2020 | VOLUME 47

Structural Integrity Associates, Inc.®

NEWS & VIEWS

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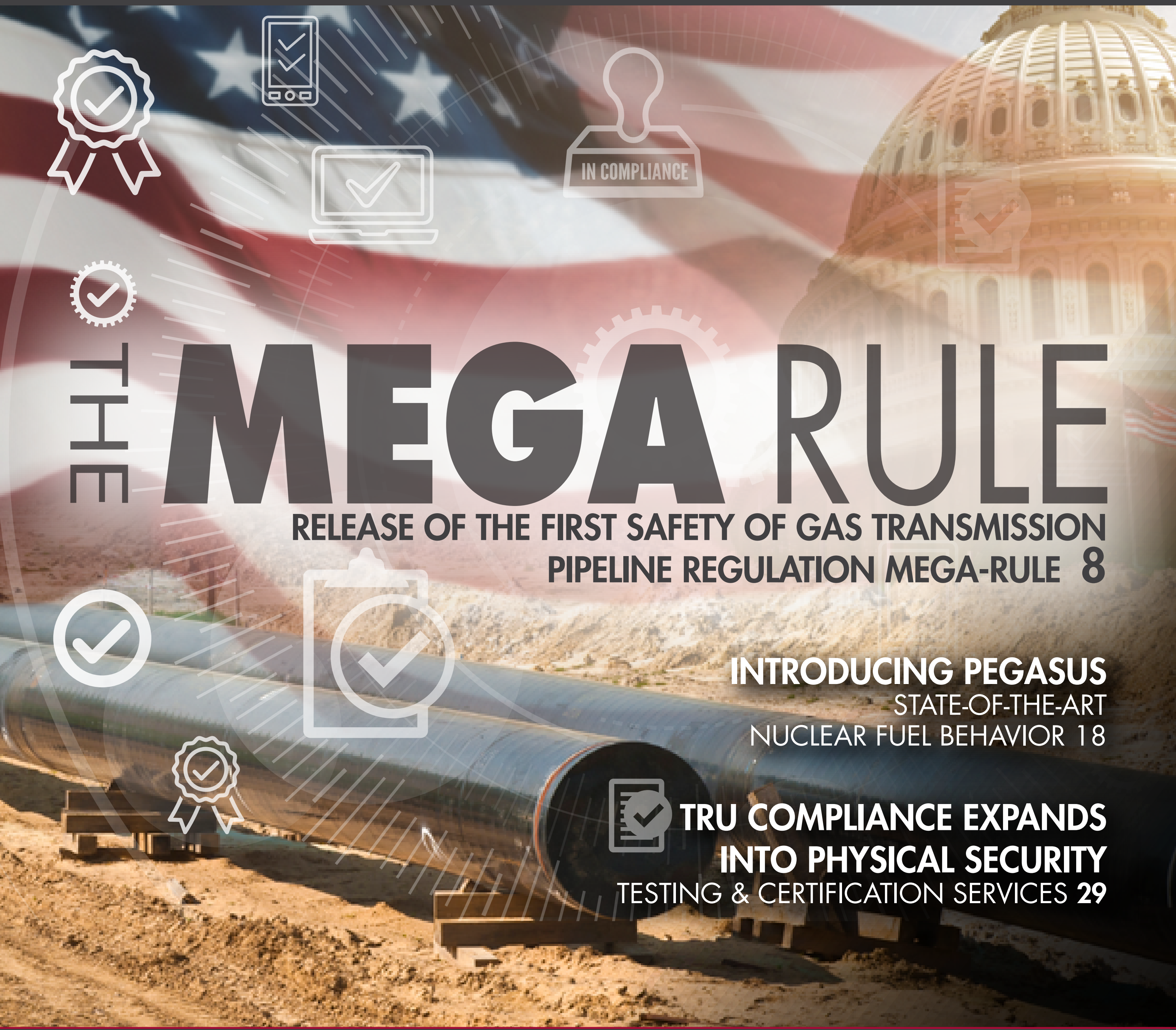

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President's Corner

Farewell Address

LANEY BISBEE
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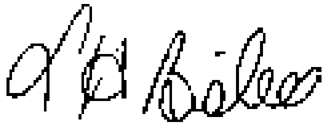
As I expect you've all heard, I retired late last year from the role I've held for the past 14 years at SI. As I transition myself to more technical work and personal activities, I'm proud to hand the reins to Mark Marano as SI's new President and CEO. Mark is a power industry veteran and a true professional, and I'm confident that employees and clients alike will be pleased in the years to come under his leadership.

As for me, I have no words to express how grateful I am for my years at SI and for the decades of an engineering career. I am thankful for the support from our employees, clients, and the engineering community who have made not only my SI experience, but my entire career, a source of great enjoyment.

I'm very excited to again be on project teams exclusively as a technical resource and to participate on the multi-disciplinary teams SI is known for as the opportunities arise. And, I'm especially thankful for being able to collaborate and routinely interact with clients and contribute to developing solutions for some of our industry's most difficult and demanding problems.

Going forward, if you have one of those challenging problems, I trust that you'll think of SI.



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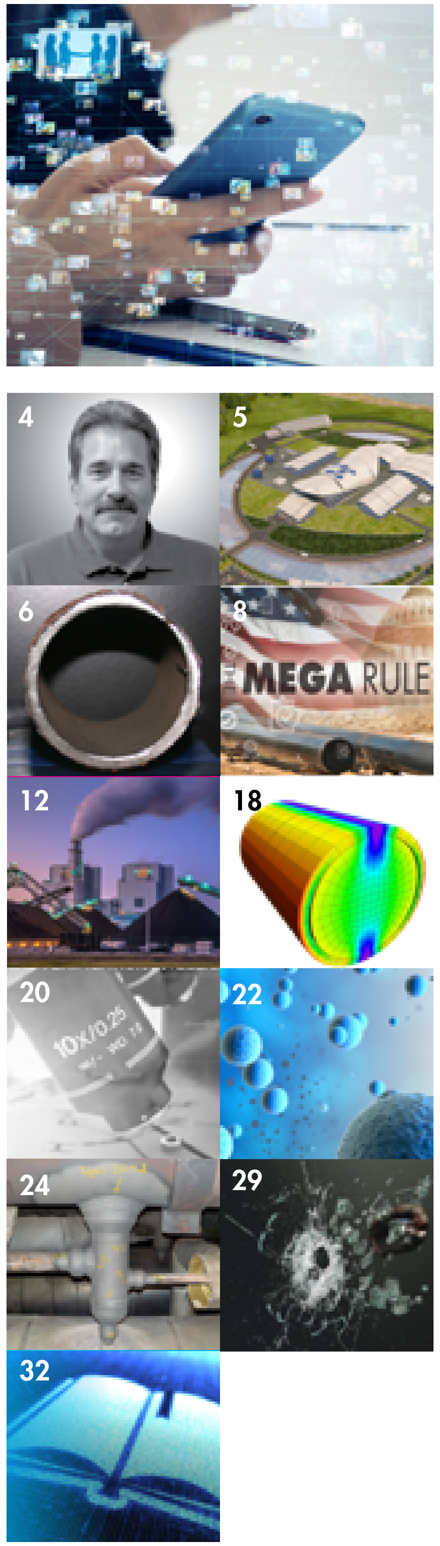
In this Issue



IN MEMORIAM

Paul Zayicek

1955-2019

It is with a heavy heart that SI announces the passing of our friend and co-worker, Paul Zayicek, on September 6, 2019 in Gastonia, NC. Paul had been with SI since 2011 as Senior Consultant and Turbine-Generator Product Manager. He had over 40 years of experience in the application and development of NDE techniques related to the power generation industry, particularly turbine and generator components, as well as business development experience in the commercial inspection market.

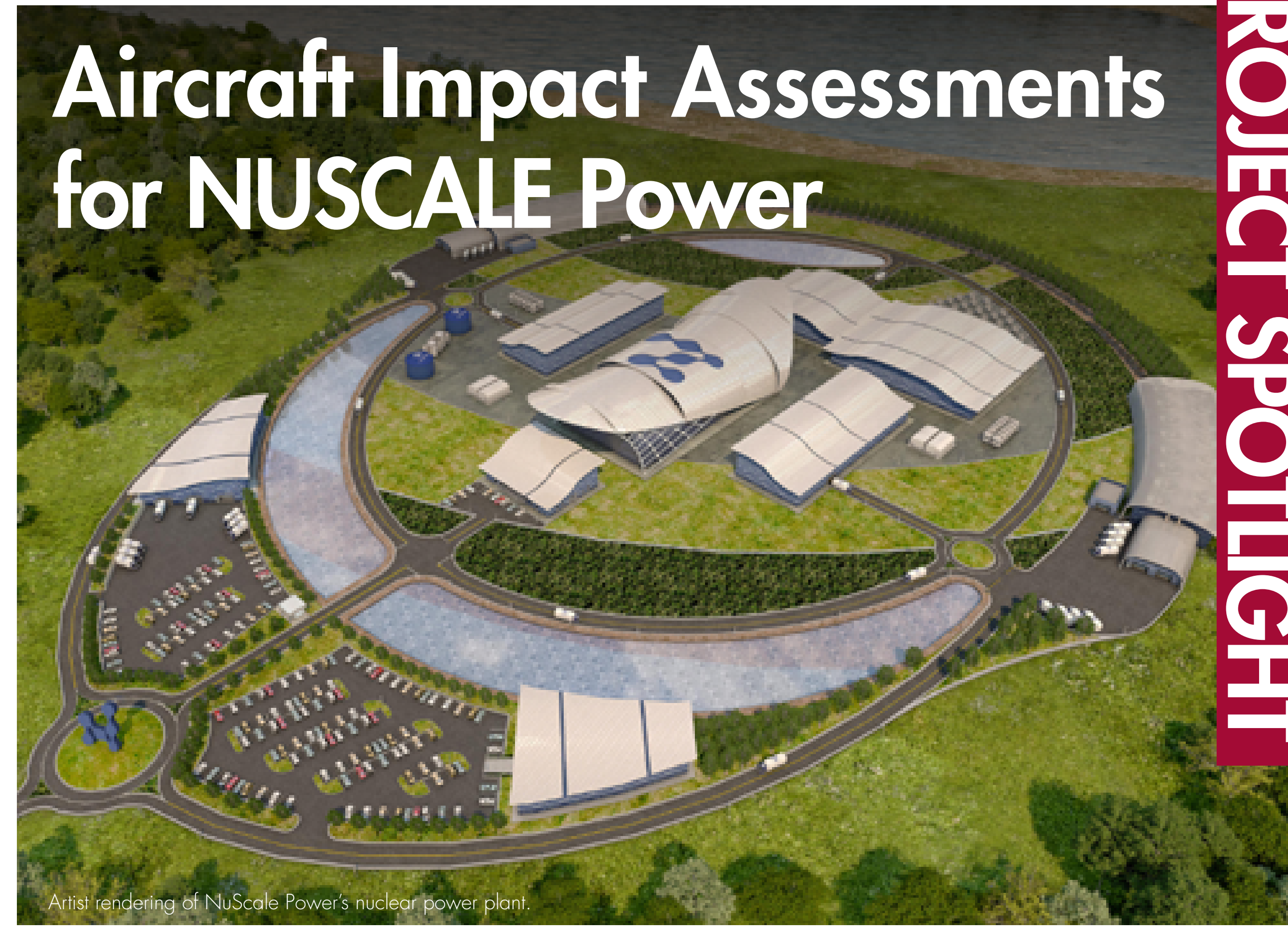
Prior to SI, Paul worked at Siemens Energy, the Electric Power Research Institute (EPRI) Nondestructive Evaluation Center, and the General Electric Company. Paul led in-service inspections of nuclear and fossil power generation equipment and has held Level III certifications in Ultrasonic Testing (UT) and Magnetic Particle Testing (MT). While at EPRI, Paul was deeply involved in a lead role in the Turbine Generator Users' Group, and many of the readers may have known him through that group and through the many EPRI projects in which Paul participated. At SI, Paul was responsible for all commercial and technical aspects of our Turbine/Generator offerings. He was active in the American Society of Nondestructive Testing (ASNT) in Charlotte, serving as Chairman and various director roles since 1991. He was awarded ASNT Fellow honors in 2008 for his commitment to the organization and the NDT field.

Paul was born in Amsterdam, NY, on November 5, 1955 and grew up in nearby Johnstown where he graduated from Johnstown High School in 1973. He attended SUNY Morrisville before relocating to the Charlotte, North Carolina area over 35 years ago where, in addition to his career obligations, he continued his education and earned his B.S. degree in Business Management.

Paul is survived by his wife and her sons; a brother; his daughter, son, and their mother; and several grandchildren. Paul had a wide range of interests, including gardening, beekeeping, and antique auto restoration. He was a man dedicated to his family and his faith. Paul was one of those unique people that never seemed to get upset, just rolled smoothly through difficult problems, and always flashed a genuine smile. He will be sorely missed at SI, especially in the Huntersville office where he was a friend to all.

PROJECT SPOTLIGHT

Aircraft Impact Assessments for NUSCALE Power



Artist rendering of NuScale Power's nuclear power plant.

From 2015 to 2019 Structural Integrity Associates, Inc. (SI) worked with NuScale Power, LLC. to develop structural details for and perform aircraft impact assessments of NuScale's SMR Reactor Building. The assessments were based on finite element analyses of various strike scenarios stemming from NEI 07-13 guidance. ANACAP, a proprietary SI concrete constitutive model, was used in the finite element analyses. Among other capabilities, the ANACAP model can capture multi-axial tensile cracking, compressive crushing with strain softening, and crack dependent shear stiffness.

Following SI's analytical assessments, SI supported NuScale during a multi-day NRC AIA inspection. The NRC had no findings following their review of SI's assessments, moving NuScale Power one step closer to bringing their Small Modular Reactor technology to market.

ERIC KJOLSING, Ph.D., PE
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SI personnel have experience in all aspects of Aircraft Impact Assessments including:

- Research for NEI 07-13 methodology development
- Application of NEI 07-13 on assessments of new US plants
- Adapting NEI 07-13 methods for plants outside the US
- Extending NEI 07-13 methods for shock propagation
- Licensing support with US and Foreign regulators

Please contact Eric Kjolsing, PhD, PE if you'd like to learn more about how SI can help you in your structural assessments.

Materials Lab Featured Damage Mechanism:

SH/RH Fireside Corrosion in Conventional Coal Fired Boilers

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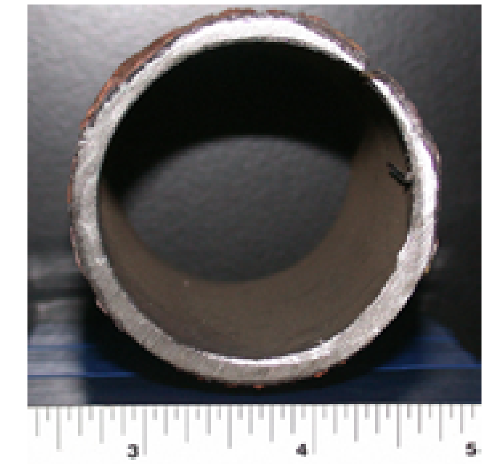
Superheater/reheater fireside corrosion is also known as coal ash corrosion in coal fired units.

Mechanism

Coal ash corrosion generally occurs as the result of the formation of low melting point, liquid phase, alkali-iron trisulfates. During coal combustion, minerals in the coal are exposed to high temperatures, causing release of volatile alkali compounds and sulfur oxides. Coal-ash corrosion occurs when flyash deposits on metal surfaces in the temperature range of 1025 to 1200°F. With time, the volatile alkali compounds and sulfur compounds condense on the flyash and react with it to form complex alkali sulfates such as $K_3Fe(SO_4)_3$ and $Na_3Fe(SO_4)_3$ at the metal/deposit interface, which are low melting point compounds. The molten slag fluxes the protective iron oxide covering the tube, exposing the metal beneath to accelerated oxidation.



