2018 | VOLUME 44

Structural Integrity Associates, Inc.®

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President's Corner

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Ten years ago, I wrote the article on the following page for our 25th anniversary. Today, I write this one for our 35th anniversary, and it is this year more than any other that convinces me – time really does fly. Ten years have seemingly passed in the proverbial blink of an eye or the passing of a single outage season, but of course that has not been the case. Many seasons have passed since that last anniversary article and there have been many changes in all our lives, including here at SI.

We have completed five acquisitions, adding competencies, clients, new markets and additional services. And most valued, we've added dedicated professional staff with a wide range of experience in various disciplines and diverse backgrounds across all our business units, not just through those acquisitions but also hiring. Our staff additions include engineering and nondestructive testing, of course, but in other specialized areas as well. We added professionals in risk, safety, marketing communications, finance, information systems, human resources, equipment control, scheduling and management. We have also continuously created and aggressively acquired innovative technology and capabilities. With the additional staff and technologies, we now solve a wider array of industry problems than I could have ever imaged just 10 years ago. I find myself stretched every day to understand, even at a fundamental level, the full breadth and depth of capabilities now within SI.

We've seen our staff grow, and with that growth, SI families being formed and new generations coming into SI, even sons and daughters joining SI to follow in their parent's footsteps. But where there are gains, we've also experienced losses. Some are retirements, and they leave with our best wishes for enjoyment in the years to come, while other losses are tragic and painful; at SI, we remember each one of them.

Many things have changed, but many things I wrote about in the article that follows remain at SI. Respect for the founders and our founding principles, commitment to our core values, and an appreciation for our clients, partners, and vendors are but a few of our perpetual keystones. We still get excited when we are challenged to solve the most difficult engineering problems regardless of the hours we must work or the distances we must travel.

Even as geographically distributed and diverse as our staff has become, we still celebrate together, whether it's an innovative technology we developed, a new office opening, a strategic acquisition, a key hire, or simply birthdays, babies, and service anniversaries. And after 35 years, we still share the pride of being an employee-owned company.

I might not be the one to write the 40th anniversary article; but I'll celebrate it wherever I am because SI has given me a career to be thankful for.

..N&V 2008 Article..

This is a very special year for Structural Integrity. We are celebrating our 25th anniversary; an impressive achievement in the world of small business, and particularly for an engineering firm that was literally launched from a dining room. Many things have changed in our company and in our lives since Structural Integrity was founded in April 1983, and so far we have survived them all.

When we started, our training sessions and meetings were most often small face-to-face groups and were carried out with overhead projectors that almost always blew a bulb. Today we have Live Meetings, Webinars, and Video-Conferencing; all are web-based and often attended by literally hundreds of participants. They are even digitally recorded and accessible via the internet so that our every mistake is replayed for everyone's enjoyment (even those that slept through it the first time) over and over again.

Multi-channel instrumentation, ranging from NDE inspection systems to vibration data acquisition systems, are now as small as your PDA, which, by the way, has replaced your telephone, rolodex, desk pad calendar, day planner, scribble pad, telephone book (including yellow pages), road atlas, encyclopedia, record collection, photo albums, calculator, camera, travel agent, steam tables, and travel alarm clock. Yet, somehow, my briefcase gets a little heavier every year.

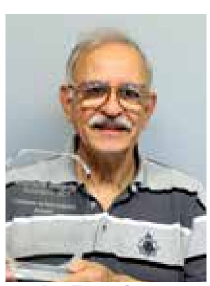
Analytical calculations were once simple elastic stress analyses performed on green engineering pads or, for really big problems, on main frame computers with punch cards. Today's automated mesh generators are now performing elastic-plastic stress analysis followed by probabilistic crack growth calculations on your PDA-- just kidding-- actually, on your 3 lb notebook computer from the comfort of economy seating on your chosen airline while you dine from a $5 snack box.

As we tried to find ways to mark this anniversary as a company, I was pleased to see Structural Integrity's employees, old and new, planning to share a day or evening together. The spirit behind these celebrations is not only one of success, but also of gratitude to the company founders, and the fact that 25 years later, Structural Integrity continues to find a way to keep alive the ideals that they set as our foundation.

Some companies may tire, become distracted , or not adequately cope with the challenges of required change over such a long period, but Structural Integrity has remained focused over its 25 years with no signs of compromise to the core values established by the company's founders:

- Creating and Maintaining Customer Trust is Paramount
- Our Employees Are Our Most Important Assets
- Innovation, Value Solutions, and Productivity Create Success
- Structural Integrity Will Be Known for the Unmatched Quality of Our Services and Deliverables
- Structural Integrity Will Be a Role Model in Corporate Citizenship

Earlier this year we internally recognized our remaining employee founders and I'm honored to recognize them here: Dr. Pete Riccardella and Dr. Tony Giannuzzi. They were presented plaques with the following inscription:



Dr. Tony Giannuzzi

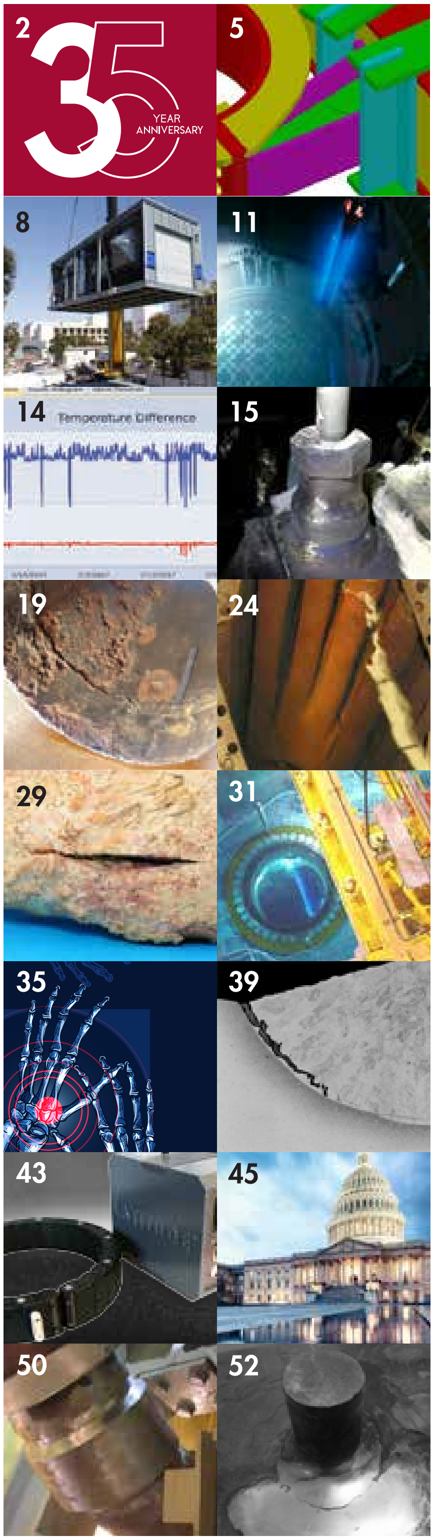
Dr. Pete Riccardella

> Men make history and not the other way around. In periods where there is no leadership, society stands still. Progress occurs when courageous, skillful leaders seize the opportunity to change things for the better.

Those that know Pete and Tony know they have bettered engineering for the benefit of the utility community and have always been respected leaders. It's incalculable how many lives these two have touched through these simple principles at Structural Integrity over the past 25 years.

I hope Structural Integrity continues to improve while adhering to it's core values over the next 25 years, and develops more leaders like our founders. In the mean time, I also wish my briefcase would get just a little bit lighter.

In this Issue



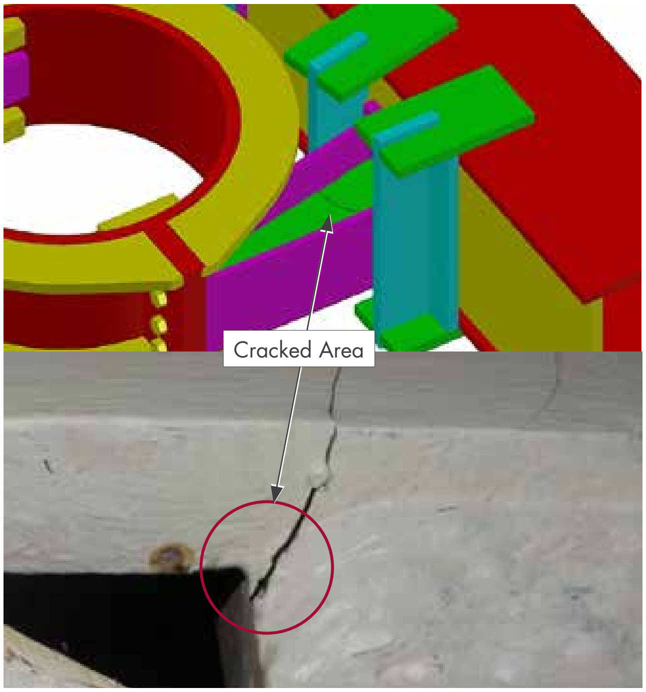
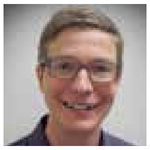


FIGURE 1. Load definition from sensors for Main Steam Support Hanger Fracture Mechanics Evaluation

Data Driven Solutions for the Most Difficult Problems



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In recent years, SI has observed an increasing trend in the use of specialty instrumentation to solve "impossible" problems or answer "indecipherable" questions. This shift was particularly apparent within commercial nuclear, where data-driven solutions have long been perceived as challenging due to short outage windows, personnel dose concerns, and a significant paperwork burden, among other factors. Widespread adoption of instrumentation-based solutions creates new paths to tackling difficult/persistent problems, and shifts the industry focus for critical assets from reactionary to more of a predictive approach. In 2017, SI assisted numerous clients with deployment of specialty instrumentation in this fashion, comprising two general scenarios: 1) new designs/modifications, and 2) repeat failures. Each application requires different sensors and varying analytical methods, but the approach used to leverage the resultant data to solve the problem is generically applicable throughout the energy sector. The text below details important considerations for both scenarios and highlights a successful application of the underlying process for management of thermal fatigue in reactor coolant system branch piping.

New Designs/Modifications

Whether developing a new reactor or modifying an existing system, most engineers are intimately familiar with the process of qualifying structures/components to meet ASME/regulatory criteria through analytical methods. However, SI has observed a tendency toward over-reliance on computer models where empirical testing/validation could be used as an alternate means of qualification. Instrumentation/data is leveraged where available (i.e. from benchmarking tests and/or Operating Experience) but is often a low priority compared to analytical work. SI has a different perspective, having observed that integration of testing/instrumentation into the design process provides advance insight on potential challenges. Early identification of unexpected conditions and/or concerns helps to avoid rework and regulatory scrutiny, and in this vein integration of design and instrumentation can have significant fiscal benefits.

SI has worked with numerous OEMs and AEs to provide confirmatory instrumentation and testing services in parallel with new designs and/or modifications. As such, we have a unique perspective on the nuances of achieving the appropriate balance between uncertainty/confidence, technical rigor, and cost of testing. For new designs, the number of unknowns can be significant, as complex geometries and innovative manufacturing techniques contribute nonlinearities to modelling efforts. Guidance and procedures for current-generation plants are based upon decades of operating experience; new designs are expected to achieve a similar level of confidence, the burden of which is borne through analytical models and prototypical tests. Full-

Continued on next page

scale testing is expensive, and thus typically limited in scope/quantity; however, such tests provide critical feedback on analytical assumptions such as boundary conditions, application of loads, and presence of complex phenomena (i.e. flow induced vibration, thermal binding, etc.).

Performance of in-situ testing in parallel with design/analysis efforts helps to validate modelling assumptions, reducing rework and helping optimize the work flow of analytical tasks. Such testing can also help to quantify specific loadings and/or eliminate the inclusion of complex phenomena, which can in turn be used to demonstrate additional margin and/or reduce iterations. SI has successfully leveraged our instrumentation and cause evaluation expertise to provide in-situ testing and evaluation of numerous components/systems under design and/or during construction. Our results have subsequently been used to validate model parameters (i.e. boundary conditions, loading amplitudes/cases, mode shapes, damping, etc.) and inform future testing activities (i.e. updated test matrices, reduced full-scale test scope, etc.). We also routinely support in-field final qualification of as-built modifications, providing confidence that the design functionality/acceptability will be maintained throughout a component's lifecycle.

Repeat Failures

When "unexpected" problems become "persistent" issues, obtaining the right data can mean the difference between recurrence and permanent mitigation. Through measured evaluation of the failure history and apparent cause evaluation(s), SI can suggest a targeted instrumentation approach to stop the failure cycle. Recent examples where SI employed this approach to successfully address problems for our Nuclear clients include:

- Cause determination and remaining life assessment for cracking observed in a main steam pipe support; (Figure 1)
- Modal characterization and subsequent piping redesign/tuning following small-bore socket weld failures (numerous examples);
- Failure analysis, phenomena identification, and redesign support following a main steam condenser failure;
- Source determination and evaluation of mitigation strategies for RHR check valve leakage;
- Root cause and design support in response to failure of an MSR bellows assembly;
- Response characterization for significant events during shipment of nuclear fuel rods on a tractor/trailer bed (Figure 2).

The trend toward data-informed solutions is not Nuclear specific; rather, multiple industries are observing fiscal benefit in employing this problem focused, technology driven approach. SI's recent projects range from evaluating the impact/effectiveness of impulse cleaning on heat recovery steam generator (HRSG) tubing arrays, to cause identification/mitigation for premature wicket gate bushing failures at hydroelectric stations. For the referenced cases, utility personal could not ascertain whether design, maintenance, or operational issues were the primary contributor degradation and/or poor performance; instrumentation quantified these relations and facilitated informed resolutions.

When faced with a recurring issue or repeat failure, a consistent problem-solving framework must be employed.

> Instrumentation can be used to address any identified gaps; SI has specific expertise developing targeted instrumentation plans to supplement existing knowledge.

The first step entails thorough documentation of the issue – what is known/unknown, what has changed, and what gaps exist in the available information. Instrumentation can be used to address any identified gaps; SI has specific expertise developing targeted instrumentation plans to supplement existing knowledge. These plans typically specify operational regimes of interest, sensor types and locations (including existing plant instrumentation), data collection approach/format, test repeatability/confidence, and any analysis/post-processing routines necessary to provide correct context during data interpretation. In some cases, the instrumentation/data does not directly

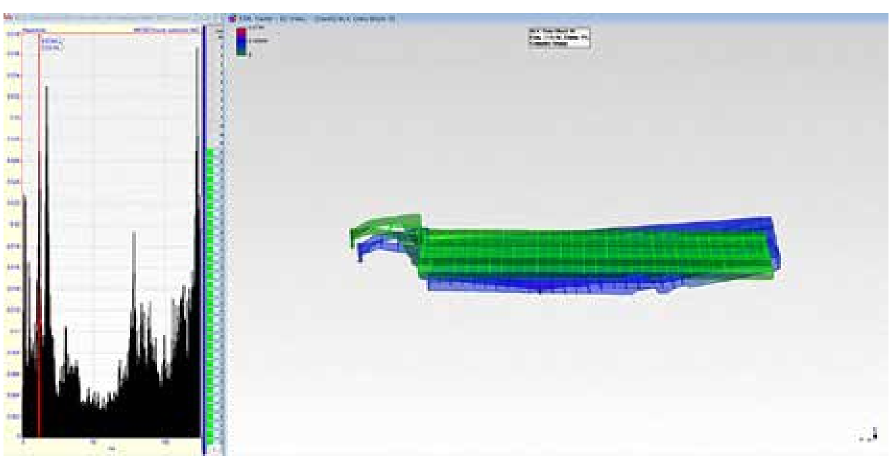

FIGURE 2. Modal Analysis of Tractor/Trailer (Identify source and Transmissibility into shipment contents)

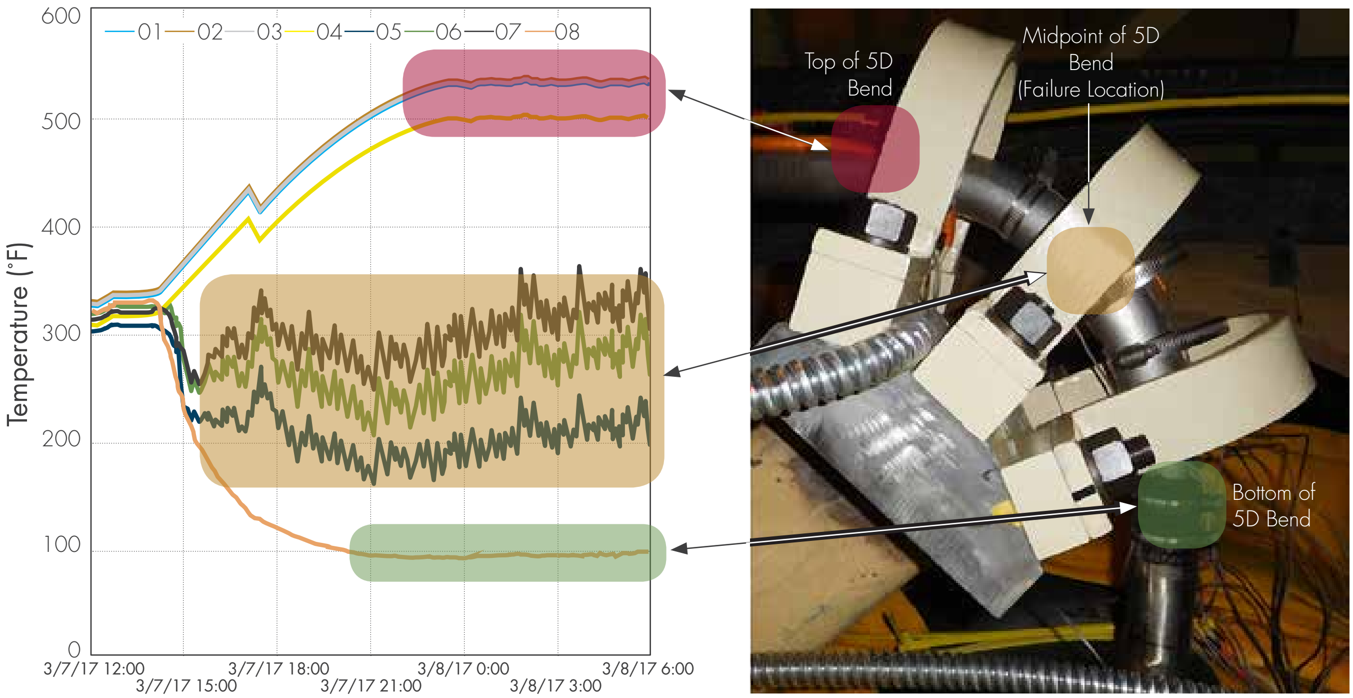

FIGURE 3. Safety Injection Line with Severe Thermal Cycling Sufficient to Induce and Grow a Crack

determine the root cause, but is instead used to evaluate/eliminate other potential causes. This approach (elimination of unsupported causes) was employed for several of the above-noted examples, helping utilities pivot their strategy and develop mitigation options to successfully address the remaining/supported causes.

Thermal Fatigue

EPRI's MRP-146 document provides guidelines for management of thermal fatigue in reactor coolant system branch lines via screening analysis and regimented inspections. Examples of affected lines include (but are not limited to): safety injection, normal/alternate charging, intermediate leg drain lines, and residual heat removal connections. Recent OE has exhibited a pronounced increase in flaws/indications, suggesting that the current approach does not support proactive management of this degradation mechanism. For example: in 2017, several utilities had to lengthen their outages to facilitate repair of flaws observed during MRP-146 examinations; in another case, a forced outage was required when a through-wall leak was identified at a thermal fatigue-susceptible location. SI assisted both these utilities with a near-turnkey implementation of an array of sensors (thermocouples, accelerometers, and strain gages) to inform complete characterization of local thermal loads and transients.

The sensors not only characterized unique, localized damage at the failure location (Figure 3) but also offered comparisons between loops and between units and stations. This offered the insight necessary to pinpoint the driving phenomenon (cross-loop leakage), quantify the effectiveness of a mitigatory design change (bleed system), and in some cases provided the confidence to increase inspection intervals. The data from these instrumentation deployments is altering management strategies from time-based to condition-based. The financial impact of this shift is significant, not only in time and dose savings from deferred inspections but also in terms of avoided cost (emergent repair/replace activities are estimated to cost at least $250k per line and up to $10M for a forced outage).

Summary

Whether implementing cutting-edge new designs or solving nightmarish recurring problems, it is important to consider alternate solutions beyond typical norms. Proper application of specialty instrumentation to systems, structures, and components offers an improved understanding of the underlying mechanics/physics, and fills knowledge gaps created by analytical limitations and/or incomplete apparent cause data. Historical barriers associated with time, dose, and cost of instrumentation don't necessarily have the same weight as before, having been offset by technology advancements as well as operating experience (OE), economic risks, and regulatory margins associated with repeat failures. SI believes the trend toward application of data-driven solutions is here to stay; we are excited to contribute to a promising future where instrumentation is viewed as an invaluable asset in a utility engineer's toolbox.

The Impact of the ASCE 7-16 Standard on Seismic Design and Certification of Equipment

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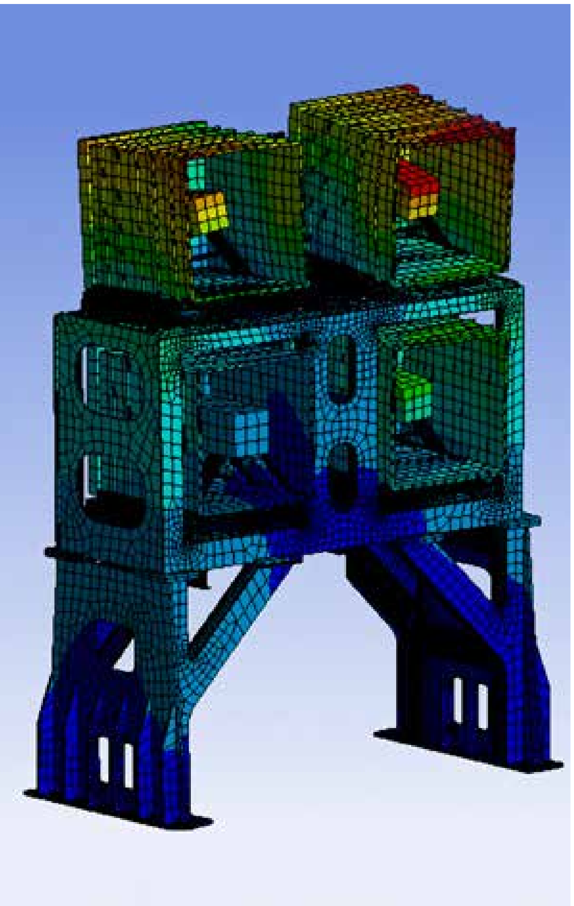

Things change, that's just a fact of life. But when it comes to engineering codes and standards, change can be confusing, frustrating and expensive. As it relates to seismic design and certification of equipment, it is beneficial to understand the impact of code changes early to begin incorporating requirements in new equipment design, product updates and in the certification process.

One of the main structural design codes used in the United States and abroad, American Society of Civil Engineering (ASCE) 7, undergoes revisions on a five-year cycle. These revisions are based on input from committee members, building officials, interested parties and academia with the goal of ensuring specific performance objectives are achieved as well as incorporating lessons learned from practice. With the increase in enforcement of seismic certification provisions over the past 10 years, there has been a noticeable increase in industry lessons learned. The updates to the seismic provisions in ASCE 7-16 relating to equipment design and certification can primarily be attributed to these lessons learned.

Limitations on R_P Used in Certification by Analysis

In the past, no guidance has been provided within ASCE 7 on proper analytical approaches to certify electrical and mechanical components. This has led many Certification Agencies and engineers to certify components through elastic analysis using seismic forces reduced by the component response modification factor (R_P). While these R_P values may provide reasonable seismic forces for anchorage design, there lacks a robust justification for these values when considering component performance objectives.

