piping with varying types of service, as numerous incidents have occurred where unexpectedly higher corrosion rates surfaced in areas where the process flow is still. Dead legs are areas of a piping system that rarely see flow, yet are still exposed to process, even if not explicitly cut off. These areas pose a substantial threat to piping integrity because they are especially prone to contamination and corrosion (Examples shown in **Figures 1** and **2**).

Ideally speaking, during the design stage of a plant, all potentially unavoidable dead legs, like a bypass to a control valve, should be identified and efforts should be made to minimize or eliminate their existence where possible. However, that is often not realistic. Most operating facilities have piping circuits containing one or multiple dead legs. These dead legs are either operational or related to the plant construction, and are required to be identified on drawings and tagged at the site as well. Designers, however, are still responsible for eliminating or minimizing unnecessary dead legs at the design stage. It is not a difficult task to replace the piping length of instrument connections with forged fittings which would practically eliminate the dead legs. Long weld-neck flanges (forged) can be used for drain and vent connections, which are potential dead legs on equipment, in order to avoid any possible thinning of those forged components over the years with stagnant flow inside. Similarly, it is also practical to have forged fittings wherever a vent or a drain connection has to be provided on static equipment. Likewise, dummy legs can also be eliminated by providing structural supports wherever required. There are cases where it is simply not possible to eliminate a dead leg, however. Examples of these include bypass lines, pump and compressor recirculation lines, level bridles, relief valve inlet and outlet piping, sample points, etc. Broad categories of dead legs are described in **Table 1**.

For any operating plant, it is imperative to identify and manage the dead legs and the assets that contain dead legs. While identifying dead legs, the following criteria may be applied:

- Is the pipe section connected to a flowing stream, not self-draining, and normally not flowing?
- Does the piping material have the potential for corrosion in service?



Figure 1. Dead leg example: control valve bypass.



Figure 2. Dead leg example: piping with normally closed block valves.

- Does the piping have a length of more than 3D or 1.22 m (4 ft), whichever is less, where D represents pipe diameter?

Within these criteria, the length of the piping segment with no-flow is the controlling parameter. The piping material, however, is also very important to consider while addressing and managing dead legs. Generally, assets constructed from corrosion-resistant materials are not marked with dead legs as their potential for corrosion, even in no-flow conditions, is minimal. Similarly, certain utility services which are not corrosive in nature do not need to be marked for dead legs. Dry services can also be excluded as there is no potential to have active corrosion.

Starting with the identification and marking of dead legs, there should be written guidelines or procedures available containing the minimum requirements agreed upon by the Inspection, Maintenance and Operations teams. Inspection should be covering the requirements for identification of dead legs based upon its basic definition; Operations should be endorsing the identification guidelines; and Maintenance should be playing the role of support to help Inspection carry out the tagging process and marking on the drawings. These guidelines should also define the nomenclature which will then be used while marking the dead legs on drawings, and then at the site. For example, a bypass line having stagnant flow could be identified as 'DLBYP'. Similarly, a dead leg related to an instrument connection could be identified as 'DLIC'. Additionally, piping systems and operating equipment with non-corrosive, non-flammable, and non-toxic service may be exempted from the identification process and should not be required to be marked/tagged with dead legs. At a minimum, two

Table 1. Categories of dead legs.

Blanked branches	CV bypass line	Drain	Vent	Equipment recirculation line
Instrument connection	Bleeders	Purge connection	Relief valve inlet	Pump recirculation line
Relief valve drain	Relief valve outlet header	Bypass line	Normally closed block valves	Injection points
Level bridges	Level transmitters	Lines with one end blanked	Corrosion probe	Sample points
Spare pump piping	Spare filter piping	Flare outlet header	Emergency valve inlet	Comp. recirculation line

Table 2. Sample master list of dead legs.

Sl. No.	P&ID	Piping tag	No. of identified dead legs	DLBYP	DLIC	DLPG	DLDRN	DLLNC
1.	UY332	SH56843	6	1	1	1	1	2
2.	UY333	PF56653	1	1	0	0	0	0
3.	UY345	PF56772	3	0	2	1	0	0

basic documents should have the markings of all the dead legs at the site: the P&ID and the piping isometrics. It should be carefully seen that the latest updated P&IDs and piping isometrics are properly utilized for identifying and marking dead legs.

To start off the process, owner-operators should review P&IDs and screen for dead legs, such as normally closed valves, instrument connections, spare pumps, control valves (having bypasses), and lines with closed ends. Drain, vent, and purge connections can also be easily found. Once these dead legs are identified on the P&ID, it is generally a good practice to validate the length of the potential dead legs as per the aforementioned criteria. A master list of dead legs should then be prepared against each piping circuit with dead legs. A sample master list is shown in **Table 2**.

Once all dead legs have been identified and marked on the P&IDs and piping isometrics, the complete set of documents should then be shared with Process and Operations teams to verify the markings and provide their comments. It should be understood that Operations has a better understanding of the assets and flow conditions than most. During their review, they may even point out those marked-up portions which actually have flow, but the P&IDs are erroneously marked with a normally closed valve instead per se. Such validations not only improve the overall confidence of the dead leg database, but also aid in identifying requisites for necessary amendments in the plant drawings through the management of change (MOC) process.

After Operations review, all piping portions that have been declared as dead legs should also be marked with condition monitoring locations (CMLs) in order to ensure that inspection of these portions are not omitted. As a general rule, each dead leg should have a minimum of one CML, while dead legs having longer lengths should consist of more CMLs depending on the piping run and its plane (vertical, horizontal, or angular). Bends, reducers, and tees should all be considered for CMLs. While marking CMLs, field visits are recommended for each P&ID along with the piping isometrics. These visits ensure that any routing deviations from the drawings are captured, highlighted, and the appropriate MOC action is taken in consultation with Operations, if required. A dead leg marked “as per dimensions” on the isometric drawing may not be a dead leg when the actual dimensions are verified in the field. In addition, there can be some additional dead legs, like a pressure gauge or a drain point, that do not appear in the

drawings. Though the latest drawings should be considered, variations between the drawings and the actual equipment are not unheard of; hence, field verification should not be omitted.

Dead legs, marked up P&IDs, isometrics, and the master list should then be handed over to the site RBI engineer so that all the tags having dead legs can be flagged in the inspection management/RBI system governing the site. Generally, assets that consist of dead legs are required to be inspected more frequently as the damage factor in the RBI analysis is significantly impacted. From this point, the actual work of dead leg inspection begins. Each piping tag that is due for nondestructive testing (NDT) to measure pressure wall thickness must have the dead legs identified, marked, and validated at the site, and must be inspected along with the rest of the asset. Data gathered for each dead leg should be managed separately from the piping tag itself. This is the minimum inspection requirement mentioned in API 570, paragraph 6.6.1: “Dead legs with CMLs should be tracked in a separate piping circuit from the mainline piping.”

Common NDT technologies used to inspect dead legs include profile radiography for smaller diameter vents and drains, and ultrasonic testing (UT) or radiographic testing (RT) for larger diameter runs. While identifying and marking dead legs, all equipment with dead legs should also be taken into consideration and marked properly so that those portions are properly inspected. In case there have been some forged, high-thickness components used, like long weld-neck flanges, such components can be exempted. However, when normal piping is used for vents, drains, purge connections, and other such components with insignificant flow, it is recommended to identify, mark, and inspect them.

In summary, management of dead legs, which includes identification, marking, validation, and inspection, should be done through controlled procedures at operating facilities. Unexpected leaks through process lines often occur due to insignificant or no-flow conditions which eventually lead to higher corrosion rates when compared to the rest of the piping components facing normal flow. That is the core reason for tracking dead legs separately from the mainline piping. ■

For more information on this subject or the author, please email us at inquiries@inspectioneering.com.



Lavender International

NDT USA, LLC



TRAINING | EXAMINATIONS | CONSULTANCY

Lavender International strives to make the world a safer place through training NDT professionals to the highest of standards. Students receive quality training from our friendly, experienced and highly knowledgeable tutors at our training center in Houston, Texas.

COURSES AVAILABLE

- **PCN (ISO9712) Level 1, 2 and 3**
- **MT and PT**
- **Eddy Current and ACFM**
- **NEW Total Focusing Method**
- **Manual UT of Welds in Plate & Pipe Nozzles, TKY Node Joints**
- **Advanced PAUT and TOFD**
- **HTHA Detection**



T: 1.281.984.7023
www.lavender-ndt.com

Risk Based Management of Corrosion Under Insulation

Frode Wiggen, Sr. Principal Engineer – Inspection Management at DNV GL

Introduction

Corrosion Under Insulation (CUI) is a major challenge for many industries. At present, it is managed in many ways, ranging from full removal of insulation to minimal maintenance and inspection (oftentimes with some non-destructive testing methods not able to detect CUI). These two extremes exhibit a lack of understanding and a lack of a systematic approach in managing CUI risks, globally.

The article will describe the results from a recent (2017-2019) CUI Joint Industry Project (JIP) where the oil and gas industry in the North Sea area has developed a methodology for managing the CUI threat. In this context, managing the CUI threat involves risk assessment, risk mitigation, risk update and experience transfer in a systematic manner. The methodology assesses four (4) CUI barriers: material, coating, water wetting and design, each of which will be elaborated on in the article.

This methodology is available for the industry in DNV GL's RP-G109 "Risk Based Management of Corrosion Under Insulation" as of December 2019. The Recommended Practice may be used in conjunction with already developed software platforms that support the work process. The software can be aligned with individual company specific requirements, as well as solely rely on the basic selected methodology, or combinations thereof.



Joint Industry Project

As a response to the lack of guidelines for risk-based management of CUI, DNV GL and major operators in the North Sea started a (JIP) in 2017 to gather industry experience and establish a recommended practice for managing the CUI threat.

In this context, managing the CUI threat involves risk assessment, risk mitigation, risk update and experience transfer in a systematic manner. Participating companies were AkerBP,



Figure 1. CUI management based on a four-phased PDCA approach.

ConocoPhillips, DNV GL, Equinor, Gassco and Neptune Energy. Norwegian PSA and the UK HSE attended as observers during the project.

The objective of the DNVGL-RP-G109 "Risk based Management of Corrosion Under Insulation" document is to provide guidance on how to manage corrosion under insulation (CUI) in process plants. The work process is built around a Plan, Do, Check, Act (PDCA) process aligned with ISO 9000 requirements of continuous improvement (see **Figure 1**). The target is to mitigate unacceptable risk in the most effective way by giving priority to high risk.

The recommended practice is primarily intended to be used for risk assessment of insulated static mechanical pressure systems when considering failures by loss of containment of the pressure envelope due to external CUI.

The described methodology is primarily designed to be applied for process systems that operate at temperatures below 200°C. Special considerations should be made for systems operating at higher temperatures and these should include assessments of CUI effects caused by temperature fluctuations into the < 200°C area due to operation or geometrical lay-out effects.

DNVGL-RP-G109 describes an approach for assessment of probability of failure related to CUI. The consequence of failure should be assessed by methodologies described in other standards.

CUI Barriers

In DNVGL-RP-G109, the PoF_{CUI} assessment methodology focus is on four barriers:

1. Material barrier

The material used in the pipe, tank, or pressure vessel, and its corrosion resistance in the relevant condition. The most essential parameter in this context is temperature.

2. Coating barrier

The protection of the material against the external environment. In this context, the protection is often a coating system, and the environment causing CUI is water and corrosive contamination.

3. Water wetting barrier

The extent of water wetting of the equipment surface, which is an effect of restricting the water to enter the insulation, the insulation's ability to hold water, and the effect of drainage and evaporation from the insulation system.

4. Design barrier

CUI challenges might be reduced or increased based on the design of the system. Parameters such as wall thickness and pipe diameters will influence the probability of failure due to CUI. Results from NDT inspections are also included in this barrier.

If either the material barrier, coating barrier, or the water wetting barrier is assessed to be intact (PoF assessed to VL or L), it can be assumed that there will be no CUI incidents for the relevant period.