OD wall loss is most severe at the 10:00 and 2:00 positions due to coal ash corrosion.

Typical Locations

Fireside corrosion will generally be most severe in the highest temperature locations of the SH and RH components. These areas include:

- Leading sides of all tubes in pendant platens; bottom bends of platens
- Out of alignment tubes
- Outlet/final tubes towards the header
- Just prior to a material change, e.g., T22 tubing just before austenitic tubing
- Wrapper tubes
- Tubes that surround a radiant cavity
- Tubes with a longer gas-touched length

Features

- Tube wastage very often occurs as flat regions at the 10:00 and 2:00 positions, but can also occur at the 12:00 position.
- The presence of a three-layered deposit that is well adhered to the tube at ambient temperatures. The layers include a hard, brittle, and porous outer layer; a white intermediate layer containing compounds of complex alkali sulfates; and a black glossy inner layer consisting of oxides, sulfates, and iron sulfides.
- The ratio of maximum wall loss to steam side oxide scale thickness will be greater than five.
- Stainless steels often show sulfidation and/or carburization.

Root Causes

There are three general groups of root causes, which include overheating of the tubes, fuel factors, and combustion factors. Overheating can be related to poor initial choice of tube material for the operating conditions, the presence of extra gas touch length, steam side oxide growth/buildup that forms during operation and insulates the tube metal from the cooling effects of the steam, high temperature laning, tube misalignment, change of fuel, and rapid startups causing the reheater to reach temperature before full flow is established. Fuel issues are generally related to the use of fuel with corrosive ash, which is often high in sulfur, sodium, potassium, and/or chlorine. Combustion factors include the use of low NOx systems, the presence of excess unburnt or partially burnt particles leading to an increase in carburization, and the use of oil on startup, which can also lead to carburization.

Release of the First Safety of Gas Transmission Pipeline Regulation Mega-Rule

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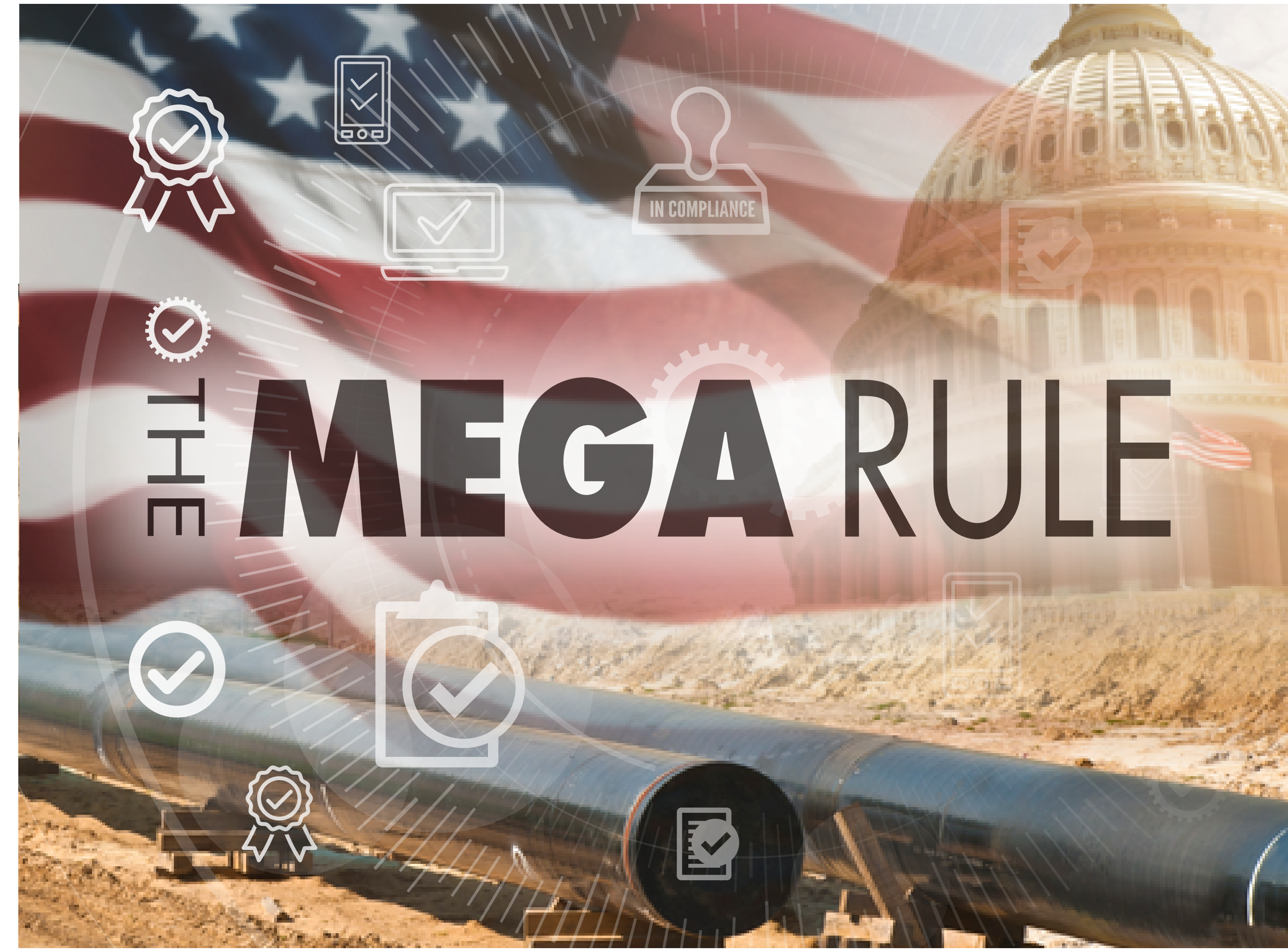
On October 1, 2019 the Pipeline and Hazardous Materials Safety Administration (PHMSA) published amendments to 49 CFR Parts 191 and 192 in the Federal Register issuing Part 1 of the Gas Transmission Mega-Rule[1]. This new regulation is commonly referred to as the Mega-Rule, as it represents the most significant regulatory impact on gas transmission pipelines since the original Gas Transmission Integrity Management Program (TIMP) Regulation was issued in 2003.

General Overview

As a result of numerous transmission pipeline accidents in the late 1990's, the congressional Pipeline Safety Improvement Act of 2002 required operators of natural gas transmission lines to create TIMP Plans to identify transmission lines in High Consequence Areas (HCAs), conduct risk assessments and manage the integrity of covered segments in HCAs by conducting periodic integrity assessments. In 2010 through 2012, multiple incidents (Deep Water Horizon, San Bruno, California, Marshall, Michigan, Sissonville, WV) created a renewed focus on pipeline safety in Congress.

On January 3, 2012, the President enacted the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act). The 2011 Act included a number of congressional mandates to PHMSA, including the consideration of bringing additional gas gathering lines under PHMSA jurisdiction, expanding gas transmission pipeline Integrity Management beyond HCAs and reconfirmation of Maximum Allowable Operating Pressure (MAOP) for certain defined gas transmission lines.

PHMSA issued an Advance Notice of Proposed Rulemaking (ANPRM) in August 2011 and a Notice of Proposed Rulemaking titled Safety of Gas Transmission and Gathering Pipelines in April 2016. At the March 2018 GPAC meeting, the PHMSA



announced that the agency would split the new regulation into three separate rulemakings, covering the following topics:

Mega-Rule I

- MAOP Reconfirmation
- Material Verification
- Analysis of Predicted Failure Pressure
- MCAs and Expanded Assessment

Mega-Rule II

- Updated repair criteria for HCAs
- New repair criteria for non-HCAs
- Inspection of pipelines following extreme weather events
- Updates to corrosion control requirements
- Strengthening assessment requirements

Mega-Rule III

- New requirements for gas gathering pipelines

Mega-Rule I – Required Actions

This first Mega-Rule, released in October 2019, addresses the congressional mandates to PHMSA from the 2011 Pipeline Safety Act, incorporates numerous prescriptive actions required for gas transmission pipeline operators to improve pipeline safety:

- MAOP Determination and Reconfirmation (§192.619 and §192.624)
- Material Verification (MV) (§192.607)
- Engineering Critical Assessments (ECAs) (§192.632)
- The identification and assessment of Moderate Consequence Areas (MCAs) (§192.3 & §192.710)
- Analysis of Predicted Failure Pressure (§192.712)
- Revisions to TIMP Plans, required new Plans, procedures and record requirements

Continued on next page

The following table provides a summary of key sections of this rulemaking and a summary of resultant actions pipeline operators will be required to take.

Code Requirement	What it Means
MAOP Determination and Reconfirmation (§192.619 and §192.624)	For on-shore transmission pipelines in an HCA, Class 3 or 4 location without Traceable, Verifiable and Complete (TV&C) records for §192.619(a)[2] , or where the MAOP was established based on the Grandfather Clause[3] and the MAOP creates a stress ≥ 30% SMYS, an operator will need to Reconfirm the MAOP. Operators must develop and document procedures by July 1, 2021 and will have until July 3, 2028 to Reconfirm 50% of their subject pipeline mileage and until July 2, 2035 to Reconfirm 100% of subject mileage. There are six methods prescriptively identified to Reconfirm MAOP: 1. A pressure test per Subpart J along with Material Verification per §192.607 2. Pressure Reduction with Material Verification in some cases 3. Engineering Critical Assessment (ECA), 4. Pipe replacement, 5. Pressure reduction for pipeline segments with Small Potential Impact Radius (≤ 150 ft.), or 6. Alternative technology submitted to PHMSA with no objection received within 90 days.
Material Verification (MV) (§192.607)	Various sections of Mega-Rule 1 require operators to ensure adequate (TV&C) material records or implement a Material Verification Program. Two specific cases include MAOP Reconfirmation methods: ▪ When Pressure testing per §192.624 Method 1, if no TV&C material records, an operator must obtain the missing records in accordance with §192.607, ▪ Or as required during the ECA process Within an operator's Material Verification Program, specific pipeline attributes must be confirmed: diameter, wall thickness, seam type and grade. Operators will be required to define sampling programs and perform destructive (laboratory) or non-destructive testing to capture this information and take additional action when inconsistent results are identified until a confidence level of 95% is achieved.
Engineering Critical Assessments (§192.632)	The ECA is one method available for reconfirming MAOP. The ECA process involves evaluating: ▪ Relevant material properties, ▪ Operational history and environment, ▪ Prior assessments, ▪ In-service degradation, ▪ Possible failure mechanisms, and ▪ Defect characteristics (prior, current and future). These factors are analyzed for the loadings and operating conditions relevant to potential threats with additional assessments performed as needed. A detailed engineering analysis can then be performed that incorporates the assessment results and material property information to determine if the pipeline segment can be considered safe to operate at a designated MAOP.
Identification and Assessment of Moderate Consequence Areas (MCAs) (§192.3 & §192.710)	In Mega-Rule 1, PHMSA defined the new term MCAs with additional integrity assessment requirements. An MCA is defined as an on-shore area, with a potential impact circle containing either: ▪ Five or more buildings intended for human occupancy; or ▪ Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes §192.710 prescribes new integrity assessment requirements on transmission lines ≥ 30% SMYS in Class 3 or 4 locations and MCAs that can accommodate instrumented In-Line Inspection tools. Initial assessment s must be completed by July 3, 2034 with periodic reassessments every 10 years not to exceed 126 months.
Analysis of Predicted Failure Pressure (§192.712)	New requirements have been added throughout Mega-Rule 1 that will require the analysis of the predicted failure pressure at the location of the anomaly or defect. Prescriptive methodologies for corrosion wall loss have been identified. For crack-like defects, a detailed fracture mechanics analysis must be applied that uses appropriate methodologies that considers the potential failure mode (ductile, brittle, or both) of the defect. Appropriate and conservative growth rate models must also be applied to determine the remaining life.
Revisions to Policies, Procedures and Plans	In addition, the Mega-Rule 1 will require revisions to a significant number of existing policies and procedures, O&M procedures and Transmission Integrity Management Plans and procedures to ensure compliance with the new regulation.

Structural Integrity has been deeply involved in the Gas Transmission Mega-Rule since 2011 and has significant expertise in pipeline safety regulations with dedicated and substantial resources to support the requirements the Mega-Rule imposes on natural gas operators. We have developed specific procedures and programs to help operators address the new requirements of this Rulemaking, including the following:

- MAOP Reconfirmation Plans
- MV Intelligence (Material Verification Intelligence page 20)
- MV Procedures Field Validated MV Programs, (Pipeline Research Council International Report)
- ECA Procedures
- APTITUDE, (News and View, Volume 42 Page 35)

References / Footnotes

[1] The Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments Final Rule

[2] In October, 2019 AGA, INGAA and APGA submitted a Petition for Reconsideration to PHMSA to reconsider the criteria in §192.624(a)(1) regarding MAOP Reconfirmation. PHMSA responded in a letter to the Associations that granted the Petition to limit the MAOP reconfirmation requirements of §192.624(a)(1) to those pipeline segments that do not have TVC pressure test records in accordance with §192.619(a)(2).At press time, the formal notice of the petition had not been posted in the Federal Register

[3] Section §192.619(c) commonly referred to as the Grandfather Clause allows for pipelines installed prior to July 1, 1970 may operate at the highest actual operating pressure to which the pipeline was subjected in the preceding 5 years from this date.

Metallurgical Lab Case Study:

Corrosion Fatigue in WaterWall Tubes Increasingly A Safety Concern as Coal Plants Cycle

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It is well known that conventional coal-fired utility boilers are cycling more today than they ever have. As these units have shifted to more of an 'on-call' demand they experience many more cycles (start-ups and shutdowns, and/or significant load swings) making other damage mechanisms such as fatigue or other related mechanisms a concern.

The most recent short-term energy outlook provided by the U.S. Energy Information Administration (EIA) indicates the share of electricity generation from coal will average 25% in 2019 and 23% in 2020, down from 27% in 2018. While the industry shifts towards new construction of flexible operating units, some of the safety issues that have been prevalent in the past are fading from memory. The inherent risks of aging seam-welded failures and waterwall tube cold-side corrosion fatigue failures are a case in point. It is well known that conventional coal-fired utility boilers are cycling more today than they ever have. As these units have shifted to more of an 'on-call' demand they experience many more cycles (start-ups and shutdowns, and/or significant load swings) making other damage mechanisms such as fatigue or other related mechanisms a concern. The following case study highlights this point by investigating a cold-side waterwall failure that experienced Corrosion Fatigue. While this failure did not lead to any injuries, it must be stressed that the potential for injuries is significant if the failure occurs on the cold-side of the tubes (towards the furnace wall).