Industry experience with shake table testing components designed with these R_P values have shown these components do not always maintain structural integrity. A review of past testing by TRU Compliance (Structural Integrity's Product Certification Agency) has shown that structural elements may be ok, but their connections may suffer premature failure. Unlike provisions for seismic design of buildings, ASCE 7 requirements for nonstructural components do not specify detailing requirements for connections in the lateral force resisting system (such as designing for over strength forces). As such, members and their connections can be designed for the same loads. This can result in a condition where seismic mechanisms assumed in design using high R_p values cannot form due to premature connection failure. As opposed to implementing material and system specific detailing requirements, which would be unrealistic given the extensive range of component types in practice, ASCE 7-16 includes provisions that require components certified by analysis to remain essentially elastic. The goal is to address premature connection failures by requiring the entire system to be designed for unreduced seismic forces, but this change may also result in the need for more material in the lateral force resisting system (and therefore more cost in the component). This code change can result in substantially higher design forces when certifying a component by analysis and may require extensive design changes to resist the same site demand as a previous certification by analysis (or alternatively derating a component capacity under ASCE 7-16).

The goal is to address premature connection failures by requiring the entire system to be designed for unreduced seismic forces.

Definition of Rugged Component

Manufacturers and consulting engineers alike have looked to use a provision within Section 13.2.2 of ASCE 7 to bypass the need to analyze or test certain components. The provision states that if a component can be shown to be inherently rugged, it can be deemed to meet seismic certification requirements without further consideration. However, there has never been a formal definition of rugged within ASCE 7 and no listing of components that are commonly considered rugged. Therefore, while the provision sounds like a useful option, it was rarely used in cases with building official review.

To the excitement of many, a formal definition of "component, rugged" has been added within ASCE 7-16. However, upon reading the definition one will quickly realize that the definition of a rugged component basically requires the component be certified by experience data. That is, for a component to be considered rugged it must be shown to function based on past earthquake data or past seismic testing. While this is not a major windfall for manufacturers, it is consistent with the approach that has been taken by TRU Compliance, Structural Integrity's wholly owned subsidiary and certification arm.

While ASCE 7-16 is essentially requiring experience data certification of rugged components, one aspect of the definition that will likely be pushed extensively by manufactures is the last sentence which provides "common examples of rugged components." These examples include AC motors, compressors and base-mounted horizontal pumps. TRU Compliance agrees that these types of components have historically met performance objectives after high levels of seismic testing, but the specific component proposed to be certified as rugged must be evaluated against the baseline for similar strength and stiffness.

For a component to be considered rugged it must be shown to function based on past earthquake data or past seismic testing.

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Design Requirements for Modular Systems

The TRU Compliance team has worked on a variety of projects involving modular mechanical and electrical systems for conventional and critical facilities. An example of such a modular system is a modular central plant in which numerous components (chillers, boilers, pumps, piping, electrical distribution, etc.) are installed in factory-built modules are deployed to a site. One of the most common approaches manufacturers attempt to pursue is to classify the entire system as a component per Chapter 13 of ASCE 7 and thereby argue no design of the system is required. In doing so, seismic design requirements are more lenient and anchorage and bracing of internals would not be required if the component importance factor was 1.0.
The intent of the building code was not to allow the use of modular construction to build to reduced seismic requirements. Systems are normally designed as buildings or structures should still be designed as such when built in a modular fashion. To provide explicit direction, a new section was added to ASCE 7-16 which specifically addresses seismic design of modular mechanical and electrical systems. This section clarifies modular mechanical and electrical systems in excess of 6 feet tall, contain or support mechanical and electrical components must be designed in accordance with the provisions for nonbuilding structures in Chapter 15.

TRU Compliance has understood the intent of the building code and has been designing modular systems in accordance with these provisions for many years. We have expertise in working with manufacturers and developing system designs that comply with code requirements in a buildable and efficient manner.

Allowable Use of AHRI Seismic Certification Standard

Years back, the Air-Conditioning, Heating and Refrigeration Institute (AHRI) developed a seismic certification standard, ANSI/AHRI Standard 1270/1271, with the intent of clarifying performance objectives and certification requirements specific to HVACR equipment. Much of the document references requirements from ICC-ES AC156 testing standard as well as items from ASCE 7, but provided further clarification of specific items requiring testing and methods of certification.

The ASCE 7 task committee on nonstructural components reviewed this standard and worked with AHRI to ensure there was alignment between code requirements and the AHRI standard. After it was determined the intentions of ASCE 7 and AHRI 1270/1271 were aligned, the standard was incorporated by reference into ASCE 7-16 with a few clarifying points. These clarifications included the assertion that all active and/or energized components must be shake table tested or certified using experience data, a component classified as rugged must comply with the definition in ASCE 7-16 and analysis shall be based on ASCE 7-16 provisions including material specification and requirements for the component to remain essentially elastic.

It is the hope more industry groups will develop detailed seismic certification standards that address items specific to their equipment types. The AHRI standard helps define requirements specific to HVACR equipment to ensure consistency in certification approaches across multiple manufacturers and product certification agencies. More industry engagement is needed to develop such product type standards, but will be a great step forward in advancing the certification industry.

Summary

Ultimately, updates to codes such as ASCE 7 are intended to align building code performance objectives with practice. The many lessons learned over the past decade of seismic certification have helped further the development of codes and standards that ensure equipment meets specified performance requirements after a design earthquake. For many years, TRU Compliance has been heavily engaged in the code development process and looks forward to continuing to assist our clients meet product certification requirements in an efficient and cost-effective manner.

Radiation Source Term Assessments

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Nuclear plant workers accrue most of their radiation exposure during refueling outages, when many plant systems are opened for corrective and preventive maintenance. The total refueling outage radiation exposure can be 100-200 person-Rem at a typical Boiling Water Reactor (BWR), and 30-100 person-Rem at a typical Pressurized Water Reactor (PWR). Accrued refueling outage radiation exposure values can be significantly greater than these values depending upon radiation fields, outage work scope, and emergent work. Outage radiation exposure is one metric used by a plant to determine outage success and by industry regulators in assessing the overall performance of a plant. Plants with high personnel radiation exposure tend to be those plants with more equipment problems and more unscheduled shutdowns and consequently, they may be subjected to increased regulatory oversight.

Radiation source term assessments are performed to understand the causes of high collective radiation exposure, and to help plants evaluate their strategies for source term reduction. This involves understanding how a plant's material choices and chemistry and operational history influence the radiation fields which develop in the plant systems. Consequently, a source term evaluation is very plant-specific, but can help a plant identify which strategies may be most effective for their specific situation.

As part of Structural Integrity's Single Point of Contact (SPOC) program implemented during the spring 2017 outage season to assist plants with emergent outage issues. SI noted in the daily outage reports of two BWRs that accrued outage radiation exposure significantly exceeded the outage goal. The SI Nuclear Chemistry and Materials Group followed up with station Chemistry and Radiation Protection Department personnel offering our assistance in determining if increased radiation source term resulted in higher radiation fields, leading to radiation exposure goal exceedance. We were subsequently contracted by one of the plants to participate in the event root cause evaluation and by the other to perform a formal radiation source term assessment project.

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From Corrosion to Radiation Field Formation

The radiation fields formed in BWRs and PWRs are primarily caused by the deposition of activated corrosion products inside plant piping and equipment. Fission products and water activation products have less of an effect on radiation fields. The content of alloying elements in the materials of construction ultimately determine the corrosion products released into the coolant. Most of the surface areas are austenitic stainless steels, however nickel-based alloys and low alloy steels are used in some of the of the reactor internals. Stellite™ , a cobalt based alloy, is used in many valves. In BWRs, carbon steels are used in the condensate, feedwater, and steam systems. In PWRs, steam generator tubing, typically Alloy 600 or 690, makes up a large portion of the exposed surface area in the primary circuit.

Corrosion products are released from component and piping surfaces by dissolution and wear. These products can be soluble or particulate, and once released into the coolant, they are transported by the reactor water around the primary circuit. Some of the corrosion products may be removed by the coolant purification systems (the Reactor Water Cleanup System in BWRs and the Chemistry and Volume Control System in PWRs). The corrosion products will deposit around the circuit, including on the fuel. The corrosion products deposited on the fuel become activated by the high levels of neutron flux in the core. The activated corrosion products can be released from the fuel by dissolution, erosion, or spallation. Once released into the coolant, the activated corrosion products can deposit on reactor coolant system piping surfaces, inside reactor coolant valves, and in other systems that are connected to the reactor coolant system, leading to radiation field formation. Figure 1 above shows the primary system of a BWR. Figure 2 illustrates the steps in Co-60 activation and transport, ultimately leading to the formation of radiation fields.

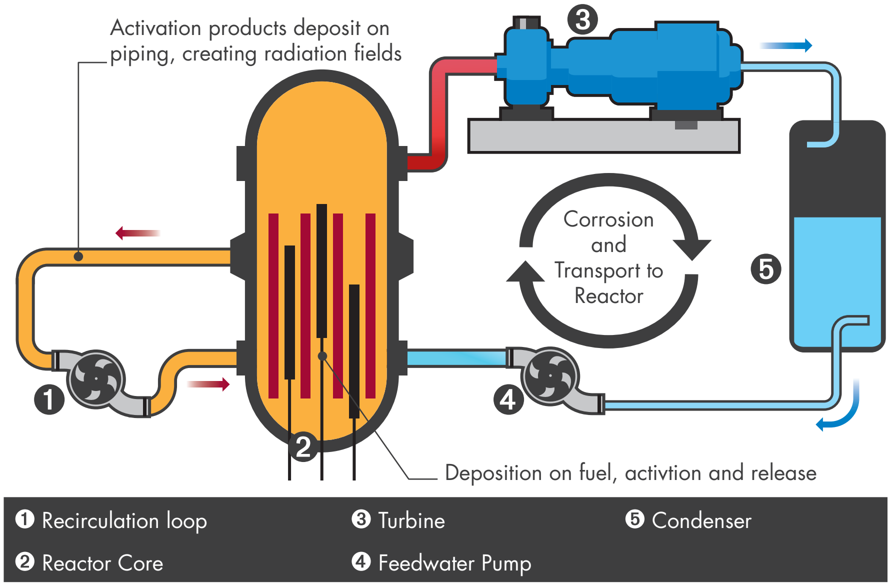

FIGURE 1. BWR Primary System

Isotopes and Radiation Fields

The gamma-emitting isotopes are responsible for the radiation fields. However, there are differences between the isotopes which are most prolific in the coolant and those which are the major contributors to the out of core radiation fields. How much an isotope contributes to the radiation fields depends on:

1. The quantity of the isotope.
2. The half-life: isotopes with short half-lives (a few hours or less) will decay away quickly, and not have much of an effect on shutdown dose rates. For example, Manganese-56, has a half-life of 2.58 hours, so it will decay quickly.
3. The yield and energy of gamma rays: isotopes with small yields and that emit low energy gammas will have less of an effect on radiation fields. For example, a Chromium-51 decay will emit, on average, 0.1 gamma rays of low energy, so it tends to not be a large contributor to radiation fields.

Cobalt-60 (Co-60) is typically the isotope of most concern in BWRs, while in PWRs, Cobalt-58 (Co-58) and Cobalt-60 are of most concern. Table 1 compares Co-58 and Co-60. Co-60 is formed from the neutron adsorption of non-radioactive Co-59, while Co-58 is formed from the neutron adsorption and decay of non-radioactive Nickel-58 (Ni-58). The primary source of non-radioactive Co-59 is the corrosion and wear of materials with Stellite™ hardfacing, as the concentration of Co-59 in Stellite™ is typically between 50 and 65% by weight. Trace Co-59 is also present in any material that contains nickel. The primary source of Ni-58 is the corrosion of various stainless steels and nickel alloys used in the plant. The Ni-58 content of typical Type 304 stainless steels is between 8 and 12% by weight. In BWRs, there are many more components with Stellite™ hardfacing that interface with the primary coolant than at PWRs. In PWRs, the large surface area of nickel alloy steam generator tubes results in a substantially greater nickel source than in most BWRs. Accrued outage radiation exposure is typically higher in BWRs than in PWRs because BWRs have higher Co-60 source term.

Other isotopes which also contribute to radiation fields include Manganese-54 (Mn-54, which originates from Iron-54), Chromium-51 (Cr-51), and Iron-59

(Fe-59). In some instances, Silver-110m (Ag-110m) and Antimony-124 (Sb-124), and Tungsten-187 (W-187) have also been identified as contributing sources. Table 2 lists some of the commonly found activation corrosion products.

Radiation Source Term Assessment

For many years, SI's Nuclear Chemistry and Materials Group have performed radiation source term assessments for BWRs. These projects have either been contracted directly through a utility or for a utility through the EPRI Radiation Management and Source Term Technical Strategy Group (RM&ST TSG). SI's BWR expertise in this area led to EPRI RM&TSG contracts for performing source term assessments at two PWRs in 2016-2017.

A typical work scope for each source term assessment includes reviews of operational and shutdown chemistry data, radiological data, water treatment equipment performance, outage schedule and water management plans, and 5-year As Low as Reasonably Achievable (ALARA) and cobalt reduction plans. In the assessment process, data reviews are completed and documented in a draft report followed by a site visit to discuss initial findings from the data reviews and to fill in data gaps. A preliminary list of findings are typically reviewed with senior management at the end of the site visit. The final report is issued after the site visit.

The findings from a radiation source term assessment will help plants identify specific actions to reduce the radiological source term and collective radiation exposure. This can include evaluating the effectiveness of chemical injection programs, such as BWR and PWR zinc injection, and BWR hydrogen water chemistry programs. Elemental cobalt source term reduction programs can be reviewed for effectiveness. Methods to optimize the operational and shutdown water treatment and chemistry control can be identified.

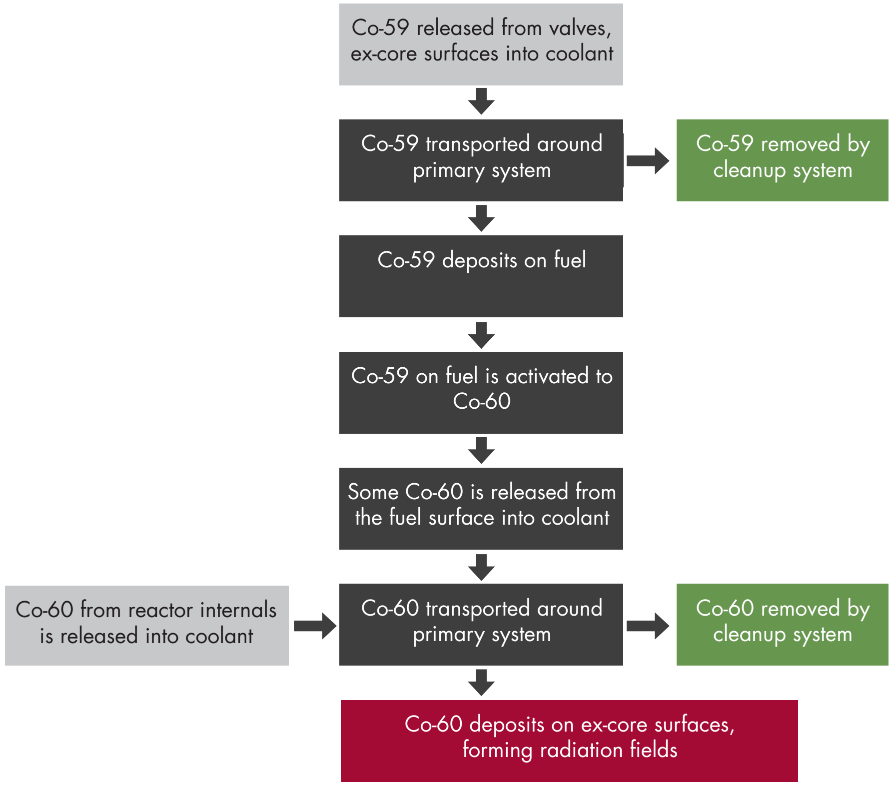

FIGURE 2. Schematic of Co-60 activation and transport

	Cobalt (Co)-58	Cobalt (Co)-60
Parent Nuclide/natural abundance	Ni-58: 68.3 %	Co-59: 100 %
Activation Reaction	$^{58}_{28}Ni + ^{1}_{0}n \rightarrow ^{58}_{27}Co + ^{1}_{1}p$	$^{59}_{27}Co + ^{1}_{0}n \rightarrow ^{60}_{27}Co + y$
Half-Life	70.86 days	5.271 years
Gamma Energies	810.8 keV (99.4%) 511.0 keV (30%)	1173.2 keV (100%) 1332.5 keV (100%)
Sources	Nickel based alloys, stainless steels	Stellite™, any nickel containing metal

Radionuclide	Half life	Source
Co-60	5.27 y	Carbon steels, stainless steels, nickel alloys
Co-58	70.9 d	
Mn-54	312 d	
Cr-51	28 d	
Fe-59	44.5 d	
Zn-65	244 d	Brass, chemical addition
Zr-95, Nb-95	64.0 d, 5.0 d	Fuel cladding, fission products
Ag-110m	250 d	Control rods, brazing materials, seals
Sb-124	60.3 d	Seals, startup source
Sb-125	2.77 y	Fuel cladding, startup source
W-187	24 hr	Welds, Stellite™

TOP TABLE 1. Comparison of Co-58 and Co-60

BOTTOM TABLE 2. Activated Corrosion Products found in BWRs and PWRs

Real-Time Damage Tracking with SI Technology and GP Strategies' EtaPro

Expanding Capabilities in Condition-based Pressure-part Integrity Management

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Structural Integrity and GP Strategies recently announced an agreement to bring SI's technology for calculating, tracking, and trending life consumption of piping and boiler components to GP Strategies EtaPRO real-time monitoring platform (Press release here). SI has a long history with creep and fatigue damage monitoring applications, most recently with the suite of applications available as part of SI's PlantTrack platform. The partnership with GP Strategies brings that technology to EtaPRO which is used worldwide by power-generating organizations to monitor the performance and reliability of their generation assets.

EtaPRO users will benefit from easy integration of SI's leading-edge Boiler and Piping Component Reliability (BPCR) modules to quantify damage to high-pressure, high-temperature components such as tubing, piping, headers, and desuperheaters. The BPCR modules track and trend accumulated creep and fatigue damage in real time using SI's proprietary algorithms that combine actual operating data and material condition with a plant's specific configuration. Plant operators can use the resulting life consumption estimates to guide asset management decisions, such as changes in operating procedures, targeted inspections, or off-line analysis of anomalous conditions.

As an example, the header damage tracking module uses process instrumentation (pressure, temperature and steam flow) and terminal tube thermocouples in combination with the specific geometric configuration and material type of the header to track the following damage modes:

- Oxide growth and creep damage accumulation in terminal tubes
- Creep related, header side, stub tube damage
- Fatigue related, tube side, stub tube damage
- Creep and fatigue damage in axial and circumferential ligaments between tube boreholes
- Creep damage in girth and seam welds

Tracking these damage mechanisms guides future inspection, maintenance or replacement plans for headers that experience flexible operation, rapid load changes or extensive cycling; as well as for aged headers with large steam temperature imbalances.

The BPCR modules utilize the EtaPRO platform so additional hardware is not required and the interface is familiar to users and administrators. This simplifies installation and configuration and enables users to have the modules up and running in a very short time.

The algorithms used in the BPCR modules to quantify damage accumulation are the same as in SI's PlantTrack Online Damage Tracking Apps. Those Apps are available for plants that either already have the PlantTrack offline data management software or don't have the EtaPRO software. Using this consistent code base ensures that whether users are using the EtaPRO BPCR modules or the PlantTrack Online Apps the same results are achieved.

Both SI and GP Strategies have been providing solutions to the power industry for decades. This offering now enables power plant owners to benefit from the combined technology developed by both companies during that time.

Dissimilar Metal Welds in Grade 91 Steel

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Introduction

A dissimilar metal weld (DMW) is created whenever alloys with substantially different chemical compositions are welded together -- for example, when a low-alloy steel such as Grade 22 (2¼ Cr-1Mo) is welded to an austenitic stainless steel such as TP304H (18Cr-8Ni). Many DMWs are commonly present in fossil-fired power plants, examples being material transitions in boiler furnace tubes, stainless steel attachments welded onto ferritic steel tubes or pipes, and stainless steel thermowells or steam sampling lines in ferritic steel pipes. The chemical composition gradients associated with DMWs present unique issues relative to their design, in-service behavior, and life management, particularly for those DMWs operating at elevated temperatures where solid-state diffusion and cyclic thermal stresses are factors, which was previously presented in News and Views (Volume 43, page 19).

With the now widespread use of Grade 91 steel (9Cr-1Mo-V-Nb) for elevated-temperature applications in modern power plants, DMWs involving this material have become common, and increasing service experience has revealed some unique characteristics and failure mechanisms, especially in thicker-section DMWs with austenitic materials. This article presents a short overview of Grade 91 DMWs: their design, fabrication, and failure, with emphasis on current industry issues. There are two basic classes of DMWs in Grade 91 steel: ferritic-to-ferritic and ferritic-to-austenitic. The first type corresponds to Grade 91 welded to another ferritic steel with a lower chromium content, such as Grade 22; the second type corresponds to Grade 91 welded to an austenitic stainless steel such as TP304H. Each of these types has unique concerns and considerations.

Grade 91 to Ferritic Steel DMWs

There are several potential issues which must be considered in the design and fabrication of DMWs of Grade 91 to other ferritic steels, perhaps the foremost being the migration of carbon atoms from the material with lower chromium content to the Grade 91 material with higher chromium content. The chromium content difference across the weld interface creates a driver for carbon diffusion which will occur during both any post-weld heat treatment (PWHT) applied or during

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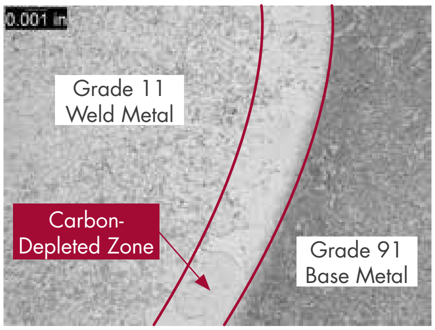
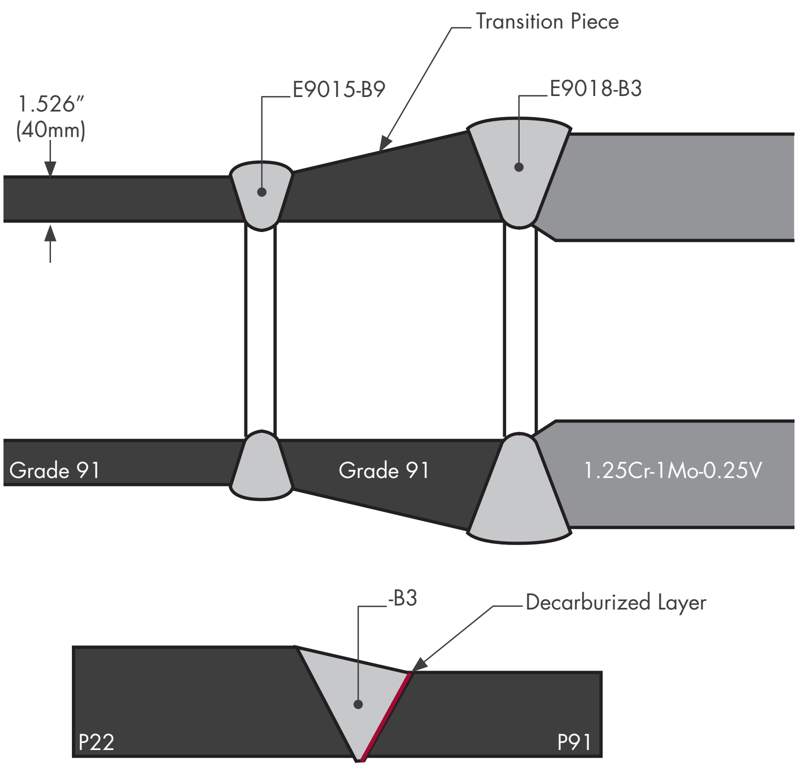


FIGURE 1.
A carbon-depleted zone which has developed in a Grade 91 base metal to Grade 11 weld metal interface after approximately 90,000 hours of operation at 1040°F. Cracking and creep damage (cavitation) were found in other areas of this weld.

service at temperatures greater than approximately 900°F. This diffusion creates a weak decarburized layer in the lower-chromium material which can result in premature cracking and failure (Figure 1). There will also be a significant difference in strength between the two materials, which can result in strain localization in the weaker material if the joint is not designed correctly. The strain localization will be enhanced by any decarburization related to carbon migration. A third issue is selecting a PWHT temperature, since the code-required ranges for the different materials do not always overlap.