Each of the four barriers are assessed based on a subset of factors. These are:

Material barrier

- Material type
- Material surface temperature
- Temperature fluctuations
- Contaminants

Coating barrier

- Coating age
- Coating type
- Quality control and workmanship
- Wetting conditions
- Temperature and temperature fluctuations

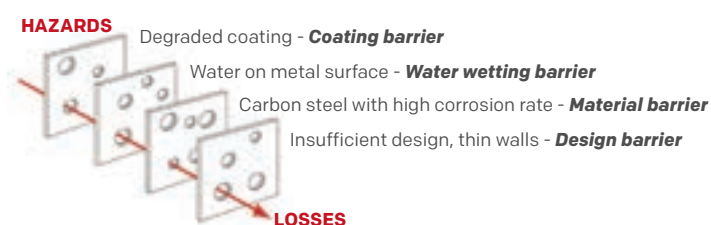
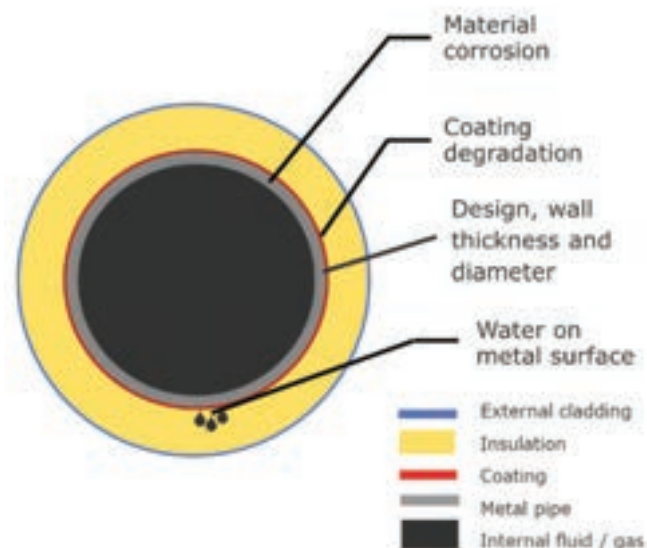
Water wetting barrier

- Location
- Dew-point temperature
- Insulation System
- Workmanship
- Maintenance routines

Design barrier

- Wall thickness
- Pipe dimensions
- NDT, method, extent, timing and results

The risk assessment model combines individual probability assessments of the four CUI barriers, material barrier, coating



barrier, water wetting barrier, and design barrier, into a “total” probability of failure category, and combines this with the consequence of failure into a risk (CUI) category.

$$PoF_{CUI} = f(PoF_{material}, PoF_{coating}, PoF_{water\ wetting}, PoF_{design})$$

$$Risk_{CUI} = f(PoF_{CUI}, CoF)$$

Whether CoF is assessed with respect to impact on safety, financial, environmental, or all parameters is not discussed in this document. Advice on this can be found in DNVGL-RP-G101/1/

The individual qualitative probability assessments of the four barriers into five categories from Very Low (VL) to Very High (VH) are described in the appendices of the Recommended Practice.

Details on how the parameters are combined into a qualitative risk assessment model for CUI are described below.

Qualitative CUI Pof Assessment

Based on the evaluation of the four barriers for CUI (see appendix A, B, C and D of the RP), the four different PoF values can be entered into a qualitative model with probability values of very low (VL), low (L), medium (M), high (H) or very high (VH).

The PoF shall be qualitatively assessed in a point model for the four barriers in a systematic approach, and the four main barriers shall be individually weighted in accordance with the importance of the barrier in the company specific CUI risk management strategy. It is however recommended that none of the barriers

should exceed 50% weighting.

DNVGL RP G109 is used as the basis for a model for assessing the total PoF_{CUI} for CUI:

$$PoF_{CUI} = f(PoF_{material}, PoF_{coating}, PoF_{water\ wetting},) + PoF_{design}$$

An initial PoF will be calculated and then adjusted by the PoF_{design} . Following this logic, elements such as wall thickness and inspection results will adjust the initial probability which is based on material, temperature, coating and insulation information.

The PoF value will be achieved by transferring the qualitative value (VL, L, M, H or VH) into a numeric value (see **Table 1**). The four different barriers can be weighted according to the company CUI strategy. However, the RP document recommends that material, coating, and water wetting barrier is equally weighted. The average value of these three barriers should then be added to the value from the design barrier to end up with a numeric PoF for CUI.

Table 1. Quantitative numbers for different qualitative PoF values

Barriers	Very Low (VL)	Low (L)	Medium (M)	High (H)	Very High (VH)
Material Barrier	-15	-10	3	6	10
Coating Barrier	-15	-10	3	6	10
Water Wetting Barrier	-15	-10	3	6	10
Design Barrier	-5	-3	0	2	3

The numeric value for PoF_{CUI} shall then be assigned a qualitative probability category derived from the probability categories in **Table 2**.

Table 2. Total probability categories based on Table 1.

Very Low (VL)	Low (L)	Medium (M)	High (H)	Very High (VH)
<-5	≤-5 - -1≤	<-1 - 3≤	<3 - 6≤	<6

The calculation will be:

$$(f(\text{Material barrier}) + f(\text{Coating barrier}) + f(\text{Water wetting barrier}))/3 + f(\text{Design barrier}) = PoF_{total\ CUI}$$

Risk Mitigation

To reduce the CUI risk, mitigations performed need to have a positive effect on the parameters leading to the given risk. As the consequence of failure (CoF) is normally not affected by the mitigation process, focus should be on achieving changes of the probability of failure parameters instead. However, it is recommended to verify that the CoF is assessed correctly.

Since the probability of failure (PoF) tends to change based on age, technical condition, and other factors, reducing PoF for CUI implies changing one or more parameters influencing the CUI barriers:

- Material barrier
- Coating barrier
- Water wetting barrier
- Design barrier

The most effective risk mitigation will be to permanently remove the insulation. It is strongly recommended to verify the necessity of the insulation through more detailed assessment with respect to heat conservation, fire safety, personnel protection, noise protection, and other relevant objectives for the insulation.

Concept of Mitigation

There are two main ways to change the parameters affecting the PoF:

1. Increase knowledge by getting more information and re-evaluate the barriers
2. Modify and change the condition

Increased knowledge can be achieved by inspection, or by performing studies or more detailed assessments. Changing the physical condition can be in form of maintenance or modifications. The latter also includes the option of permanent removal of insulation.

When risk reduction is required, the PoF factors leading to high risk should be identified so these can be evaluated for potential alteration first. A cost-benefit assessment is also necessary to ensure a cost-effective risk mitigation. It is important to notice that certain parameters (e.g., temperature and wall thickness) cannot easily be altered even though they might lead to high risk.

Increase Knowledge

In this context, increasing knowledge will reduce the uncertainty or remove conservatism and might reduce or increase the risk depending on the new knowledge. Knowledge might come from visual inspection and other NDT inspection results, or as updated lifetime information on the coating system. Typical elements leading to new knowledge are:

- Inspection results including methods such as: NDT without removal of insulation, external inspection of cladding, and visual inspection of the object underneath the insulation
- New knowledge on Probability of Detection for the inspection methods
- New knowledge on QA during surface preparation and coating application
- New knowledge of coating system lifetime
- New knowledge of the insulation solution used
- New information of process upsets and temperature alterations

Table 3. List of susceptible areas and their relevance to the different CUI barriers

Hot-spot	Material barrier	Coating barrier	Water wetting barrier	Design barrier	Other
Field joints		X		X	
Complex geometries		X	X	X	
Penetration to cladding / weather-proofing		X	X	X	
Areas with restricted availability for coating application, i.e., deck penetrations or under supports		X		X	
CS bolts and nuts in SS systems	X			X	
Damaged cladding or degraded waterproofing			X		Area with potential of receiving water from damage
Branch connections with temperatures in higher PoF areas than the main pipe.	X			X	
Areas subjected to excessive water exposure			X	X	
Vessel insulation support rings and other elements that trap water			X	X	
Branch connections		X	X	X	
Steam heat tracing	X		X		

Note: For a more extensive list of susceptible areas see chapter 5 of API 583 or chapter 5 of EFC no. 55.

- Updated design information
- New procedures for fire water testing
- New CUI risk assessment analysis
- Experience from other assets and lessons learned
- Installation of monitoring systems that will give better CUI information (modification that effect the increased knowledge part)

Modification

In this context, typical modifications that will mitigate the risk are:

- Permanent removal of insulation
- Replace one insulation system with another and better design solution
- New coating. For example, full refurbishment or just spot repair of degraded coating. The different coating repair activities will have different mitigating effects
- Re-design of pipe-routing, new material selection, alteration in pipe or vessel wall thickness
- Alteration of temperature variations
- Permanent or temporary repair of degraded parts

Susceptible Areas for CUI

Locations for CUI

In the mitigation process it is considered helpful to inspect

locations that are more subjected to CUI than others due to layout or local conditions.

Inspection results from susceptible areas can, under certain conditions, represent areas that are not inspected. Thus, it can be expected that other “not inspected, not susceptible areas” are in a “better” condition. In this context “areas that are not inspected” need to have similar characteristics with respect to material, temperature, coating, insulation design solutions, and similar degradation is expected. “Areas that are not inspected” can be the same tag or a group of tags. This approach is similar to performing NDT on selected inspection points to detect degradation in corrosion circuits.

Susceptible Areas Related to Specific CUI Barriers

To mitigate a risk, it might be useful to use susceptible areas relevant to the actual PoF factor leading to unacceptable risk. A list of susceptible areas and their relevance to the different CUI barriers can be found in **Table 3**.

Extract of Detail Barrier Assessment

PoF for Carbon Steel

The probability of failure due to CUI for carbon steel increases with temperature up to 110°C. At temperatures above 110°C, the water will evaporate from the material surface and corrosion rates will decrease. In **Figure 2**, the probability of failure is categorised stepwise in different temperature ranges into qualitative PoF categories.

The different steps of PoF_{material} are based on a compilation

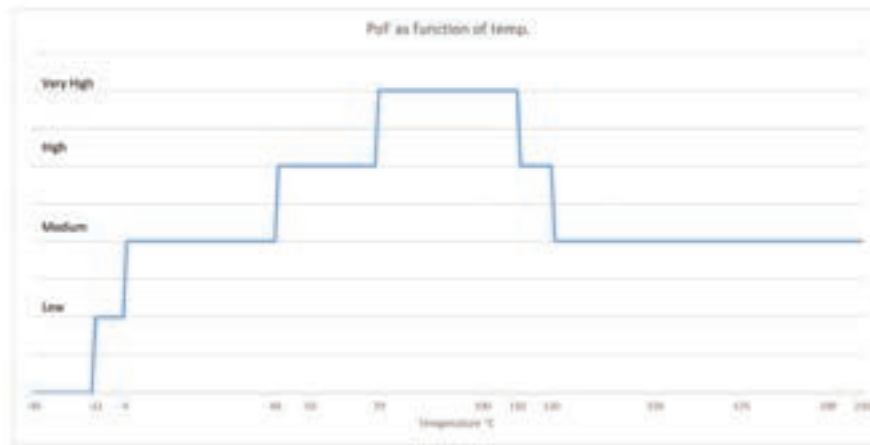


Figure 2. Probability of Failure of material barrier (POFmaterial) as a function of temperature