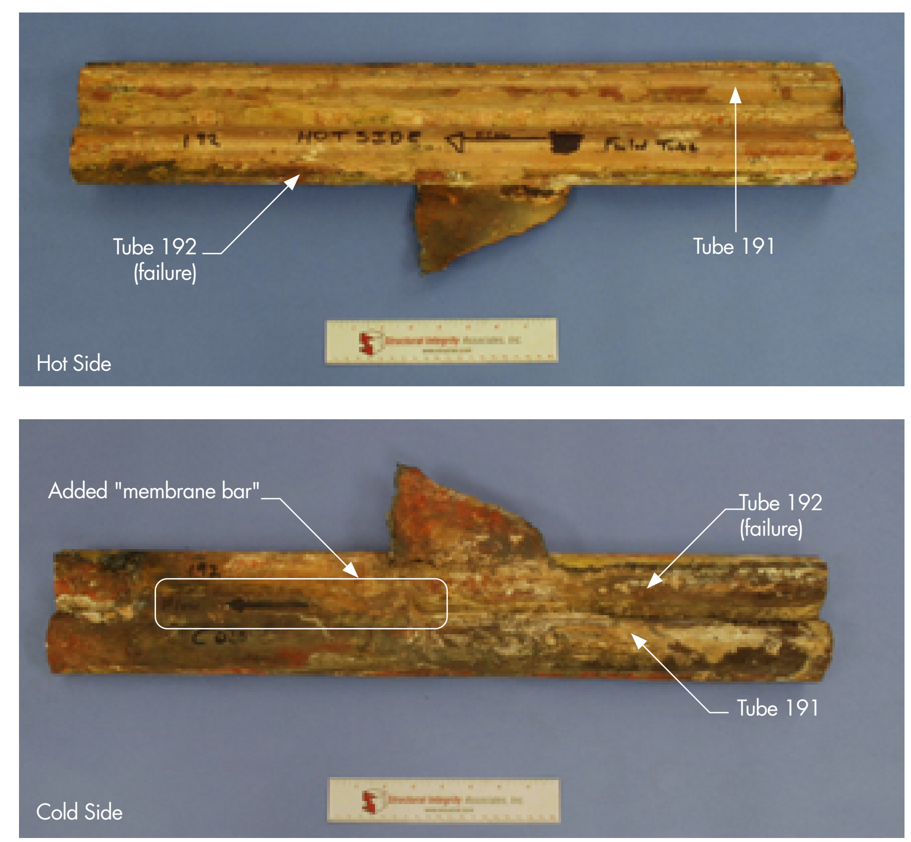


FIGURE 1. As-received photographs of the submitted waterwall tubes (Tube 191 and Tube 192). Tube 192 was marked as "failed". These tubes are adjoined via neutral axis membrane weld. However, on the cold side an added "membrane bar" ~10" in length was noted.

1.0 INTRODUCTION

Structural Integrity Associates, Inc. (SI) was recently asked to investigate the failure of a waterwall tube and to provide recommendations, as necessary.

Multiple tubes were examined, including one that contained the failure. They were specified as SA-192 carbon steel (CS) material with dimensions of 2.00" outside diameter (OD) x 0.220" specified minimum wall thickness (MWT). The tube that failed was the last tube of the right sidewall (sidewall tubes are connected via tube-to-tube solid membrane) and the cold side waterwall tube casing reportedly attaches via seal weld to this last tube (similar on the left sidewall).

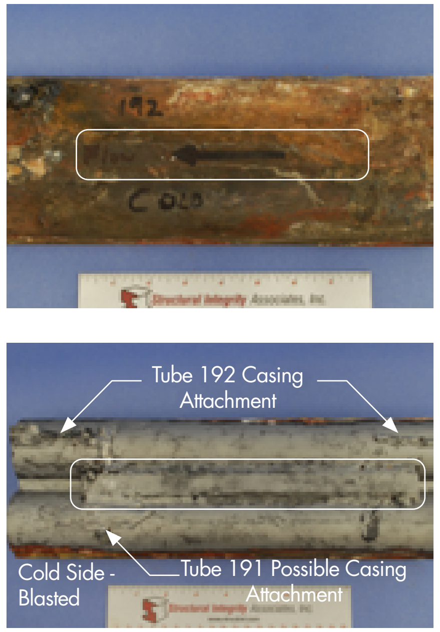


FIGURE 2. Additional photographs of the cold side of the tube after removal of the OD deposits/oxides where a number of pad welds were noted.

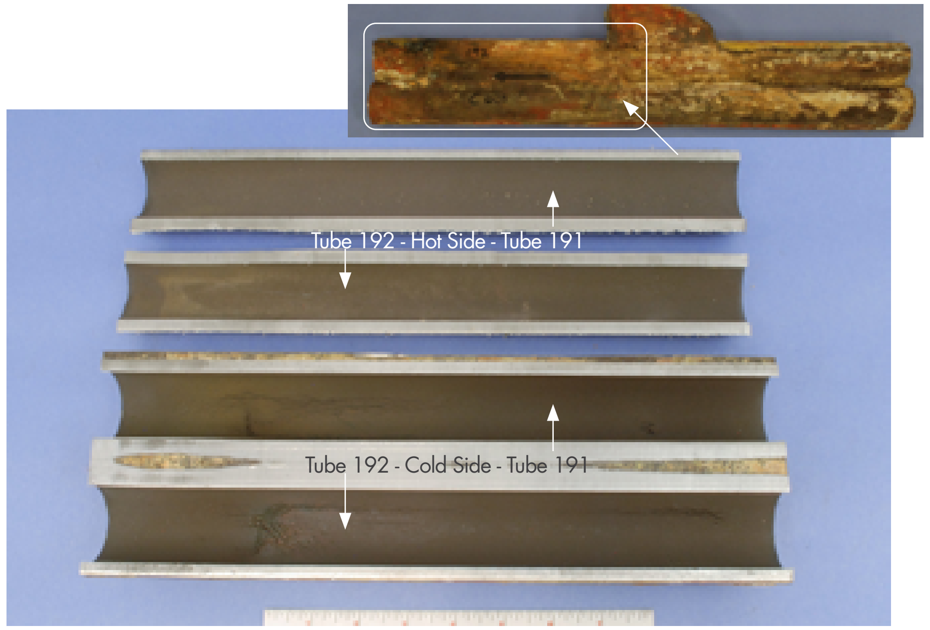


FIGURE 3. A review of the internal surface prior to sectioning identified indications along the ~14" length of tubing noted in the yellow box. After sectioning along the neutral axis (membrane weld) a multi-array of cracking was noted on the cold side only. A number of parallel cracks oriented in both the longitudinal and circumferential directions were observed and appear directly related to the stress field developed as a result of the welds on the cold side OD surface.

2.0 EXAMINATION PROCEDURES AND RESULTS

2.1 Visual Examination

Figure 1 shows the tubes (Tube 191 and Tube 192) in the as-received condition. An annotation by plant personnel notates Tube 192 as the failed tube, although the specific region of failure was not noted. The waterwall tubes are adjoined via membrane weld; however, on the cold side an added "membrane bar" ~10" in length was noted. This "membrane bar" was not fully fused to the tube-to-tube membrane weld, so a gap between the two was present. To facilitate a better examination of the cold side, the tube was grit-blasted to remove the deposits/ oxides along the OD surface. Figure 2 shows photographs of the cold side before and after-blasting. A significant number of pad welds, attachment welds, etc. were noted along the cold side OD surface. External or cold side casing attachment points for Tube 192 were confirmed by plant personnel. However, it was unclear if the regions notated for Tube 191 were also attachment points to the casing.

A review of the internal surface prior to sectioning identified indications along an ~14" length of tubing (noted in Figure 3). The tubes were sectioned in this region along the neutral axis (original tube-to-tube membrane weld). The ID surface along the cold side for both tubes exhibited a multi-array of cracking with Tube 192 exhibiting more extensive damage. A number of parallel cracks oriented in both the longitudinal and circumferential directions were observed and appear directly related to the stress field developed as a result of the welds on the cold side OD surface of both tubes. Figure 4 shows photographs correlating the pad/attachment welds on the cold side OD surface of both tubes to the damage on the ID surfaces.

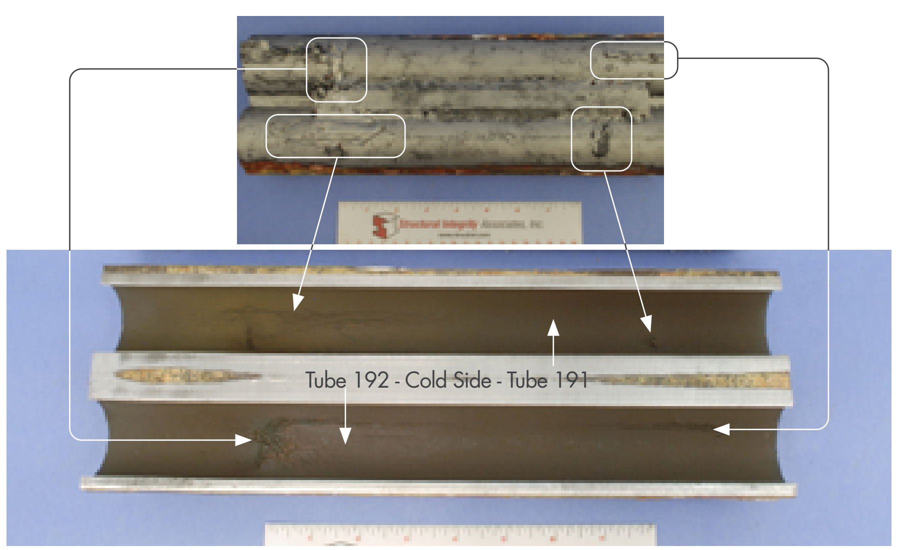


FIGURE 4. Additional photographs providing a visual representation of the OD surface pad welds and the resulting damage on the ID surface.

To help identify the actual leak location, a soap solution was applied to the cold side OD surfaces and pressurized air was applied against the cold side ID surfaces. The leak location was identified on Tube 192 at the location shown in Figure 5.

2.2 Metallographic Evaluation

Figure 6 contains macrophotographs of 3 separate metallurgical cross-sections removed from the cold side of both tube sections.

Sample A –
Circumferential cross-section through the identified leak (Tube 192)

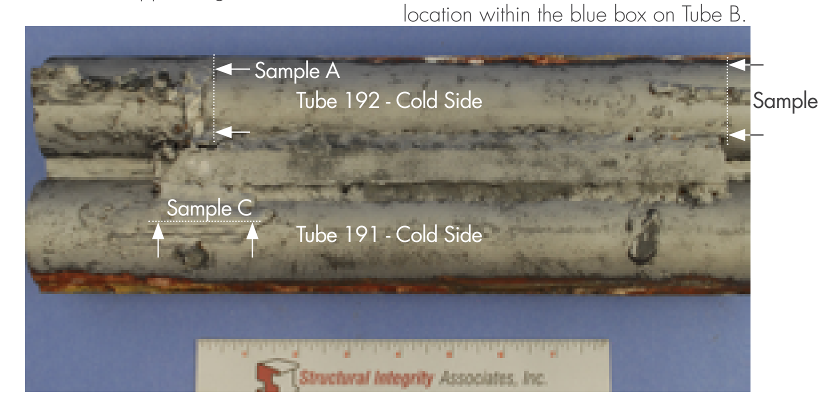
Sample B –
Circumferential cross-section through damage, but remote from the failure (Tube 192)

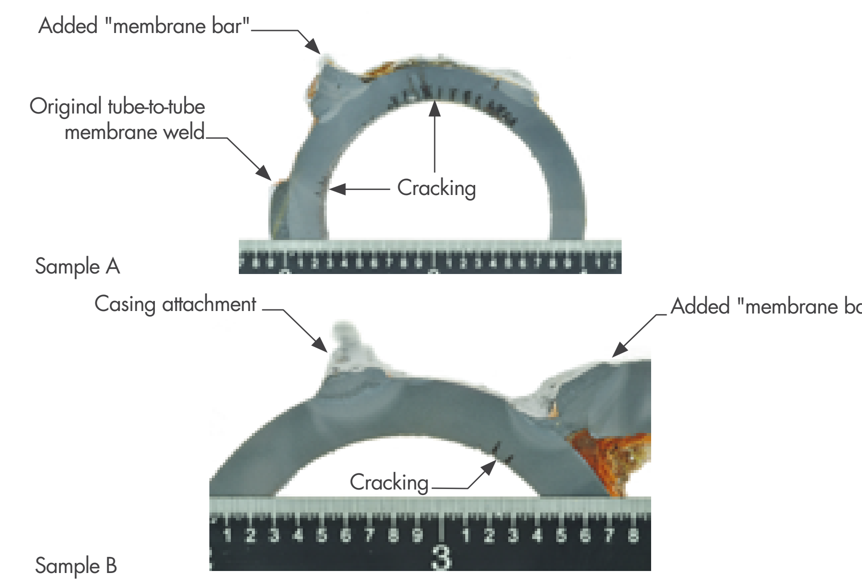
Sample C –
Longitudinal cross-section through pad weld (Tube 191)

All of the cross-sections revealed cracking emanating from the ID surface. Sample A exhibited extensive and distinct cracks along the cold side crown at approximately the same circumferential zone where the circumferential weld is located on the OD surface/adjacent to the added "membrane bar". In addition, cracking was noted along the original tube-to-tube membrane weld on the cold side. Sample B exhibited obvious cracking adjacent to the added "membrane bar" on the cold side. No damage was noted in proximity to the casing attachment weld. Sample C exhibited obvious cracking underneath the pad weld.

Figure 7 contains an overall stitched photomicrograph of Sample A from Tube 192 documenting the through-wall location. This location exhibited typical crack profiles representative of corrosion fatigue with signs of discontinuous growth via corrosion bulges. Copper deposits were also noted. At the through-wall location it appeared that the damage progressed to ~90% of the local wall thickness before failure resulted.

FIGURE 5. To facilitate the actual leak location, which was still not obvious at this point, a soap solution was applied to the cold side OD surfaces and pressurized air was applied against the ID surface. The leak location was identified at the location within the blue box on Tube B.





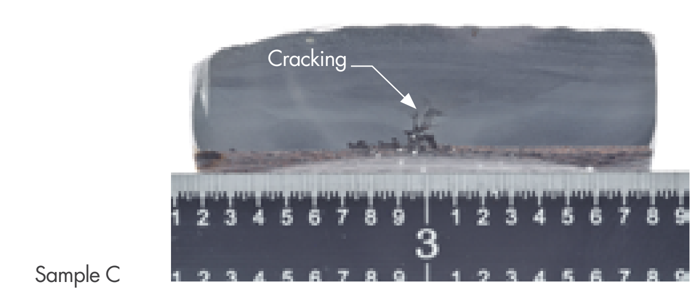


FIGURE 6. Macrophotographs of the metallurgical cross-sections removed.

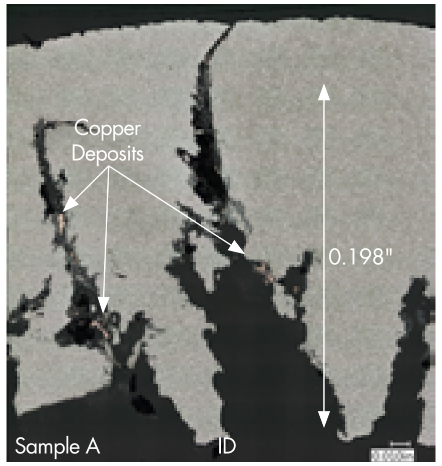


FIGURE 7. Overall stitched photomicrograph of Sample A at the through-wall location. This location exhibited typical crack profiles representative of corrosion fatigue with signs of discontinuous growth via corrosion bulges. Copper deposits were also noted. At the through-wall location it appeared that the damage progressed to ~90% of the wall thickness before failure resulted.

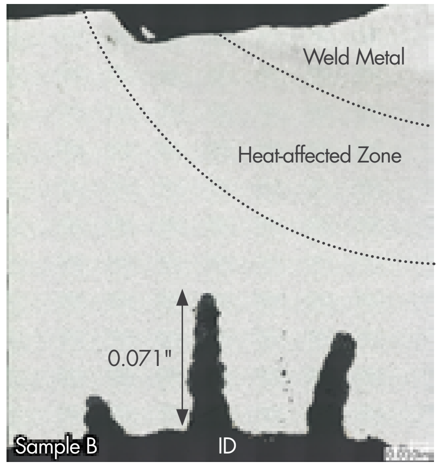


FIGURE 8. Overall stitched photomicrograph of Sample B at the deepest location. This location exhibited typical crack profiles representative of corrosion fatigue with signs of discontinuous growth via corrosion bulges. Minor amounts of copper deposits lined the crack and ID surfaces. At the deepest point, the damage progressed to ~35% of the wall thickness.