TOP Good design: a Grade 91 piece is used to transition between the thicknesses of the Grade 91 pipe and a CrMoV valve body. The filler metal used in the thicker weld could be either matching to Grade 22 (B3 type) or Grade 91 (B9 or B91 type).

BOTTOM Bad design: the Grade 22-type (B3) filler metal is loaded at a stress equivalent to the Grade 91 base metal, and a decarburized layer will form at this location.

FIGURE 2. Examples of good and bad Grade 91 to ferritic steel DMW designs.

DMWs between Grade 91 and lower alloy ferritic steels are generally more problematic than DMWs between different low-alloy steels (e.g., between Grade 22 and Grades 11/12) and DMWs between low-alloy steels and carbon steels. This is because ferritic-to-ferritic DMWs involving Grade 91 have greater differentials in chromium content, higher PWHT and operating temperatures (higher carbon diffusion rates) and greater strength mismatches.

While every configuration is unique, it is generally best to make a Grade 91-to-ferritic DMW using a filler metal matching in composition to Grade 91 (e.g., type B9 or B91) rather than to the lower-alloy material (e.g., type B3), although both are options depending on the specific configuration and requirements. It is not advisable to make DMWs between Grade 91 and Grades 11/12 steels or low-carbon steels due to the large mismatches in strength, chromium content, and PWHT temperature.

Because there are typically transitions in both material and component thickness at a DMW, it is critical to design the DMW accounting for both types of transitions and the expected operating conditions of the component (service temperature, frequency of thermal cycling, etc). Figure 2 shows examples of good and bad transition designs. In the good design a separate piece is used to make the thickness transition in the stronger material and the DMW is placed in the high thickness region; in the bad design the low-alloy material (and the decarburized layer) is present at the lower thickness (and correspondingly higher stress levels) of the Grade 91 component.

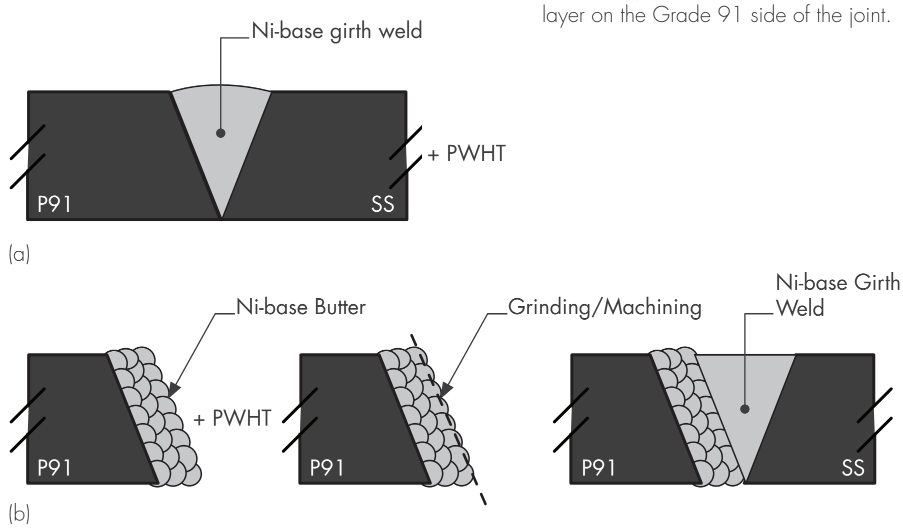
DMWs connecting Grade 91 piping to steam turbine stop/control valves have been found with premature service damage and cracking. In these cases, the Grade 91 pipe is typically connected to a steam turbine OEM proprietary CrMoV valve body casting, sometimes using a relatively low strength filler metal such as type B3, or even B2; a typical and the "bad" design configuration shown in Figure 2. In such configurations a Grade 91 matching filler metal would perform better. See the article; *Example Grade 91 High Energy Piping DMW Joint Stress and Metallurgical Analysis, (page 39).*

Grade 91 to Austenitic Steel DMWs

DMWs joining Grade 91 to austenitic stainless steels are relatively common, perhaps more so than realized. In addition to butt welds, connecting stainless steel furnace tubing to Grade 91 outlet header tube stubs in modern conventional boilers, Grade 91 to austenitic DMWs are present where stainless steel attachments have been welded to Grade 91 tubes, where stainless steel thermowells or steam sampling lines have been used in Grade 91 piping systems, and where stainless steel support lugs are welded to Grade 91 headers. There are also more isolated cases of DMWs in which Grade 91 pipe has been welded to austenitic stainless steel pipe, for example where stainless steel in-line flowmeters are present in a Grade 91 piping system, or boilers in which stainless steel outlet headers connect to a Grade 91 piping system.

To date, DMWs joining Grade 91 to stainless steel have been made using nickel-base alloy weld consumables such as ERNiCr-3/ENiCrFe-3 (nickel alloy 82/182) using welding parameters (preheat, interpass, and PWHT temperatures) suitable for Grade 91. In thin-section welds, the two materials are typically joined directly and the completed weld given a PWHT at Grade 91 conditions (Figure 3a). In thicker-section welds the Grade 91 side of the joint is sometimes first "buttered" with several layers of nickel-base filler, subjected to a PWHT, and then a final closure weld is made to the stainless side of the joint (again with a nickel-base filler). No PWHT is performed after the closure weld (Figure 3b). Note that

FIGURE 3.
Two common fabrication routes used in manufacturing Grade 91 to stainless steel DMWs: (a) weld with Ni-base filler and PWHT of entire weld; (b) use of a nickel-base butter layer on the Grade 91 side of the joint.



nickel-base fillers which strengthen or embrittle at typical Grade 91 service temperatures should be avoided. These include alloys 625 (E/ERNiCrMo-3) and 617 (E/ERNiCrCoMo-1).

Use of a nickel-base filler metal avoids the issue of carbon migration in the DMW, since carbon does not readily diffuse into the nickel-base material. However, the significant differences in thermophysical properties (especially thermal expansion coefficient) between the components of the DMW can lead to adverse thermal cycling effects. Since the thermal expansion coefficient of Grade 91 is slightly lower than low-alloy steels such as Grade 22, thermal stresses will be higher in Grade 91 to austenitic DMWs than in Grade 22 to austenitic DMWs. As with the Grade 91 to ferritic DMWs, strength and thickness mismatches typically exist, although in the austenitic DMW case Grade 91 is the weaker material, at least at the service temperature. Hence similar attention must be paid to overall joint design and thickness transitions.

The service experience with Grade 91 to austenitic DMWs made as butt welds in thin sections (e.g., tubing) has so far been positive; the few reported failures in these welds have been primarily attributed to factors other than the DMW itself, for example high thermal stresses due to sootblower impingement.

In contrast, however, many premature failures have occurred in Grade 91 to austenitic DMWs with thick sections (e.g., pipe butt welds) or significant weld constraint (e.g., fillet welds). An EPRI report documenting recent service experience with thick-section Grade 91 DMWs was prepared by Structural Integrity in 2014 (Report 3002006759). The most common failure mode for these cases has been cracking along the weld fusion line between the Grade 91 and the nickel-base weld metal (Figure 4). Through-wall cracking has occurred in relatively short service durations, fewer than 20,000 hours in one case. The cracking appears to be creep-related, in that cavities are frequently observed along the fusion line ahead of the crack tip. This is particularly true for DMWs operating at temperatures around 1000°F and slightly above. In contrast, creep cavitation was found at both the fusion line and in the Grade 91 heat-affected zone ("Type IV" damage) in a pipe DMW which operated at 1050°F.

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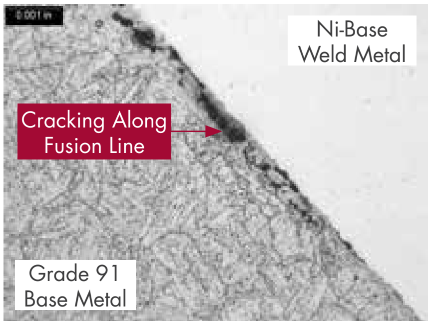

FIGURE 4. Micrograph showing typical cracking along the Grade 91 to nickel-base weld metal fusion line in a thick-section DMW.

The risk presented by stainless steel in-line flow elements was identified and documented in 2010 by Matherne[1], et al., and in 2011 by Paterson[2], et al.; these flow elements were installed in many early Grade 91 piping systems because Grade 91 flow elements were unavailable. If still present, they should be replaced at earliest opportunity because of the risk of unpredictable catastrophic rupture along the stainless to Grade 91 DMWs.

More attention is now being paid to Grade 91 to stainless DMWs in fillet weld applications such as tube attachments, thermowell fittings, and steam sampling line fittings because these are increasingly found to be cracked in piping inspections. Cracking is again typically along the Grade 91 to nickel-base weld metal fusion line; examples are shown in Figures 5 and 6. The thermowells are of particular concern because of the significant projectile safety hazard associated with their liberation (this has occurred). Any such DMWs present in a Grade 91 piping system should be eliminated where possible by replacing the stainless steel components with equivalent Grade 91 components; if this is not possible these DMWs must be regularly inspected (10,000 to 20,000 hour intervals). EPRI plans to perform a service experience review for thermowells and steam sampling lines in 2018.

The metallurgical root cause for these premature failures in thick-section Grade

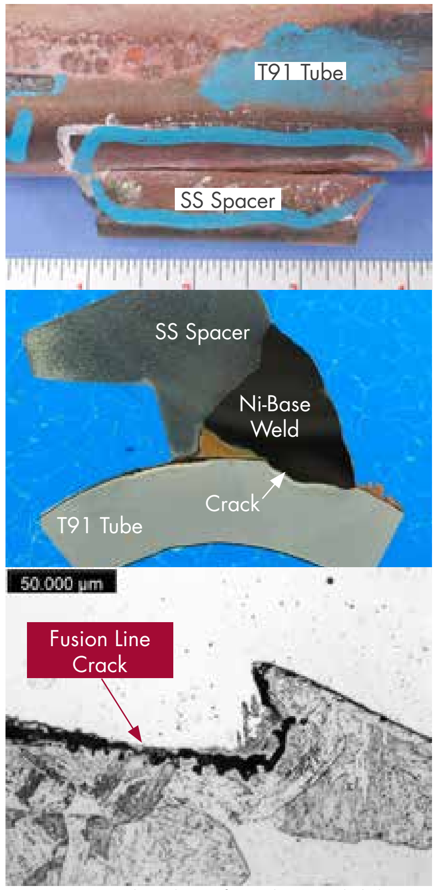

FIGURE 5. Disbonding of stainless steel slide spacer welded onto a Grade 91 tube. The weld was made using a nickel-base filler metal, and cracking occurred along the fusion line between the weld metal and the Grade 91 tube.

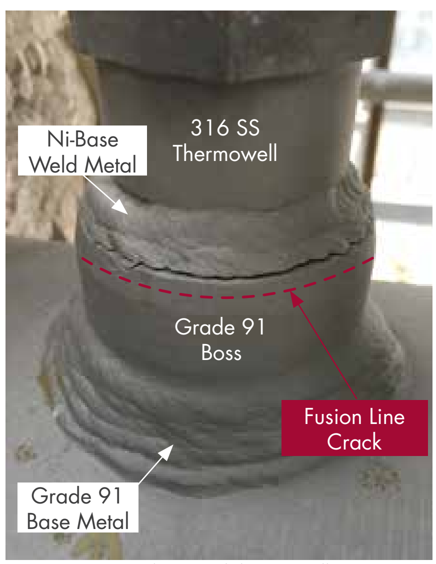

FIGURE 6. Stainless steel thermowell in a Grade 91 piping system found cracked along the fusion line between the Grade 91 boss and the nickel-base weld metal. If the weld had completely cracked, the thermowell would have been ejected from the pipe.

91 to austenitic DMWs is not fully understood and is the topic of on-going research by EPRI. It is not currently possible to make life predictions for these welds based on their nominal service loading; early failures have occurred in welds operating at very low service stresses. The best strategy for utilities is to identify where such welds are present in a plant, eliminate them where possible, and frequently inspect the remainder.

Conclusion

In summary, Grade 91 DMWs present an additional set of concerns and considerations compared to low-alloy steel DMWs. When properly designed and fabricated, DMWs between Grade 91 and lower-alloy steels such as Grade 22 should not present a particular risk for premature failure, and current service experience suggests that this is also the case for Grade 91-to-stainless tube butt DMWs. However, for Grade 91-to-stainless DMWs in thick sections or other configurations with high weld constraint present a high risk for premature failure; these welds should be identified, carefully monitored, and eliminated where possible.

References

[1] Matherne, C., D. DeRouen, and W. Baxter. "Catastrophic Failure of a Dissimilar Metal Weld in a High Pressure Steam Venturi". in 2010 AIChE Spring National Meeting. March 21-25, 2010. San Antonio, TX.

[2] Paterson, S.R., R. Gialdini, and M. Cronin. "Early Service Life Cracking of Steam Piping Welds in Combined Cycle Power Plants". in 2nd International EPRI Conference on Welding and Fabrication Technology for New Power Plants and Components. June 21-24, 2011. Orlando, FL.

Strategic Internal Corrosion Monitoring for Gas Pipelines

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REGULATORY OVERVIEW

A March 16, 2017, Pipeline and Hazardous Materials Safety Administration (PHMSA) advisory bulletin (Docket No. PHMSA-2016-0131 – "Pipeline Safety: Deactivation of Threats") gave guidance on the deactivation of pipeline threats, including the threat of internal corrosion. On April 8, 2016, PHMSA issued a Notice of Proposed Rulemaking (NPRM) entitled "Safety of Gas Transmission and Gathering Pipelines". Section §192.478 "Internal Corrosion Control: Onshore transmission monitoring and mitigation" of the NPRM would increase the scrutiny and requirements for monitoring and mitigating the threat of internal corrosion for the gas industry.

This bulletin and NPRM reinforce the requirements of CFR part 192-subpart O, Section 192.937, requiring gas pipeline operators to continuously assess their pipelines for the threat of internal corrosion as part of their overall integrity management program. One of the requirements is to determine if the gas entering the system is corrosive or not corrosive. The optimal way to prove that the gas is not corrosive is to build a thorough continuous monitoring program that considers guidance from the NPRM and the advisory bulletin.

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INTERNAL CORROSION MONITORING GUIDANCE

Following regulatory guidance and general corrosion principles, SI has partnered with EnhanceCo to develop a program to properly evaluate the possibility of deactivating the threat of internal corrosion on gas pipelines. Upon the successful completion of the Internal Corrosion Direct Assessment (ICDA) process or an in-line inspection (ILI) with no instances or indications of internal corrosion, the implementation of a comprehensive internal corrosion monitoring program for affected pipeline systems is recommended. A monitoring program would still be recommended if an ICDA or ILI discovered indications of internal corrosion, however the monitoring program would have additional requirements.

After completing a baseline assessment, there are multiple elements considered best practices for conducting subsequent internal corrosion assessments and monitoring:

ELEMENT 1
Gas Composition Analysis (moisture, CO2, O2, total sulfur, and H2S)

This analysis can be conducted using portable analyzers, stain tubes, or on-line monitoring equipment (gas chromatographs). Criteria must be established, and data should be periodically reviewed to ensure the criteria is achieved to exclude the threat of internal corrosion.

ELEMENT 2
Corrosion Rate Analysis (Electrical Resistance (ER) probes, Coupled Multiple Array Sensor (CMAS) probes, coupons, etc.)

This analysis is conducted by using weight loss coupons, electrical resistance (ER) probes, coupled multi-array sensor (CMAS) probes, or other corrosion rate monitoring equipment. Coupons should be removed and analyzed at a minimum of twice per year. ER and CMAS probes will provide significantly more resolution and can be monitored connected to an existing supervisory control and data acquisition (SCADA) system for continuous monitoring.

ELEMENT 3
Liquids and Solids Analysis

Liquids and solids, when detected, should be collected for analysis whenever piping and/or equipment is opened for inspections such as ILI operations, drip blowing or internal inspections. Sampling and analysis of this material provides invaluable information regarding the presence of corrosion by-products.

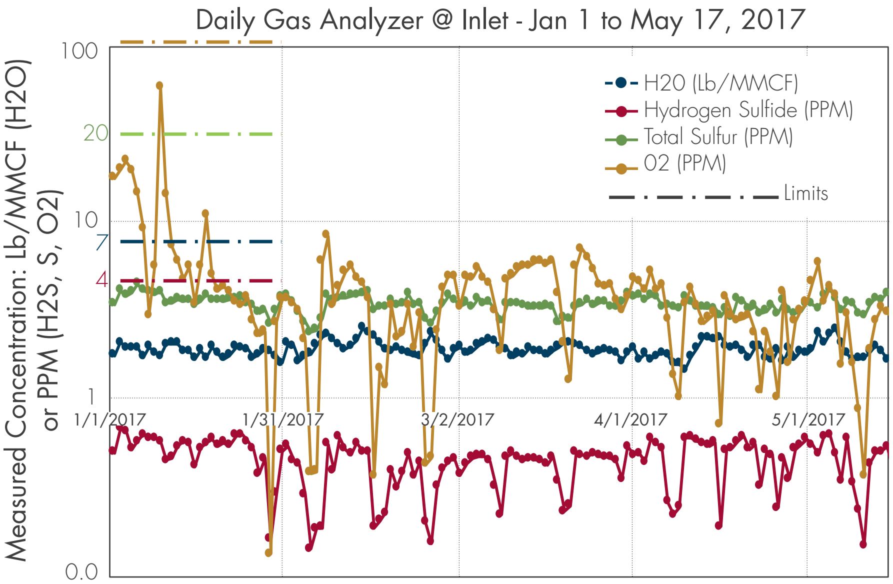

FIGURE 1. Gas Composition Analysis Chart

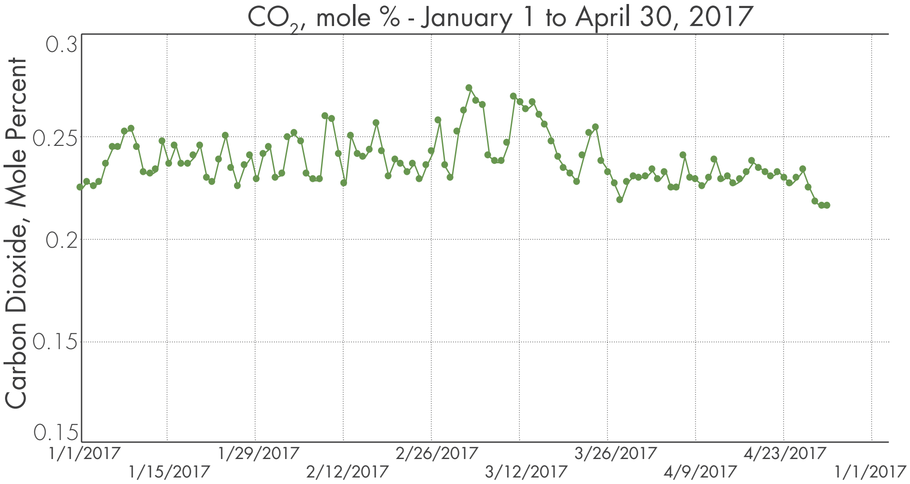

FIGURE 2. CO2 Analysis Chart

ELEMENT 4
Internal Examination Records

Internal surface examination records provide direct evidence to the existence or absence of internal corrosion. The internal surface of a pipeline or vessel should be examined anytime it is opened or removed from service.

ELEMENT 5
Excavations and NDT Analysis

Excavations done during routine maintenance, leak inspection, or integrity assessments provide an opportunity to perform NDT inspections to ascertain the possibility of internal corrosion.

ELEMENT 6
Leak or Rupture Repair Records

Available leak or rupture records shall be evaluated for internal corrosion listed as the root cause.

Multiple assessment elements are recommended for proper implementation of an Internal Corrosion (IC) monitoring program to ensure that all factors that could influence the threat of internal corrosion are accounted for in the program.

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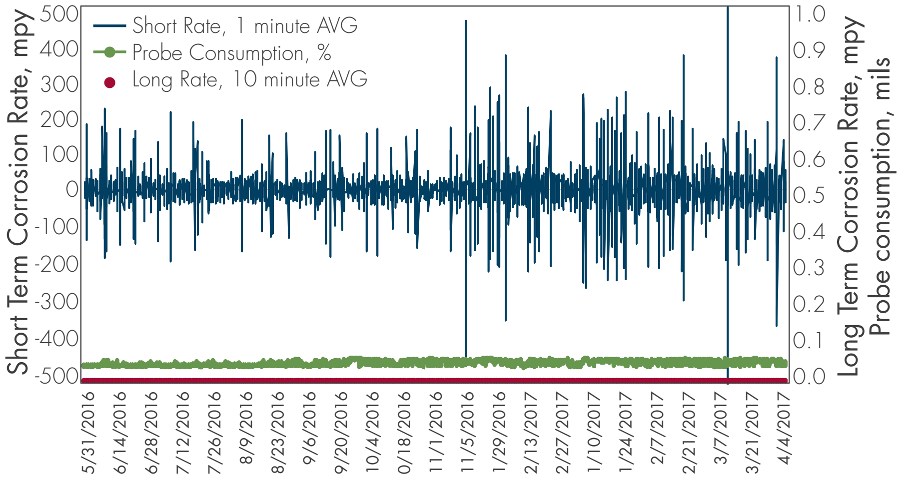

FIGURE 3. Corrosion Rate Analysis Chart for ER Probe

INTERNAL CORROSION CASE STUDY

Pipeline System Background

The particular pipeline system being used in this case study is a typically dry natural gas pipeline which operates continuously with some periods of increased gas consumption in the winter. A baseline ICDA was conducted on this line segment, and no internal corrosion was observed. No known history of internal corrosion in the system has been documented. Evaluation of the one gas inlet on this system demonstrates the value of IC monitoring.

A gas chromatograph has been installed at this inlet, allowing for review of the gas quality data for continuous monitoring of liquid upsets. Additionally, an ER probe and transmitter were installed and tied in to the SCADA system as an additional monitoring methodology to supplement the IC monitoring strategy.

Gas Composition Analysis

The IC monitoring program considers the presence of excess amounts of moisture (H2O), hydrogen sulfide (H2S), total sulfur, oxygen (O2) and carbon dioxide (CO2) as conditions with the potential to increase the threat of internal corrosion. As shown in the charts above, none of these constituents were above allowable limits during this analysis period.

ER Probe Analysis

The short-term corrosion rate (STCR) (blue line in Figure 3), is based on one-minute data collection measurements that are averaged and stored in the SCADA system. For the period analyzed, May 2016 to April 2017, the minute-by-minute STCR data was averaged and stored every 3 hours and 25 minutes, providing 2,599 records for analysis. The average STCR was 0.0 mils per year (mpy). The fluctuations in the STCR are likely from solid build up on the probe.

The long-term corrosion rate (LTCR) (red line in Figure 3) data is an average of one-minute probe readings, averaged each 10 minutes, then each 10-minute average is cumulatively averaged over the entire duration and stored in SCADA. The LTCR calculated rates are 0.0 mpy. These LTCRs indicate no significant internal corrosion issues.