Table 4. Probability of coating breakdown as a function of coating type and age

Description	NORSOK M-501 system ref.	NACE SP0398 2010 syst. ref.	Temp. area	Age of the coating								Comment
				0-5	6-10	11-15	16-20	21-25	26-30	31-35	>35	
Primer (<50 µm)	N/A	N/A	+60°C	VH	VH	VH	VH	VH	VH	VH	VH	Not intended to be used as a protective layer under insulation.
Hot Dip Galvanizing (HCS)	N/A	N/A	+200°C	L	M	H	VH	VH	VH	VH	VH	Ref ISO 14713-1.
Zinc Silicate with top sealer	N/A	N/A	+325°C	L	M	H	VH	VH	VH	VH	VH	Not to be used under insulation according to NORSOK M-501.
2 layer with zinc rich primer as first layer (vinyl)	System 1	N/A	+80°C	M	H	VH	VH	VH	VH	VH	VH	Not to be used under insulation according to NORSOK M-501.
3 layer with zinc rich primer as first layer (epoxy)	System 3	N/A	+80°C	M	L	M	H	VH	VH	VH	VH	Not to be used under insulation according to NORSOK M-501.
Two component epoxy or polyester based coating	System 7A	N/A	+80°C	M	M	L	M	H	VH	VH	VH	Not to be used under insulation according to NORSOK M-501. Need prequalification.
3 layer on epoxy primer (zinc free)	System 6 (A/B) (SS)	N/A	+80°C	L	M	H	VH	VH	VH	VH	VH	Not to be used under insulation according to NORSOK M-501.
2 layer epoxy coating (>250 µm)	System 7 (B/C)	SS-1/CS-1	-45 to +60°C	M	L	M	H	VH	VH	VH	VH	Not to be used under insulation according to NORSOK M-501. Need prequalification.
2 layer epoxy Phenolic / Novolac	System 6C (SS) System 9 (CS)	SS-2/9 / CS-3/4	-45 to +120°C (SS) +60°C	M	M	L	M	H	VH	VH	VH	Ref NORSOK 501.
Fusion Bond Epoxy (FBE)	N/A	CS-2	-45 to +60°C	L	M	H	VH	VH	VH	VH	VH	Ref NACE SP0398. Shop application only. Potential for cracking.
Thermal Spray Aluminum (TSA) with top sealer	System 2A	SS-6/CS-5	-45 to +550°C	M	M	M	M	L	M	H	VH	Normative ref NORSOK M-501.
Air dried silicone or Modified silicone	N/A	SS-4	-45 to +140°C	M	H	VH	VH	VH	VH	VH	VH	Ref NACE SP0398. Limited information on this system available. Testing and prequalification needed.
Inorganic copolymer or coatings with an inert multipolymeric matrix	N/A	SS-5 / CS-6	+300°C to +650°C	L	M	H	VH	VH	VH	VH	VH	Ref NACE SP0398. Evaluation based on testing of 2 generation products. Limited practical experience. Further testing and prequalification needed.

*1 3-layer on epoxy primer (zinc free) – Applied on CS, assessed to be as good as phenolic epoxy system for SS under insulation given temp. below 80°C.

*2 Inorganic copolymer coating has so far proven most capable in the temperature range above 100°C with only short periods below that temperature.

of information from acknowledged technical documents and industry experience.

When assigning a PoF category, awareness shall be given to fluctuations in the temperature, both as a function of process changes but also as a function of geometrical layout, including stagnant conditions or partial insulation. To ensure conservatism when there is fluctuation between two different PoF categories, the higher category should be used.

Probability of Coating Breakdown

Coating Breakdown Table

The probability of coating breakdown is set as a function of coating type and coating age (see Table 4).

Note: Table 4 is presenting generic values and properties for different coating systems. Values and properties might vary a lot for products defined under the same generic system.

Table 4 is based on the following assumptions:

- The assigned PoF category assumes that coating systems are chosen based on correct exposure temperatures, and surface treatment and application are executed in compliance with international standards and suppliers' recommendations.
- The object (vessel/pipe) is subjected to wet conditions.
- The given probability of coating breakdown categories (VL–VH) should be adjusted for any of the below conditions:
 - If the operating temperature is outside the coating systems designed temperature interval the $PoF_{coating}$ shall be set to Very High (VH).
 - If the application of coating is done with poor quality, the

expected lifetime of the coating system shall be reduced, and the age of the system set equivalent to Medium (M) which indicates 5 years of remaining lifetime. The quality of the work can be documented and confirmed through quality control inspections. Until a good application is confirmed the coating application should be considered “poor”.

- c. If coating systems are repaired or restored onsite/offshore, the ability to control environmental conditions, surface preparation and coating application is often poorer than in a shop. Coating systems applied onsite/offshore are likely to fail after a short time if the parameters listed under B5 are not kept under control. For coating applied in the field with limited control of parameters, or only mechanical surface preparation, the PoF_{coating} shall be set to medium after spot-repair.
- d. After full refurbishment of the coating the PoF_{coating} can be set to “0 years old” provided that the conditions during application are controlled and documented to be in accordance with international standards and supplier’s recommendations. In addition, there should be a good Quality Assurance / Quality Control system in place.
- e. If the probability of water wetting is low or very low, this shall also be reflected in the coating assessment, which is originally based on wet conditions. Coating lifetime can

then be extended with 5 (L) or 10 (VL) years for coatings (moved to the left in the table above).

- f. Higher temperatures (above 80 °C) tend to reduce the service life of protective coatings but this has less effect on inorganic coatings (i.e., TSA or inorganic copolymer) and for systems qualified for very high temperatures (> 200 °C). Coating use in higher temperature areas should be assessed in more detail and lifetime might be reduced by 5-10 years.
- g. Fluctuations in temperature can reduce the coating lifetime and needs to be addressed specifically in each case. In general, reducing the lifetime by 5-10 years should be considered if the glass transition temperature is crossed repeatedly.

Conclusion

CUI risk management methodology described in DNVGL-RP-G109 is a practical and efficient way of managing the risk represented by CUI. The methodology is based on assessing, mitigating and updating the probability of breach of 4 distinct barriers: the Material barrier, Coating barrier, Water wetting barrier, and Design barrier. DNVGL-RP-G109 complements other important documents describing challenges related to CUI such as API 583, EFC. No. 55, and NACE SP0198. ■

For more information on this subject or the author, please email us at inquiries@inspectioneering.com.

COMPANY SPOTLIGHT / Fixed Equipment Reliability (FER)

Fixed Equipment Reliability (FER) Fixed Equipment Reliability (FER) has been providing first class API certified, NDE inspection services since 2011. Our method and motto for success at FER is a simple one, “anticipate our client’s needs and adapt with the ever-changing industry”.

In this digital age, inspection departments have begun to switch from traditional paper-based reporting to cloud-based data gathering via tablets and other mobile devices. Streamlining the process of acquiring and analyzing data within databases (Meridium, IDMS, UltraPIPE, PCMS, etc.) has proven advantageous and extremely efficient. Furthermore, FER



bridges this gap with custom software designed to remove human error common in manual data entry. Our system has been tested in the field, utilized in multiple turnarounds and other projects with unparalleled success.

Our services include but are not limited to: Gap Analysis / Database Review, MI Implementation & Optimization, Corrosion Control Documents, Inspection Test Plans, Risk Based Inspection, Turnaround Planning and Execution, Digital Turnaround Tracking (RAMI Scope), Quality

& Assurance, Radiography, Traditional and Advanced NDE, Rope Access, Tank Services, Fired Heaters and Boilers (MACT-5 Testing), Refractory Services, and Vendor Surveillance.

The FER management team comes from a diverse background including offshore rope access inspections, run and maintain, specialty NDE, welding, turnarounds, mechanical integrity projects, and RBI implementation/optimization. Get in touch with us today and you will immediately understand the tremendous synergy and how every service we provide delivers effective and measurable results for your mechanical integrity programs. ■

Fixed Equipment Reliability

**Improving Reliability with
World-Class Inspection Services**



Fixed Equipment Reliability (FER) focuses on making the Oil & Gas inspection world more efficient by utilizing the utmost quality manpower and technology to design, implement, and optimize inspection databases. Our full range of services include:

- Gap Analysis / Database Review
- MI Implementation / Optimization
- CCDs - Corrosion Control Documents
- ITPs - Inspection Test Plans
- RBI - Risk Based Inspection
- Turnaround Planning and Execution
- Digital Turnaround Tracking (RAMI Scope)
- Quality Control / Quality Assurance
- RT - Conventional / Digital / Real Time
- Traditional and Advanced NDE
- Rope Access
- Tank Services
- Fired Heaters and Boilers (MACT-5 Testing)
- Refractory Services
- Vendor Surveillance

To contact us for your next project, please visit: www.ferinspection.com



Fitness-for-Service Forum with Greg Garic, PE

Managing Principal at Stress Engineering Services, Inc.

Fitness-for-Service Forum: Updates to the New & Improved API 579 Standard

Introduction

The current edition of API 579/FFS-1, Fitness-for-Service, was released in 2016. Five years later, the newest edition is expected in December 2021, so it should have been released by publication of this article.

There are many excellent changes and updates in this new edition, including significant technical changes and improvements, and hundreds of smaller editorial changes and corrections. In this FFS Forum article I'll go through many of what I believe to be the most important changes. The document itself includes a more detailed list of important changes, which is worth a read.

I've organized this article by Parts, so you can focus on your particular areas of interest. I've skipped sections where I feel there are no major changes.

Part 2, Fitness-for-Service Engineering Assessment Procedure

MAWP by Analysis

This part includes what I perceive to be a fairly significant change to FFS procedures. All FFS assessments are cast in terms of evaluating the deficiency at the Maximum Allowable Working Pressure (MAWP), and the MAWP has always been calculated by the Code formula (where one exists, e.g., shells and heads). The new edition of API 579 includes a provision to allow the MAWP to be calculated by the stress analysis procedure of Annex 2D, which lists procedures for elastic, limit load, and plastic collapse analysis. This means that in an FFS context, the MAWP can be calculated by elastic-plastic stress analysis methods. This could increase the rated MAWP of components and have a corresponding effect on the allowable pressure or thickness from an FFS assessment.

Division 2 Allowables for Division 1 Equipment

In the 2016 Edition, Annex C, paragraph 2C.2.4(c) stated:

"If a pressure vessel was constructed to VIII-1 and the flaw is located in the base material of a cylindrical shell, conical, or spherical shell outside the weld band, the allowable stress may be established in accordance with VIII-2."

This paragraph has been deleted in the latest revision. No more using VIII-2 allowables! This was an artifact of API 510 before the ASME Div 2 safety factor changed to 2.4 (from 3.0).

Updated Ramberg-Osgood Model

For those of you who use elastic-plastic analysis to obtain FFS assessments, you'll find the Ramberg-Osgood model has been

revised. The Ramberg-Osgood model is used to approximate the shape of the full stress-strain curve based on basic material properties, such as yield and ultimate stress.

Part 3, Brittle Fracture

There are many changes and improvements in the brittle fracture section—probably more changes than any other section. This isn't surprising, since there have been some conspicuous brittle fracture problems unearthed in the last 5 to 10 years and there has been a good deal of activity in this area.

Supplemental Guidance for SA-212 Grade B Material

SA-212, Grade B material has a history of brittle fracture problems in pressure systems. There is new guidance on this issue in the section "Applicability and Limitations of the Procedure".

Supplemental guidance for SA-212 Grade B Material, points out the history of toughness issues and indicates that toughness values can be below typical lower bound predictions. Detailed NDE crack detection is recommended in addition to brittle fracture screening. Weld repairs should be carefully inspected for cracks. It is also pointed out that PWHT can reduce the risk of fracture. However, the material classification remains unchanged on the exemption curves. In both 2016 and the new edition, the material is on Curve A if it is NOT produced to fine grain practice, and on Curve B if it is.

Corrected MAT Problems for Nut & Bolt Materials

There have been some changes to Table 3.3, Impact Test Exemption Temperature for Bolting Material. These fixed some errors in the previous edition.

Expanded Guidance on "Shock Chilling"

The 2016 edition guidance is vague with regard to shock chilling. This new language does a good job of providing needed clarifications. For example:

- Shock chilling is defined as sudden contact between a liquid (including 2-phase fluids) and a metal surface.
- It defines a minimum temperature difference of at least 100°F to experience shock chilling, and if you know something about the heat-transfer conditions, that temperature difference may be able to be increased, eliminating (in some cases) the need to consider shock chilling.

PWHT Credit for Alternative Weld Methods

There has been some misinterpretation over the years regarding

application of PWHT credit in Level 2 brittle fracture assessments (BFA). Some have argued that so-called “alternative PWHTs”, like temper-bead welding or high pre-heat, constitute a PWHT and, as such, qualify for the PWHT temperature credit. Level 1 and 2 procedures clarify that this is NOT allowed.

Modified Flange Rules

There has been significant expansion and clarity added to the rules for flanged connections.