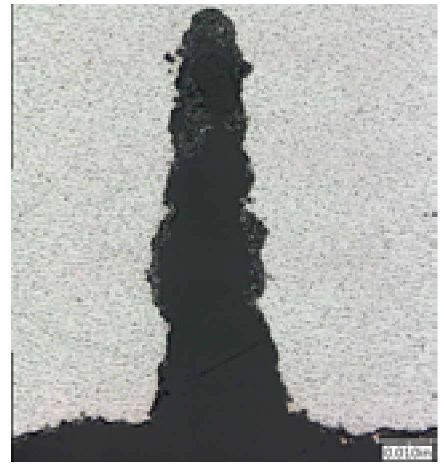


FIGURE 9. Higher magnification of the deepest location from Sample B. The copper is more clearly observed.

Figure 8 contains an overall stitched photomicrograph of Sample B at the deepest location. This location exhibited typical crack profiles representative of corrosion fatigue with signs of discontinuous growth via corrosion bulges. Minor amounts of copper deposits lined the crack and ID surfaces. At the deepest point, the damage progressed to ~35% of the local wall thickness. These cracks were in line with the added "membrane bar". A higher magnification photomicrograph of the deepest location from Sample B is shown in Figure 9. The crack is blunt-tipped, contains corrosion bulges, and is lined with deposits/oxides.

Figure 10 contains an overall stitched photomicrograph of Sample C from Tube 191. This location also exhibited a crack profile representative of corrosion fatigue. At the deepest point, the damage progressed to ~37% of the local wall thickness (note: the pad weld increased the wall thickness to ~0.400"). A significant amount of weld metal is present at this location and could possibly indicate previous repair attempts. The cracking extended through the heat-affected zone (HAZ) until linking with a possible lack of fusion site in the weld metal. In the longitudinal direction, the un-affected base metal exhibited a banded microstructure.

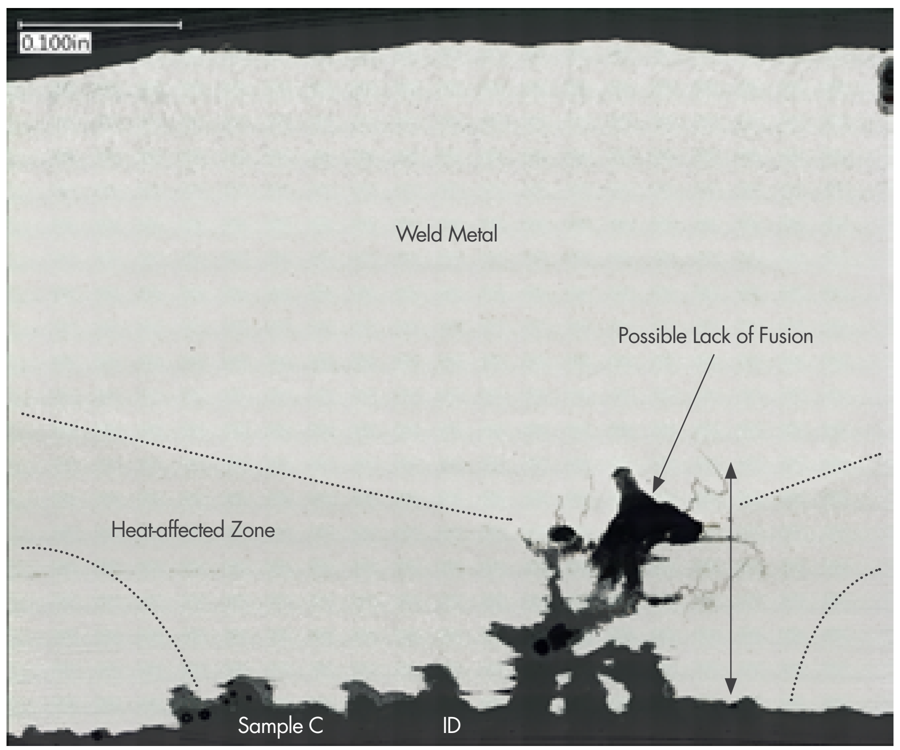


FIGURE 10. Overall stitched photomicrograph of Sample C at the deepest location. This location exhibited typical crack profiles representative of corrosion fatigue with signs of discontinuous growth via corrosion bulges. At the deepest point, the damage progressed to ~37% of the wall thickness. It should be noted that a significant amount of weld build-up was observed in this sample and is most likely a result of a previous repair effort.

In general, pitting was noted on the ID surface adjacent to damage sites. These incipient pits were lined with deposits/oxides and were less than 10 mils in through-wall thickness. The typical microstructure from Tube 192 cross-sections (Sample A and B), consisted of intact pearlite colonies within a ferrite matrix.

3.0 DISCUSSION

Tube 192 failed as a result of extensive corrosion fatigue (CF) damage on the cold side of the tube that initiated from the ID surface. Each tube exhibited a significant number of pad welds, attachment welds, membranes, etc. scattered along the OD surfaces of the cold side. Along the ID of Tube 192 a multi-array of cracking was noted with a number of parallel cracks oriented in both the longitudinal and circumferential directions and appear directly related to the stress field developed as a result of the welds on the OD surface. Significant cold side damage was also noted for the adjacent tube (Tube 191).

No apparent damage was noted on the hot side ID surfaces for either tube. Crack morphologies exhibited discontinuous growth via corrosion bulges along the length of each crack. Oxides/deposits (including copper) lined the crack surfaces. Adjacent to the damage sites incipient pitting was observed typically less than 10 mils in through-wall thickness and were also lined with oxides/deposits.

CF is a discontinuous cracking mechanism, whereby the cracks propagate through the tube wall by a repetitive oxide fracture process. The magnetite that grows indigenously on the inside tube surface is a protective oxide, unless it is subjected to strains in excess of its fracture strain (about 0.2%). During normal full load operation the strain in the tube is very low, and only during certain operating regimes does the strain locally increase due to the restriction in expansion caused by membrane and attachment welds. Experience has shown that these regimes may be related to operational regimens (startup, shutdown, forced cool, transient operation, trips) or due to mechanical loading by other boiler equipment (coal pipes, burner equipment). These operating regimes are referred to as the "operating space", and the key to solving CF is to identify the harmful operating space and modify that space so that the imposed strain is below the fracture strain. The best way to identify the operating spaces and thus to solve the problem is to instrument a couple of key CF locations with thermocouples and strain gauges and to monitor these as the unit is operated through the operating spaces. The boiler chemistry is also known to exacerbate the CF mechanism and rate, with the most important parameter being the reduction in the boiler water pH from normal operating ranges. Situations in which the pH is depressed while peak strains are imposed on the oxide are particularly harmful and need to be identified.

3.1 Recommendations

It is extremely important that plant personnel clearly identify the geography and history of failures over time. At this junction, it may be prudent to inspect visually the casing side and the ID with borescope at a similar elevation as this failure on the other four corners of the boiler. Drawings/information identifying other casing attachment points at other elevations would also be good locations to inspect, as well. These can help determine if the "attachments" for this particular location were correct or altered at some unknown date.

A replacement in-kind will always help remove the current damage, but mitigation of the problem is not

It is extremely important that plant personnel clearly identify the geography and history of failures over time.

ensured. Damage accumulation is heavily dependent on how the "operating space" at the plant has evolved over the years. A selection of pertinent locations for monitoring temperature/strain history using thermocouples and strain gauges will help gauge damage accumulation rates and whether transients can be adjusted to help lower the fracture strain.

Of equal importance, cycle chemistry should be monitored to ensure that pH levels are not depressed during transient operation.

Ultimately, through some of these items it may be determined that operational conditions and/or the mechanical loading (attachments, etc.) of the tubes will require modifications.

PEGASUS

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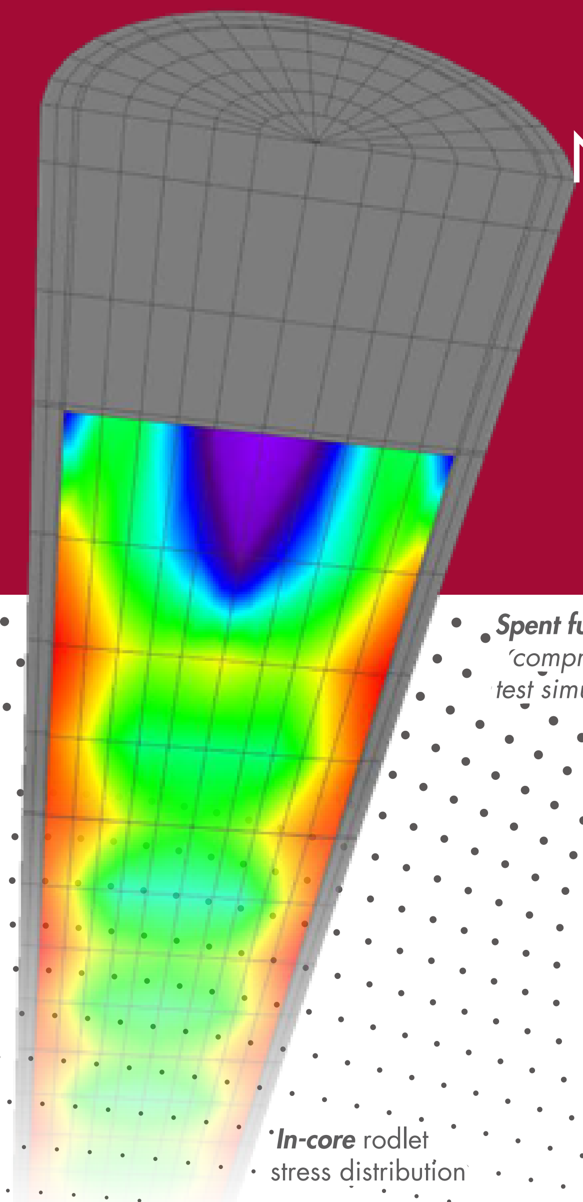
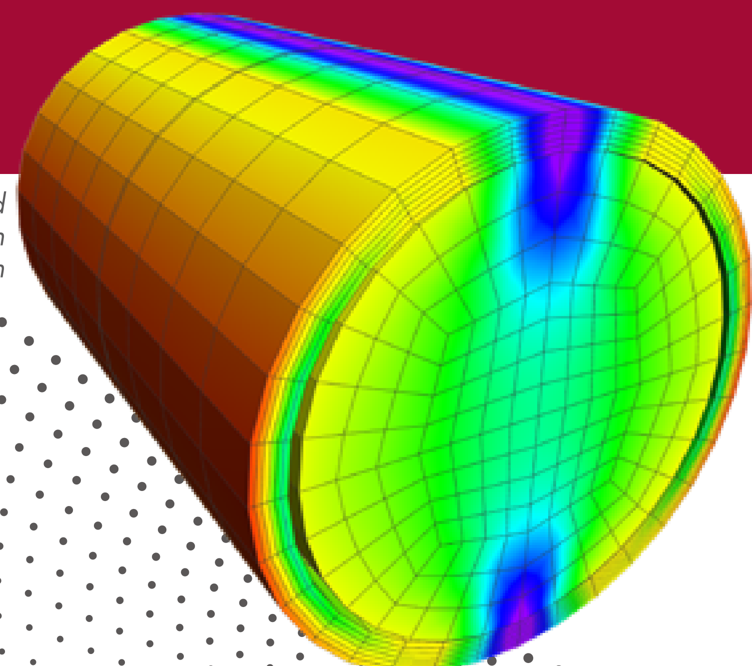
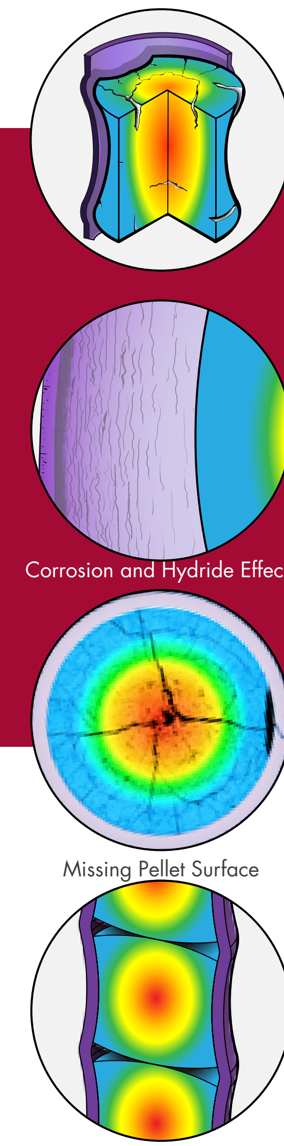


In-core rodlet stress distribution



Spent fuel rod compression test simulation

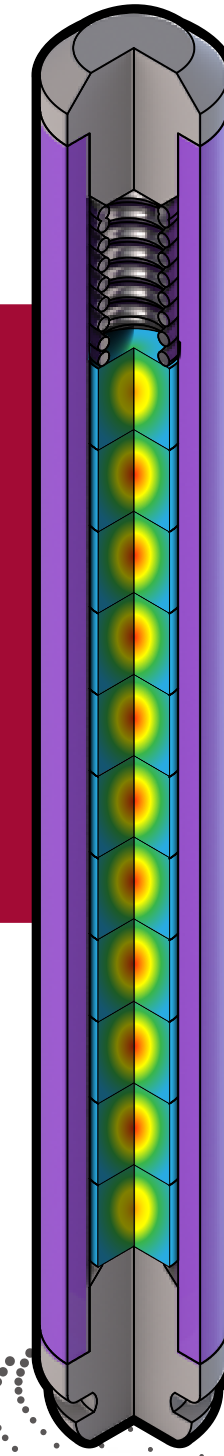
Fuel Rod Phenomena



Corrosion and Hydride Effects

Missing Pellet Surface

Strong Pellet-Cladding Mechanical Interaction



Introducing Pegasus

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The Pegasus code is a culmination of nuclear fuel behavior knowledge and experience that spans a period of over five decades. It is a total fuel-cycle simulation of fuel response from initial insertion in reactor to deposition in permanent storage. The goal of Pegasus is to treat, with equal fidelity, the modeling of fuel behavior during the active fuel cycle and the back-end cycle of spent-fuel storage and transportation in a single, self-consistent, and highly cost-effective analysis approach. In the active part of the fuel cycle, Pegasus's superior three-dimensional thermo-mechanics, coupled with validated nuclear and material behavior models, and robust fuel-cladding interface treatment make it a high-fidelity predictor of fuel-rod response during flexible power operations and operational transients.