The ER probe condition is shown by the green line in Figure 3. Once a probe reaches 50% of its useful life, it should be replaced. At the current time, the probe is at 4% of its life with 4.78 years until likely replacement at the current exposure conditions.

Solids Analysis

Based on the fluctuations seen in the STCR as noted above, the ER probe was removed and inspected. Once the probe was removed for inspection, a sample of the surface deposit was collected for elemental analysis using scanning electron microscopy / electron dispersive microscopy (SEM/EDS) to provide information on the elemental characteristics. A light layer of a black deposit covered all exposed surfaces, some of which was easily removed manually with a cloth. Solvent cleaning had little effect, suggesting the deposit was not predominantly hydrocarbon based (i.e., grease, lubricant, oil). The probes were successfully cleaned with a light abrasive pad prior to returning to service.

FIGURE 4. TOP ER Probe as removed MIDDLE ER Probe with Velocity shield removed BOTTOM ER Probe after samples collected & cleaning

The deposits where primarily composed of Fe, S, O, C, Al, Mg, Si, S, K, Ca and Mn. Presence of iron and sulfur is consistent with iron sulfide corrosion products. The source of these deposits is from the gas supplier's line as the probe is mounted just downstream of the station inlet.

The presence of aluminum, magnesium, silica, potassium and calcium (Al, Mg, Si, K and Ca) are common elements found in water or dirt and can react or otherwise precipitate out of solutions as a myriad of fine solids like calcium carbonate, and silicates as the moisture content drops.

Monitoring Conclusions

- A thin layer of a black, organic-based material was lightly covering the probe at the inlet location. Based on the findings obtained from the SEM/EDS analysis, the material is most likely a combination of corrosion products and solids that precipitate as moisture in the system is consumed upstream.

- The probe readings did not indicate any significant long-term corrosion rates at the location being monitored (<1 mpy). These readings were evaluated and averaged from hourly, weekly, and monthly perspectives.

- The ER probe metal loss measurements suggest a corrosion rate less than 1 mpy at this gas inlet. Within the corrosion control industry, managing degradation below 1 mpy is considered non-corrosive.

- Evaluation of the daily gas analysis information (e.g., H_2O, H_2S, Total S and O_2) revealed no excursions above the established criteria.

- The current threat of internal corrosion is low based on the data assessment gathered from the monitoring methods used, however there is a potential threat from solids that is prudent to monitor.

Integrated Flow Distributors (IFD)

Initial Installation and Performance at Browns Ferry Nuclear Station

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The Browns Ferry Nuclear Station (BFNS) intends to implement an extended power uprate (EPU) at all three units beginning in 2018 for Unit 3 and Unit 1, and in 2019 for Unit 2. EPU implementation will increase the total thermal power of each unit by 494 MWth resulting in a total uprate of 20% from the originally licensed thermal power of 3293 MWth.

Each BFNS unit is currently designed with ten bottom tubesheet condensate filter/demineralizers (CF/Ds) in the condensate treatment system that require an application of a powdered resin precoat to perform the function of demineralization. The precoat material is applied as an overlay on top of vertical filter septa. The filter septa have an inner pleated area, and with a precoat overlay, perform the function of demineralization as well as particulate iron removal. In the absence of circulating water leakage into the condenser, the primary function of the CF/Ds is to remove particulate iron that collects in the condenser hotwell. The iron source is from the corrosion of carbon steel piping and components in contact with main steam and heater drain systems.

Each of the 30 CF/D vessels at the three-unit BFNS site must be periodically backwashed and a new precoat applied. When there is minimal condenser leakage, the backwash frequency is a function of the differential pressure (dP) rise rate across the filter septa, with the dP rise rate a function of filter flow rate and particulate iron concentration. Plants typically will initiate a filter backwash based on reaching an administrative run length limit (operational days). Experience has shown operating well beyond a preestablished run length limit in the long-term can shorten septa life leading to costly septa replacements (typically there are over 300 septa per filter vessel). Prior to EPU, the 30 CF/D vessels are backwashed at a rate of about 0.81 backwashes/day, equating to about 296 backwashes/year.

Under rated EPU conditions, main steam, condensate and feedwater system flows will increase by about 14.3%. Experience has also shown under EPU conditions, the iron concentration in the condenser hotwell will likely increase due to an increase in carbon steel corrosion rates from higher steam and heater drain system flows. The combination of higher flow rates and higher iron levels will result in an increase in the dP rise rate across each filter leading to more frequent filter backwashes and precoats.

In the fall of 2015, Structural Integrity (SI) Chemistry and Materials was contracted by BFNS to perform an assessment on the impact of EPU implementation on CF/D system operation and reactor coolant chemistry. SI has performed similar assessments in the past for other Boiling Water Reactors (BWRs) and has noted that while the Nuclear Steam Supply System (NSSS) vendor and/or the contracted design organization assesses the design capability of each plant system under EPU conditions, they do not assess the impact of EPU on achieving station chemistry goals and industry chemistry performance indicators as well as the impact of EPU operation on system waste generation related to maintaining excellent chemistry control.

Using CF/D operational data from each unit, SI modeled CF/D performance under EPU conditions for higher flow rates and postulated increased iron concentrations. The projection predicted the current 3.0 year - 4.5 year CF/D septa life would decrease at all three units by between 40% and 50% if there was a hotwell iron concentration increase of 25% (typical for EPU). Maintaining the current operating strategy and backwash frequency would increase the total operating cost by about \$1.1 million annually, since there would be about eight additional vessels with septa replacements per year. SI then projected the added costs for doubling the amount of backwash and precoats that are performed to reduce the number of annual septa replacements with the 25% increase in hotwell iron concentration. The calculated increase in annual operating costs for this case

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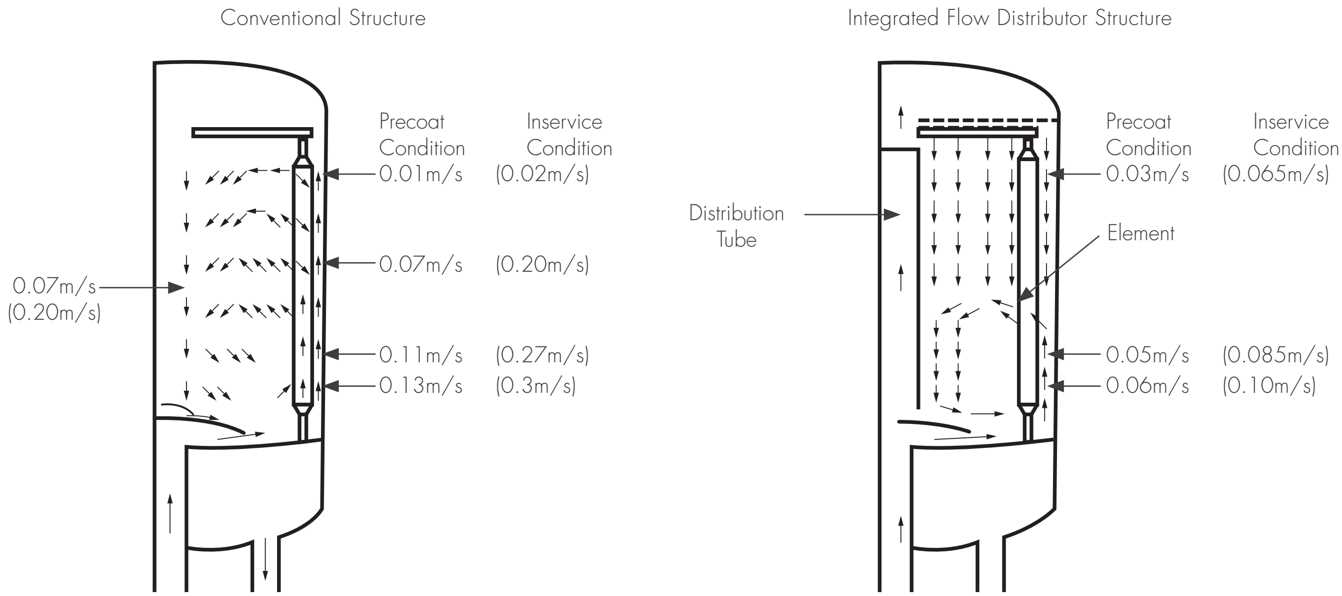

FIGURE 1. Bottom Tubesheet F/D Flow Distribution Improvement with IFD

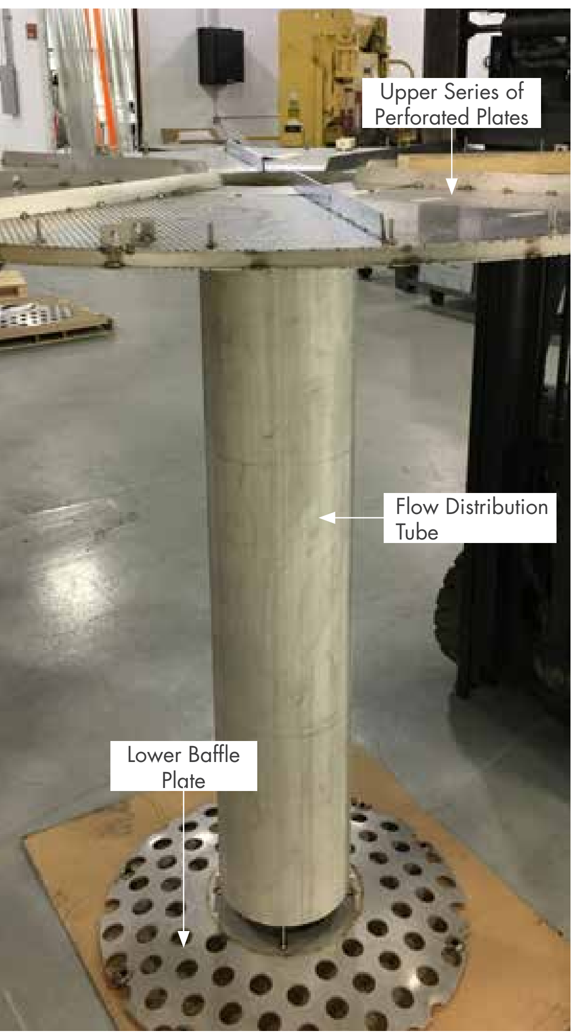

FIGURE 2. Browns Ferry IFD

was about $1.2 million. Although the number of additional septa replacements were projected to be reduced from eight to three, the net cost increase is higher due to the increase costs associated with the addition of new precoat material and more significantly, the increase in precoat material radioactive waste disposal costs.

When each CF/D is backwashed, the backwash waste stream of over 5000 gallons is collected in a Backwash Receiving Tank (BWRT), with the contents of the BWRT being subsequently transferred to the Radwaste Plant for further processing in the Condensate Phase Separators (CPS). In the past at BFNS, processing of CF/D backwash waste in the CPS has caused bottlenecks that have led to delays in startup and power ascension and issues with water storage in the Radwaste Plant. Doubling the amount of CF/D backwashes after EPU would only further challenge the liquid radwaste processing system.

SI's proposed solution to this significant challenge from EPU implementation was the installation of integrated flow distributors (IFDs) in each of the CF/Ds. IFD technology, which was previously presented in Volume 40 of News and Views (2016), are devices that improve the internal flow distribution in bottom tubesheet F/Ds. The improvement in flow distribution in a vessel with an IFD installed compared to the conventional F/D without an IFD is portrayed in Figure 1.

The components of an IFD include a modified lower baffle plate, a flow distribution tube, and an upper series of perforated plates as shown in Figure 2. IFDs distribute flow within bottom tubesheet F/Ds more evenly, promoting flow uniformity along the entire septum length, resulting in more uniform precoats, improved resin utilization, and minimal precoat erosion. The improvement in precoat uniformity is evident in Figure 3 which shows the precoat condition before and after IFD installation at another BWR.

IFD designs are performed by SI's partner, the Organo Corporation, from Japan. The designs for each type of bottom tubesheet vessel are confirmed via computational fluid dynamics modeling. IFD installation does not require any welding inside the F/D vessel.

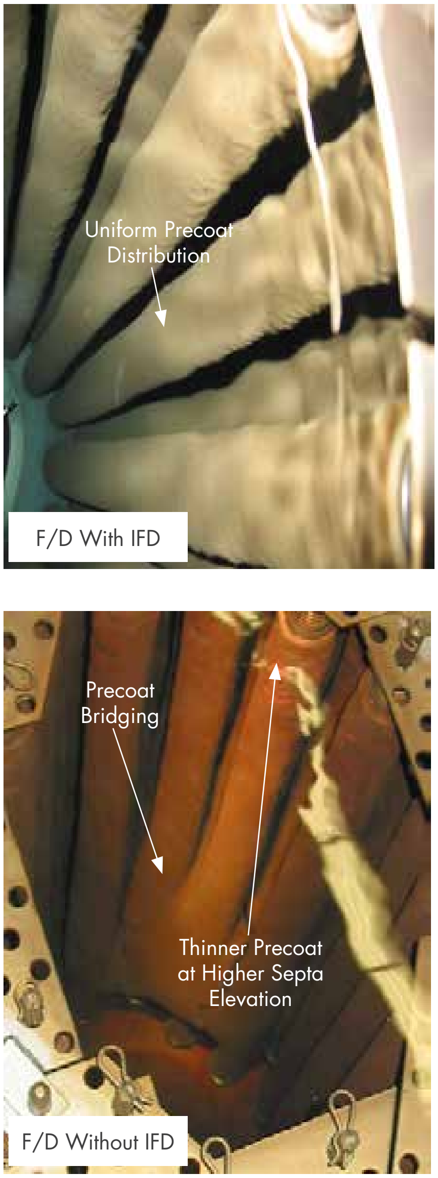

FIGURE 3: CF/C Precoat Uniformity Before and After IFD Installation

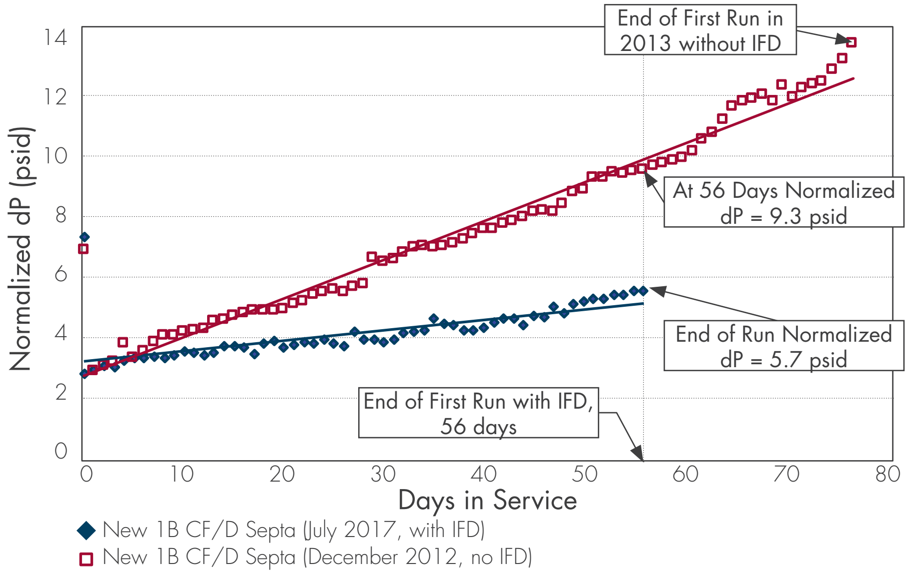

FIGURE 4. Browns Ferry CF/D 1B Differential Pressure after New Septa Installation

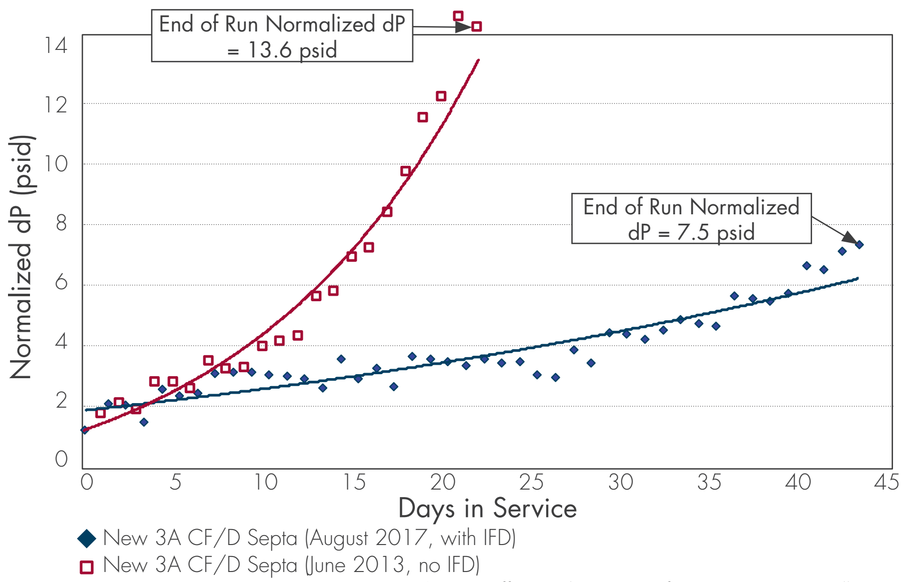

FIGURE 5. Browns Ferry CF/D 3A Differential Pressure after New Septa Installation

SI projected with IFD installation at BFNS and under EPU operation, the projected annual cost increase of $1.1-$1.2 million noted above would essentially be negated, as the projected annual savings was between $990,000-$1.05 million. The projected payback with installation of IFDs in all 30 CF/Ds was about 2.5 years.

BFNS initiated the purchase of IFDs in 2017. IFDs require the removal of some filter septa, so installation was coordinated with septa replacement. The first IFD was installed in the 1B CF/D vessel; the second IFD was installed in the 3A CF/D vessel. The dP trends for the first precoat run for these two vessels are shown in Figure 4 and Figure 5. The dP trends for the first run after the previous time new septa were installed in each of these two vessels (2012 and 2013) are also shown in each plot. Lower dP values with IFDs installed are clearly evident in the plots. The previous septa replacement for vessel 1B conducted in 2012 had a longer run length for the first run; the station has since adjusted operating practices and limits run lengths much shorter in order to extend septa life.

Continued on next page

The ranges and averages for calculated dP rise rates from the first three runs with IFDs compared to the first three runs following the 2012 and 2013 septa replacements are shown in Figure 6 and Figure 7. The dP rise rates are about a factor of two lower for the first three runs with the IFDs compared to historical data for the same filter vessel. The data show the IFD installations have allowed the CF/D vessels at Browns Ferry to be operated with lower differential pressures which will further extend septa life.

BFNS also has bottom tube sheet F/Ds in the Reactor Water Clean-up (RWCU) system. For RWCU applications, precoat runs are terminated based on ion exchange performance, not dP. Plants typically will use conductivity, silica, and/or isotopic Cobalt-60 for terminating precoat runs. As part of the 2015 assessment project, SI concluded that IFD installation in the RWCU F/Ds at BFNS would result in improved chemistry performance and longer run lengths. The station will be installing IFDs along with new septa in all six RWCU F/Ds starting in the spring of 2018. IFDs have been installed in bottom tubesheet F/Ds at five other BWR sites, including four sites with multiple units. RWCU F/D performance data with an IFD from one of these sites was previously presented in Volume 40 of News and Views (2016).

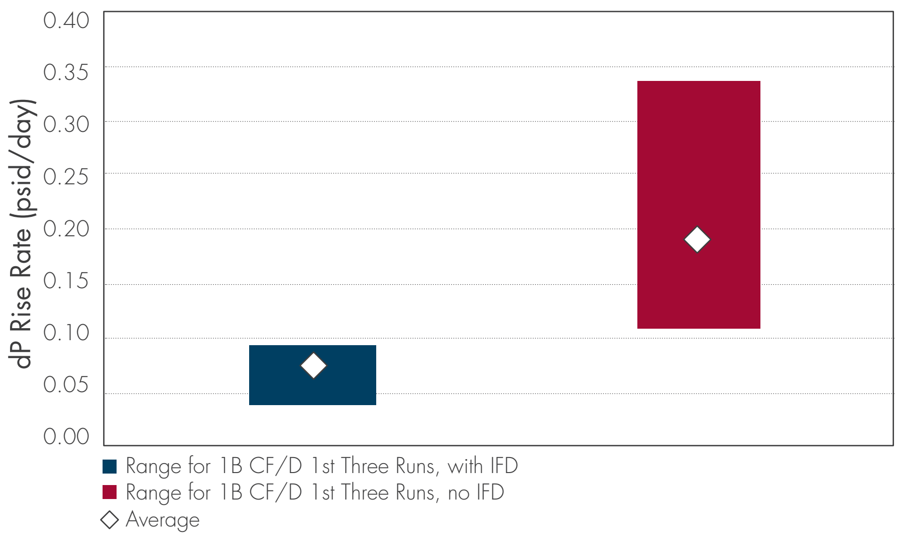

FIGURE 6. Browns Ferry CF/D 1B dP Rise Rate during the 1st Three Runs After Septa Replacement

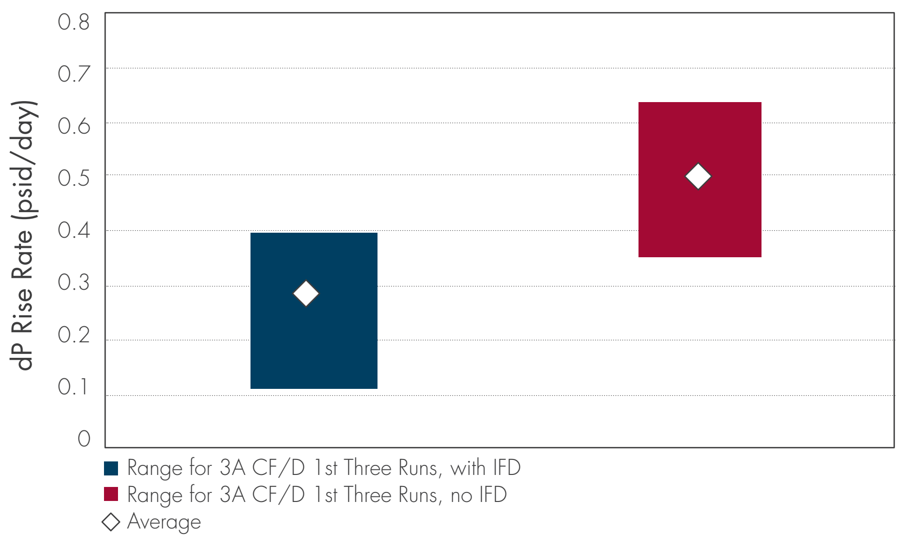

FIGURE 7. Browns Ferry CF/D 3A dP Rise Rate during the 1st Three Runs After Septa Replacement

Metallurgical Lab Featured Damage Mechanism

Long-Term Overheating/Creep (LTOC) in Steam-Cooled Boiler Tubes

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Thick-edged longitudinal rupture in tube section

Long-term overheating and creep damage are often the damage mechanisms associated with the normal or expected end of life of steam-touched tubes, generally occurring after 100,000 hours or more of service life at elevated temperatures and pressures. Long-term overheating and creep can also occur when the rate or accumulation of creep damage is moderately higher than anticipated by original design. There are a number of possible reasons for this, but in general the problem can be attributed to one of the following: a non-conservative original design, higher-than-anticipated heat absorption, lower-than-anticipated steam flow, or wall loss caused by external wastage.

Mechanism

The mechanism of failure for LTOC is simply the accelerated accumulation of creep damage in the component over a span of time that is well short of the anticipated design life, but sufficiently long that creep is the dominant damage mode. This damage is typically associated with the is operation of the tube above

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the oxidation limit for the material involved. This has two effects, which both contribute to long-term creep failure: reduction in wall thickness due to oxidation loss, and build-up of oxide on the tube internal surface, which insulates the tube from the cooling effect of the steam, leading to increasing tube metal temperatures over time.