In the 2016 edition, Level 1 assessment [3.4.2.1(d)(1)(i)(IV)] of flanges is pretty straightforward with a MAT = -20°F for ANSI 16.5 or 16.47 flanges (unless exemption curve is higher for the flange material). The new rules are more involved and discriminate based on multiple factors, such as material and PWHT condition. I have provided some highlights below. (References to “Curve A” and “Curve B” refer to the exemption curve categorization.)

- Flange materials have changed their exemption curve assignments a bit. In the new edition:
 - SA-105, as-forged, 1989 (or later) flanges are Curve A (representing a demotion in their toughness rating)
 - But the same as-forged SA-105 flanges, if pre-1989, or any year if normalized, are on Curve B.
- Other explicit rules have also been included for ferritic flanges meeting ASME B16.5, ASME B16.47, or the Long Weld Neck (LWN) requirements of ASME VIII-1, UCS-66(c)(4)
 - MAT = -20°F for as-forged, pre-1989 flanges
 - MAT = -20°F for normalized flanges, any year. The previous wording of “fine grain practices” has been dropped.
 - MAT = 0°F for as-forged flanges of 1989 and later

Limited MAT for As-Welded Condition

Some changes have been made to the minimum allowable temperature (MAT) rules. For materials impact tested above -50°F, with no PWHT, the MAT is limited to -50°F.

Part 4, General Metal Loss

Revised qualification for “Point Thickness” approach

The coefficient of variation (COV) calculation is no longer used to evaluate qualification for the Point Thickness Reading (PTR) approach. There were problems with users increasing the number of point readings to pass the COV calculation.

The new qualification is simply:

$$t_{mm} \geq 0.9 \cdot t_{avg}$$

Validation of Inspection Results for $t \leq 0.1$ ”

A recommendation was added to validate inspection results in cases where the thickness readings are less than or equal to 0.1 inches.

UT Grid Spacing

In those cases where the corroded surface is not visible, the recommended grid spacing was simplified to:

$$L_s = \min [2 \cdot t_{rd}, 1 \text{ inch}]$$

Previously it was a function of $2t_{rd}$ and another quantity “L”, which was itself a function of D, t, and Q factor (which required calculation, or a look-up table).

Part 6, Pitting

The Grade 2 pitting chart in the 2016 edition was incorrect. It was a duplicate of the Grade 1 chart. This has been corrected in the latest revision.

Part 9, Crack-Like Flaws

New Flaw Interaction Rules

When multiple flaws are in close proximity to one another, flaw interaction rules tell us if and how we need to combine these smaller flaws into a larger flaw for assessment. One difficulty with prior editions has been a lack of guidance on how to deal with flaws after they have been combined. That is, if you evaluate three smaller flaws A, B, and C, and find that A & B are sufficiently close together that they must be considered one larger flaw (call it “AB”), do you then need to evaluate the interaction of flaw AB with flaw C? If so, it can become very difficult to pass an assessment with multiple small flaws.

New guidance in this edition provides some relief by clearly stating:

“If two or more flaws are combined after applying the flaw combination criteria, it is not required to further evaluate interactions based on the dimensions of the combined flaw with other flaws [underline is mine].”

Expanded SIF and Reference Stress Solutions

The library of stress intensity and reference stress solutions has been expanded in a couple of areas, including new solutions for thick-wall cylinders and some improvements for circumferential flaws in cylinders.

Annex 9F, Material Properties for Crack-Like Flaws

There have been many changes in Annex 9F. I’ll list a few of them below.

- New equations have been provided for reference temperature calculations in Part 9 and Part 12.
- There are extensive re-writes in the section covering fracture toughness estimates of ferritic steels in the transition and lower shelf regions. The Master Curve discussion and procedure is greatly expanded.
- The Wallin Master Curve approach for toughness estimation of carbon and low alloy steel in the upper shelf region has been revised.
- Some ductile tearing data was added.
- Fracture toughness estimates for austenitic stainless steel, in the 2016 edition, was simply given as 200 ksi-√in for base metal. In the new edition, a somewhat more expanded discussion is included and the user is referenced to a table of J_{Ic} values which addresses different temperature ranges, base vs. weld material, and provides mean and lower bound values. J_{Ic} values can be converted to K_{Ic} values, if desired.

New Annex 9H

A new Annex 9H has been included to allow the adjustment of Level 2 fracture toughness values to account for the lower levels of constraint in surface flaws. This can provide more accurate solutions and result in more forgiving crack solutions.

New Annex 9I

Similar to 9H, the new Annex 9I also allows for a more sophisticated Level 2 analysis to provide more accurate answers and remove some of the conservatism. This annex allows calculation of crack solutions integrated over the crack front, rather than basing them on the peak solution on the crack front.

New Annex 9J, Fracture Mechanics Based MAT Procedure

Level 3 brittle fracture assessments have always referenced the user to Part 9, but in this edition, the new Annex 9J provides specific guidance for determination of the MAT by Part 9 methods. It also provides a simplified, fracture mechanics based, brittle fracture screening method.

Additionally, Annex 9J provides some helpful guidance on toughness adjustments for 2.25Cr-1Mo material when used in hydrogen-charging service.

Part 10, Creep

New Level 1 Screening Curves and Damage Limit

The Level 1 procedure has been substantially revised. Previously there were two Level 1 methods. The “Screening Curve” presented a series of Stress vs. Temperature curves and was applicable for a single design condition. The “Damage Curve” presented data in terms of damage rate. It was a little more complicated than the Screening Curve, but it could be used with multiple design conditions.

In the new edition, this has been simplified to one Stress vs. Time curve that can handle both single and multiple design conditions. This new curve provides improved consistency with Level 2 assessment methods.

Also, the Level 1 damage limit has been increased with the introduction of the new screening curve, from $D_c^{total} \leq 0.25$ to $D_c^{total} \leq 0.8$. In evaluation of creep damage, the “damage” is defined as:

“...the actual life expended under a given set of conditions, divided by the predicted life under those conditions.”

For example, a component has operated at a given pressure and temperature for 5 years. Calculations indicate that the predicted life at that same temperature and pressure is 10 years. Then we would say that the component has experienced $5/10 = 50\%$ damage.

Structural t_{min}

A new “structural t_{min} ” check has been added to both Level 1 and 2 creep assessments. This limits the wall thickness at the end of the operating condition (including corrosion) to:

$$t_{lim} = \min [0.9 \cdot t_{nom}, 0.10 \text{ inch}]$$

New Creep Data

A few corrections and additions have been incorporated into Annex 10B, “Material Data for Creep Assessment”.

- Some of the Omega material coefficients have been updated and coefficients for several new materials have been added.
- Omega coefficients for carbon steel have now been separated by ultimate tensile strength (UTS).
 - The Larson-Miller material coefficients have been revised to reflect the new changes in WRC 541.
 - Some errors have been corrected in the elevated temperature fatigue curve coefficients.

Part 11, Fire Damage

Common wisdom has long been that correlations between hardness and UTS only worked for carbon and low alloy steels. In the new edition of API 579, the correlations have been extended to include austenitic stainless steels. Correlations are provided for Brinell and Vickers.

Part 12, Dents, Gouges, and Dent-Gouge Combinations

There are many changes to Part 12. Almost every sub-section has at least some small change. I'll list some of the many changes.

- New definition of “kinked dent”
- New D/t ratio limit for dent-gouge combinations
- Level 2 dent-gouge assessment is limited to longitudinal gouges. Level 3 is required for circumferential gouges.
- Several clarifications to toughness requirements
- New inspection requirements included for dents in weld region and for surface dents and gouges
- Changes to the Level 2 equations used for calculation of acceptable cycles for dents

Assessments in Part 12 require care since there are numerous changes throughout.

Part 14, Fatigue

Added Fatigue Data

Some additional information has been added regarding the fatigue curves.

- New closed-form equations have been added for smooth bar fatigue curves
- Fatigue data has been added for some for new materials
- Smooth bar fatigue curves on testing in air have been added
- Validity limits have been included for smooth bar fatigue curve equations

Addition of Welded Joint Fatigue Screening

All of the Level 1 methods are screening techniques. That is, they

are not actually fatigue calculations; rather, they are methods to determine if fatigue analysis is required.

Methods A, B, and C in the 2016 edition provided screening methods based on comparable equipment operations and smooth-bar fatigue curves. Method D for welded joint fatigue was “under development” in 2016. This new edition includes the new Method D for welded joint fatigue.

New Ratcheting Check Procedure

Ratcheting is progressive deformation accumulated during cyclic plastic loading. In many operating cases (typically cycles below twice-yield) ratcheting does not occur at all because the loading “shakes down” to elastic cycling.

The ratcheting procedure has been rewritten in the new edition and is now based on the “Bree Diagram”. The Bree diagram defines regimes where either elastic, plastic, elastic-shakedown, or ratcheting behavior are expected to occur.

There are a number of Bree diagrams based on different types of loads (e.g., fixed primary and cyclic secondary stress). The Bree diagrams are 2-dimensional plots where the X and Y-axis are parameters representing a ratio of secondary-stress-to-yield strength (Y-axis) and primary-stress-to-yield strength (X-axis).

Procedure Updates

There have been updates to several of the Level 1 and Level 2 procedures. Specifically, Level 1/Method C, Level 1/Method D, and Level 2/Method C have all experienced changes to the basic procedure.

If you’ve done these analyses previously, please be careful to check for changes in the procedures before doing new work based on the new edition.

In Summary...

This is a major revision that includes many improvements, changes, and technical updates. It represents a significant step forward in improving FFS procedures. Be sure to work carefully with the new edition since it may not be obvious where subtle changes have been introduced.

If there are any topics you’d like to see in the FFS Forum, or if you have comments in this article, leave a note in the “Comments” section below or send me an email at FFS@inspectioneering.com.

Thanks...GG

P.S. Special thanks to my colleague Tina Rautio with Stress Engineering Services. Tina has done the heavy lifting of looking in detail for changes and improvements in the new document. Her diligence and attention to detail has been remarkable. ■

For more information on this subject or the author, please email us at inquiries@inspectioneering.com.

About the Author: Greg Garic, PE, has over 35 years of experience in FFS and mechanical integrity assessment of pressure systems. He began his career at NASA’s Stennis Space Center, where his tenure spanned 15 years. After rising to the position of Senior Engineer, he joined Stress Engineering Services and has been there for over 20 years. As a Managing Principal with Stress, Greg focuses most of his work on stress analysis, fracture mechanics, pressure systems engineering, and FFS across the process industries. He also teaches FFS training courses, is qualified as a stress analysis expert in federal court, and leads Stress’ New Orleans office. Suffice it to say, he’s been around the block more than a few times and knows FFS.

Please send your inputs to the author at ffs@inspectioneering.com.

Showcase YOUR EXPERTISE

Validate your knowledge and skills and achieve industry recognition. Schedule your Industry Sector Qualification - Oil & Gas (ISQ-O&G) exam TODAY.



THE ISQ PROGRAM

- Standardizes performance demonstration initiative testing of NDT technicians
- Alleviates the burden of owner/operators from providing their own NDT performance demonstration program
- Provides a program for owner/operators that do not have their own NDT performance demonstration program
- Establishes an industry-recognized program for the oil and gas sector while minimizing the impact of cost and redundant testing of NDT technicians

REQUEST A REMOTE ISQ EXAM AT ONE OF THE FOLLOWING LOCATIONS:

- Anaheim, California
- San Francisco, California
- Salt Lake City, Utah
- New Orleans, Louisiana
- Exams by request. Candidate minimum required.
Email **ISQ@asnt.org**.
- Other locations will be assessed based on volume.

▶ Request a remote ISQ exam.
Visit **asntcertification.org/ISQ**
for dates and locations.

**ASNT CERTIFICATION
SERVICES LLC.**





Damage Control with Phillip E. Prueter, PE

Principal Engineer II and Team Leader - Materials & Corrosion at The Equity Engineering Group, Inc.

Wet H₂S Damage Detection

Editor's Note: This regular column offers practical insights into various damage mechanisms affecting equipment in the O&G, petrochemical, chemical, power generation, and related industries. Readers are encouraged to send us suggestions for future topics, comments on the current article, and raise issues of concern. All submissions will be reviewed and used to pick topics and guide the direction of this column. We will treat all submissions as strictly confidential. Only Inspectioneering and the author will know the names and identities of those that submit. Please send your inputs to the author at damagecontrol@inspectioneering.com.