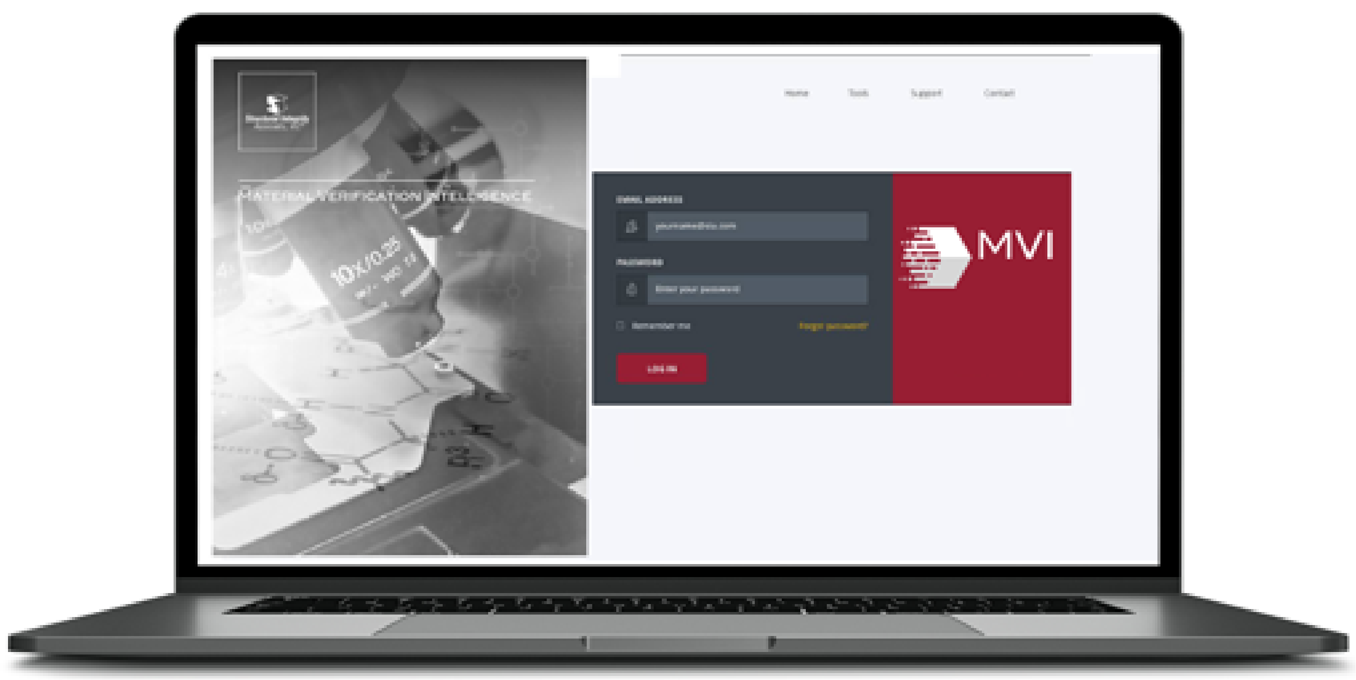
In the backend fuel cycle, Pegasus can perform analyses in a seamless transition from in-reactor to wet storage, to dry storage and eventually transportation under normal conditions and hypothetical-accident conditions of transport. The value of this Pegasus approach, which allows the analyst to combine fuel rod performance AND structural analysis into one seamless process, can best be appreciated by comparing it to the conventional time-consuming low-fidelity procedure of transferring output from fuel performance codes to structural analysis codes.

FEATURES

- 2D and 3D finite element engine
- First-of-a-kind fuel-cladding gap thermo-mechanical contact algorithm
- Steady-state and transient fuel rod modeling
- Fully integrated Pellet Cladding Interaction (PCI) modeling

APPLICATIONS

- Advanced Technology and Accident Tolerant Fuels
- PWR, BWR, and SMR fuel types
- Pellet Cladding Interaction/ Missing Pellet Surface assessments for startup and flexible power operations
- Spent fuel integrity for storage and transportation



Material Verification Intelligence

A new program to help pipeline operators implement the Material Verification requirements in recently released pipeline regulation (Mega Rule)

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On October 1, 2019, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published the long-awaited Mega-Rule (Part 1). One of the major new requirements identified in these amendments is when missing traceable, verifiable, and complete records, operators must implement a Material Verification (MV) (§192.607) program. MV requires operators of natural gas transmission pipelines, to develop and implement procedures to verify the material properties and attributes of their pipeline system. Included in the new regulation for MV are:

- Develop procedures for conducting destructive and non-destructive testing
- Define population groupings and implement sampling programs
- Implement and document laboratory testing
- Complete in situ and non-destructive evaluations (NDE)
- Expand sampling if inconsistent results based on NDE and laboratory testing
- Document program results and preserve for the life of the pipeline asset

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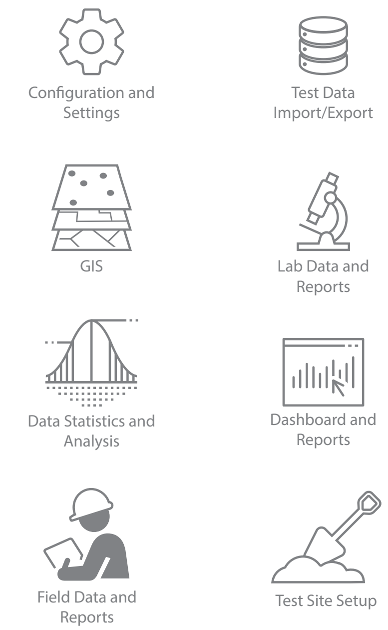
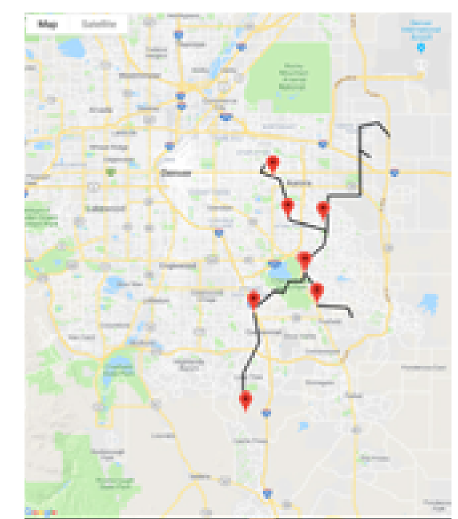


These MV requirements will create new data management challenges in terms of different departments, laboratories, and subcontractors requiring different levels of access to information and different needs to update information as results of the verification process are completed. For example, Integrity Managers and Engineers may be responsible to develop procedures, identify populations, and make decisions based on results of testing; however, operational personnel may make the decision on the selection and testing of test sites; while laboratory and NDE subcontractors perform the actual material testing. Often these stakeholders will likely reside in different offices and/or geographic locations and all have requirements to view, upload, and analyze information in different ways.

In addition to data management issues, the ability to ensure compliance and track progress through implementation of the MV process pose additional challenges. Pipeline operators will need the ability to quickly view and analyze MV results and communicate decisions when inconsistencies are identified.

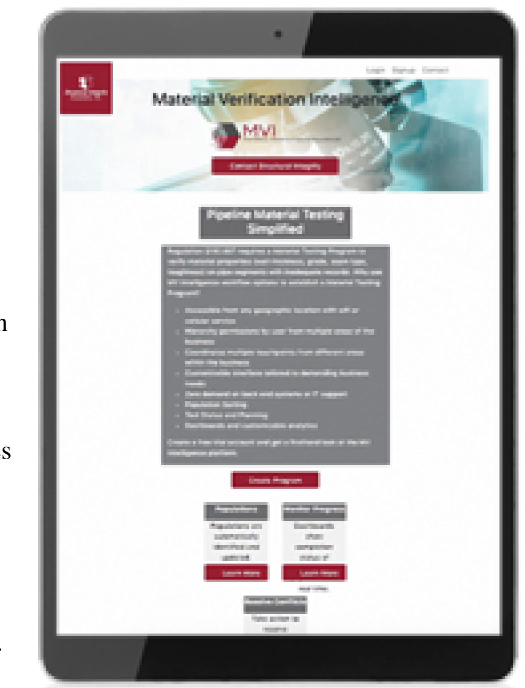
To help address these challenges, Structural Integrity has developed a new tool, Material Verification Intelligence (MVI), as a web-based application that can help identify and organize essential data and ensure implementation is aligned with supporting MV procedures. MVI is intended to help operators with two main strategic goals: efficiency and speed. MVI automates the comparison of MV results to specified or required values, notifies individuals on availability of information (including inconsistencies identified) and provides an intuitive dashboard to view key performance indicators and results.

By automating many of the repetitive calculations, operators can focus resources where they are most needed. MVI also ensures consistency and quality of the results with little labor



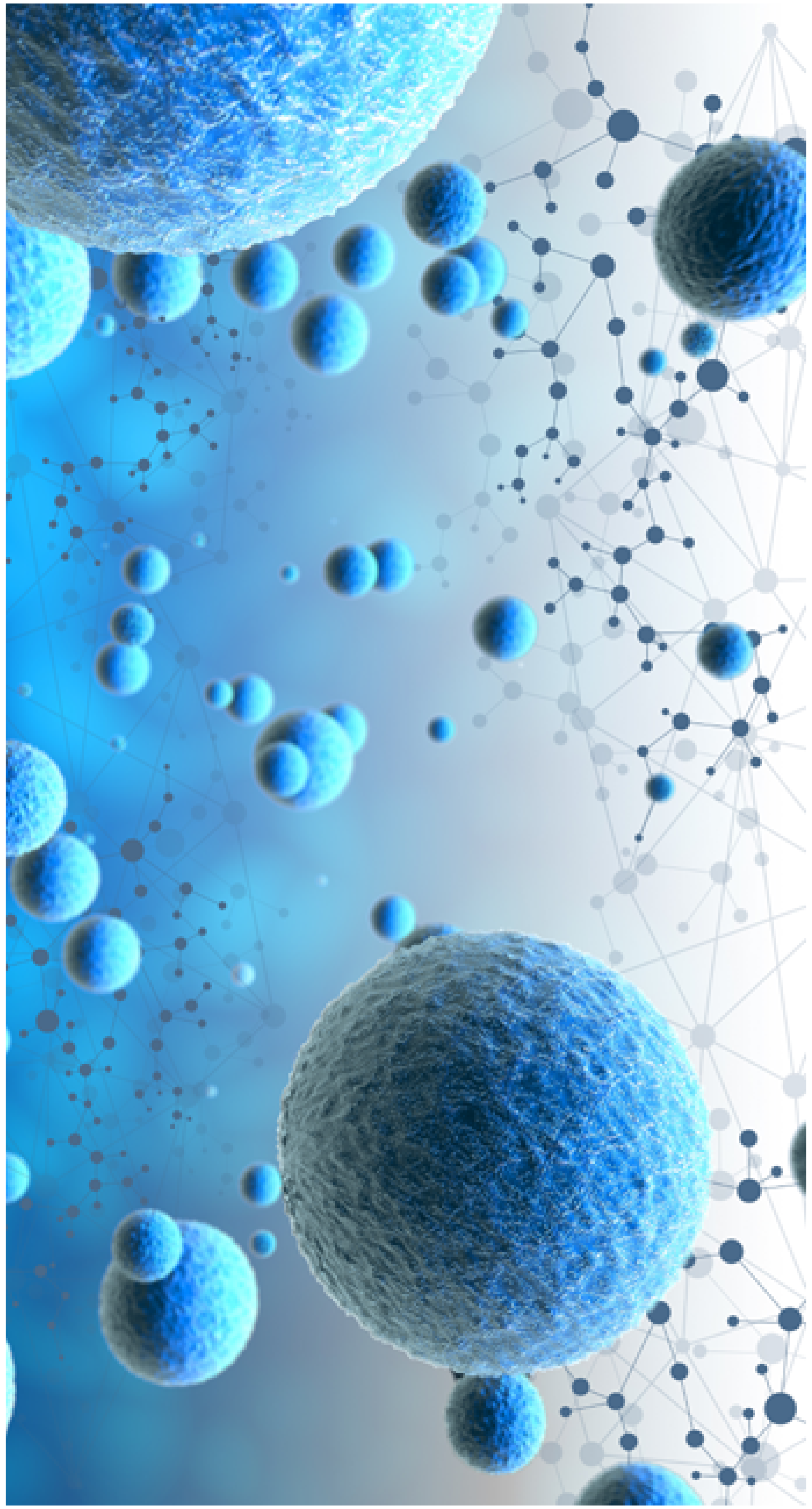
input needed. Continuous monitoring of the program status allows an operator to always act based on the most up-to-date information – whether the use of that information is selecting integrity digs, selecting material testing methods, fitness for service, MAOP, or other purposes.

The material testing program is not a one-time, linear process but rather a continuous, cyclical one. Populations are continually updated as new data



becomes available, and segments can move between populations as identified. Thus, a one-time population definition is not enough – operators will need to re-evaluate populations continuously. When conflicts arise (as when material testing data does not confirm record data), an operator using MVI can be notified immediately and respond accordingly.

To get started with MVI, visit si-megarule.com/mvi. If you wish, an SI expert can assist you with developing the required MV procedures, support program setup and management.



Biofilms? MIC? What Are They?

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Has the heat conversion efficiency of your heat exchangers degraded? Is the flow of your cooling water system being impeded? Are you repairing or replacing equipment due to localized corrosion causing through-wall failure? Inefficiencies and equipment failures are big problems in any industrial process, but the cause of the problem may be smaller than you think. You might have a biofilm problem. Bacteria floating in a cooling or process water can become colonies on wetted surfaces and can form robust biofilms over remarkably short times. Biofilms are collections of living and dead cells that are enclosed in an extracellular polymeric substance matrix secreted by living organisms. The unchecked growth of biofilms can significantly decrease thermal efficiency on surfaces as the biofilm acts as an insulating layer. Highly localized chemical effects can also be created that lead to microbiologically influenced corrosion (MIC).

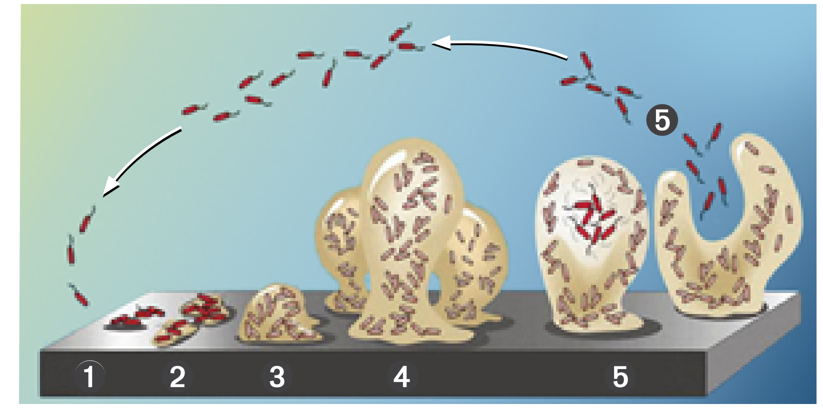

FIGURE 1. Stages of Biofilm Development

But how do biofilms even develop? When the minimal conditions for bacterial growth are met, (temperature, nutrients, oxygen content) a biofilm begins development as bacteria near a surface consume nutrients and multiply. The bacteria become **sessile**, affixed to a surface, by secreting exopolymeric saccharides (EPS) that allow the cells to adhere to the surface and other cells. Growth continues and other bacteria species join the colony as all these cells use **quorum sensing** to perceive and respond to microbial population density. Aerobic (with oxygen) and anaerobic (without oxygen) regions form within the biofilm, supporting a diverse and synergistic community of microbes. The biofilm grows, building mass and thickness to a point of reaching equilibrium where, as more growth occurs, a natural erosion of viable bacteria from the outer surface of the biofilm also occurs, releasing living cells back to the bulk fluid that can seed growth on other surfaces of the system.

Well so what? Now I have a biofilm. Why does that impact my performance? Bacteria and biofilms are mostly water. Therefore, the thermal conductivity of biofilm is comparable with that of water, however, biofilms are fixed to the surface and will act as stagnant insulating layers hindering the heat transfer across surfaces. As the biofilm grows, it also traps ions and creates localized chemical and physical gradients at the metal surface allowing corrosion mechanisms for microbiologically influenced corrosion (MIC) to take place.

OK, the biofilm has formed, but how can a biofilm lead to corrosion? An electrochemical cell like the one shown in Figure 2 can be formed by the chemical and physical gradients existing in biofilms. A potential difference is created by cathodic and anodic regions driving the exchange of electrons and the release of metal ions. Over time, the release of the metal ions can cause tubercles and/or pits to develop on the metal surface as the metal dissolves beneath the affected region.

The presence of a biofilm is necessary for MIC to initiate, but not necessarily required for MIC to propagate. There are conditions where localized corrosion may be initiated by MIC but propagate completely abiotically [2]. One way to completely mitigate the risk of MIC occurring is to have a completely sterile system that is free from any living bacteria. However, doing so is immensely impractical in real world scenarios. The addition of chemical biocides and dispersants help to slow or eliminate the buildup of bacteria and biofilms on system surfaces. However, the overuse of these chemicals can increase the oxidizing power of the environment and aggravate an already existing corrosion condition that may have been initiated by MIC attack or not.