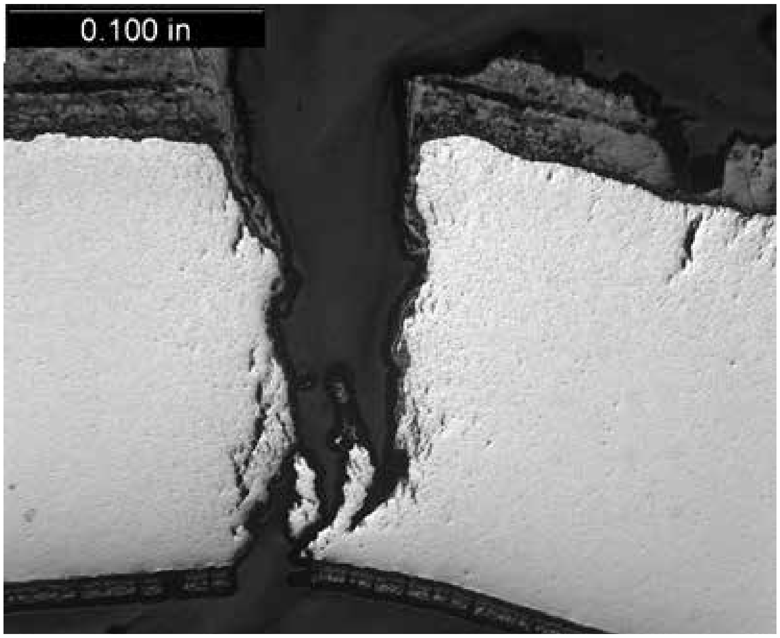
Creep is a time-dependent deformation process that occurs at elevated temperatures under the application of stress for a prolonged duration. Creep results in progressive damage development where initially the material undergoes creep strain accumulation without any detectable microstructural changes. Eventually, the strain accumulation leads to grain boundary cavity development. Further straining results in the coalescence of the grain boundary cavities into grain boundary microcracks. Eventually, the microcracks link to form macrocracks. Under the temperature and loading conditions that initiate damage, the progression of cavitation, microcracking, and macrocracking continues during a period of stable damage progression until a critical crack size is reached and rapid failure occurs. In long-term creep failures the total ductility at failure is typically relatively low, so there will be limited swelling prior to tube rupture.

Typical Locations

- Tubes with higher operating temperatures
- Lower alloys at material transitions
- Thinner tubes at thickness transitions
- Leading tubes
- Outlet tubes leading into outlet headers

Features

- Thick-edged longitudinal rupture
- Swelling of tube diameter
- Elephant-hide appearance on external surface
- Creep voids and microcracks in microstructure
- Thick internal oxide layer



TOP Ring-section through rupture showing some swelling and thick outer diameter and inner diameter oxide

BOTTOM Cross-section through rupture showing severe creep damage

Planned and Emergent Outage Support

Structural Integrity is on Your Team

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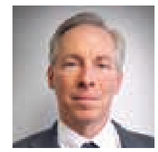

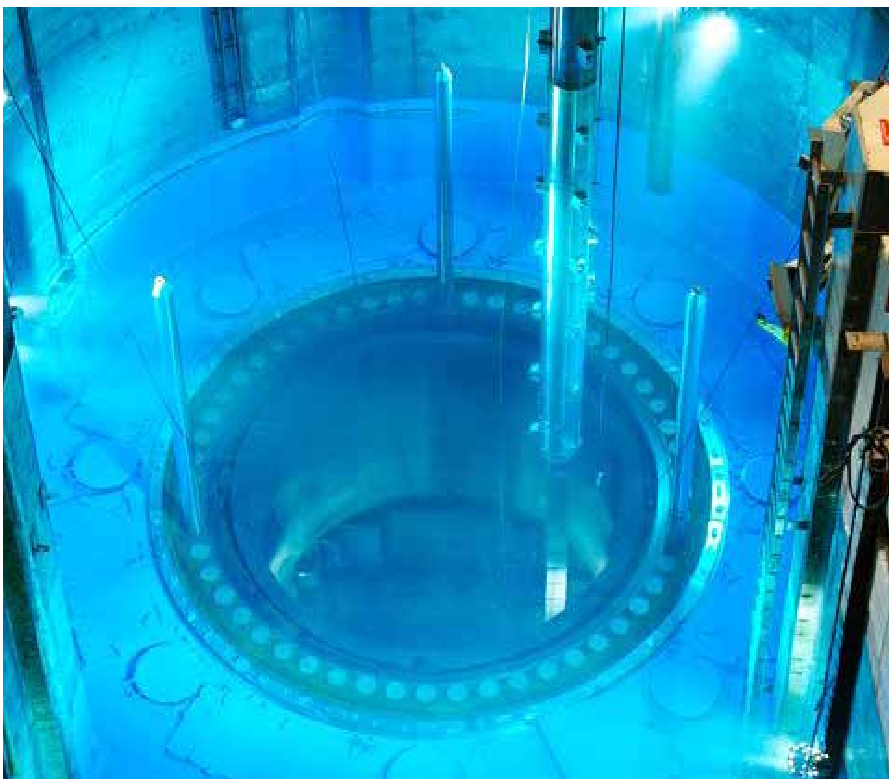

While the 2018 Spring outage season is mostly behind us, we all know a key element in being able to provide safe, reliable, clean and economic power to energy consumers is how successful plant outages are accomplished. I know from personal experience how good planning, including contingency planning, has significantly reduced outage durations (see Figure 1). I worked my first outage in 1981. It ran 110 days and was punctuated by rework, surprise discoveries and last-minute procurement of materials and services. By the late 1990s the industry had established outage milestones for design changes, significantly improved the level of detail in schedules, performed more work with the plant on line and implemented focused outage control organizations. Except for major activities like condenser retubing, power uprates and emergent issues that impact the scheduled critical path, outage durations today are almost exclusively associated with refueling activities.

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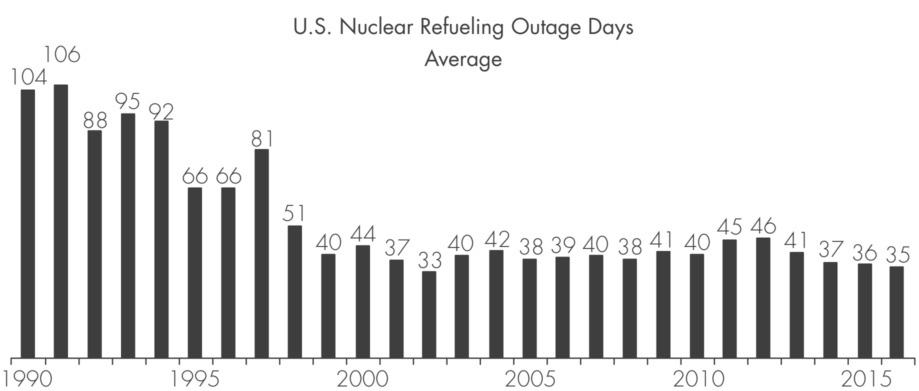

FIGURE 1. Average US Refueling Outage Duration (1990 – 2016)

Support for Planned Outage Activities

Outage activities which cannot be performed on line include refueling and inspections associated with the reactor, reactor coolant pressure boundary, power conversion system components and certain cooling systems. A partial listing of the services Structural Integrity provides for these activities include:

- Third party independent review of critical/high risk engineering work performed by others.
- License Renewal commitment support.
- NDE inspections for PWSCC, IGSCC, fatigue, FAC, raw water corrosion, etc.
- NDE inspections of turbine rotors (both with and without bore holes) and rotor blade attachments, generator shaft keyways and rotor dovetails, as well as turbine casings.
- Engineering review and torsional vibration monitoring of replacement turbines.
- Development of flaw handbooks to establish acceptance criteria in advance of reactor pressure vessel (RPV) and in-vessel visual inspections (IVVI) of core spray piping, shroud welds, jet pumps, top guide, etc.
- Development of acceptance criteria and analytical models to provide rapid evaluation of containment inspections (including BWR Mark 1 torus inspections and coating evaluations).
- Development of thinning handbooks for systems susceptible to accelerated/localized corrosion mechanisms and, for piping within the scope of ASME Code Case N-513, flaw handbooks that demonstrate structural integrity for flaws which may exhibit leaks to postpone repair/replacement for a limited time.
- Design and licensing support for full structural and optimized weld overlays.
- Performing analyses in support of relief requests to defer or eliminate certain ISI exams.
- Chemistry support for water processing, decontamination and start-up water chemistry (hydrogen water chemistry, noble metal chemicals, filter/demineralizer optimization, etc.)
- Reactor engineering support for fuel procurement, flexible operation and reload analysis.

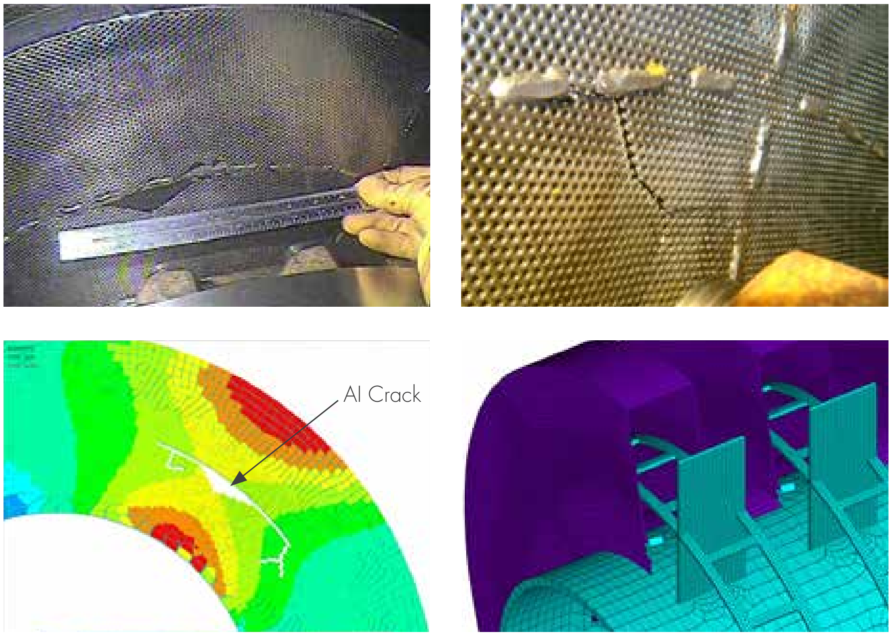

FIGURE 2. ECCS Strainer Damage – Finite Element Models

FIGURE 3. Smallbore Line Post-Repair Monitoring

Support for Emergent Outage Issues

Unfortunately, emergent issues requiring immediate support sometimes occur during planned outages despite best efforts. These can include chemistry excursions and contamination events, planned inspections that reveal more significant damage than had been anticipated in the outage plan, self-revealing issues as normally inaccessible locations are entered and issues which result from planned activities. Additionally, emergent issues occur that result in unplanned outages and we receive a call due to SI's well-earned reputation for being able to respond effectively to these kinds of issues. Examples of recent support SI has provided for these kinds of issues include:

- Diagnosed the cause of a failed snubber piston rod (located inside containment).
- Performed stress, fatigue and crack growth analysis of an ECCS suction strainer to both evaluate past operability and remediate the condition in support of plant startup (see Figure 2).
- Established the cause of a smallbore failure (confirmed to be vibration-induced), evaluating extent of condition, providing welding engineering support for application of Code Case N-666 overlay, performing Class 1 analysis of repair design and post repair vibration testing (see Figure 3).
- Provided immediate onsite and offsite metallurgical and structural engineering support following failure of a large surface condenser to establish the cause of the failure, develop and implement a repair design, identify any other overstressed structural elements (see Figure 4) and to monitor structural strain and vibration (see Figure 5) for validation of the underlying cause and identify previously unidentified loading conditions (see Figure 6).
- Performed a serviceability evaluation of structural components associated with failure of a steam condenser to establish a basis for future operation in the event a flaw was discovered during a short-duration outage window (see Figure 6).
- Performed flaw evaluations of core spray line welds, core shroud, RPV top head.
- Designed a weld pad repair per ASME Code Case N-561-2 to allow deferring a permanent repair until the next refueling outage.
- Developed plant-specific alternate heat exchanger tube plugging criteria to avoid exceeding tube plugging limits and extend operation of the heat exchanger to allow tube plugging on a non-emergent basis.
- Performed ASME Section III qualification of gouged steam generator channel head instrument nozzles on an interim basis and provided follow-up qualification through the remaining license term following plant startup.
- Performed a structural evaluation of a valve yoke degraded by boric acid corrosion to establish operability of the valve and postpone repair to a future outage.

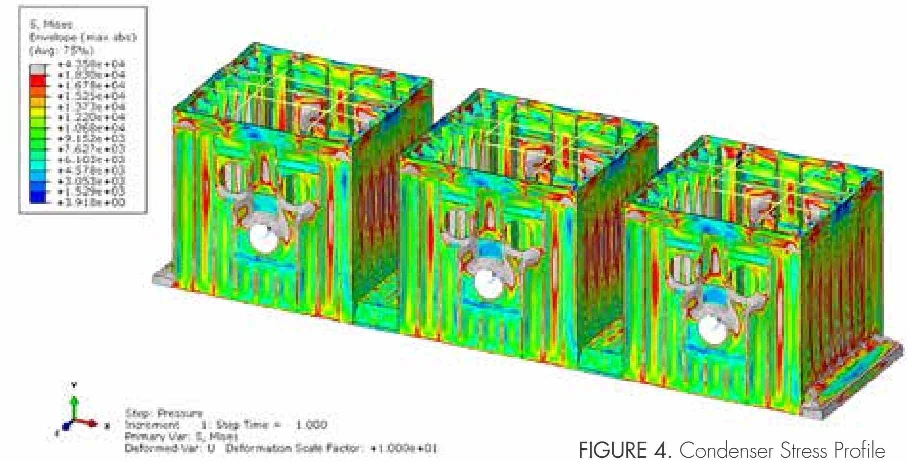

FIGURE 4. Condenser Stress Profile

FIGURE 5. Monitoring Structural Response

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Single Point of Contact (SPOC) Initiative

During the Spring of 2017 there were a record number of outages. One of the things I know from personal experience is when emergent issues occur, it can be very helpful to have a handy list of who the OCC or EOCC can call.

To provide the best possible support for our clients, SI initiated an initiative whereby a Single Point of Contact (SPOC) was assigned to each plant with an upcoming outage. Each SPOC is committed to mobilizing the resources necessary to address any issue that may arise over the course of the outage. Notwithstanding, clients may also contact any SI associate they have worked with in the past, or feel free to call our toll-free number, 877-4SI-POWER, which has live answering and emergency call routing.

In addition, we developed a one-page sheet with information listing SI's SPOC and experts to call 24/7. We laminate and provide this list to plants typically a few weeks in advance of their outage. Several plants have put this laminated list on the board in the OCC and/or EOCC for ready reference and have told us this has been very helpful in shortening the time it takes to reach the right people to help with an issue.

At SI, we know the importance of keeping outages as short and effective as possible. As part of your outage support team, we're committed to doing our best to making that happen.

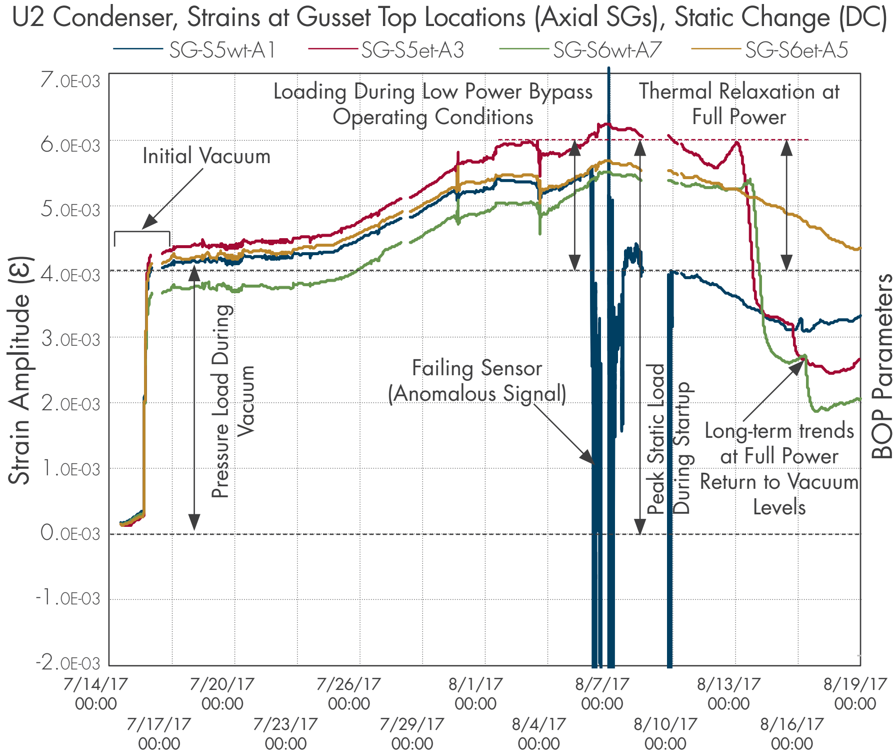


FIGURE 6. Loading Conditions from Installed Instruments

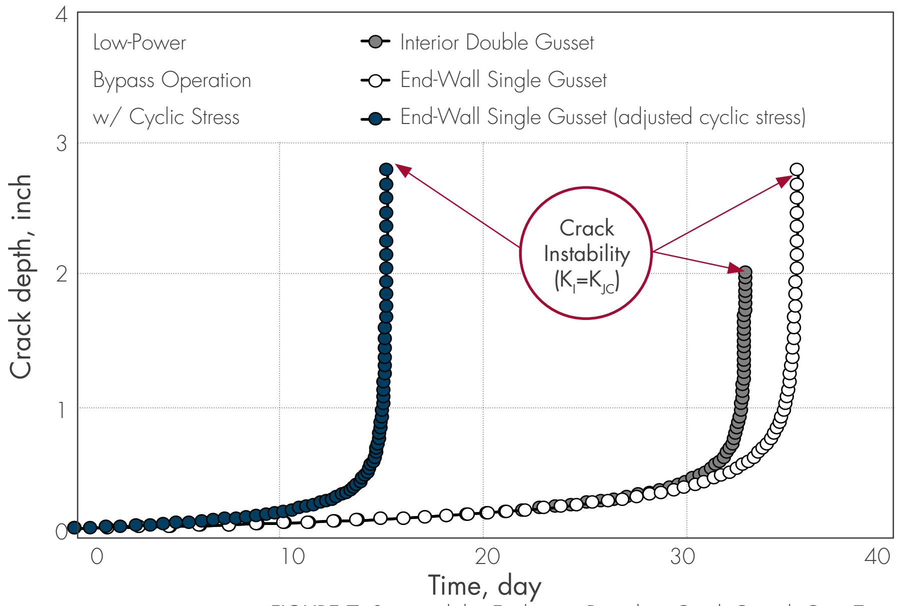
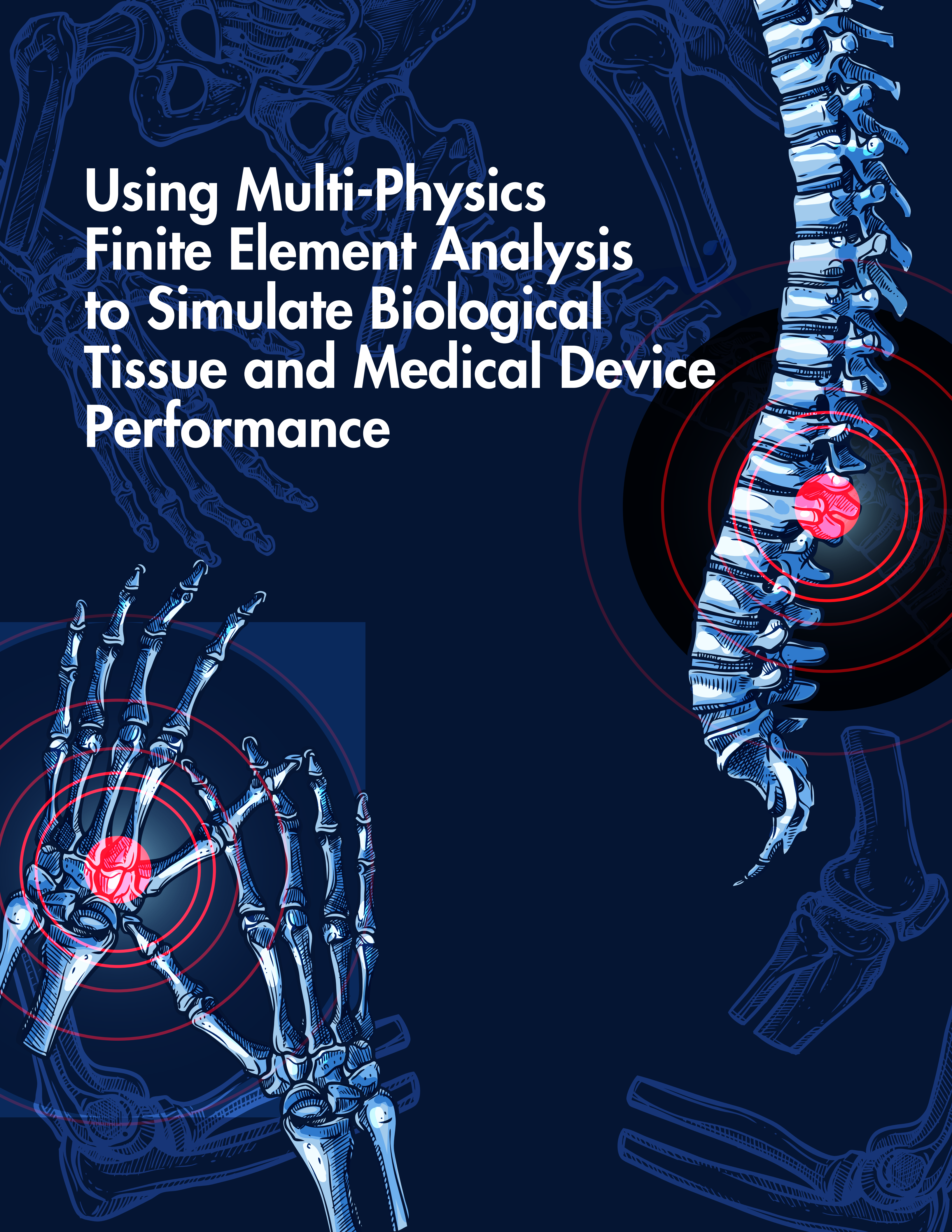
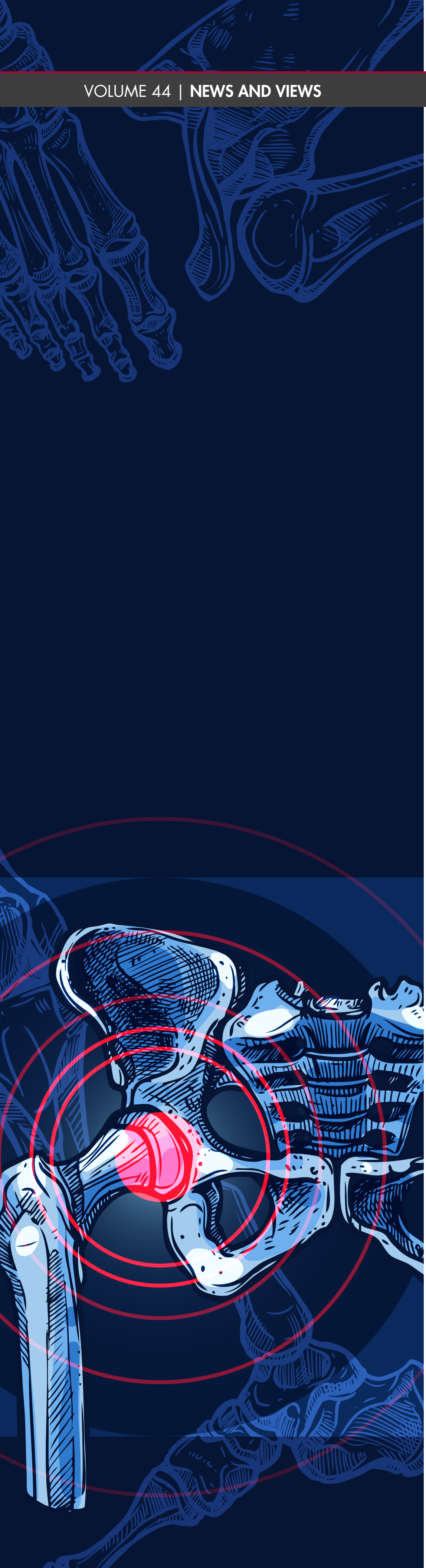


FIGURE 7. Serviceability Evaluation Based on Crack Growth Over Time

Using Multi-Physics Finite Element Analysis to Simulate Biological Tissue and Medical Device Performance





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The ability to accurately model and simulate biological tissue and its interactions with foreign medical tools is becoming of utmost importance as surgical procedures and medical devices become more complex and numerous. Traditionally, medical device designers and surgeons have solely relied on extensive, costly experimental testing, and empirical evidence to develop new medical devices and surgical techniques. Accurately simulating, through computational modeling, the internal physics occurring within biological tissue when interacting with medical devices allows for faster, more accurate, and safer device design by allowing a more comprehensive design process.