Introduction

Aqueous phase process environments containing sulfur and specifically, hydrogen sulfide (H₂S), are generally referred to as sour environments or sour service^[1]. H₂S is a flammable, colorless gas that poses a process safety risk to plant personnel due to its toxicity. Furthermore, H₂S (and sulfur) can occur naturally or can be generated from common oil and gas production/refining methods. H₂S contributes to corrosion mechanisms such as high temperature sulfidation (H₂/H₂S corrosion) and acidic sour water corrosion; however, the cracking mechanisms associated with hydrogen charging in wet H₂S environments are the focus of this Damage Control series. Wet H₂S damage can detrimentally affect the load-carrying capacity of pressure retaining equipment and can manifest itself in numerous forms of material degradation, including the following:

- Hydrogen blistering
- Hydrogen induced cracking (HIC)
- Stress-oriented hydrogen induced cracking (SOHIC)
- Sulfide stress cracking (SSC)

Wet H₂S damage is complex and often misunderstood because the overall propensity for these damage mechanisms is governed by different controlling metallurgical and environmental variables. Furthermore, each form of wet H₂S damage exhibits distinctive morphologies, introduces varying levels of risk, and ultimately can promote different failure modes. Damage propagation rates can also be difficult to predict and can be accelerated by minor changes in process environments. This article will summarize the fundamentals of these wet H₂S-related damage mechanisms, discuss operating conditions and other factors influencing damage progression, and present the typical damage characteristics and morphologies of each mechanism. Additionally, this article will offer some practical inspection guidance and will discuss common locations predisposed to wet H₂S damage on typical pressure equipment. A case study of a notable industry failure caused by different forms of wet H₂S damage will also be reviewed.

In general, wet H₂S damage affects carbon and low-alloy steels

most notably in the oil and gas industry, although H₂S can also be present in process environments in the mining, food processing, pulp and paper, wastewater treatment, and power generation industries. H₂S is more soluble in crude oil than in water, and H₂S concentrations of 100-200 ppm are relatively common in typical crudes^[2]. Furthermore, any equipment subject to wet H₂S process conditions can be susceptible to damage under certain scenarios. It is believed that some of the first industry experiences with different forms of wet H₂S damage occurred in the 1950s in both the U.S. and Canadian oil fields^[1]. In some of these early documented cases, sour environment corrosion occurred within approximately one month of equipment installation. These unfavorable operating experiences led to the use of corrosion inhibitors to extend equipment service life. Even today, wet H₂S damage continues to afflict pressure vessels, tanks, piping, and other equipment in the oil and gas and related industries. Understanding the different types of wet H₂S damage, identifying which process units and equipment are most prone to such damage, and establishing appropriate inspection plans for in-service equipment can mitigate costly unplanned outages and equipment failures.

Understanding the different types of wet H₂S damage, identifying which process units and equipment are most prone to such damage, and establishing appropriate inspection plans for in-service equipment can mitigate costly unplanned outages and equipment failures.

Wet H₂S Chemical Reactions And Damage Mechanics

The primary reactions that lead to the presence of H₂S in oil and gas reservoirs are bacterial sulfate reduction (BSR) and thermochemical sulfate reduction (TSR)^[3]. At high pressures, sulfanes are formed in the gas phase by the dissolution of elemental sulfur. When pressure is decreased (e.g., during oil/gas extraction and production), these gaseous sulfanes dissociate to form elemental sulfur, and in the presence of water, form H₂S. Sulfur can also be formed due to an oxidation reaction of H₂S by air or by other oxides (e.g., iron oxide). This reaction can be detrimental to steels because sulfur can contribute to corrosion, and it produces water, which increases the corrosivity of H₂S^[4]. Additionally, the

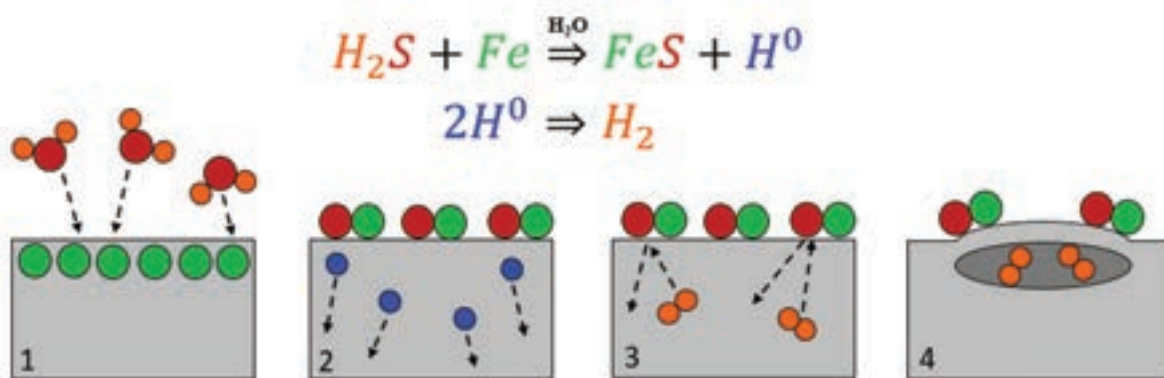


Figure 1. Schematic of Wet H₂S (Sulfide Corrosion) Chemical Reaction Process in an Idealized Steel Plate.

solubility of sulfur in water generally increases with temperature: for example, approximately 10 ppm-20 ppm at 77°F (25°C) and approximately 50 ppm at 122°F (50°C)^[1]. Furthermore, the dissolution of sulfur in water produces H₂S and sulfuric acid. This reaction tends to occur relatively slowly at ambient temperatures, but nevertheless can generate sufficient H₂S to cause damage.

The inception of the different forms of wet H₂S damage described herein is based on the fundamental sulfide surface corrosion reaction where, in an aqueous environment, H₂S and iron (e.g., carbon or low-alloy steels) react to form iron sulfide and hydrogen atoms. These hydrogen atoms diffuse into the steel (hydrogen charging) and collect at any internal material imperfections or discontinuities^[4]. These hydrogen atoms then coalesce to form hydrogen molecules that, due to their size, are unable to diffuse out of the embedded local cavity or discontinuity in the steel. Subsequently, as the volume of trapped hydrogen molecules increases, pressure builds to a point where local permanent deformation occurs; that is, local stresses near these steel imperfections exceed the yield strength of the material (e.g., the ligament might bulge towards the ID or OD surface) to create a void, blister, or crack-like flaw^[5,6]. **Figure 1** shows a schematic of this overall sulfide corrosion process on an idealized steel plate.

Further discussion on how this damage progression process leads to different types of wet H₂S damage is provided below. Given these damage progression mechanics, older or “dirty” steels are particularly prone to wet H₂S damage because they generally have more volumetric inclusions, laminations, and original fabrication imperfections in both base metal and weld deposit regions. Also, steel plate is usually more likely to have inclusions than other product forms; therefore, the shell of pressure vessels, tanks, or sections of larger diameter longitudinal seam-welded piping components are ordinarily more susceptible to wet H₂S damage than conventional seamless piping, tubing, or forgings.

Hydrogen Blistering

Hydrogen blistering is generally characterized by internal blisters (i.e., planar cavities that result in physical bulges) in steel that are caused by the accumulation of molecular hydrogen (per the damage progression described above). These blisters tend to occur at locations of large non-metallic inclusions, laminations, or other metallurgical discontinuities in steel components^[7]. Hydrogen

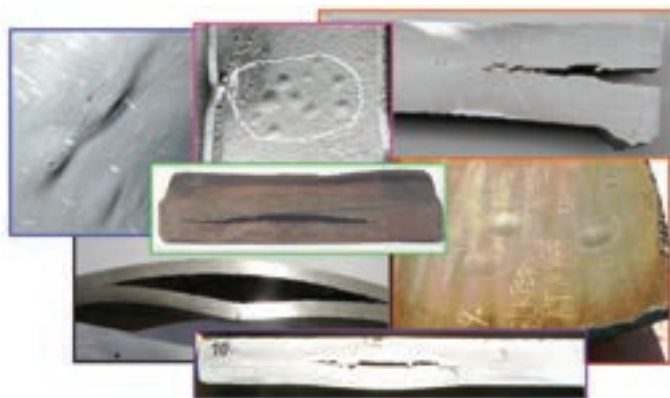


Figure 2. Examples of Hydrogen Blistering in Pressure Equipment Plate Samples.

blisters can induce visible surface bulging on the inside surface, outside surface, or within the wall thickness of pressure equipment. Blistering is frequently believed to occur near a mid-wall plane of weakness, where inclusions may appear and segregate during the plate solidification process^[5]. Additionally, sometimes crack-like flaws can extend from the periphery of a blister, potentially propagating in the through-wall direction, especially near welds. This implies that hydrogen blistering can be a precursor for HIC or SOHIC. Another important consideration is that no externally applied stress is necessary to facilitate hydrogen blister formation^[7]. It is also noted that blisters occur from hydrogen generated by the sulfide corrosion process (see **Figure 1**), not strictly from hydrogen gas in the process stream^[4]. Additionally, these wet H₂S-driven blisters differ from voids, blisters, or cracking associated with high temperature hydrogen attack (HTHA)^[8]. **Figure 2** shows examples of hydrogen blistering observed in common pressure equipment. In **Figure 2**, examples of both cross sections of internal blister voids/cavities and inside surface bulging due to local material yielding are shown in pressure boundary plate samples.

Hydrogen Induced Cracking (HIC)

HIC is a form of internal hydrogen damage caused by the initiation and propagation of small crack-like flaws, often resembling small internal voids or blisters, that are generally laminar (in-plane) and oriented parallel to the inside and outside surfaces of steel. Over time, these cracks tend to coalesce or link-up due

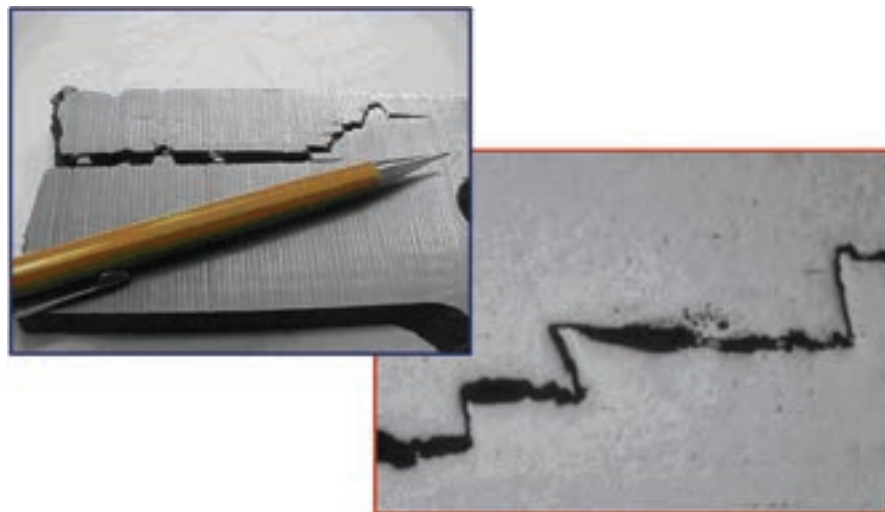


Figure 3. Examples of HIC Damage Morphology (Characteristic Stepwise Cracking)^[4].

to internal pressure build-up and possibly local stress fields in damaged regions. Furthermore, this behavior often results in damage progression in the through-thickness direction, and due to its characteristic damage morphology, is referred to as “step-wise” cracking (i.e., linked-up cracks in different planes resemble steps extending through the wall of pressure equipment). One potential explanation for this phenomenon is that internal planar cracking creates local plastic zones that interact due to shear loading, thus forming larger cracks oriented at 45° through-wall^[5]. Susceptibility to HIC can be influenced by steel composition, deoxidation practices, and processing history since these variables tend to correlate to non-metallic inclusions and the hydrogen permeation properties of the material^[9]. Examples of stepwise cracking (HIC damage) are shown in **Figure 3**.