SI offers a solution to monitor the effectiveness of these chemical treatments. The BIoGEORGE™ BG4 Biofilm Growth Detector system provides biofilm activity data online and in real-time so facilities can better correlate biocide chemical use with biofilm growth decreases. Monitoring biofilm activity in this way helps avoid overdosing and underdosing biocide. For more information visit si-biofilmgrowth.com.

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[2] *Licina, George J. "Treatment Optimization Through Effectiveness Monitoring". NACE Corrosion 2013 Conference and Expo. Orlando, FL. 2013*

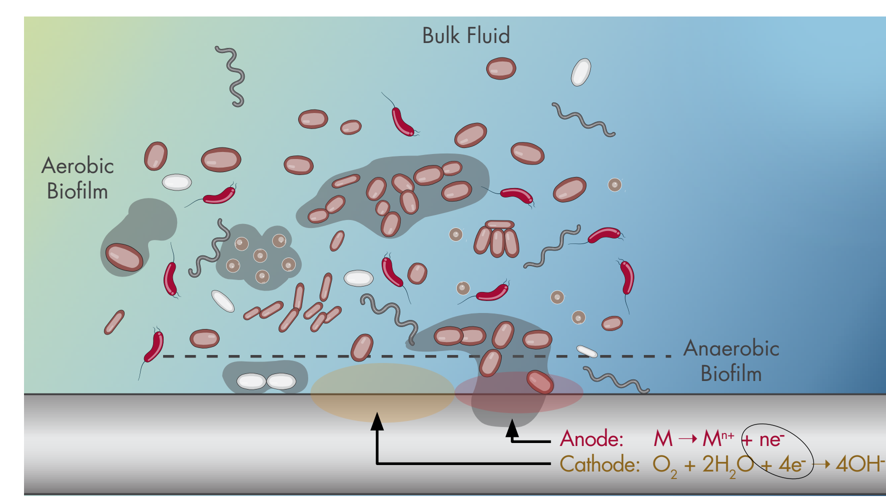

FIGURE 2. Electrochemical Cell Involving a Biofilm on a Metal Surface [1]

Surface Preparation – A Pivotal Step in the Inspection Process

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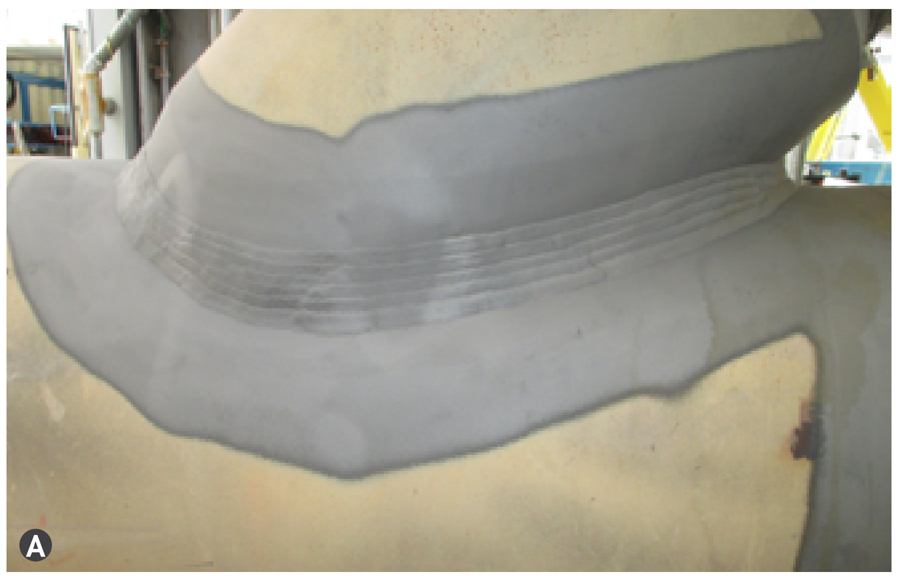

FIGURE 1. Examples of Proper Surface Prep Obtained by Grit Blasting at (A) a Saddle Weld, (B) a Tee with Multiple Welds, (C) Fillet Welds at Fittings, and (D) a Seam Welded Component

Introduction

Properly inspecting plant piping and components for service damage is an integral part of proper asset management. High energy systems constructed in accordance with ASME codes require appropriate inspections that are based on established industry practices, such as implementation of complimentary and non-destructive examination (NDE) methods that are best suited for detecting the types of damage expected within the system. In any instance where NDE is used to target service damage, it is desirable to perform high quality inspections while at the same time optimizing inspection efficiency in light of the need to return the unit to service. This concept is universally applicable to high energy piping, tubing, headers, valves, turbines, and various other power and industrial systems and components.

Optimized planning and execution of inspections includes one seemingly minor activity that can actually have a very significant impact on the success of NDE inspections – that is surface preparation ("surface prep"). Further, the quality of each NDE examination, which is paramount to safety, is very dependent on proper surface prep. Not only can poor surface prep lead to delays in the outage schedule, it can mask evidence of flaws or service damage, leading to missed indications and increased risk. Therefore, it is critical for workers and examiners to understand both the details and importance of proper surface prep.

Inspection Methodologies

In high energy and critical industrial piping systems, locations that require inspection are normally associated with circumferential butt welds (girth welds), longitudinal seam welds, saddle welds, and attachment (fillet) welds. Commonly used NDE methods for these locations are listed in Table 1 in accordance with their application to either the entire weld region or localized areas at or near welds. For purposes of this article, discussion of surface preparation is primarily focused on broad areas associated with the entire weld region.

Typical Baseline Surface Preparation Requirements

Whether a specific inspection method is targeting surface-connected, near-surface, or volumetric damage, proper surface preparation is critical for a successful inspection. As the areas that require surface prep are associated with welds, these areas essentially extend outward from the weld of interest, as described in Table 2. Also note that the required dimensions of surface prep areas are associated with the weld width and the component thickness. This is because angle-beam ultrasonic testing methods require specific angles that can only be maintained by shifting the probe farther from the weld as component thickness increases. This means that thicker components require wider surface prep regions along the welds.

NDE Methodology	Description
Visual Inspection (VT)	Surface (VT/MT/PT) and Volumetric (LPA-UT/TOFD) Inspections Involving the Entire Weld Region
Magnetic Particle Testing (MT)	
Liquid Dye Penetrant Testing (PT)	
Linear Phased Array Ultrasonic Testing (LPA-UT)	
Time-of-Flight Diffraction Ultrasonic Testing (TOFD)	
Annular Phased Array Ultrasonic Testing (APA-UT)	Surface (Reps, PMI, HT) and Volumetric (APA-UT/UTT) Inspections Performed at Specific Locations
Metallographic Replications (Reps)	
Positive Material Identification (PMI)	
Hardness Testing (HT)	
Ultrasonic Thickness Testing (UTT)	

TABLE 1. Commonly Applied Non-Destructive Examination (NDE) Methods[1]

[1]Although some of the listed NDE methods may be used for new construction ("code") examinations, this article is specific to "in-service" examinations; for more information on differences between code and in-service examinations, see "Volumetric Ultrasonic Examinations: ASME Code Compliant vs. In-Service Evaluations", News & Views Issue 38, Spring 2015.

Weld Type	Surface Prep Area =
Circumferential Welds	Weld + (6 x Wall Thickness), Centered on Weld
Saddle Welds	2" on Pipe Side + Weld + (3 x Wall Thickness)
Large Pipe-to-Fitting Welds	2" on Fitting Side + Weld + (3 x Wall Thickness)
Attachment (Fillet) Welds	Weld + 1" on Each Side of Weld
Tube Socket Welds	1" on Header + Weld + 4" on Tube Surface
Longitudinal Seam Welds	Weld + (4 x Wall Thickness) Each Side of Weld

TABLE 2. Typical Minimum Requirements for Surface Prep Dimensions1

[1]In All Locations, 12" Clearance from Insulation to Surface Prep Area is Typically Required

The preferred method for surface preparation of coated or oxidized components is abrasive grit blasting. Coatings or oxide layers must be removed entirely within the surface prep area (Figure 1). For inspection methods involving surface-connected flaws or damage, coatings or oxide can cover or fill the indications, preventing detection during the inspection. Blasting is more desirable than other means of surface prep due to the consistent surface finish that it produces and for its ability to clean bead-to-bead interfaces and weld toes. Ultimately, the prepared surface should be a white metal finish in accordance with SSPC-SP-5, SA 3, and NACE 1 standards (essentially an exposed, clean metal surface with no significant surface damage, or residual roughness, from the surface prep process).

Grinding is an acceptable alternative, and may be the preferred method in locations where blasting media could cause issues within the plant (such as welds near turbines or where valves have been disassembled for service). Grinding is less efficient than grit blasting, but requires less effort in terms of containment, equipment setup, and cleanup. In

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FIGURE 2. Examples of Good Surface Prep Obtained by Hand Grinding

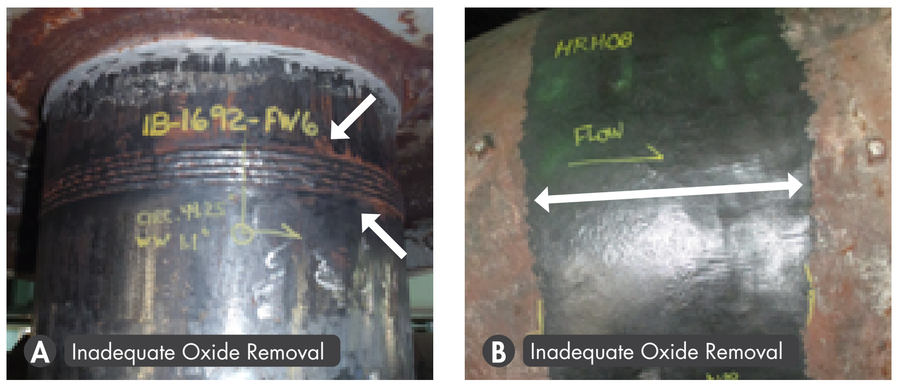


FIGURE 3. Examples of Improper Surface Prep (A) by Light Hand Grinding and (B) Wire Brushing

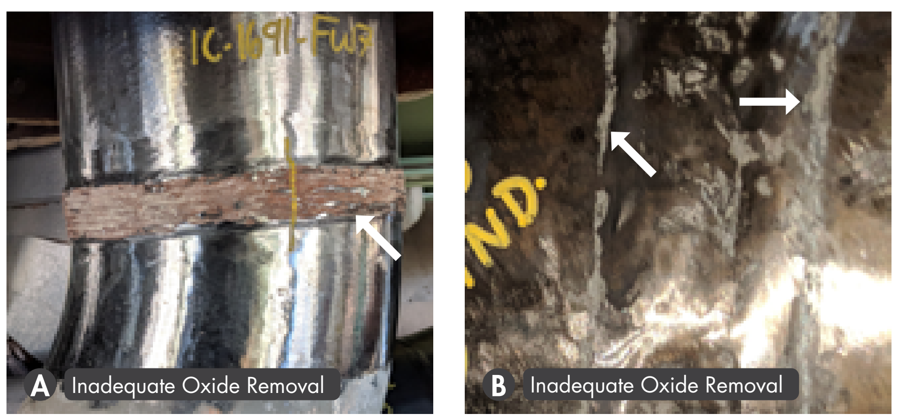


FIGURE 4. Examples of Inadequate Surface Prep at (A) Multiple Weld Passes and (B) Weld Toes

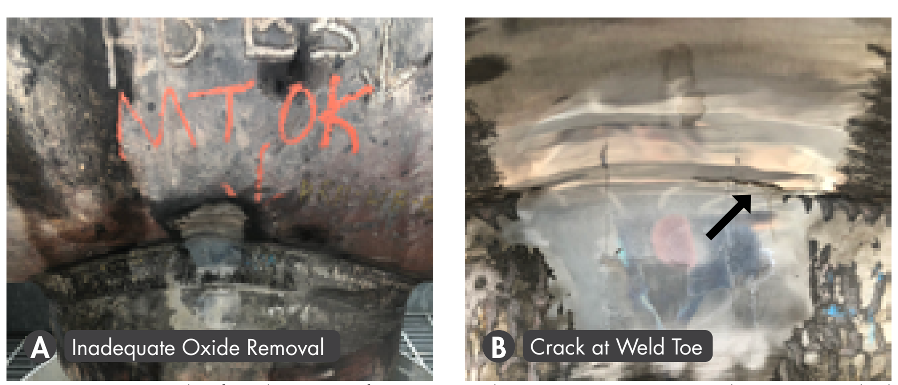


FIGURE 5. Example of Inadequate Surface Prep Leading to an "MT OK" (A) Finding on a Cracked Saddle Weld; the image in (B) is a Close View of the Crack Location (Note that the MT Inspection was Not Performed by Structural Integrity)

most instances, it is best to remove coatings or oxide layers using grinding stones as a first pass, and to follow-up with a second pass using an abrasive wheel with a grit size ranging from 40 to 120 grit (Figure 2). However, grinding preparation is impractical for many branch connection and tube-to-header welds.

In comparison to grit blasting and multi-step grinding, other methods of surface preparation are typically inadequate for NDE inspections. Superficial grinding or prepping with wire wheel brush attachments, for example, removes loose material from the component surface, but does not adequately remove tightly adhered coatings or oxide layers (Figure 3). Blasting using non-conventional media, such as dry ice or walnut shell particles, may remove some coatings and oxide, but is often slower, and with tenacious oxides does not perform as well as harder abrasives. While laser blasting has some uses within the power generation industry, the most commonly available services use a green laser (~500 nm wavelength), which has not been adequately efficient in removing all surface oxides from chromium-alloyed steel (the surface finish is comparable to that from wire wheel brushing).

Since most service damage in welds occurs at the weld toes, between weld passes, or within the heat-affected zones (just below the weld toes), removing all non-metallic material along weld toes is imperative. This detail is perhaps the most common requirement that leads to delays, as incomplete surface prep leaves a thin line of oxide in and along the weld toes (in the exact location where service-induced damage is most likely to occur) (Figure 4). Welds prepared in this manner cannot be properly inspected with VT, MT, or PT methods (Figure 5).