When attempting to simulate biological tissue, especially soft biological tissue, several challenges present themselves. Firstly, the mechanical structure of biological tissue is inherently complex. It is heterogenous and often multi-phasic, meaning it is composed of several different materials and often has fluid flowing through and interacting with the solid tissue. Additionally, nearly all biological tissue acts non-linearly and undergoes large deformations. Thus, computational modeling efforts have been limited in scope and accuracy; however, great advancements in this arena are currently being made. Structural Integrity (SI), through utilizing its non-linear computational modeling capabilities and building on work conducted at the Advanced Medical Technologies Laboratory at the University of Colorado, has the ability to provide high fidelity simulations to evaluate the safety and performance of medical devices and procedures.

Mechanical Structure and Modeling Soft Biological Tissue

Most soft biological tissues (i.e. blood vessels, cartilage, muscle, liver, etc.) consist of a fibrous (typically collagenous) extra-cellular matrix (ECM) which provides the primary structural strength. This ECM is a porous structure with hydrophilic molecules attached to it. This means water or other fluids flow through the structure and also become bound to the

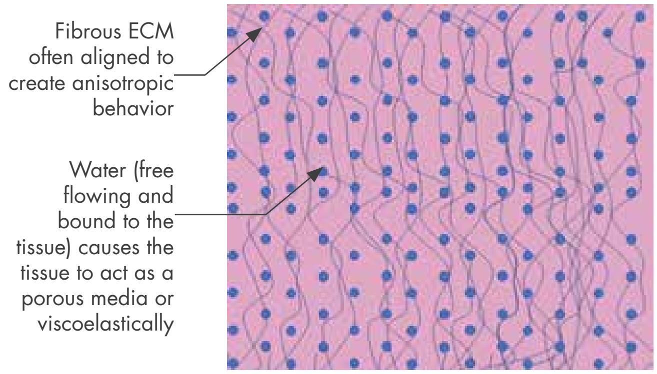

FIGURE 1. A general depiction of soft biological tissue.

structure when the tissue is acted upon by outside mechanical or thermal loads. Thus, stiffness and strength of the tissue are non-linearly dependent not only on the stress within the tissue but on the tissue water content and porosity as well. To model this phenomenon several approaches can be taken. They vary from simply using a non-linear hyperelastic material model with factors accounting for the water content in the tissue to modeling the tissue as a porous medium where both the stress in the tissue and water transport through the tissue are simulated. Additionally, surgeons often employ tools that use heat and/or energy to impart physical change within the tissue during procedures such as Lasik surgery, electrocautery, tumor removal, and fusion of bowel, skin, and arterial tissue. This adds yet another factor to account for during the simulation of surgeries. The sections following provide examples of two cutting edge methods now available at Structural Integrity to simulate the multi-physics occurring in biological tissue during surgery.

Predictive Thermo-Mechanical Damage Modeling of Arterial Tissue Fusion and Cutting

Currently, surgeons employ electro-surgical devices to cut and fuse closed arteries during surgery to eliminate introduction of foreign objects such as sutures and mechanical clips into the body. To design these devices engineers must use solely empirical evidence to evaluate design performance. This means they must construct and conduct numerous costly experimental studies during each design iteration. The study presented in this section provides an example of how non-linear thermo-mechanical finite element (FE) modeling can be used to elucidate material properties from mechanical testing via inverse finite element methods and to predict a medical devices ability to cut an artery using temperature and pressure. The first necessary step to employing a predictive model was to determine the conditions at which an artery is cut. Previous studies had been conducted in which sections of arteries had been cut into strips. For each strip a temperature and pressure was applied via a surgical device and the surgical outcome (whether the artery was cut or not) was recorded. As the primary metrics determining tissue strength, tissue strain energy and tissue temperature, for each test could not be easily calculated by hand, an inverse FE method was used to determine the strain energy and the temperature occurring within the tissue during each test. Each simulation was conducted using the FE software Abaqus. In Abaqus, a non-linear anisotropic, hyperelastic thermo-mechanical user subroutine, that accounts for the change in water content and material properties of the tissue representing the artery wall, was implemented to represent the internal mechanics occurring in the artery tissue. Using these simulations, a damage equation, representing when artery tissue is cut as a function of tissue strain energy and temperature was developed. This equation was then used in simulations in Abaqus to evaluate device performance. Figure 2 shows a full surgical simulation setup in Abaqus. Figure 3 shows the ability of the Abaqus model to predict a surgical outcome. This ability to accurately predict surgical device performance allows for device designers to generate and evaluate numerous prototypes without going through costly experimental studies. Structural Integrity's experience in advanced non-linear FE modeling can provide valuable support to medical device companies saving them both time and resources.

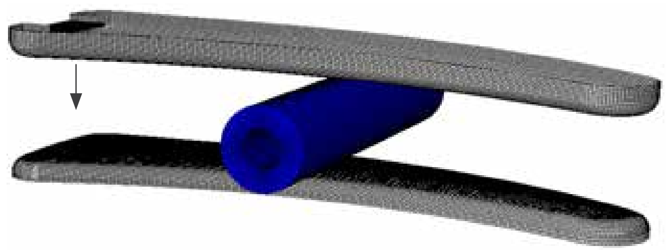

FIGURE 2. Abaqus simulation of a full surgery

Large Deformation Thermo-Poromechanics Modeling

While examining the strength and deformation of biological tissue is important, to completely evaluate medical device performance and accurately capture the physics occurring within biological tissue a multi-physics modeling approach must be taken. As noted earlier, biological tissue is typically biphasic (or triphasic if heated to boiling temperatures as seen during fusion and ablation), thus a poromechanics or thermo-poromechanics (TPM) FE model must be used. Poromechanics and thermo-poromechanics FE modeling efforts have been used extensively in geomechanics for years. However, their use in biomechanics has been limited due the fact that biological tissue undergoes very large strains (10's to 1000's of percent) and rotations regularly. Only recently have both

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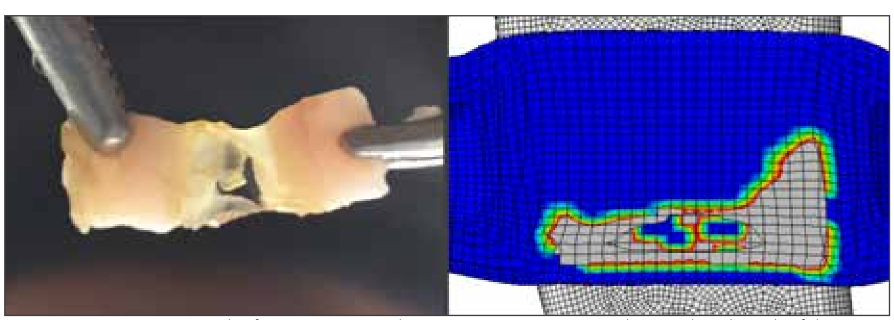

FIGURE 3. LEFT A result of an experimental artery cutting test. RIGHT The simulated result of the same test in Abaqus, the gray represents completely damaged tissue [1].

computational power and porous media FE theory been able to capture the intense coupled non-linearities that occur in multi-physics modeling of biological tissue. Recently, at the University of Colorado, a large deformation, fully coupled, thermo-poromechanics FE code has been developed. It has shown the ability to accurately capture the highly non-linear, large deformation mechanics occurring within tissue during arterial fusion. Structural Integrity is working to commercialize and extend these capabilities to be able to simulate a wide range of surgical and medical procedures.

The newly developed large deformation, coupled TPM code has been shown to accurately predict not only tissue deformation, but also the heat and water transport – including water phase change – occurring during a thermal tissue fusion surgical procedure. Figure 6 shows the predicted artery wall temperature, water content, and deformation occurring during a thermal tissue fusion simulation.

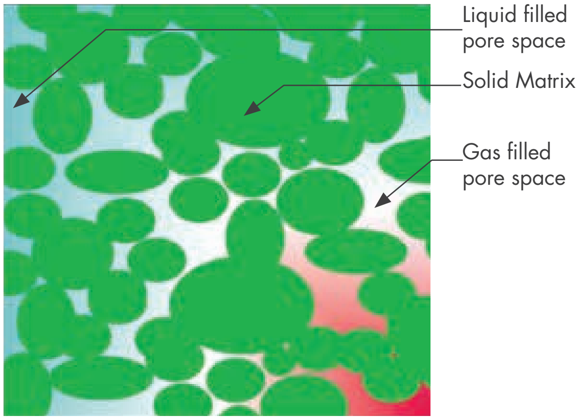

FIGURE 4. Depicts a porous medium and the ongoing physics represented by TPM theory.

Conclusion

Presented here are just two of countless ways the FE modeling capabilities and expertise at Structural Integrity can be utilized to analyze medical devices and procedures. With complex non-linear FE modeling experience along with the development of large deformation, TPM FE code, SI can provide valuable services to medical companies looking to gain a fuller understanding of their procedures, get products to market less expensively, quicker and develop safer more effective products.

References

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[2] Fankell, D.P., "A thermo - poromechanics finite element model for predicting arterial tissue fusion", Doctoral Dissertation, presented at the University of Colorado, July 2017

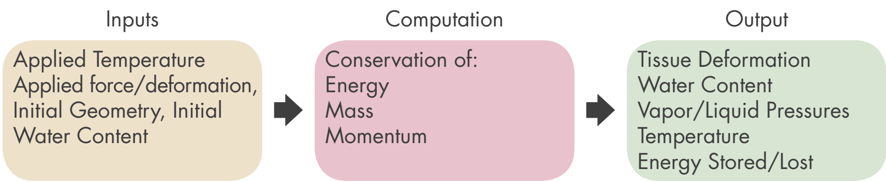

FIGURE 5. Displays the input parameters and the results of the TPM finite element code.

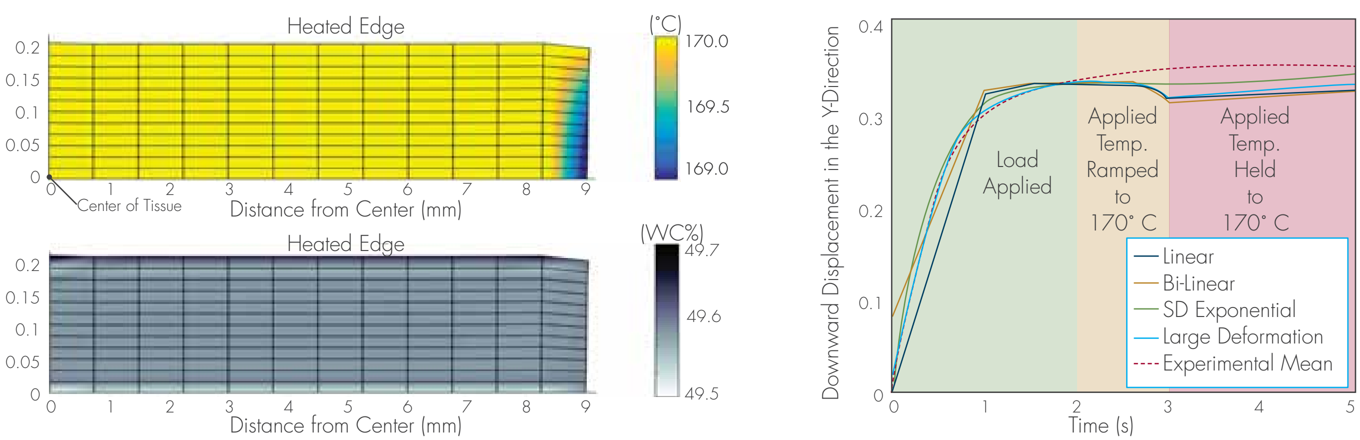

FIGURE 6. LEFT The predicted temperature and water content occurring within a slice of artery wall during the tissue fusion process. RIGHT The downward deflection of the tissue for small deformation (linear, bi-linear, and SD exponential) and large deformation TPM simulations as compared to experimental results. Notice how the large deformation more closely captures the tissue behavior. [2]

Example Grade 91 High Energy Piping DMW Joint Stress and Metallurgical Analysis

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Determining a course of action once in-service damage is discovered often requires applying a multi-disciplinary approach that utilizes Nondestructive Examination (NDE), analytical techniques such as stress analysis, and metallurgical lab examination. Such was the case recently for a combined cycle plant where indications were found through NDE on the inlet sides of two identical main steam stop/control valves but were not seen on the outlet side. In this case, Structural Integrity (SI) did not perform the field NDE but was requested to perform analytical and metallurgical assessments of the welds. The welds in question joined the 1Cr-1Mo-1/2V (SA-356 Grade 9) main stop/control valve body castings to Grade 91 piping, so the welds represent a ferritic-to-ferritic dissimilar metal weld (DMW). See the *Dissimilar Metal Welds in Grade 91 Steel, (page 15)* for further information. The welds were made using a 1Cr-1/2Mo (AWS type B2) filler metal, which matches the chromium content of the valve body, but is significantly undermatching

in strength to both the valve body material and the Grade 91 piping. The course of action taken was to perform local stress analysis and remaining life estimates for the downstream (outlet) connections of the valves to assess likelihood of future damage and establish an appropriate re-inspection interval. Detailed metallurgical analysis was also performed on a ring (entire circumference) section removed from one of the upstream welds (which exhibited both surface and volumetric indications in the weld metal) in order to provide insight into the damage mechanism and inform the stress analysis and

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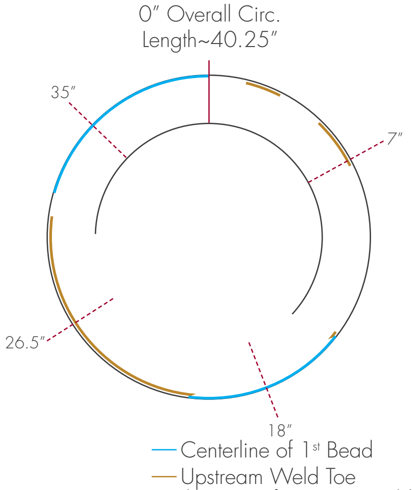

FIGURE 1. Schematic of upstream weld ring section illustrating the extent of crack-like surface indications found in laboratory visual and magnetic particle inspections. The circumferential locations of four metallographic sections removed from the ring are also noted.

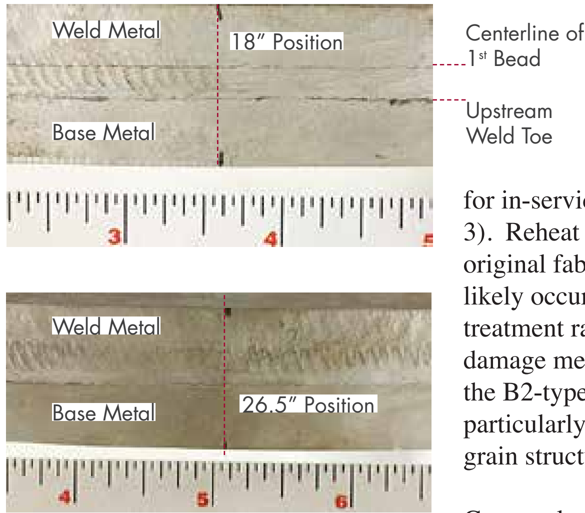

FIGURE 2. Close views of crack-like visual indications on the weld surface at two circumferential locations. Cracks were found at both weld toe and at the centerline of the first weld bead.

remaining life estimates.

Metallurgical Analysis of Upstream (Inlet) Weld

The ring section was subjected to an initial visual and magnetic particle inspection, which revealed surface indications that were not detected or reported during the third-party NDE performed on site; the extent and appearance of these indications are shown in Figures 1 and 2.

Metallographic sections were prepared through the weld at the four circumferential locations noted in Figure 1. Examination of the sections identified two separate damage mechanisms: reheat cracking occurring in the large columnar grains at the centerline of the surface weld deposit, and creep damage in the weld deposit adjacent to a carbon-depleted region along the fusion line. Microchemical analysis by energy-dispersive x-ray spectroscopy in the scanning electron microscope (SEM-EDS) confirmed that the weld metal deposit was indeed a type B2 material (1Cr-1/2Mo), while the pipe base metal was Grade 91 (9Cr-1Mo-V-Nb). Figure 3 shows a macroscopic overview of one of the sections; Figure 4 shows a closer view of creep-related weld toe cracking in another section.

Evidence for reheat cracking was found in the form of intergranular cavitation and cracking in the surface weld beads. In some areas it appears these cracks acted as initiation sites for in-service creep cracking (Figure 3). Reheat cracking is related to original fabrication, with the cracking likely occurring during post-weld heat treatment rather than in service. This damage mechanism is not common for the B2-type filler metal but is possible, particularly given the large columnar grain structure in the weld deposit.

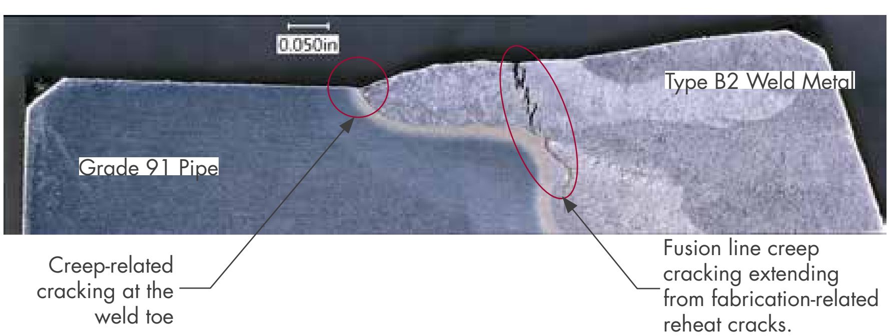

FIGURE 3. Overview of the metallographic section prepared at the 18″ circumferential location, with creep-related cracking present at the weld toe, in the first weld bead, and along the fusion line. Creep cracking in the first weld bead likely developed from fabrication-related reheat cracks.

Creep-related fusion line cracking is common for welds between ferritic materials with dissimilar chromium content. The chromium gradient drives carbon migration from the lower-chromium material to the higher-chromium material, creating a weaker, carbon-depleted region in the lower chromium material, which in this case is the weld deposit. See the *Dissimilar Metal Welds in Grade 91 Steel, (page 15)* for further information. A corresponding carbon-enriched zone forms in the higher-chromium material. Creep damage will preferentially form in or immediately adjacent to the carbon depleted zone due to the local strength mismatch between the depleted and non-depleted materials (Figure 4). The carbon migration and consequential creep damage results from service exposure at normal operating temperatures (~1040°F). The degree of carbon migration was typical for a weld between Grade 91 and B2-type (1Cr-Mo) filler metal that has experienced approximately 90,000 hours of service.

Creep damage associated with the carbon-depleted zone is the fundamental damage mechanism that will control the life (failure time) of such ferritic dissimilar metal welds. In this case, the creep-damaged region (cavities and linkage to macro-cracking) represents approximately 15% of the wall thickness. As a result,

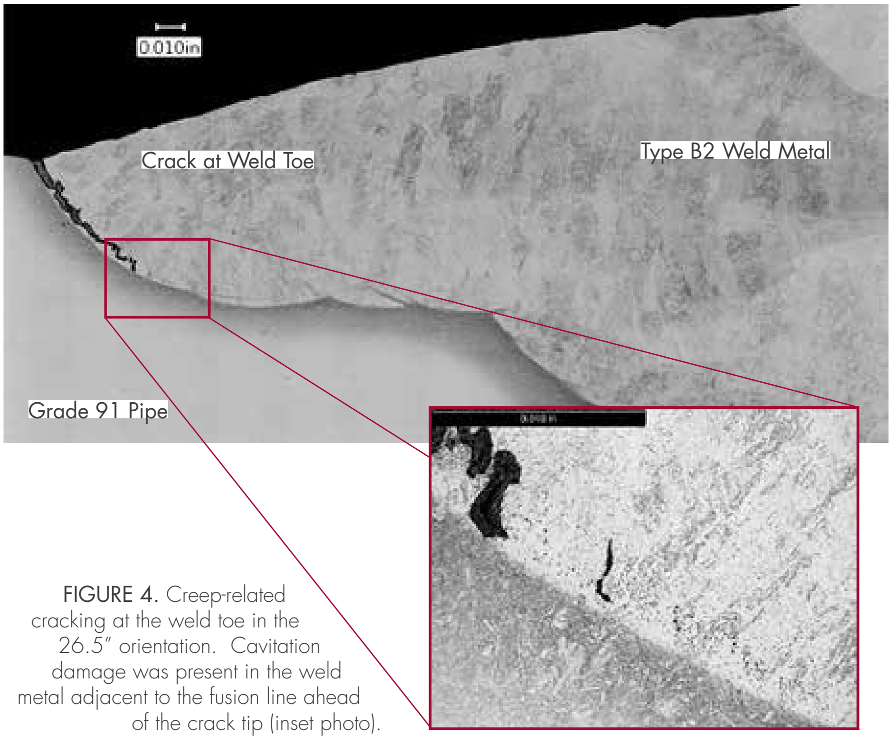

FIGURE 4. Creep-related cracking at the weld toe in the 26.5" orientation. Cavitation damage was present in the weld metal adjacent to the fusion line ahead of the crack tip (inset photo).

this weld could have endured some continued service before cracking would have extended fully through the wall and resulted in a steam leak. When performing life assessment of such welds, the region of creep-weak material adjacent to the fusion line should be included in any analytical models. This is highlighted further in the next section which discusses stress analysis of such welds.

Stress Analysis

After discovery of significant indications on the upstream (inlet) welds to the main steam stop/control valves as documented in the metallurgical section above, a detailed stress analysis and lifetime prediction was requested for the downstream (outlet) welds. Detailed creep-redistributed stress analysis was performed using a finite element model geometry that was based on field measurement of the thickness profile from the valve body to the transition piece. The finite element model accounted for the different creep strengths of the various materials associated with the weld joint, in particular the lower strength of the B2-type weld deposit and the carbon-depleted zone which forms adjacent to the weld fusion line between the weld deposit and the Grade 91 pipe. The calculation results (Figure 5) indicated that the creep deformation of the weaker weld deposit would be constrained by the stronger surrounding Cr-Mo-V and Grade 91 materials, and under internal pressure alone the lifetime for the downstream weld was predicted to be approximately 150,000 hours, accounting for the effects of carbon migration.