Stress Oriented Hydrogen Induced Cracking (SOHIC)

SOHIC is a form of HIC that can potentially be more detrimental to the structural integrity of equipment than conventional stepwise cracking. The hydrogen charging process for SOHIC is the same as HIC and hydrogen blistering; however, SOHIC damage morphology usually appears as an array of cracks stacked on top of one another. This can result in a through-wall crack (sometimes zigzag) that is perpendicular to the surface of the component. Unlike HIC or hydrogen blistering, SOHIC damage progression is generally driven by relatively high tensile levels of both applied and residual stresses (e.g., weld residual stress)^[4]. Furthermore, damage usually occurs in base metal directly adjacent to weld deposit heat affected zones (HAZs) where damage often initiates from HIC, SSC, or other fabrication-related cracks, defects, lack of fusion, etc. SOHIC damage can also initiate from stress concentrations such as the tip of an existing crack (e.g., from surface-breaking SSC in high-hardness HAZs) or defects, or from the interaction of closely-spaced hydrogen blisters on different planes^[6,7]. While SOHIC is typically less common than HIC or hydrogen blistering, given the perpendicular (through-thickness) propagation direction of SOHIC, it is more likely to cause through-wall leaks or catastrophic loss of containment than HIC or hydrogen blistering, in general. **Figure 4** shows an example of

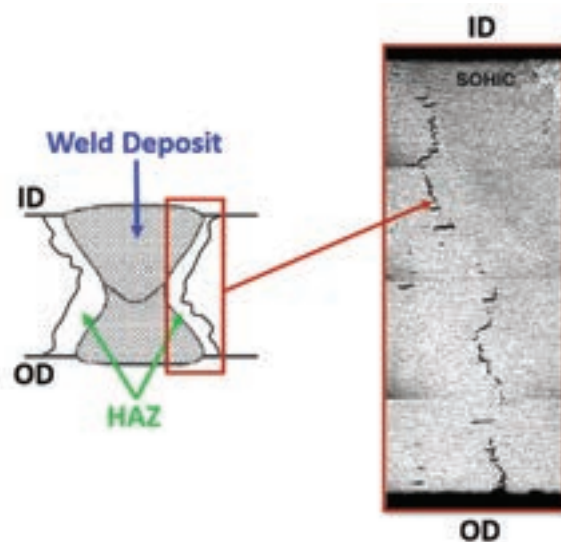


Figure 4. Example of Typical SOHIC Damage Morphology Near a Full-Penetration Weld.

SOHIC damage (perpendicular crack-like flaw) near a full-penetration (double-sided or double-v) butt-weld. This damage has essentially propagated through the entire thickness of the plate.

Sulfide Stress Cracking (SSC)

SSC is defined as cracking produced by a form of hydrogen embrittlement cracking under the combined effect of tensile stress (applied or residual) and sulfide surface corrosion driven by the presence of H₂S (see **Figure 1**). SSC usually initiates on the surface of either high-strength steels or high-hardness regions such as weld deposits and HAZs^[7]. Regions with elevated hardness can often be found in weld cover passes and attachment welds that are not tempered by subsequent weld passes. To this end, welds that have not received post-weld heat treatment (PWHT) are markedly prone to this type of cracking due to elevated tensile residual stresses and lack of tempering/softening of the weld deposit and HAZ^[4]. Additionally, SSC usually does not occur in seamless piping that has been welded from one side because it does not

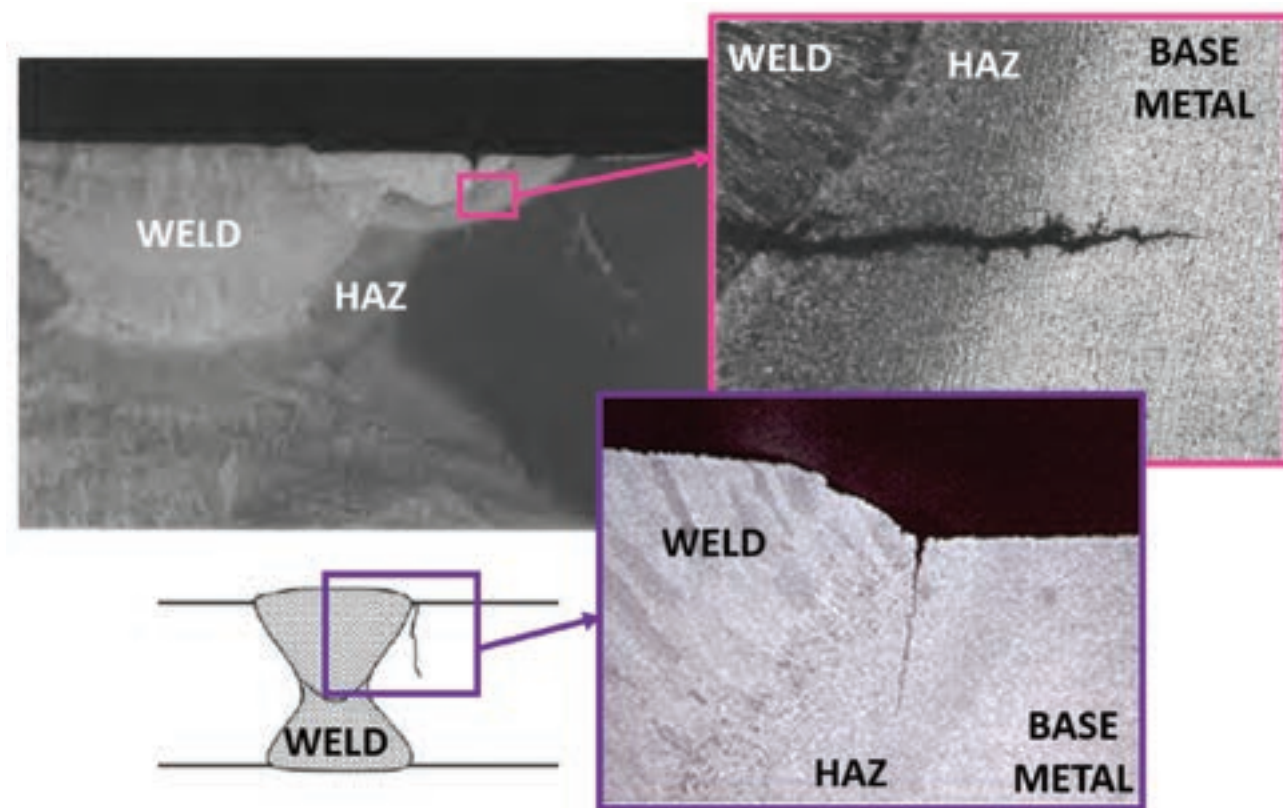


Figure 5. Examples of SSC Near Weld Deposits/HAZs (upper images adapted from^[7]).

contain a hard weldment on the ID surface that is exposed to H_2S (the initial weld pass benefits from the tempering effect of subsequent passes as the weld is applied from the OD). Cracking is usually intergranular in high-strength steels (yield strength > 100 ksi) or in areas of excessive hardness, whereas it tends to be more transgranular in lower strength steels. In general, high-strength steels are more susceptible to SSC than typical lower-strength steels (e.g., typical pressure vessel carbon steels). It is believed that grain boundary impurities in high-strength steels can promote SSC. The presence of phosphorous and sulfur may also lead to SSC^[10]. Characteristically, SSC is also often oriented perpendicular to the applied stress^[9].

Pressure vessel steels with inherently favorable resistance to SSC can become susceptible through improper welding. Repair welds on carbon steel, excessive ferrite in Duplex 2205 welds, or dissimilar metal welds (e.g., between ferritic and austenitic materials) in sour service reflect situations where welding procedures can make ordinarily resistant materials susceptible to SSC failure by inducing local regions with high hardness. Additionally, some martensitic stainless steels (e.g., 17-4 PH and 410 stainless steels) and B7 bolts are intrinsically hard and thus, have a relatively high susceptibility to SSC. Pressure safety valve (PSV) springs, valve trim, and compressor shafts often exhibit high hardness and can be prone to SSC in wet H_2S environments. Also, hard regions in primarily soft (acceptable) weld deposits can occur with submerged arc welding when an active flux is used along with high-voltage heat input^[11,12].

Under certain operating conditions, SSC can rapidly lead to

extensive cracking and ultimately, failure. In general, the time to failure decreases as material strength, total tensile stress, and environmental charging potential increase; however, even short sour water excursions (e.g., during equipment shutdown) can rapidly propagate SSC damage^[13]. **Figure 5** shows two examples of SSC near weld deposits; the upper images show crack propagation through the HAZ and into the base metal, and the lower images show the crack remaining in the HAZ. Commonly, SSC cracks initiate at or near the surface as straight (non-branched) flaws and extend through-thickness over time. As these flaws propagate further through-thickness or enter the base metal, SOHIC often becomes the dominant damage mechanism. Lastly, modern (post-1980) steels are typically more immune to SSC than vintage steels, but again, poor-quality welding (leading to high hardness) can invalidate this assumption^[12].

Union Oil Amine Absorber Vessel Failure (1984)

While there have been numerous documented equipment failures, leaks, and lost production due to wet H_2S damage, one notable industry failure attributed to numerous forms of H_2S -related damage (SSC, HIC, and likely SOHIC) was the Union Oil Chicago Refinery explosion and fire on July 23, 1984 in Romeoville, IL^[5,9,14]. An amine absorber vessel (used to strip H_2S from the propane and butane process stream) ruptured and initiated an uncontrolled combustion event that resulted in 17 fatalities and extensive damage to other refinery equipment. Following the fire, the upper portion of this vertical pressure vessel was found approximately 0.6 miles (1 km) away from the base of the vessel that

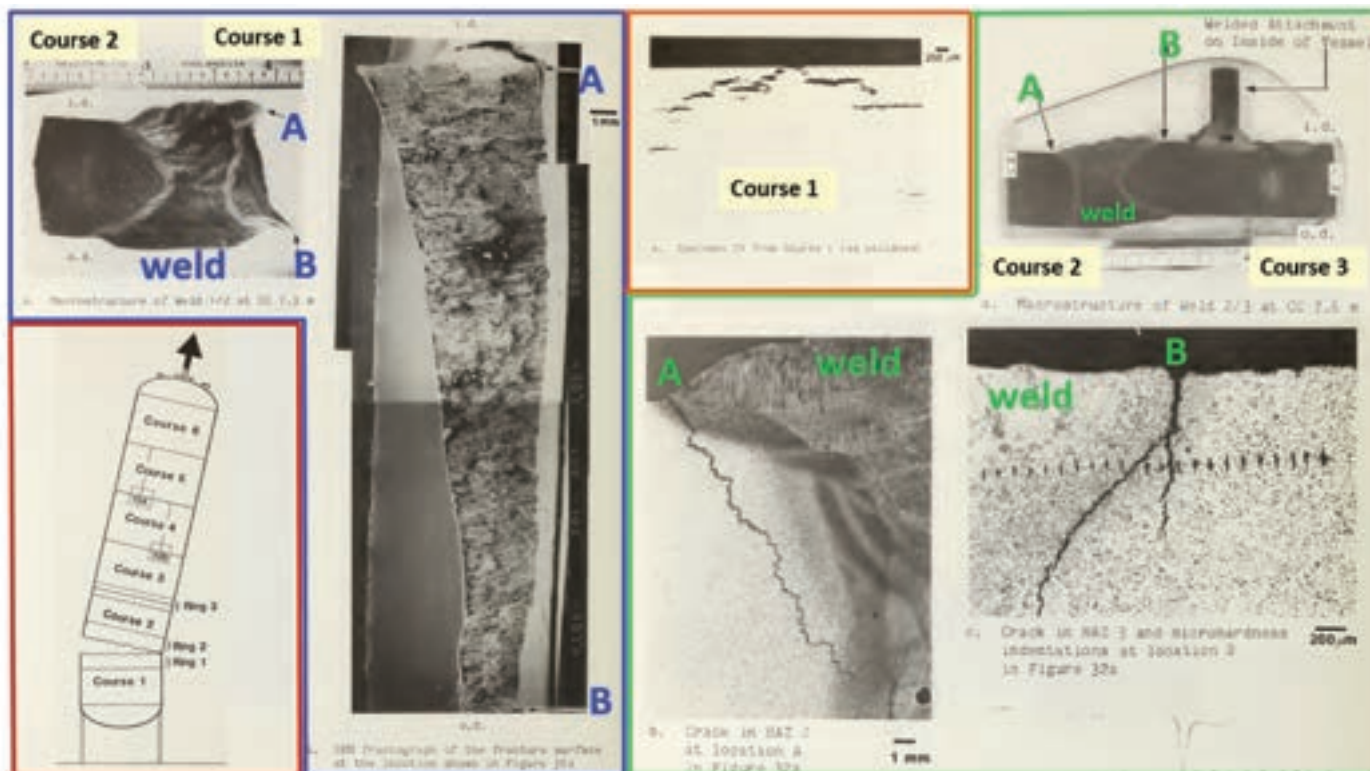


Figure 6. Sketch of Failure and Cracking Damage Morphology From 1984 Union Oil Metallurgical Amine Absorber Investigation (adapted from^[14]).

was still intact^[14]. This vessel was approximately 61.5 ft. (18.8 m) tall, with a diameter of 8.5 ft. (2.6 m), and a shell thickness of 1-inch (25 mm). The pressure boundary was made of carbon steel plates (SA-516 Gr. 70). Furthermore, the vessel was fabricated in 1968 and placed into service in 1970, with planned outages every two years to facilitate inspection. In 1974, extensive hydrogen blistering and cracking necessitated the replacement of the second shell course, although the first (adjacent) shell course also exhibited wet H₂S damage at that time. Two years later (1976), a Monel (nickel-copper alloy 400) liner was installed in the bottom of the vessel covering most of the first shell course to attempt to mitigate the progressing damage^[14]. H₂S would also regularly gravitate towards the lower portion of the vessel given process conditions.