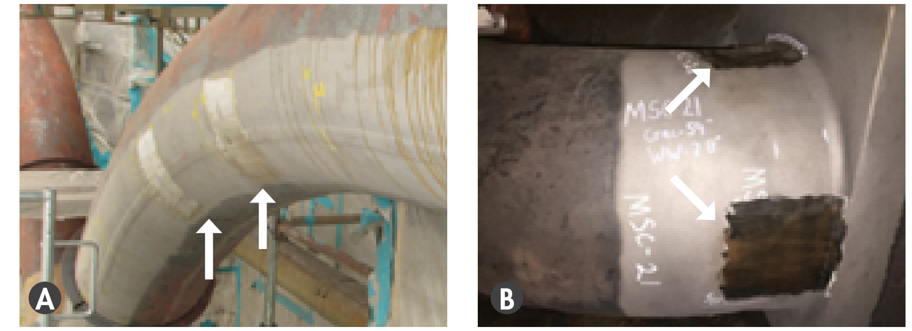
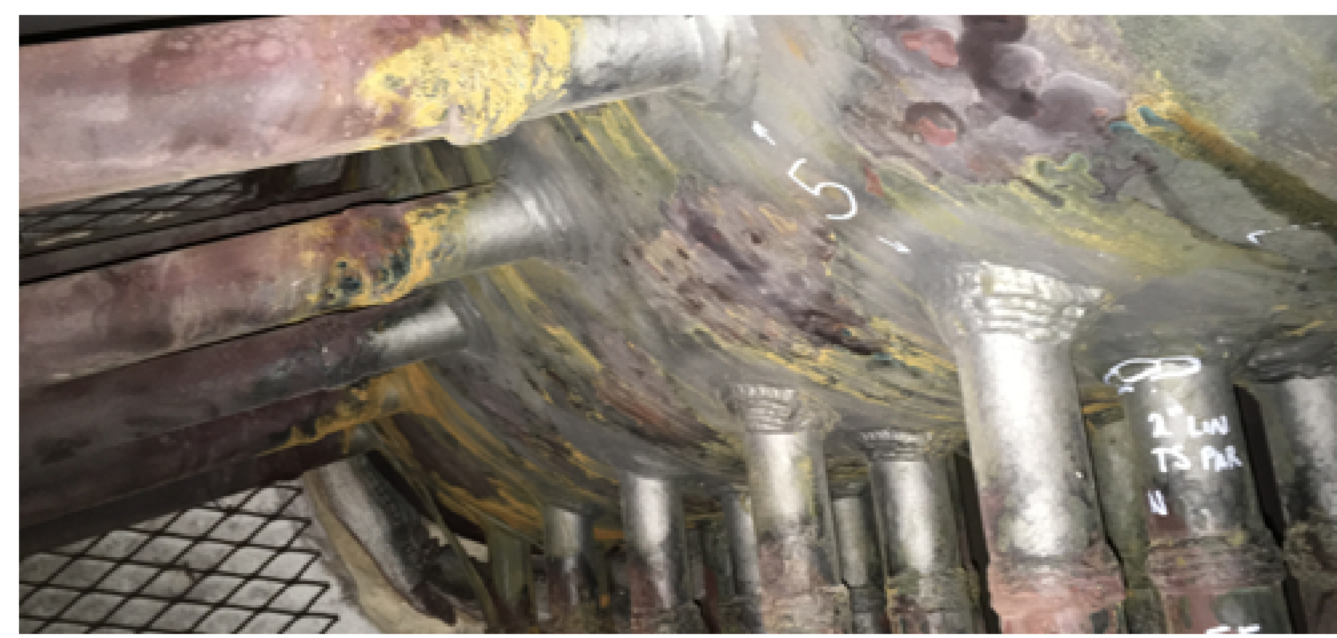


FIGURE 6. Examples of Hand-Ground APA-UT Spots (Arrows) at Grit Blasted Surfaces at (A) a Longitudinal Seam Weld and (B) a Circumferential Joint Weld at a Fitting

FIGURE 7. ABOVE AND BELOW Examples of Good Surface Prep Obtained by Grit Blasting at Header Stub Tube Welds (Note in the UPPER Image that a Header Girth Weld was Not Prepped for Inspection)



Special Requirements

In addition to the broader surface prep areas described above, attachment welds often require surface prep for MT or PT inspections for surface-connected flaws or damage. Locations where small bore pipe, thermowells, or support lugs are attached to the piping are often not examined using ultrasonic methods and therefore only require removal of coatings and oxide layers within one to two inches of the weld (e.g., Figure 1c.).

Ultrasonic testing using focused annular phased array requires four to six-inch long areas that must be ground flush with the outer surface of the component (Figure 6). The final surface finish should be white metal (as is the case with the broader area around the weld), but the OD surface must be flat in the area of the examination. This is typically achieved by grinding, even if the broader area is initially prepped using grit blasting.

For tube inspections carried out using VT and MT, grit blasting is efficient and can easily prepare surfaces within six inches of the weld (Figure 7). For examinations involving dissimilar

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metal welds (DMWs) in boiler tubing, surface preparation is required at accessible surfaces on the low alloy, or ferritic side of the weld (where the ultrasonic transducer will be placed onto the tube or pipe). The prepared area, which should extend six inches along the tube surface from the weld toe, must be clean, white metal. It is important that surface prep is applied to the ferritic side of the weld rather than the austenitic (stainless) side of the weld, and wire brushing is not acceptable as remnant surface oxide can lead to a low quality signal and associated uncertainty in the analysis (Figure 8). In most instances, the surface prep area does not need to include the weld or austenitic base metal. For any tube examinations where internal oxide thickness will be measured using UTT, heating of components should be avoided as it can cause exfoliation of the internal oxides that are being assessed.

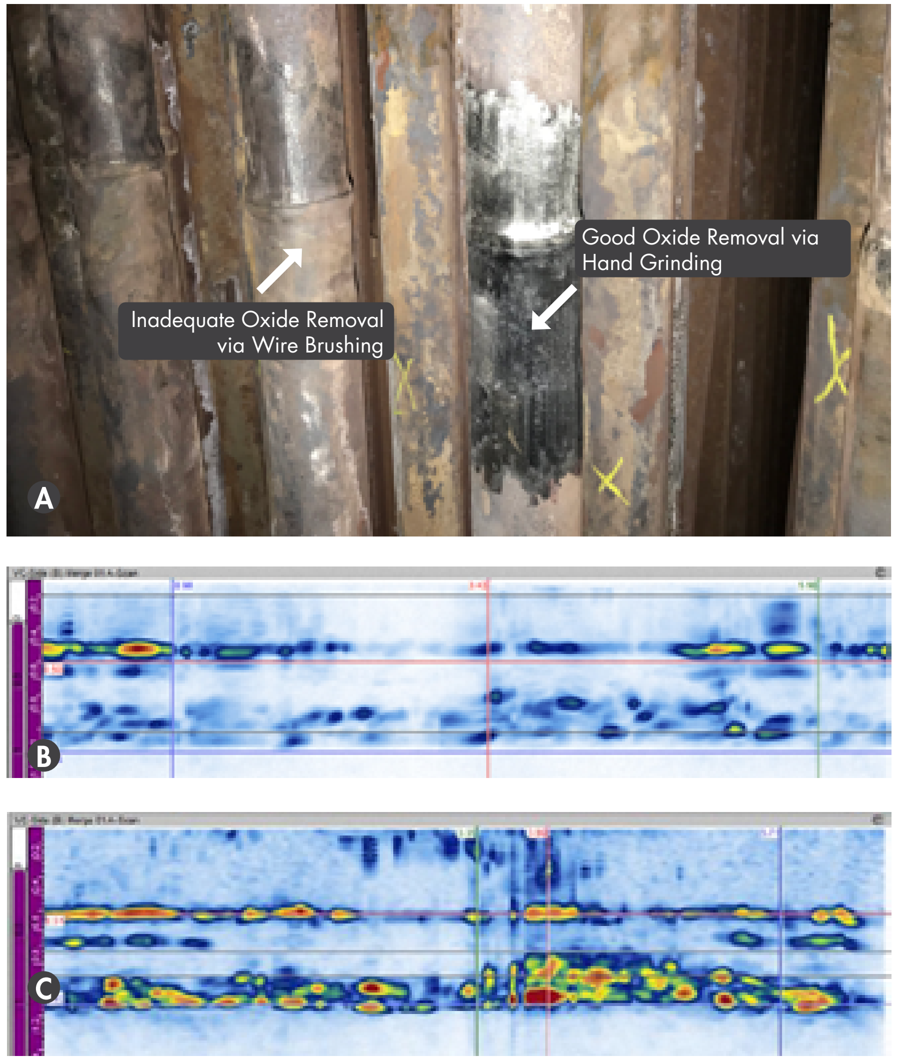

FIGURE 8. (A) Examples of Improper and Good Surface Prep at DMW Welds and (B) the Associated Phased Array Scans Obtained after Wire Brushing and (C) Proper Hand Grinding (Note that the Surface Prep Shown includes Weld Metal and Austenitic (Stainless) Tubing Above the Welds, whereas Only the Ferritic Tubing Requires Prep)

Closing Comments

In summary, surfaces should be prepared to a white metal finish throughout the specified areas with no remnant debris or oxide along the weld toes. This level of detail is critical to the quality of each NDE process, which, in turn, is the foundation for safe operation of high energy piping systems and long-term asset management. Clear and detailed communication to surface prep personnel, in combination with appropriate surface prep methodology, is the best way to ensure that the preparation process is effective in producing the correct conditions for NDE inspections. A focus on proper and timely surface prep is also an easy way to avoid costly (and unnecessary) outage delays.

For additional information on Surface Preparation, contact Ben Ruchte at BRuchte@structint.com

TRU Compliance Expands into Physical Security

Testing and Certification Services

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This service coincides with the upcoming publication of the Structural Design for Physical Security Manual of Practice by the American Society of Civil Engineers, with TRU Compliance Director Andy Coughlin as coauthor.

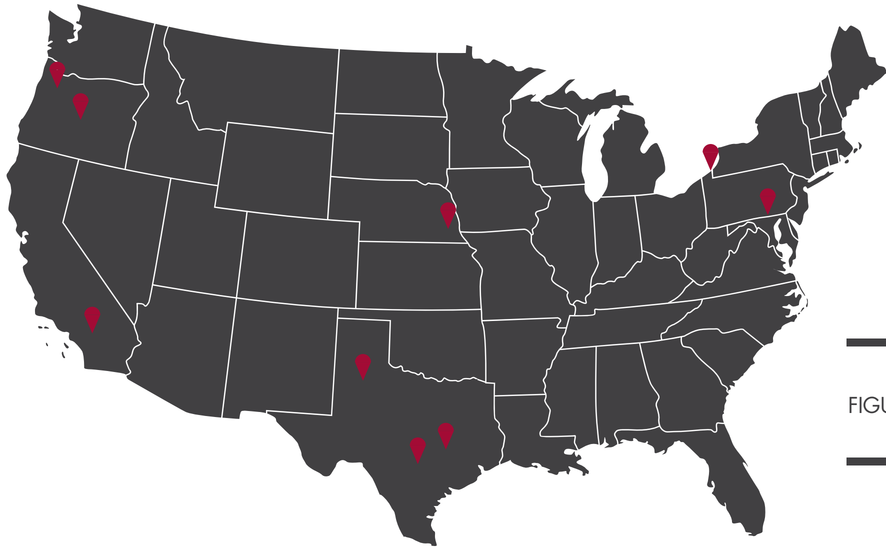
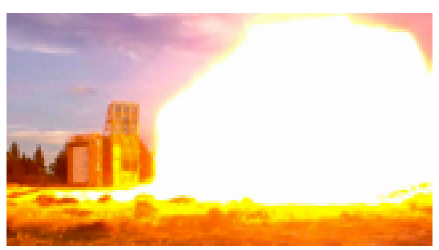


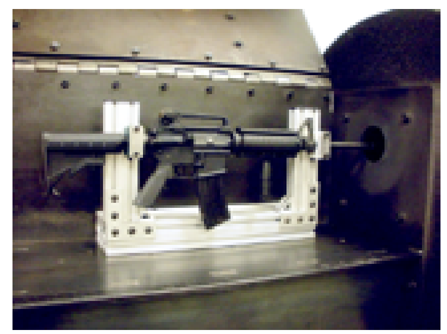
FIGURE 1. Map of Partner Security Test Facilities

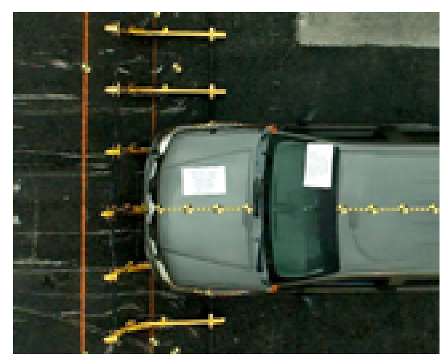
TRU Compliance's testing and certification services is expanding into the dynamic field of Physical Security. This service coincides with the upcoming publication of the Structural Design for Physical Security Manual of Practice by the American Society of Civil Engineers, with TRU Compliance Director Andy Coughlin as coauthor. TRU's practice in this arena includes Blast, Ballistics, Vehicle Impact and Forced Entry services. This is possible through TRU's partnerships with leading test laboratories such as Oregon Ballistics Labs, Stone-OBL, BakerRisk, Calspan, and others. Physical Security certification by TRU is accredited by the International Accreditation Service and compliments TRU's accredited Seismic and Wind Certifications.

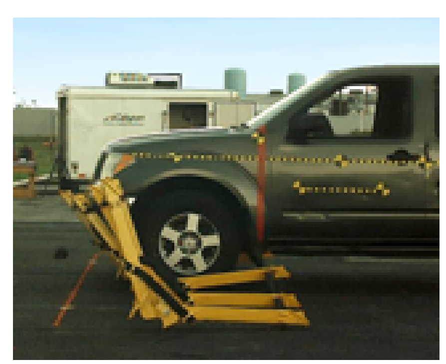


Blast testing is generally performed using open-air explosives, shock tubes or quasi-static pressure loading. The products tested range from doors, windows and building materials to parts/ assemblies for industrial application. Analysis can also be a viable option due to the relatively high cost of blast testing. A blast certification lists all the information needed for an engineer to specify a particular product in a blast resistant application, including the blast pressure and durations, level of damage, and installation guidelines.

Ballistics certification conforms to standards such as UL 752 or NIJ 0101.06 and typically consists of firing a set projectile at a specific velocity range and impacting a structure. The firearm caliber, distance, and pattern vary based on the desired rating.

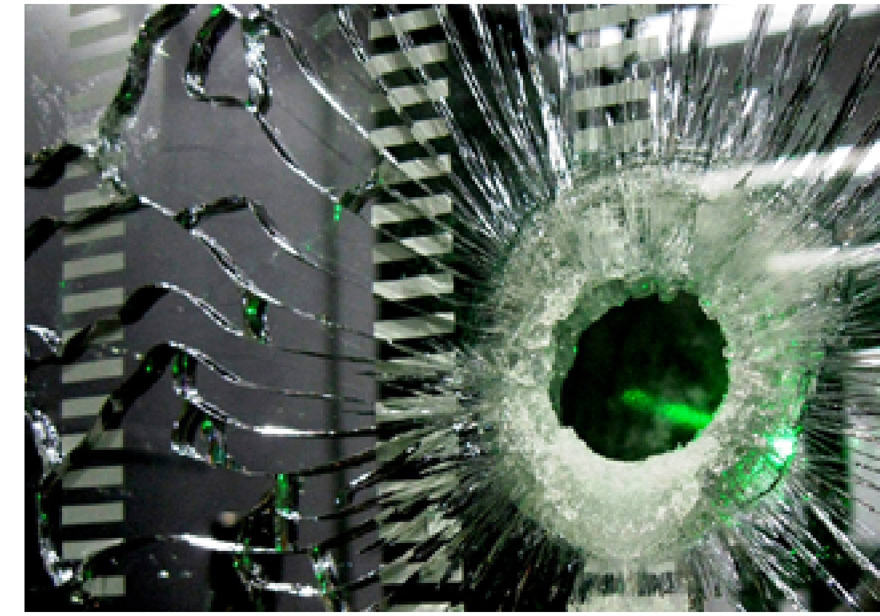




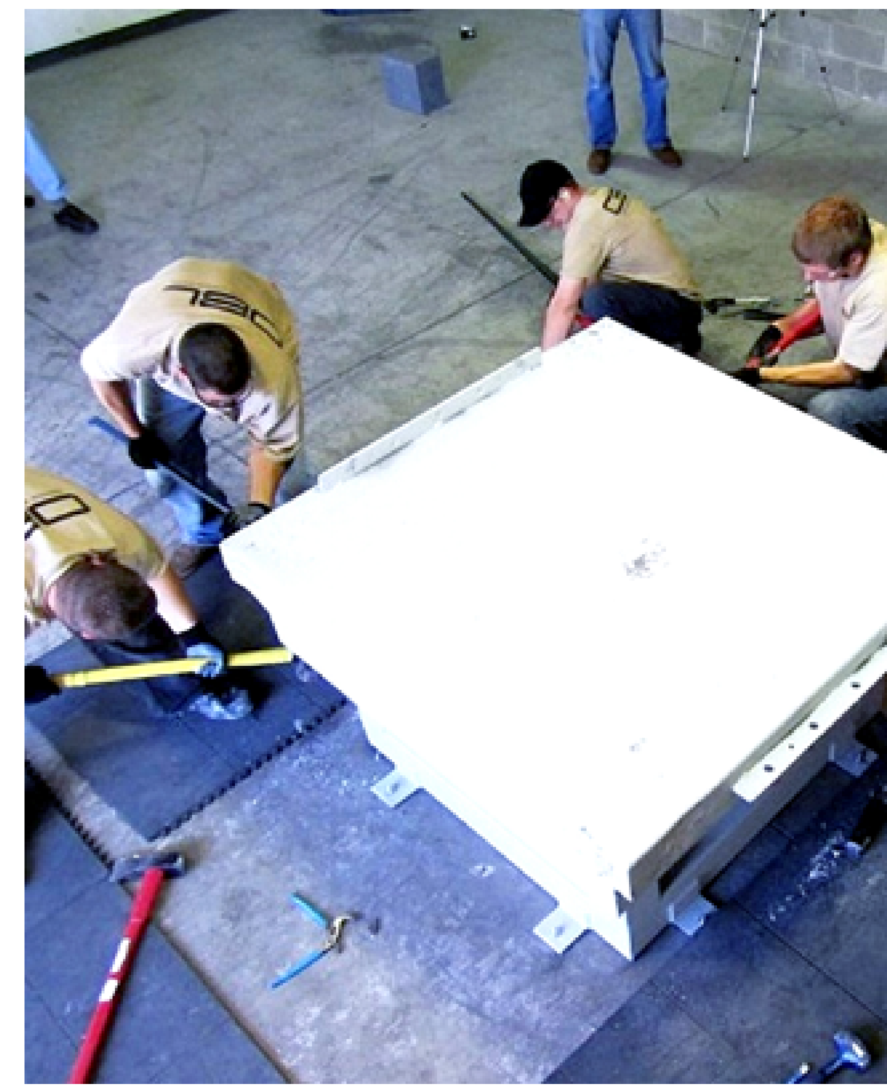


Vehicle Impact testing , sometimes called anti-ram, falls into two categories: intentional impacts and unintentional impacts (highway safely). There is a growing need for intentional impact tests due to the increasing frequency of those events. The vehicle type and impact speed are specified, and the rating is based on the distance the vehicle is able to penetrate past the barrier.