This is consistent with the lack of damage found in third-party NDE of the downstream welds. Detailed numerical analysis of the upstream weld was not performed as part of this study, but based on the geometric differences between the upstream and downstream welds, the stress in the upstream weld was estimated to be approximately 10% higher than that in the downstream weld (potentially even higher if there were additional axial system stress). This suggests, based on creep rupture data, the upstream weld would have approximately 70% of the life of the downstream weld. Given the downstream weld estimated life of 150,000 hours, the estimated lifetime of the upstream weld would be approximately 100,000 hours, similar to the stated operating time of ~90,000 hours at which extensive cracking was present.

These calculations suggest damage in the upstream weld was very likely (life fraction nearly fully consumed), whereas the downstream weld had reached a life fraction of approximately 70%. Hence some indications (creep damage) are likely at the downstream weld, but these may have not linked to form a macroscopic crack, consistent with the lack of NDE indications for this weld.

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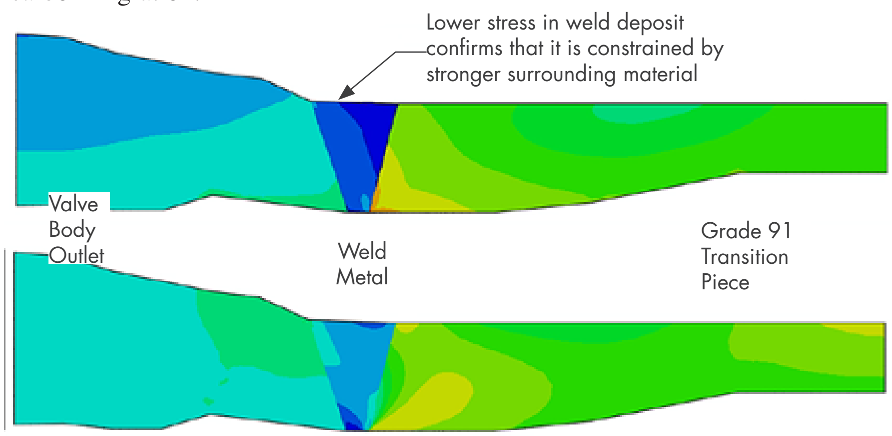

FIGURE 5. FEA output showing spatial distributions of creep-redistributed von Mises equivalent stress TOP and maximum principal stress BOTTOM in the modeled weldment.

Discussion

This is an interesting case study because the transition between the valve body and piping included a tapered transition piece to bridge the thickness differential between the valve body and piping. On the face of it, that would be regarded as "good practice", particularly since failures at other similar connections have been exacerbated by the lack of a transition piece leaving the weld deposit to bridge the thickness differential. Hence, even with a transition piece, the connection is vulnerable because of the carbon migration that occurs as a result of the difference in chromium content, in this case between the weld deposit and transition piece. The use of a significantly under-matched filler metal (type B2) does not help in this case. While the filler metal is constrained by the stronger surrounding material, the triaxial stresses that result from creep stress redistribution promote creep damage formation.

The primary mitigation in the present case, would be to remove the B2-type (1Cr-1/2Mo) weld deposit and replace it with a B9-type (9Cr-1Mo-V-Nb) deposit on the upstream and downstream welds. This would remove any prior creep damage and local carbon migration. The use of B9-type filler metal provides a closer strength match to the piping and valve body, although a chromium differential still exists on the valve side of the weld deposit. So this weld remains vulnerable to failure, but the closer match in strength will mitigate some stress triaxiality. As a result, such welds should be subject to occasional inspection with an appropriate interval being selected from creep redistributed stress analysis and subsequent lifing based on a similar approach to the stress analysis described earlier.

This case study also highlights indications can be missed during routine NDE. In this case it appears surface preparation techniques may have contributed to masking of damage. This is why use of a grit-blasting surface preparation technique should be adopted (versus wire-wheel), and this should be accompanied by use of wet fluorescent magnetic particle testing (WFMT) which provides good sensitivity to oxide-filled cracks in components that operate at high temperature. Inspection should also include use of linear phased array (LPA) ultrasonic techniques since subsurface cracking is likely in such welds.

More generally, the life of such ferritic dissimilar welds is significantly reduced by higher stresses acting across the weld, directly stressing the weaker carbon denuded region. For that reason it is always prudent to have a detailed creep redistributed stress analysis for piping systems that operate in the creep range; this provides accurate estimates of cross-weld stress can be used in lifing calculations. This should obviously be accompanied by occasional pipe support surveys to ensure the piping system movement is consistent with the stress analysis.

A First-of-a-Kind NDE Innovation from SI

The first PDI qualified manually-encoded DM weld procedure

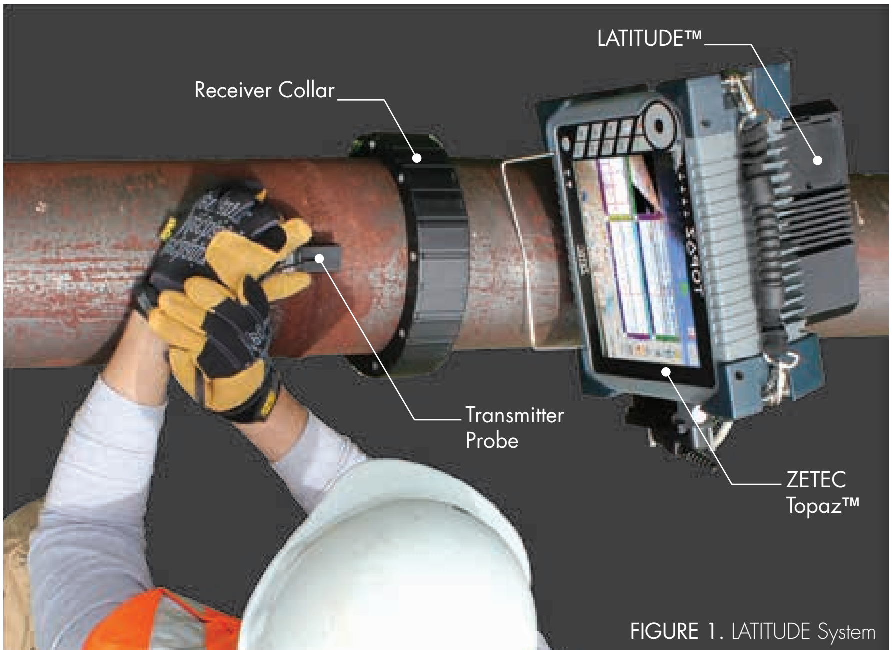

FIGURE 1. LATITUDE System

For More Information Visit SI-LATITUDE.com

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In our last issue of News and Views (Volume 43, page 32), we introduced LATITUDE™ , a revolutionary non-mechanized position and orientation encoding technology that is designed for use with nondestructive evaluation (NDE) equipment. The Latitude system, when coupled with an NDE data acquisition system, allows an operator to acquire high-quality encoded data using a manual examination process. Fast-forward a mere five months and Structural Integrity (SI) is pleased to announce that it has qualified the first ever manually encoded phased array UT procedure for the examination of dissimilar metal welds (DMWs) in nuclear power plants. The procedure qualification was administered by the Electric Power Research Institute (EPRI) in accordance with Performance Demonstration Initiative (PDI) requirements.

This procedure, along with the use of LATITUDE, allows SI to provide several advantages to its clients. They are as follows:

- **The use of SI-UT-217 and LATITUDE provides a faster encoded examination than currently available qualified procedures.** This technique significantly improves the production rate for acquiring encoded data by employing a novel manual scanning technique and by eliminating the need for cumbersome and complicated automated inspection equipment. Time for in-processing, scanning, transportation between welds, and out-processing are all reduced;
- **The number of personnel required to deploy this procedure is minimized.** LATITUDE has fewer parts and set-up is simpler when compared to automated inspection equipment. The LATITUDE system is compact, arriving on site in a few transportable ruggedized cases and operates entirely on battery power;

Continued on next page

- **The total amount of equipment needed to deploy SI-UT-217 in containment is drastically minimized.** The total system (see Figure 1) is comprised of a Topaz phased-array UT instrument, and a LATITUDE system, probe and collar. This reduced equipment size lowers the overall risk and cost associated with decontamination. Compared with an automated setup, the amount of equipment brought to site to deploy SI-UT-217 is drastically reduced;
- **The overall cost and potential dose impact to the plant is reduced.**

Additionally, experimental data collected on DMW practice samples showed that manual scanning (i.e., scanning by hand) often yielded higher-quality data than automated scanning. This is illustrated in Figure 2, which shows a comparison of manually-acquired data using the LATITUDE system with automated data acquired on the same sample. The comparison shows an appreciable improvement in the signal-to-noise ratio for the manually-acquired data, which is especially important for this sample because it contains one of the most difficult flaws in the practice sample population. In Figure 3, a similar comparison is shown for axial flaws in another practice sample.

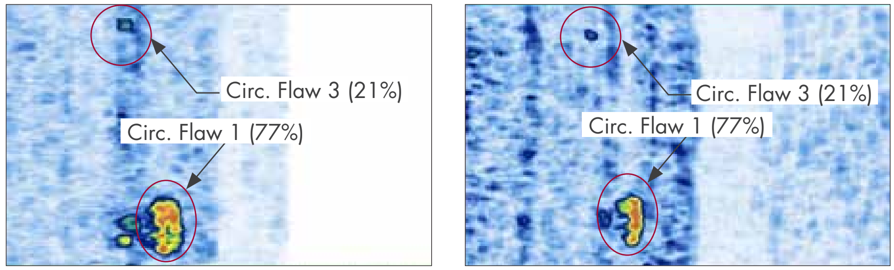

FIGURE 2. Circumferential Flaw 1 & 3 Data

LATITUDE™ Data 13 LINES
Scan Increment = 0.080″
Index Increment = 0.400″

AUT Data 34 LINES
Scan Increment = 0.040″
Index Increment = 0.150″

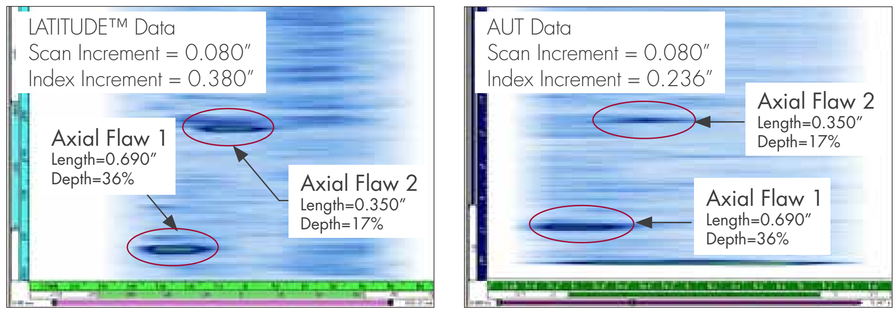

FIGURE 3. Axial Flaws 1 & 2

Among the most difficult of flaws to detect in PDI samples LATITUDE data acquired with a larger index increment Less data, less scan time Better Signal to Noise Ratio (SNR) with LATITUDE approach

This improved fidelity is believed to be a result of superior probe coupling that is inherent to manual data acquisition. Although automated data acquisition systems have provisions for maintaining probe coupling, they cannot replicate the tactile adjustments of the probe that the human hand can make in response to hoop shrinkage and other imperfections in the surface conditions. Per the 2017 EPRI Technical Report entitled *Nondestructive Evaluation: Guideline for Conducting Ultrasonic Examinations of Dissimilar Metal Welds, Revision 2*, operational experience noted surface condition as a key determinant of data quality and cited poor surface conditions and inadequate probe coupling/contact as causes for missed detections when performing ultrasonic examinations on dissimilar metal welds. Another cited cause of missed detections was the absence of encoded data (i.e., when a manual, non-encoded examination was performed) that resulted in missed detections of five significant flaws; two of which were identified by leakage after a machining operation. The LATITUDE system can mitigate both issues by facilitating improved probe coupling via manual data acquisition, while still providing the same permanent data record given by automated data acquisition.

The procedure, SI-UT-217, is a raster technique and is qualified for diameters 11.8” and greater, component thicknesses ranging from 0.86” to 2.94”, and has been qualified by demonstration in accordance with the requirements of the ASME Boiler & Pressure Vessel Code, Section XI, Appendix VIII, as modified by the PDI program description. This procedure additionally meets the requirements of 10 CFR Part 50.55a, Codes and Standards. It is important to note that the procedure is qualified for the detection and length sizing of circumferentially and axially oriented flaws in the qualified DMW configurations, where single or dual side access is available.

SI-UT-217 brings to the market an innovative approach to examining piping welds in a nuclear power plant. The ability to quickly deploy and acquire encoded results in an expedited manner will help plants stay competitive in an ever-changing market. Future development efforts for SI-UT-217 and LATITUDE will involve qualifying and adding small bore DMWs and complex geometries to the procedure as needed. Other non-PDI focus areas will include ASME Code UT examinations, FAC examinations, and other internal corrosion mapping applications for feedwater heaters, service water piping, tanks, and other BOP-related assets.

Update on Proposed Safety of Gas Transmission and Gathering Pipeline Regulation

New Addition to the Team

Erica Fisette (Senior Consultant): Ms. Fisette is an engineer with over 18 years of experience in the natural gas utility industry. She has significant experience in the operation and compliance program management of natural gas pipelines, including various roles as Sr. Project Manager of Transmission Integrity Management Program and the Distribution Integrity Management Program as well as Director of Gas Control Operations where she was responsible for the Control Room Management Program. Erica has been responsible for managing many operations, engineering and control room personnel and has valuable experience ensuring compliance with relevant state and federal regulations. She worked for Southern Company Gas who owned and operated seven utilities in seven separate states. Atlanta Gas Light - Georgia, Chattanooga City Gas - Tennessee, Elizabethtown Gas- New Jersey, Elkton Gas - Maryland, Florida City Gas - Florida, Nicor Gas - Illinois and Virginia Natural Gas - Virginia.

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Note: The GPAC voting is based on concepts rather than specific regulatory language. Therefore, the following list represents a conceptual summary of agreements rather than specific regulatory language.

Structural Integrity (SI) has significant depth and expertise in current pipeline safety regulations and dedicates substantial resources to ensure a comprehensive understanding of proposed pipeline safety regulations. Using the most current insights relative to upcoming regulations, Structural Integrity guides our clients with strategic direction to best position their pipeline safety programs to comply with the new regulations. Structural Integrity takes a proactive role in attending key Pipeline and Hazardous Materials Safety Administration (PHMSA) meetings such as the Gas Pipeline Advisory Committee (GPAC) meetings as well as supporting the rulemaking efforts of the American Gas Association (AGA), Interstate Natural Gas Association of America (INGAA), Pipeline Research Council International (PRCI) and other key associations.

The GPAC is a statutorily mandated Committee that advises PHMSA on proposed gas pipeline safety standards and regulations. The Committee consist of members from Federal and State governments (PHMSA and National Association of Pipeline Safety Representatives or NAPSR), the regulated industry, and the general public. The Committee is responsible for reviewing the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed standards and regulations relative to pipeline safety. The goal of the Committee is to provide recommended revisions and/or actions in response to standards and/or regulations proposed by the Federal Department of Transportation (DOT)/PHMSA.

SI personnel have attended the recent GPAC meetings focused on evaluation of the proposed rule titled "Safety of Gas Transmission and Gathering Pipelines" (Notice of Proposed Rule Making April 8, 2016). The meetings produced recommendations on several elements of the proposed Rule to provide changes that are technically feasible, cost-effective, and reasonable. The following list represents some of the topics discussed at the GPAC meetings as well as key takeaways and consensus direction which may have resultant changes in the Final Rule.

SUMMARY OF DECEMBER 14-15, 2017 GPAC MEETING

On December 14-15, 2017 PHMSA conducted a GPAC meeting in Washington DC. Key items discussed during the GPAC meeting are summarized below:

Material Verification (MV)

Proposed regulation §192.607 Verification of Pipeline Material: Onshore steel transmission pipelines was reviewed in detail. General agreement was made for eliminating several prescriptive and impractical requirements for performing MV programs. GPAC language for this specific element was approved on December 14, 2017. Included in the GPAC agreements were the following:

- Clarify that material verification applies to onshore steel transmission lines only (and not distribution or gathering lines)
- Delete "Applicable Locations" as proposed in §192.607(a)
- A MV Procedure would be required to obtain missing or inadequate records as well as verify pipeline

- attributes if and when required by §192.624 or other code sections
- Delete requirements for creating a MV Program Plan, but a MV Procedure would still be required
- Keep flexibility to allow either destructive or non-destructive tests when verification is needed
- Omit the list of mandatory attributes operators must verify, but require operators to keep records developed through this material verification method
- Omit accuracy specifications, but retain the requirement that test methods must be validated and calibrated equipment be used
- Omit mandatory requirements for testing multiple pipe joints within the same large excavation
- Revisions to the statistical criteria used for MV techniques
- Agreement to consider changing the threshold for non-line pipe components to larger than 2-inch nominal diameter rather than 2-inch and larger
- Agreement to delete the requirement for testing when the pipe is exposed for "any other reason"
- Reduce the number of quadrants of pipe tested (from 4 to 2 locations) where NDE testing is required
- Alternate tools, procedures or techniques will be applicable when submitted by operator and "no objection" letter received from PHMSA within 90 days. PHMSA to notify the operator if additional review time is needed
- Delete specific MV Program requirements and allow operators to address sampling failures through a specific company specific sampling program

Maximum Allowable Operating Pressure (MAOP) Determination and Reconfirmation (§192.619 and §192.624)

The GPAC dedicated significant time discussing various important issues related to PHMSA's proposed MAOP verification/reconfirmation requirements for transmission lines. Detailed discussion was held on the following three topics:

1. PHMSA should limit the applicability of MAOP reconfirmation to pipeline segments with MAOPs greater than 30% of Specified Minimum Yield Strength (SMYS) and eliminate Method 5 (pressure reduction for segments with small Potential Impact Radius (PIR) and diameter)

2. PHMSA should focus the MAOP reconfirmation process on one-time actions needed to confirm material strength and MAOP. Industry recommendations for revision include:
   - Eliminate the requirement that operators use a spike test to reconfirm MAOP for certain segments
   - Refine Engineering Critical Assessments (Method 3) to focus on inspections and analyses necessary to assess manufacturing-related features and confirm material strength
   - Revise the applicability of §192.624 to exclude segments that have valid pressure test records, but have experienced a reportable incident
   - Relocate the fracture mechanics modeling to a new section: §192.712
3. PHMSA should minimize changes to §192.619, which apply to all gas pipelines

Strengthening Potential Impact Radius (IM) Assessment Methods

An in-depth discussion took place with regards to the provisions for Internal Corrosion Direct Assessment (ICDA), Stress Corrosion Cracking Direct Assessment (SCCDA) requirements, Guided Wave Ultrasonic testing (GWUT), the passage of ILI devices along with emphasis on spike pressure test requirements in the proposed §192.506. The GPAC recognized the importance of spike testing as an assessment tool to expose significant time-dependent linear defects. There was discussion on revisions to the proposed language of this section to consider different spike test parameters and time frame associated with the spike interval. In addition, a revision to the "Method 6 Alternative Technology" notification to PHMSA and "no objection" process consistent with the recommended §192.607 procedure was approved.

SUMMARY OF MARCH 2, 2018 GPAC MEETING

On March 2nd PHMSA conducted a GPAC meeting by teleconference. Key items discussed during the GPAC teleconference are summarized below:

Strengthening IM Assessment Methods

Applicability of this part will be addressed at the next GPAC meeting. Included in the details for the spike test procedure in the proposed §192.506 was the following:

- Change spike pressure to the lesser of 100% SMYS (change from 105%) or 1.5 times MAOP
- Industry recommended the application of spike tests only when specific crack defects are of concern (e.g., fatigue manufacturing defects, environmental crack growth, etc.)
- Reduce spike hold time to a minimum of 15 minutes (reduced from the 30 minutes proposed in the NPRM) after the spike pressure stabilizes
- Revise language to refer to time dependent cracking

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- Revise proposed §192.506(g) to incorporate same "no objection" language the committee approved for §192.607 and with a timeframe of 90 days
- Revise proposed §192.506(g)(8) to incorporate "qualified technical subject matter expert" language at the SME requirements

Pipeline Assessments Outside of High Consequence Areas (HCAs)

One of the fundamental revisions of the proposed Rule is the expansion of transmission pipeline integrity assessments outside of HCAs. There was significant discussion regarding the proposed 15-year initial assessment and 20-year re-assessment intervals, elevated highways as they relate to vertical Potential Impact Radius (PIRs) as well as concerns related to the proposed definition of Moderate Consequence Area (MCA), specifically related to "occupied site". With regards to the proposed MCA definition in §192.3, the following details were discussed:

- A recommendation was made to modify the proposed definition for MCAs to remove "5 or more persons" and the timeframe of "50 days in any twelve (12) month period" from the criteria for an occupied site. Industry expressed great concern over the practicality and feasibility to identify the number of occupants for these small occupied sites
- Clarification that highways with 4 or more lanes are included as MCAs and a commitment to work with Federal Highway Administration (FHA) to provide operators with more clear information to be included in the Preamble of the Final Rule
- Revise the MCA highway description to remove reference to "rights-of-way" and add language so that the highway definition consists of "any portion of the paved surface, including shoulders"
- The preamble in the Final Rule will discuss the definition of "piggable pipeline"

With regards to Assessments Outside of HCAs in proposed section §192.710 the following details were discussed:

- Revise the requirement for the initial assessment from 15 years as proposed to 14 years and reduce the timeframe for periodic reassessments from 20-year intervals to 10-year intervals. Assessment schedules to be prioritized based on risk and applicable to lines with an MAOP greater than or equal to 30% SMYS
- Operators must select assessment methods based on the threats to which the pipeline is susceptible. Direct assessment is allowed where appropriate but may only be used to assess applicable threats

- Revise the "Applicability" requirements in proposed §192.710(a) to apply only to lines with MAOP > 30% SMYS and remove low-stress assessments (<30% SMYS) as proposed in §192.710(c)(8)

Record Retention Requirements

PHMSA proposed to clarify numerous records requirements. The GPAC meeting in March 2, 2018 addressed those record requirements for §§192.13(e), 192.67, 192.127 and 192.205 as well as Appendix A. Detailed discussions were held on the following topics:

- Remove the proposed additional records requirements in §192.13(e) and the associated records requirements in Appendix A
- Provide specific records requirements language in the Code rather than outside of regulatory requirements (i.e. Advisory Bulletins) or other guidance documents to better allow operators to prepare for the necessary records requirements
- Clarify the records requirements for pipeline components in the proposed §192.205 apply only to components > 2 inches nominal diameter
- Revise the proposed material, pipe design and pipe component requirements are not retroactive

Repair Criteria (inside and outside of HCA)

Remaining technical issues such as "response versus repair" criteria and remaining strength calculations were left for discussion at the March 26-28 GPAC meeting. The general consensus was the need for PHMSA to provide industry with additional technical data supporting metal loss with respect to predicted failure pressure calculations. The discussion among Committee members was that PHMSA was being overly conservative on this issue. Specific recommendations for "Repair Criteria" were discussed in greater detail at the March 26-28 meeting.