The subsequent failure investigation revealed that the vessel fractured along a path adjacent to the 1974 weld repair/shell replacement (circumferential field weld). It is believed that pre-existing defects/cracks initiated and propagated in areas of high hardness that formed during the welding process of the second replacement shell course. No tempering or PWHT was performed following this repair procedure. Eventually, as hydrogen-induced cracking progressed over time, a through-wall crack of approximately 31-inches (800mm) occurred, which led to loss of containment (leakage). Consequently, this sizable crack triggered the ensuing catastrophic rupture about 15 minutes after a leak was identified by plant personnel^[14]. **Figure 6** shows a sketch of the failure location in the vessel along with cracking observed in several samples from the bottom shell courses. Examples of stepwise cracking (HIC) were found in shell course 1, and characteristic

surface-connected straight-sided crack like flaws in the weld HAZ near the fusion line (SSC) that begin to zigzag through the thickness of the base metal (SOHIC) were identified at the failed fracture surface and at other nearby welds.

Ultimately, it is believed that SOHIC propagating through-wall near the circumferential repair weld, exacerbated by existing hydrogen damage, including surface-breaking SSC (which likely served as a crack initiator) led to this catastrophic and deadly failure. The high hardness near this repair weld and high weld residual stress (due to the omission of stress relief) likely accelerated damage. Post-mortem fracture toughness testing indicated that hydrogen embrittlement also significantly reduced the fracture resistance of the steel. Additionally, the Monel lining installed directly below the fracture location potentially contributed to the failure. Monel is not generally suitable for monoethanolamin (MEA) service and is essentially anodic to steel, which likely promoted hydrogen charging in this case. This case study highlights the dire consequences of a series of unfavorable fabrication, welding, and repair practices coupled with an aggressive wet H₂S process environment.

Critical Factors Influencing Damage Progression

Many variables dictate the probability of experiencing in-service wet H₂S damage. Furthermore, there are many different nuances associated with process conditions/contaminants, welding/steel making practices, applied/residual stress fields, etc., that promote different forms of wet H₂S cracking or blistering. The following summaries describe the main factors that influence equipment's

GROW YOUR KNOWLEDGE

Participate in Upcoming Events at API

SEPTEMBER 13, 2022

2022 COS Forum

Westin Houston Memorial City
Houston, Texas

OCTOBER 10-14, 2022

2022 Fall Committee on Petroleum Measurement Standards Meeting

Hyatt Regency Orlando
Orlando, Florida

OCTOBER 10-13, 2022

2022 API Storage Tank Conference & Expo

Marriott Marquis San Diego Marina
San Diego, California

NOVEMBER 08-09, 2022

17th Annual API Cybersecurity Conference for the Oil and Natural Gas Industry

Woodlands Waterway Marriott, The
Woodlands, Texas

NOVEMBER 14-16, 2022

2022 Fall Refining and Equipment Standards Meeting

Hyatt Regency New Orleans
New Orleans, Louisiana

NOVEMBER 16-17, 2022

2022 API/AFPM Fall Operating Practices Symposium and Roundtable

Hyatt Regency New Orleans
New Orleans, Louisiana

JANUARY 23-27, 2023

2023 Exploration and Production Winter Standards Meeting

Hyatt Regency New Orleans
New Orleans, Louisiana

JANUARY 24-27, 2023

2023 API/AGA Joint Committee on Pipeline Welding Practices

Hyatt Regency New Orleans
New Orleans, Louisiana

MARCH 06-10, 2023

2023 Spring Committee on Petroleum Measurement Standards Meeting

Grand Hyatt San Antonio
San Antonio, Texas

MAY 15-19, 2023

2023 Spring Refining and Equipment Standards Meeting

Hyatt Regency Seattle
Seattle, Washington

MAY 17, 2023

2023 API/AFPM Spring Operating Practices Symposium

Hyatt Regency Seattle
Seattle, Washington

Visit www.events.api.org for more information.

Copyright 2022 – American Petroleum Institute, all rights reserved. API and the API logo are either trademarks or registered trademarks of API in the United States and/or other countries. API Marketing & Communications: 2022-130 | PDF



American
Petroleum
Institute

overall susceptibility to wet H₂S damage and the rate at which damage progresses.

Steelmaking Practices/Microstructure

- The more inclusions and laminations in steel (e.g., “dirty steels”), the more damage initiation sites there are for hydrogen blisters, HIC, etc.
- Modern (post-1980) steels are generally less prone to damage than vintage steels^[12].
- Improved steel cleanliness will directionally offer improvement; however, SOHIC can still occur even with little-to-no anomalies (cracking or blisters) visible on the surface^[4].

Weld Quality (Hardness)/PWHT

- Welds/HAZs with high hardness primarily promote SSC. Hardness values above 237 Brinell Hardness Number (BHN) are considered to enable SSC^[13].
- Hydrogen blistering, HIC, and SOHIC are not generally considered to be influenced by weld hardness; however, SSC can serve as an initiation point for other forms of damage (e.g., SOHIC propagation).
- A lack of PWHT, resulting in elevated weld residual stresses and potentially high hardness, can increase the likelihood of SSC and SOHIC, but it will not generally affect the propensity for hydrogen blistering or HIC.

Operating Temperature

- Hydrogen blistering, HIC, and SOHIC have been identified on equipment that typically operates between ambient temperatures and 300°F (150°C)^[4,12].
- Hydrogen charging tends to increase with increasing temperature (assuming the aqueous phase is not eliminated); however, wet H₂S damage may occur at lower temperatures such as a low-temperature excursion for equipment that usually operates at elevated temperatures^[13].
- SSC generally occurs at temperatures below around 180°F (82°C)^[4]. Specifically, SSC is believed to be most aggressive around 70°F (20°C) with a decreasing risk at either higher or lower temperatures^[12].

Process Stream pH

- Hydrogen permeation properties (i.e., diffusion rates) are typically minimal at around pH 7 and increase at higher and lower pH^[4].
- Chemistry conditions that are known to promote all forms of wet H₂S damage include the following^[4,12,13]:
 - > 50 wppm dissolved H₂S in the free water
 - Free water with pH < 4 and some dissolved H₂S present
 - Free water with pH > 7.6, 20 wppm dissolved hydrogen cyanide (HCN) in the water, and some dissolved H₂S present
 - > 0.003 MPa (0.05 psia) partial pressure of H₂S in the gas phase (associated with the aqueous phase of the process)

- Increased levels of ammonia may subsequently increase the pH to a level where cracking may occur.
- Increasing ammonium bisulfide above 2% (e.g., in hydroprocessing units) can increase susceptibility to hydrogen blistering, HIC, and SOHIC^[4].
- Salts or other contaminants in the water phase that decrease pH or increase the corrosion rate can accelerate wet H₂S damage^[13].
- Rich amine (alkaline) environments can promote wet H₂S damage^[13].

H₂S Concentration

- Hydrogen permeation (charging) generally increases with higher H₂S partial pressures.
- A practical threshold of 50 wppm H₂S in the water phase is often used in the refining industry to set a limit where wet H₂S damage becomes problematic; however, this limit should not be universally applied as documented cases of damage have occurred at lower H₂S levels.
- The presence of even 1 wppm of H₂S is understood to be sufficient to facilitate hydrogen charging of steel^[4].

It is important to consider that wet H₂S damage is not usually a steady-state process. In fact, damage often happens in short periods of time or bursts of activity. Operating excursions or process changes (e.g., pH fluctuations) can lead to this type of behavior. For example, the addition of cyanides to wet H₂S environments can dissolve the iron sulfide scale on the surface. This in turn accelerates corrosion and hydrogen atom permeation/diffusion, thus promoting more severe wet H₂S damage. To this end, past inspection data, assumed damage rates, or engineering (fitness-for-service) assessments can be invalidated if equipment has been subjected to even minor process changes and possible rapid damage propagation.

Commonly Affected Equipment

Wet H₂S damage can occur in any equipment that meets the above operating, process, and fabrication criteria; however, specific to the refining industry, several process units are distinctly prone to damage. One of the most informative summaries of susceptible refinery units is from the 1990 industry survey coordinated by NACE Working Group T-8-16a^[8], where inspection results for almost 5,000 pressure vessels in different units were compiled. Overall, this survey reported a wet H₂S-related cracking incidence of 26%. A summary of the cracking rate (percentage) in affected refining units/sections is provided in **Table 1**. Note that these cracking percentages should not be interpreted as being absolute given possible inconsistencies in inspection coverage/method across different owner-users, varying fabrication/weld qualities, different crude feed compositions, and the potential for other damage mechanisms to be misidentified as wet H₂S damage (e.g., potential carbonate cracking in FCCU fractionation/overhead systems). Additionally, the sample size varies for different units as shown in **Table 1**.

Table 1. Summary of Common Refinery Units Affected by Wet H₂S Cracking^[8].

Refinery Unit	Number of Vessels Inspected	% Cracked
FCCU Light Ends	704	45
Liquefied Petroleum Gas (LPG)	49	41
FCCU Fractionation (Overhead)	252	41
Atmospheric Light Ends	140	38
Catalytic Reformer	134	34
Flare System	23	30
Coker Light ends	91	30
Amine/Caustic	811	29
Sour Water Stripper	132	28
Hydrocracking	156	28
Sulfur Recovery	96	27
Hydrotreating	368	25
Other	364	23
Amine	574	21
Vacuum	71	21
Coker Fractionation (Overhead)	44	19
Crude	300	18

There are specific locations within each of these process units that are especially prone to wet H₂S damage. A few examples of this include reactor effluent air cooler (REAC) systems (duplex stainless steel welds with high ferrite content are distinctly prone to SSC) and high/low pressure separators in hydroprocessing units, amine treating unit absorbers/contactors (especially near sour gas inlet nozzles), regenerators, overhead condensers, and knock-out drums, sulfur recovery unit (SRU) acid gas knock-out drums, and sour water stripper (SWS) unit overhead equipment (e.g., condensers and reflux drums). Additionally, in fluid catalytic cracking units (FCCUs), light ends recovery/fractionation (overhead) equipment and especially locations downstream of wet gas compressors, intercoolers/aftercoolers, knock-out drums, sponge absorbers, and deethanizers are historically problem areas for wet H₂S damage.