Forced Entry testing consists of a team of mock attackers attempting to gain access through the door, wall, window or other barrier being tested. They have access to prescribed tools and the test specimen is rated based on the time delay. Full size mockups are usually required due to a lack of forced entry analysis tools.



TRU has previously performed physical security testing and certification services for Finnish Shelter company Temet Oy and will be testing two products for Stone Protective Solutions products in the coming months (Protect-O-Flex and Extreme Wood-Lam). The importance of Physical Security is rapidly growing. Countless events have occurred related to where physical security systems could have prevented injuries or fatalities. These events can be very costly, not only in terms of property damage/ destruction, but also in lives lost and people injured. The need for tested and certified Physical Security products is increasing as manufactures develop new methods to prevent and minimize these events. TRU Compliance, an IAS accredited certification body, is prepared to fill this need.



How To Make Knowing A Good Thing: Thinning Handbooks

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SI has developed a process to mitigate the negative outcomes of piping examination. One part of that process is Thinning Handbooks, which have resulted in direct savings in excess of $10 Million for one nuclear plant.

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Examination of Safety Related Service Water piping is driven by a number of factors, all of which tend to converge on the objective of finding localized thinning prior to the thinning becoming a problem. In other words, examinations are performed to eliminate the risk of a leak and ensure that the wall thickness remains greater than t_{min} (the minimum required uniform wall thickness). However, the rules, regulations, and economic realities mean that only bad things happen from an exam regardless of what is found.

Examinations that find thinning below t_{min} result in emergent repair or replacement activities. If a repair is deferred, there are additional burdens taken on by the plant that may include submittal of a Relief Request to the NRC. Emergent activities are significantly more costly, contain their own inherent risks, and erode regulatory margin.

Examinations that find little or no evidence of thinning have used resources that could have been better applied elsewhere. This may impact the ability to obtain funding for additional examinations elsewhere in the system.

Even a "successful" examination that finds thinning before it becomes a problem is likely to generate the same question from the NRC, INPO, management, and others: Why didn't you find this sooner? It is reminiscent of the movie "Office Space" in which the main character laments that fear of losing his job "will only make someone work just hard enough to not get fired."

Examinations help you understand the condition of your Service Water system. Knowing the state of the Service Water system should not be a bad thing. SI has developed a process to mitigate the negative outcomes of examinations. Put simply, SI's process helps to Make Knowing a Good Thing.

Typical examination campaigns start with selection of locations, then develop acceptance criteria, and end with the examination. SI's process is shown in Figure 1 and is a significant departure from this norm. A feedback loop is utilized to inform the next round of examinations.

SI has helped a number of utilities implement portions of this process. This article focuses on the development of finite element model (FEM) based Thinning Handbooks. The conservatively calculated t_{min} value is often used as acceptance criteria for examinations. This approach does not account for the degradation mechanism most common in Service Water piping. The t_{min} value assumes uniformly thinned piping, which would result from general uniform corrosion. However, localized corrosion that produces uneven wall thickness is the dominant degradation mechanism. SI's acceptance criteria relies on FEM Thinning Handbooks that account for the non-uniform wall thickness observed in actual Service Water piping.

Thinning Handbooks are created before the examinations occur and are used to show that the non-uniform wall thickness meets the system Code of Construction stress limits. They are applicable to both ASME Section III and B31.1 designed systems. Typical handbook results show that thinning well below t_{min} meets the Code stress limits and is acceptable for continued operation.

One nuclear plant has implemented SI's FEM Thinning Handbooks

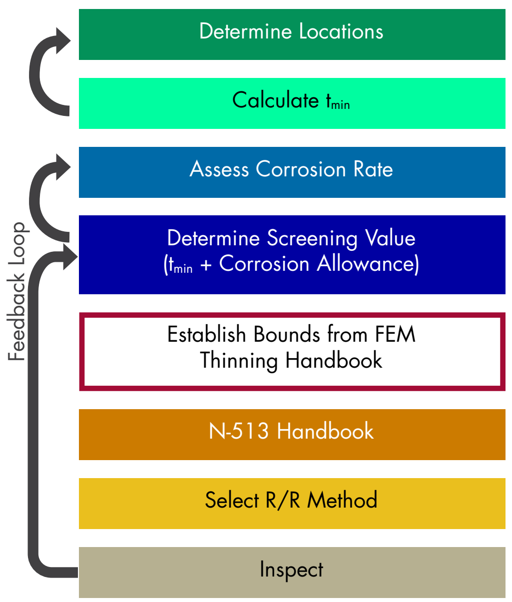

FIGURE 1. How to Make Knowing a Good Thing - The Overall Process

extensively. They applied Thinning Handbooks to historic NDE data to determine that many of the planned repeat examinations provided no value. This allowed them to eliminate some repeat examinations while deferring others based on the additional margin obtained from the thinning handbook results. This resulted in significant savings, especially for buried piping examinations. The Thinning Handbooks also extended the end-of-life for one of the safety related system headers to beyond the date of the system retirement. This allowed the plant to cancel replacement of the header, which would have resulted in a costly (and unnecessary) replacement. To date, FEM Thinning Handbooks have resulted in direct savings in excess of $10 Million for this nuclear plant.

The plant also utilized FEM Thinning Handbooks to support their most recent round of examinations. During this campaign, thinning below t_{min} was discovered in a line that presents considerable challenges

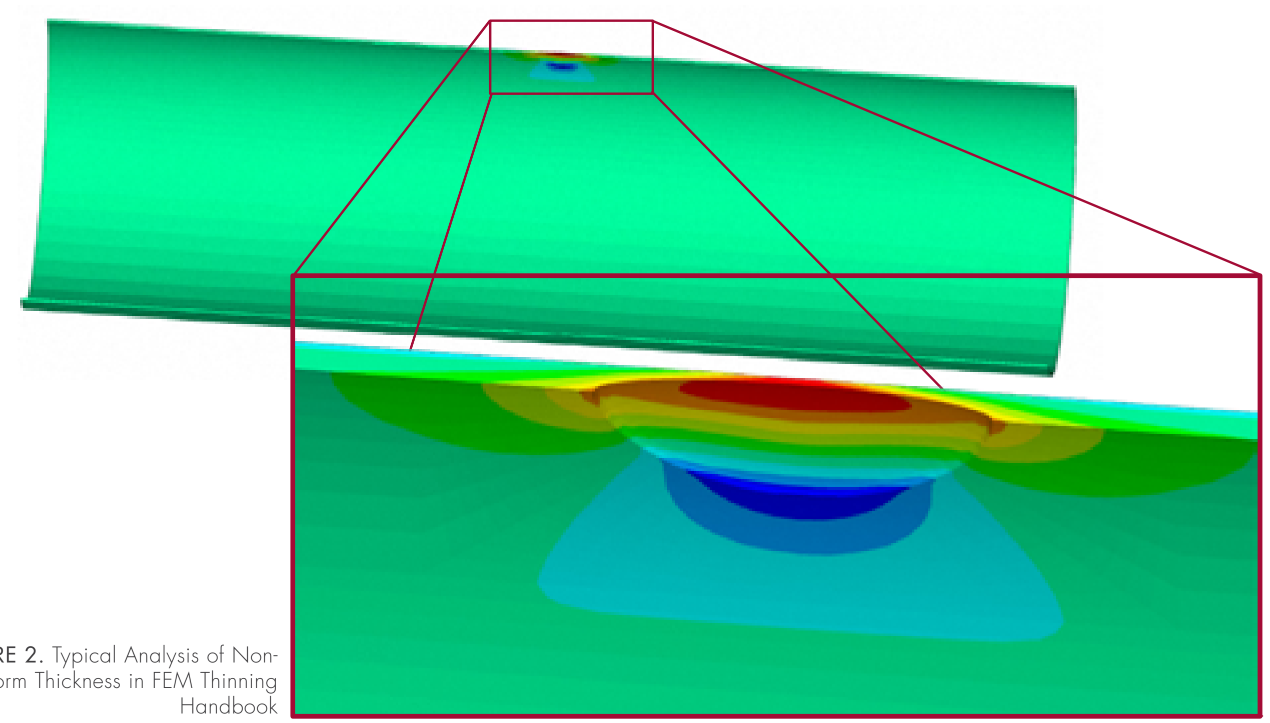

FIGURE 2. Typical Analysis of Non-Uniform Thickness in FEM Thinning Handbook

to repair. Rather than perform an emergent repair, the site utilized an FEM Thinning Handbook to show that the location meets the Code of Construction stress limits. In fact, this location is predicted to meet the stress limits for an additional two years. The plant is currently running with this thinned location while repair plans are being developed, which is exactly the point of the FEM Thinning Handbook. An examination identified local thinning before it became a leak. The FEM Thinning Handbook allowed the site to avoid an emergent repair, which would have significantly increased the cost and risk associated with this difficult location. Instead, the site now has time to prepare for this challenging iteration. The use of FEM Thinning Handbooks helped the site to Make Knowing a Good Thing.

To find out How to Make Knowing a Good Thing at your plant, contact Eric Houston (ehouston@structint.com) or Stephen Parker (sparker@structint.com).

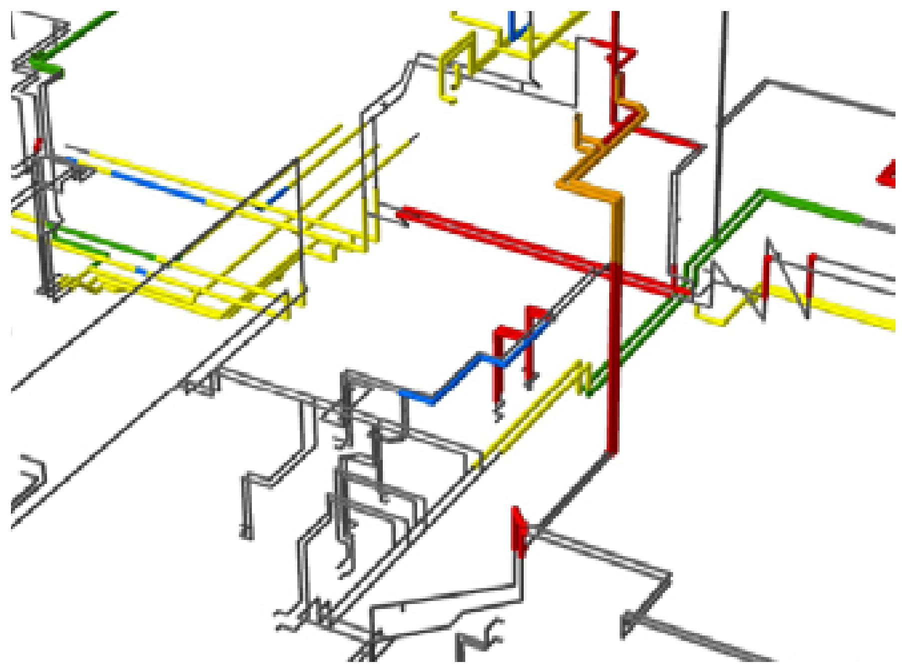

FIGURE 3. Nuclear Plant Service Water Piping Showing Inspection Results Classifications

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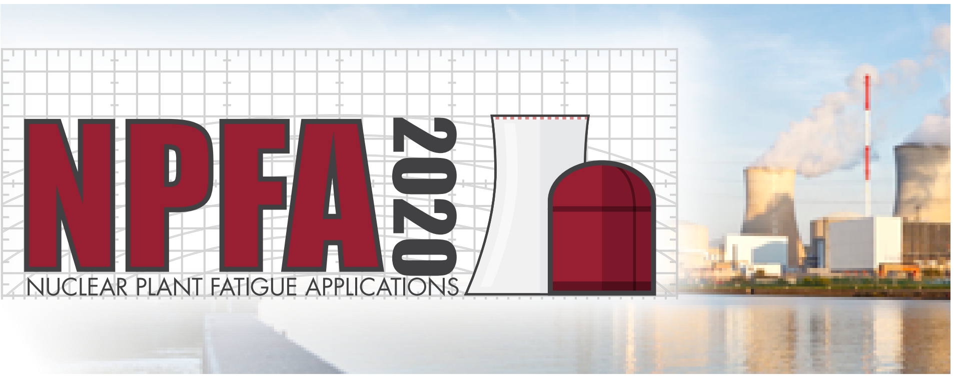

The next **Nuclear Plant Fatigue Applications Workshop (NPFA)** will be held in conjunction with the EPRI International Nuclear Reactor Materials Reliability Conference – **November 2020** in **New Orleans**, **Louisiana.**

We are currently looking for individuals with experience or research findings directly related to Nuclear Plant Fatigue Management. In order to make this year's NPFA workshop a success, we need your assistance. If you have a topic that you would like to present at the workshop, please submit an abstract for consideration. Presentations abstracts and a brief biography and overview of your credentials must be submitted by March 31, 2020.

Guidelines for Presentation Abstracts

- Must be written in English
- Should be no more than 500 words
- Must contain presenter's name, title, company/organization and a brief biography including, education and/or relevant experience
- To submit your abstract, please visit the web-page and fill out the form: Submit Presentation Abstract.
- The NPFA Workshop is a premiere forum for discussion of fatigue issues facing utility/plant staff. Registration will be open in 2020; in the meantime, please visit Structint.com/npfa2020 for further details.

If you have questions regarding the NPFA workshop? Visit our website, email us or call toll free 800-4SI-POWER (877-474-7693).

UPCOMING EVENTS

EPRI Fuel Reliability Program
February 17 – 22 | New Orleans, LA

NAES O&M
February 24 | Nashville, TN

EPRI BPIG
February 28 – 21 | Kissimmee, FL

PRCI Research Exchange
March 3 -4 | San Diego, CA

CEATI HydroPower
March 3 -4 | Palm Springs, CA

RIC Conference
March 10 – 12 | Bethesda, MD

ACI Conference
March 29 – April 2 | Chicago, IL