General Inspection Considerations

In many cases, it may be appropriate to institute special emphasis mechanical integrity (SEMI) programs for “high risk” equipment in wet H₂S service. Consultation with materials and corrosion experts is recommended to develop suitable inspection scopes for different equipment items, to help review areas of past damage, and to guide inspection methods, coverage, and frequency, etc. Since weld seams and nozzle attachment welds are notably prone to SSC and SOHIC, they are often targets of any inspection. A summary of some of the commonly used nondestructive examination (NDE) methods for detecting and characterizing wet H₂S damage is offered below^[8].

Visual Inspection (VT)

- Visual inspection represents the first line of defense to identify hydrogen blistering (e.g., internal bulges). Again, blistering is often a precursor for or an accessory to HIC.
- Visual inspection of any internal coatings or cladding issues is an effective way to target any potential problem areas.

Wet Fluorescent Magnetic Particle Testing (WFMT)

- This is a common surface inspection method that is sensitive enough to reliably detect surface breaking cracks. This is usually the preferred method for discovering surface damage, especially near welds (e.g., SSC).
- WFMT usually requires extensive surface preparation (e.g., grit blasting, water blasting, and cleaning) which can adversely affect future hydrogen permeation rates and damage because of the removal of the iron sulfide scale/film^[15]. Roughly 6-inches (150 mm) on either side of a weld often requires blasting/cleaning for successful WFMT^[8].
- To avoid sudden and rapid hydrogen charging following inspection, it may be appropriate to apply a suitable coating to any areas that were grit blasted or cleaned.

Ultrasonic Testing (UT)

- UT includes shear wave (SWUT), phased array (PAUT), total focusing method (TFM), full matrix capture (FMC), time of flight diffraction (TOFD), etc. These methods are ideal for categorizing embedded or volumetric damage (e.g., blistering, HIC, or SOHIC). An example of a TFM scan highlighting embedded hydrogen blistering with ID-connected HIC is shown in

Figure 7.

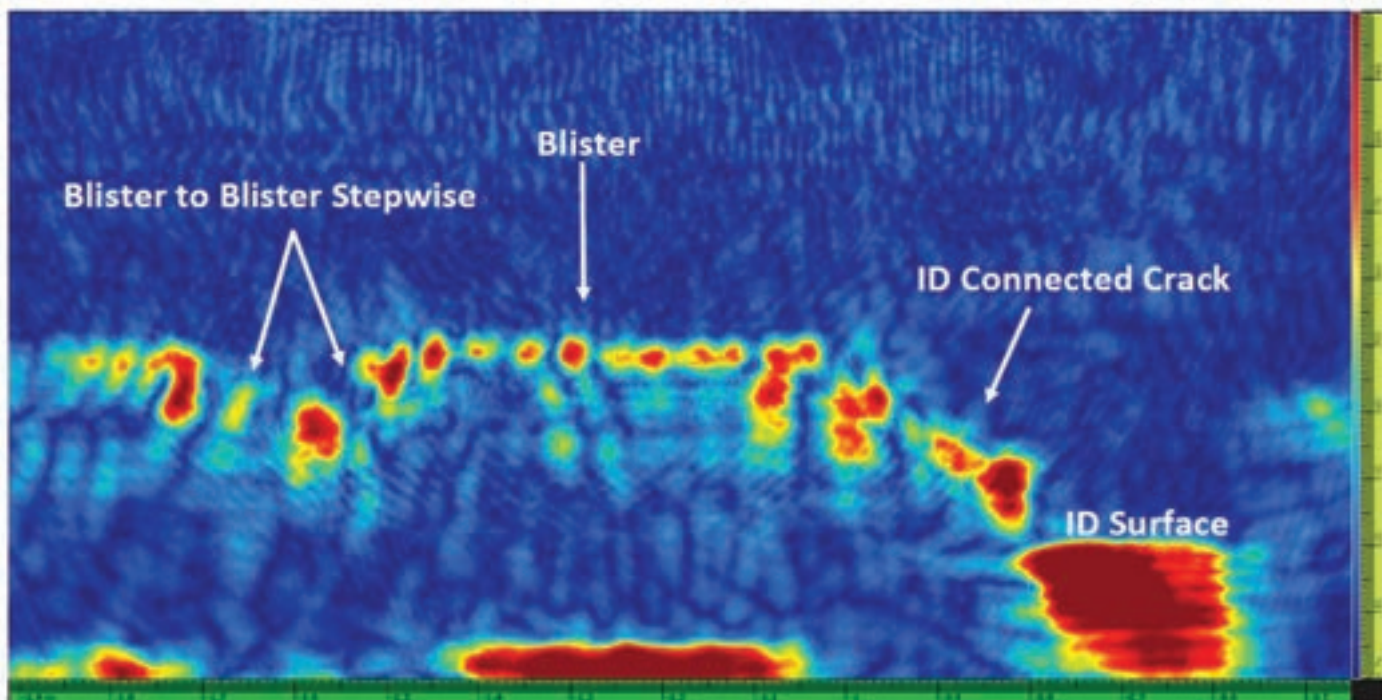


Figure 7. Example of a TFM Scan Showing Embedded Hydrogen Blisters with ID-Connected HIC.

- These methods may be recommended pre-turnaround as a screening tool to determine the most practical inspection scope and to identify potential wet H_2S damage to further address or repair during a planned outage.
- One advantage is that UT methods can sometimes be used without the need for excessive removal of protective iron sulfide surface scales.
- These UT methods are most frequently employed for sizing (e.g., depth, width, length, orientation, etc.) of hydrogen blisters and crack-like flaws (HIC or SOHIC) for FFS assessments.
- For regions of extensive damage, automated UT (AUT) techniques may be appropriate.
- In general, UT methods require a skilled inspector to accurately identify/characterize wet H_2S damage and to differentiate blisters from HIC/SOHIC or other forms of volumetric damage.

Other inspection techniques such as acoustic emission testing (AET), alternating current field measurement (ACFM), and eddy current testing (ECT) represent alternative methods that can be used for wet H_2S damage detection situations; however, for the sake of brevity, they are not discussed herein^[8]. Regardless of the NDE method used, it is essential that the limitations and margin of error be well-understood, and that qualified and experienced inspectors are involved. Again, given the possibly unpredictable or sudden damage progression associated with wet H_2S damage mechanisms, it is important to ensure that high-risk equipment, and especially regions of previously identified damage, are routinely monitored. Additionally, these different

NDE methods play an integral role in establishing a successful wet H_2S inspection/SEMI program. Once damage is identified, proper engineering evaluation, repair, or equipment replacement is required. The next installment of Damage Control will focus on recommended fitness-for-service (FFS) methods for assessing the different forms of wet H_2S damage. Furthermore, leveraging technically-based FFS methods to qualify damaged equipment in wet H_2S service can extend the useful operating life of critical in-service components. ■

For more information on this subject or the author, please email us at inquiries@inspectionengineering.com.

About the Author: Phillip E. Prueter, P.E. is a Principal Engineer II and Team Leader - Materials & Corrosion at The Equity Engineering Group, Inc. in Shaker Heights, Ohio, where his responsibilities include providing technical consulting expertise to the refining, petrochemical, specialty chemical, and power generation industries and managing Nuclear Consulting Services. He specializes in fitness-for-service, design by analysis, explicit dynamics, transient thermal-mechanical fatigue analysis, elevated temperature creep, seismic and natural frequency analysis, fracture mechanics, root-cause failure analysis, damage mechanism reviews, and high temperature hydrogen attack. He holds a BS and MS in mechanical engineering and is a Registered Professional Engineer in nine states. Additionally, he is a member of the ASME Working Groups on Design by Analysis and Elevated Temperature Design, serves as an organizer for the ASME Pressure Vessels and Piping Conference, is an instructor for the ASME Master Classes on Design by Analysis and Fatigue, and has authored or co-authored more than 40 technical publications.

14. McHenry, H.I, Shives, T.R., Read, D.T., McColskey, J.D., Brady, C.H. and Purtscher, P.T., March 1986, "Examination of a Pressure Vessel that Ruptured at the Chicago Refinery of the Union Oil Company on July 23, 1984," NBSIR 86-3049. Institute for Material Science and Engineering – National Bureau of Standards, Boulder, CO.
15. Kane, R.D. and Cayard, M.S., May/June 1995, "Wet H₂S Cracking in Steel Vessels – Part 1: An Evaluation of WFMP Techniques," Inspectioneering Journal.

REFERENCES

1. Papavinasam, S., 2014, "Corrosion Control in the Oil and Gas Industry," Gulf Professional Publishing, Waltham, MA.
2. Heidersbach, R., 2018, "Metallurgy and Corrosion Control in Oil and Gas Production," 2nd Edition, John Wiley & Sons, Inc., Hoboken, NJ.
3. Balliache, N.M., January 28-29, 2020, "Understanding the Origin of H₂S in Carbonate Oil and Gas Reservoirs: A Review," AAPG Middle East Region Geoscience Technology Workshop: 3rd Edition Carbonate Reservoirs of the Middle East, Abu Dhabi, UAE.
4. Dobis, J.D., Cantwell, J.E., and Prager, M., 2019, "WRC Bulletin 489 (2nd Edition): Damage Mechanisms Affecting Fixed Equipment in the Refining Industry," The Welding Research Council, Shaker Heights, OH.
5. Staats, J.C., Buchheim, G.M., and Osage, D.A., 2010, "WRC Bulletin 531: Development of Fitness-For-Service Rules for the Assessment of Hydrogen Blisters, HIC, and SOHIC," The Welding Research Council, Shaker Heights, OH.
6. API/ASME, 2016, "API 579-1/ASME FFS-1, Fitness-For-Service," 3rd Edition, The American Petroleum Institute and The American Society of Mechanical Engineers, Washington DC/New York.
7. Cayard, M.S., Kane, R.D., Kaley, L., and Prager, M., 1994, "WRC Bulletin 396: Research Report on Characterization and Monitoring of Cracking in Wet H₂S Service," The Welding Research Council, Shaker Heights, OH.
8. NACE, 2020, "SP0296-2020: Detection, Repair, and Mitigation of Cracking in Refinery Equipment in Wet H₂S Environments," NACE International, Houston, TX.
9. Kane, R.D., Wilhelm, S.M., and Oldfield, J.W., March 28-30, 1989, "Review of Hydrogen Induced Cracking of Steels in Wet H₂S Refinery Service," Proceedings of the International Conference on the Interaction of Steels with Hydrogen in Petroleum Industry Pressure Vessel Service, Paris, France.
10. NACE, 2013, "8X294: Review of Published Literature on Wet H₂S Cracking of Steels Through 1989," NACE International, Houston, TX.
11. Kotecki, D.J. and Howden, D.G., 1973, "WRC Bulletin 184: Submerged-Arc-Weld Hardness and Cracking in Wet Sulfide Service," The Welding Research Council, Shaker Heights, OH.
12. API, 2020, "API RP 571, Damage Mechanisms Affecting Fixed Equipment in the Refining Industry," 3rd Edition, American Petroleum Institute, Washington, D.C.
13. NACE, 2015, "ANSI/NACE MR0103/ISO 17945:2015: Petroleum, Petrochemical and Natural Gas Industries – Metallic Materials Resistant to Sulfide Stress Cracking in Corrosive Petroleum refining Environments," NACE International, Houston, TX.



Inspectioneering® Training Solutions

Empowering better decisions — one course at a time.

Inspectioneering Training was created to support and improve Fixed Equipment Mechanical Integrity (FEMI) programs through competency-based, specialist training. Through our courses, participants gain a deeper understanding and, more importantly, valuable context for their responsibilities as integrity and reliability professionals.

All of our courses are available online and offer optional hybrid learning models including live sessions with our trainers. Completion certificates include Professional Development Hours (PDH) that qualify for API's ICP recertification requirements. So whether you're looking to build upon competency and expertise or coming up for recertification, we have you covered.

Check out our current and upcoming courses at: www.inspectioneering.com/training

The Next Evolution of Mechanical Integrity is **here.**

Quantitative Reliability Optimization (QRO) empowers leaders at industrial facilities to make better reliability decisions. QRO is an evolution in modeling that combines the best traditional reliability methods, data science, and subject matter expertise into one hybrid model.

Learn more at pinnacle-reliability.com