SUMMARY OF MARCH 26-28, 2018 GPAC MEETING

On March 26-28, 2018 PHMSA conducted a GPAC meeting in Washington, DC. Key items discussed during the GPAC teleconference are summarized below:

The Gas Transmission and Gathering Pipeline Rule will be split into three Packages to facilitate the rulemaking process

1. MAOP Reconfirmation, Expansion of Assessments and other related issues
2. Repair Criteria
3. Expansion of regulations to additional Gas Gathering Lines

Major Topics of Discussion

1. Overview of Approach to Address Gas Gathering lines to be the primary topic on the agenda at June 12-14 GPAC Meeting
2. MAOP Reconfirmation and related items. Continuation of discussions from December meeting:
   - Strike proposed §192.624(a)(1) and address cracks in HCAs in new §192.917(e)(6)
   - Revise language in §192.624(a)(2) to reference "Records to establish MAOP" and strike Subpart J
   - Proposed MAOP verification for grandfather pipelines to be limited to ≥ 30% SMYS PHMSA to conduct a cost-benefit analysis for Class locations 3& 4 and non-HCAs < 30% SMYS
   - Method 2- Pressure reduction; expand the "look-back" period from 18 mos. to 5 years
   - Remove FM requirements from §192.624 and place in a new §192.712. Use actual toughness values or default Charpy values proposed by Interstate Natural Gas Association of America (INGAA) study (13 ft-lb (body) and 4 ft-lb (seam) until actual values are obtained by testing
   - Method 5- Pressure reductions for small PIR and diameters revise to apply to PIR ≤ 150 ft., expand the "look-back" period for from 18 mos. to 5 years. Strike ECDA, crack assessments, odorization and remaining life calculations. Reduce patrols/ leak surveys to 4 times/year (Class 1&2) or 6 times/year (Class 3&4)
   - Subpart J pressure test records must be Interstate Natural Gas Association of America (TV&C)

3. Other Proposed Rule Amendments Related to MAOP
   - Remove text in §192.619(e) that duplicates §192.624. Move into (a)
   - PHMSA to provide guidance regarding TV&C Records in the preamble of the Final Rule
   - Increase PT factor for Class 1 location from 1.1 to 1.25
   - §192.619(f) is not retroactive and applies only to onshore, steel Gas Transmission lines
   - §192.619(a)(3) is not applicable if pipeline was pressure tested in accordance w/ §192.619(a)(2)
   - Scope of §192.607 is not applicable to distribution lines
   - Proposed changes to §192.605(b)(5) will be deleted to eliminate confusion
4. Revisions Related to Integrity Management (§192.917(e)(3) & (e)(4))
   - Revise §192.917(e)(3) & (e)(4) to incorporate language previously included in §192.624(a)(1) and reference the new FM section (§192.712)
   - Insert a new §192.917(e)(6) to address cracking in HCAs (similar to corrosion in §192.917(e)(5)
5. New Definitions (192.3)
   - Withdraw proposed definitions for legacy construction, legacy pipe, modern pipe and electrical survey
   - Agreed on definitions for Close Interval Survey, new definition for dry gas, transmission line, in-line inspection, ILI tool, segments that can accommodate inspection by ILI tool, TV&C will be explained in the Preamble
   - Transmission line means a pipeline, **or related series of pipelines**, other than a gathering line, that (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) **has an MAOP** of 20 percent or more of SMYS; transports gas within a storage field; **or (4) is voluntarily designated as a transmission line by the operator.** PHMSA will include a new definition for "distribution center" in the Final Rule
6. Repair Criteria Revisions (§§192.711, 192.713 & 192.933)
   - PHMSA proposed and the GPAC voted to approve significant new repair criteria for both inside and outside of HCAs, including additional criteria over and above that proposed in the NPRM

Structural Integrity will attend and continue to provide client updates following the next GPAC meeting scheduled for June 12-14, 2018 in Washington, DC.

Weld Overlay Repair Mitigates Thermal Fatigue Flaw Growth

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BELOW FIGURE 4. Installed FSWOL

A circumferential flaw in a 14-inch diameter residual heat removal (RHR) suction pipe-to-elbow stainless steel weld was identified in both units of a nuclear power plant as depicted in Figure 1. The two units are Westinghouse designed four-loop pressurized water reactor (PWR) plants and are mirror images of each other. The pipe-to-elbow weld is the first junction remote from the hot leg piping. The circumferential flaw at this location was first discovered on Unit 2 during the spring of 2016 and subsequently on Unit 1 in the spring of 2017. The flaws are located at comparable circumferential positions, given the two pipes are mirror images of each other and at the same distance from the RHR nozzle. Structural Integrity (SI) performed the flaw evaluation for each unit at the time of discovery. The flaws are ID connected and located at the weld heat affected zone (HAZ) on the pipe side. Although stress corrosion cracking has not be observed in the HAZ of austenitic stainless steel in PWR systems, the flaws were evaluated for both fatigue crack growth and

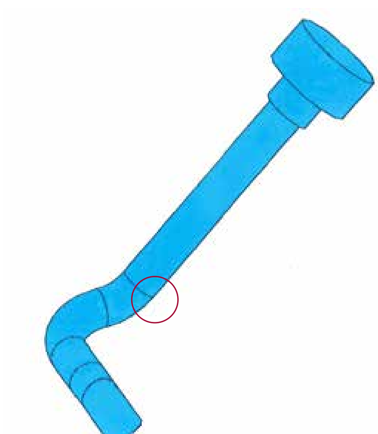

FIGURE 1. Flaw Location

stress corrosion crack growth. The flaw evaluations indicated there was life remaining for a short period of operation, with the appropriate safety margin, but not sufficient to allow the client to operate the plant until the end of the operating license for the given unit. Subsequently, a repair plan was developed to allow the units to operate to the end of the operating license.

It was suspected the flaw was the result of thermal fatigue. As part of the client's thermal fatigue program, the RHR suction line was assessed in accordance with EPRI MRP-146. MRP-146 provides guidance for the management of thermal fatigue in normally stagnant non-isolable reactor coolant system branch lines. The RHR suction line screened out for thermal fatigue using the EPRI MRP-170 software. To confirm the thermal fatigue condition, the client installed an array of thermocouples at the flaw location and at additional locations downstream of the flaw. Analysis of this data indicated two conditions existed:

- high frequency temperature oscillations during periods of sustained steady-state conditions at 100% power operation
- establishment of a complex thermally-stratified condition as the plant heats up from cold shutdown conditions, reversing itself during shutdown

The steady state thermally stratified condition of the line is shown in Figure 2 and Figure 3 is a zoomed-in and rescaled view of the flaw location. This model was based on the thermocouple data and provided the loads used in the design of a full structural weld overlay (FSWOL) repair. SI performed the design of the FSWOL for the client. Since a FSWOL has not been applied in a PWR to a similar metal weld of this size for thermal fatigue mitigation, some unique challenges were overcome. The FSWOL was designed using a higher strength Alloy 52M filler material. This filler material is typically used for FSWOLs applied to dissimilar metal welds. The use of Alloy 52M allowed the use of a smaller weld volume, reducing welding duration and personnel radiological exposure (dose). Since the ASME Boiler and Pressure Vessel Code does not contain rules for a FSWOL repair of a similar metal austenitic stainless steel piping weld using Alloy 52M, a Request for Alternative was submitted to the NRC. SI assisted the client in developing the Request for Alternative and with submitting responses to a related Request for Additional Information from the NRC. The NRC approved the Request for Alternative shortly before the Unit 2 outage in February 2018.

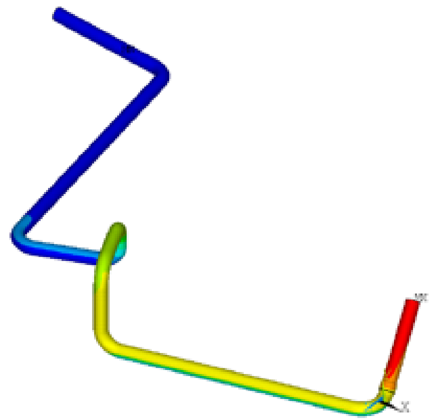

FIGURE 2. RHR Suction Line Thermal Stratification

As part of the FSWOL repair scope, the flaw location was ultrasonically examined prior to the repair to substantiate the flaw growth calculations. While the calculations indicated there would be some measurable growth, the inspection resulted in no measurable change of the flaw depth or extent. This is an indication the flaw growth calculations, using a bounding set of thermal cycling data, were conservative.

The client selected AZZ Specialty Welding for installation of the FSWOL. AZZ Specialty Welding, formerly known a Welding Services Inc. or WSI for short, is a longtime partner of SI for installation of weld overlays and small-bore nozzle repairs. AZZ successfully completed the installation of the FSWOL under the scheduled duration, and with no rejected indications in both the surface

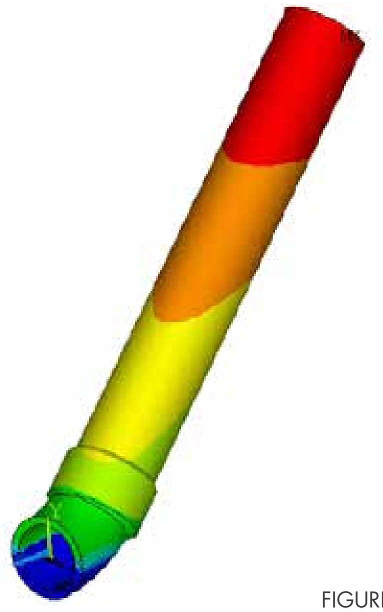

FIGURE 3.
Thermal stratification at FSWOL Location (FSWOL Shown)

and volumetric examinations. The completed FSWOL, ready for inspection, is shown in Figure 4.

Now that the repair is complete, SI will perform the post FSWOL analyses and verifications to demonstrate the acceptability of the repair. These include calculation residual stresses from the installation of the FSWOL, fracture mechanics analysis with the FSWOL installed, verification that the installation of the FSWOL does not impact the conclusions of the existing piping analysis, and that the added weight on the piping does not adversely affect the system. With the successful installation of the FSWOL, the risk of the flaw growing to an unacceptable size within the remaining plant life is mitigated. SI will support the client next year when the FSWOL is installed in the other unit.

Failed Grade 91 "Soft" Pipe Bend - A Case Study

Failure Occurred With Less Than 35,000 Operating Hours

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Grade 91 steel is widely used in tubes, headers and piping of superheaters and reheaters because of its higher strength at elevated temperature compared to low alloy steels such as Grade 22. The improved strength is a result of a tempered martensitic microstructure with a fine distribution of carbonitride precipitates. This microstructure is achieved through careful heat treatment: normalizing, tempering, and subsequent forming and post weld heat treatments. If these heat treatments are not performed properly, then the strength of the material essentially reverts to that of a low alloy steel like Grade 22, and is usually accompanied by a reduction in hardness, leaving the Grade 91 material in a so-called "soft" condition.

This article summarizes a case study for Grade 91 material in the "soft" condition which was responsible for a steam leak after only 5 years of operation, illustrating how this material condition can result in forced shutdowns and safety hazards. It is because of these consequences that it is recommended to have a Grade 91 life management program to understand if your plant may have such vulnerability. This case study provides general background to the steam leak and describes the subsequent metallurgical evaluations performed to verify mal-heat treatment of the Grade 91 steel was the root cause of the leak. A follow-on article (see the next issue Volume 45 of News and Views) will provide additional insight into local stresses and analytical prediction of such failures, as well as highlighting key aspects of a Grade 91 life

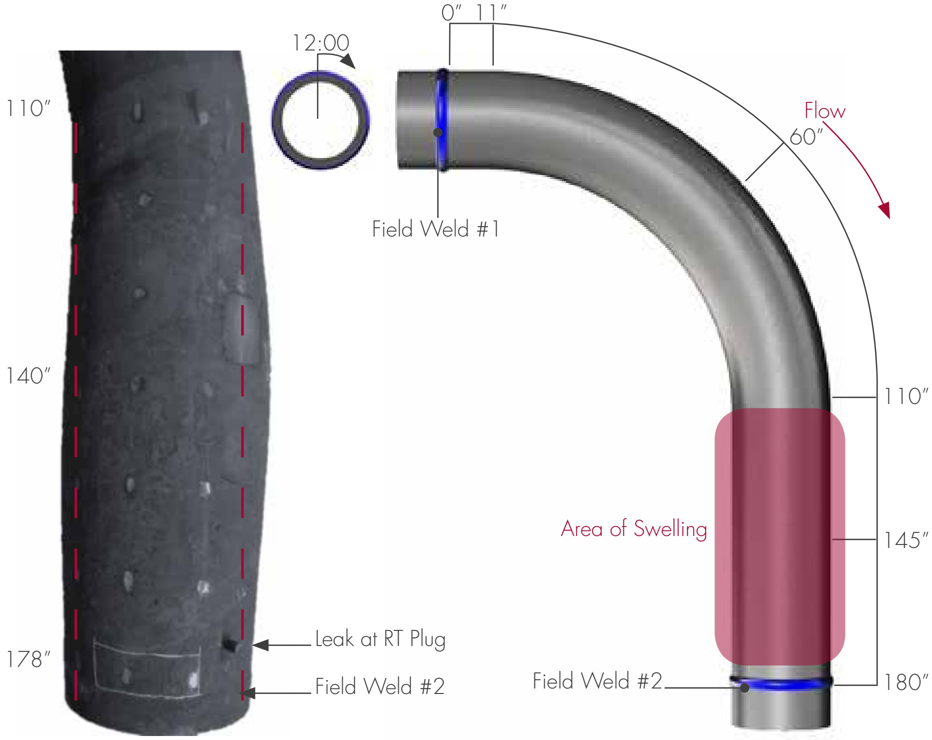

FIGURE 1. Swelled P91 Main Steam Piping

LEFT Showing Hardness Test Locations and Schematic Drawing

RIGHT Showing Approximate Axial Distances and Circumferential Clock Positions management program. Suffices to say if this plant had implemented such a program, the vulnerability of the affected spool would have been identified and mitigating actions could have been taken to avoid the leak.

LEAK DISCOVERED WITH ONLY 35,000 OPERATING HOURS

A leak was detected in the main steam piping of the combined cycle plant after approximately 35,000 hours of operation. Upon investigation, the leak was located at a radiographic testing (RT) plug, apparently caused by excessive swelling (bulging) of the pipe section. The bulging was observed in the straight section of pipe downstream of a 90º bend. Figure 1 shows a picture of the bulged pipe with dashed lines illustrating the degree of swelling. Also shown in Figure 1 is a schematic of the failed component geometry with axial centerline and circumferential clock positions identified; these are referenced throughout this article.

After the leak was identified and the unit brought off line, in-situ (field) hardness testing was performed by another contractor (not Structural Integrity) on the bulged region with hardness values found to range from 158 to 209 Brinell hardness (HB). Based on these low values and the degree of visible swelling, the decision was made to replace the entire pipe section during the forced outage.

LABORATORY ANALYSIS

The removed spool was submitted to Structural Integrity (SI) for laboratory analysis to further assess the cause of the low hardness and localized swelling. SI made diameter measurements and performed additional hardness tests along the spool length to determine the extents of swelling and "soft" material. Two window sections were also removed to evaluate the microstructure, chemistry, and through-thickness hardness. One window was removed from the bulged area, between 137" and 147", and the other was removed remote from the bulging near Field Weld #1, between 2" and 6".

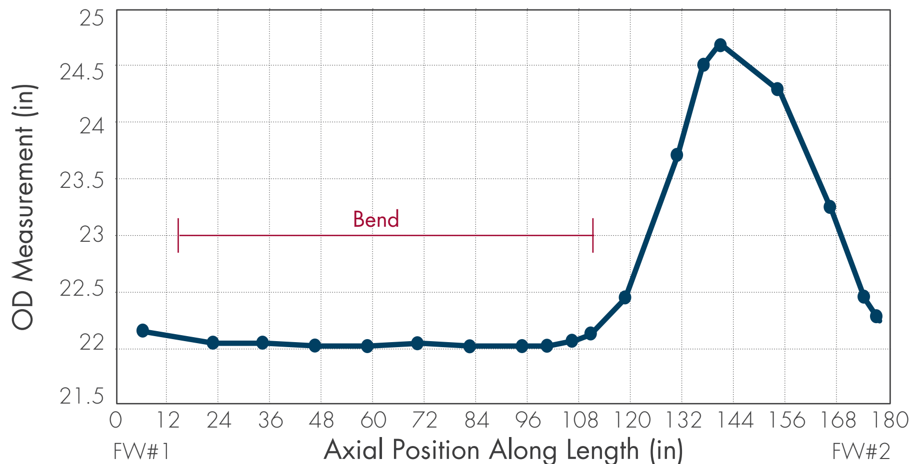

FIGURE 2. Summary of OD Measurements Along the Spool Length

The cracked pipe section was specified as ASME SA-335, Grade P91 with 22.0 inch OD and 2.004 inch minimum wall thickness. The design pressure and temperature were reported as 2646 psig and 1050°F, respectively.

DIAMETER MEASUREMENTS

Figure 2 presents the measured diameters along the pipe length, showing the swelling was confined to the straight section of the pipe spool between 110" and 177". The maximum diameter was at the 140" position and was approximately 12% greater than the non-bulged diameter.

HARDNESS MEASUREMENTS

Due to the significant scatter in the field hardness data obtained by others (values ranging from 158 to 209 HB), in-situ hardness testing using a portable device (UCI probe) was first performed on the swelled region to verify the "soft" condition and evaluate its axial extent. The results showed uniformly low hardness (~160 HB) in the swelled region. The region of low hardness extended approximately 10 inches into the upstream bend. The center of the bend exhibited hardness values in the acceptable range for Grade 91 (~200 HB), which correlates with swelling being confined to the downstream end of the spool.

Hardness testing was also performed at both field girth welds to assess the adjacent upstream and downstream spools. The measured hardness values on the adjacent spools were in the acceptable range for Grade 91 piping, indicating the welding and post-weld heat treatment procedures were performed correctly.

After bounding the extents of low surface hardness and swelling, through-thickness hardness testing was performed on the two window sections. The results were consistent with those reported on the pipe surface: the through-thickness hardness in the swelled section ranged from 159 to 165 HB, while the through-thickness hardness in the section remote from the swelling ranged from 200 to 210 HB.

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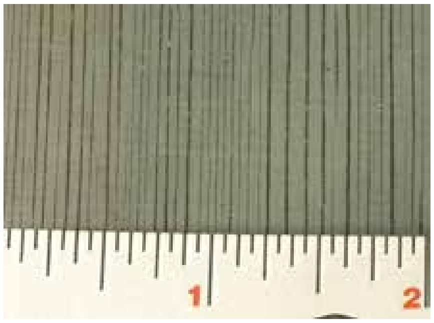


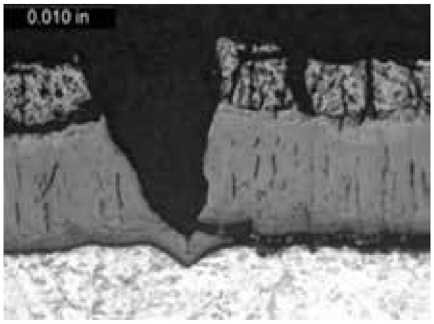


FIGURE 3. Typical appearances of the external LEFT and internal CENTER surfaces in the swelled region exhibiting axially-oriented cracks in the oxide layer. On the RIGHT is a cross sectional view of one oxide crack on the external surface. (Scale shown in inches.)

VISUAL INSPECTION & THICKNESS

Close-up views of the external and internal surfaces on the window section removed from the swollen area revealed axially-oriented oxide cracking, shown in Figure 3. The oxide cracking was consistent with significant in-service swelling of the pipe and did not extend significantly into the base material. The average thickness of the window section was 1.654 inch, which was below the specified minimum value of 2.004 inch. The minimum thicknesses measured remote from the bulging near Field Weld #1, which should be representative of the thickness in the straight sections prior to swelling, was 2.184 inch, in excess of the minimum specified value.

MICROSTRUCTURE ASSESSMENT

Cross sections from the window sections were examined using a metallurgical microscope to assess the microstructure; Figure 4 shows the microstructure from each window section. The microstructure on the swollen section consisted of dispersed alloy carbides in a ferrite matrix, which is not the desired microstructure for Grade 91, but is consistent with the low hardness values. Isolated creep voids were observed across the entire thickness of the section. The microstructure on the window section removed remote from the swelling consisted of the desired tempered martensitic microstructure for Grade 91 piping.

CHEMICAL COMPOSITION

Chemical analysis was performed on a sample from the bulged window section; the results for significant impurity elements copper, nickel, and tin are presented in Table 1 along with the chemical requirements for ASME SA-335 Grade P91 and the more stringent requirements recommended by EPRI in their publicly available report 3002006390 (2015).

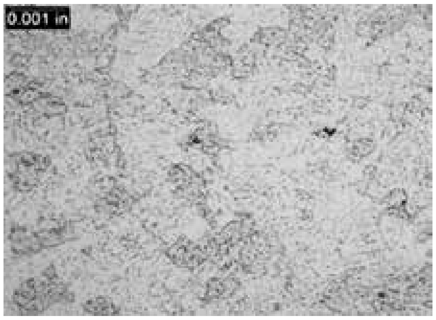
The results showed the sample met the chemical requirements of ASME SA-335 Grade P91, but the copper, nickel, and tin contents were greater than the EPRI-recommended values. These higher impurity element concentrations indicate this heat of material likely exhibited lower creep strength and lower damage tolerance (greater creep cavitation susceptibility) than average. However, the mal-heat treatment which caused the degraded hardness results in a reduction of strength well beyond the compositional effects.

EXAMINATION OF THE CRACK

The final area evaluated on the spool was the leak associated with the RT plug. Figure 4 shows the crack along the toe of the RT plug weld; the area surrounding the crack was ground, polished, and etched in preparation for metallographic replication. Figure 5 shows two high-magnification views of the crack as seen in the replica, which was located at the toe of the RT plug weld to the main run pipe. The location of cracking was as expected given the swelling of the pipe section. The crack was oxide-filled and consisted

Element	Sample	ASME SA-335 P91	EPRI Recommended
Copper	0.19	Not Specified	0.10 max
Nickel	0.34	0.40 max	0.20 max
Tin	0.011	Not Specified	0.010 max

TABLE 1. Chemical Analysis Results (weight percent)



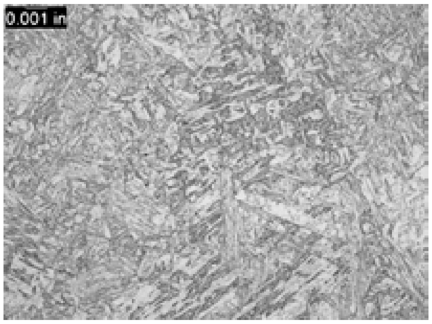


FIGURE 4. Typical microstructures observed in the swelled region [LEFT] consisting of patches of alloy carbides in a ferrite matrix and remote from the swelling [RIGHT] consisting of the desired tempered martensite. (Etchant: Vilellas)

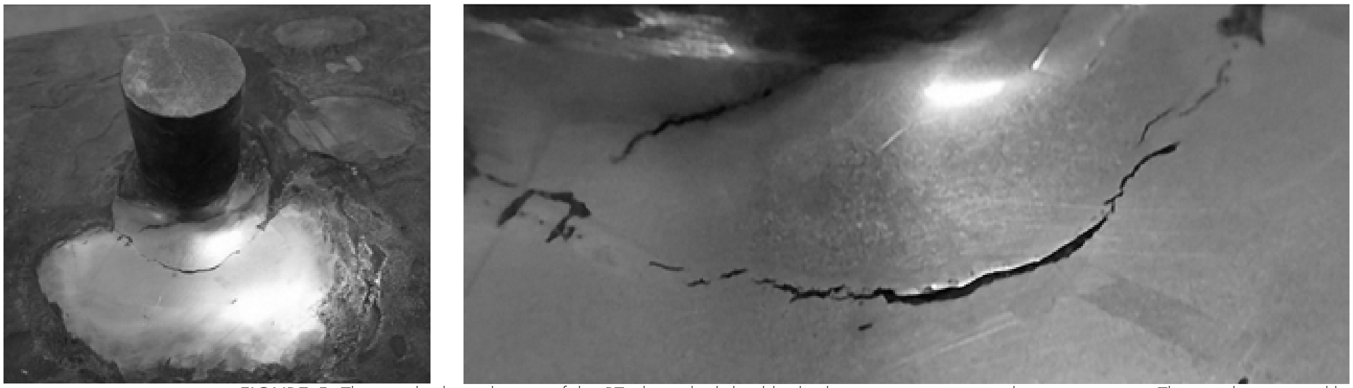


FIGURE 5. The crack along the toe of the RT plug which had leaked in service, initiating the investigation. The crack was readily visible after the surface was ground and polished.

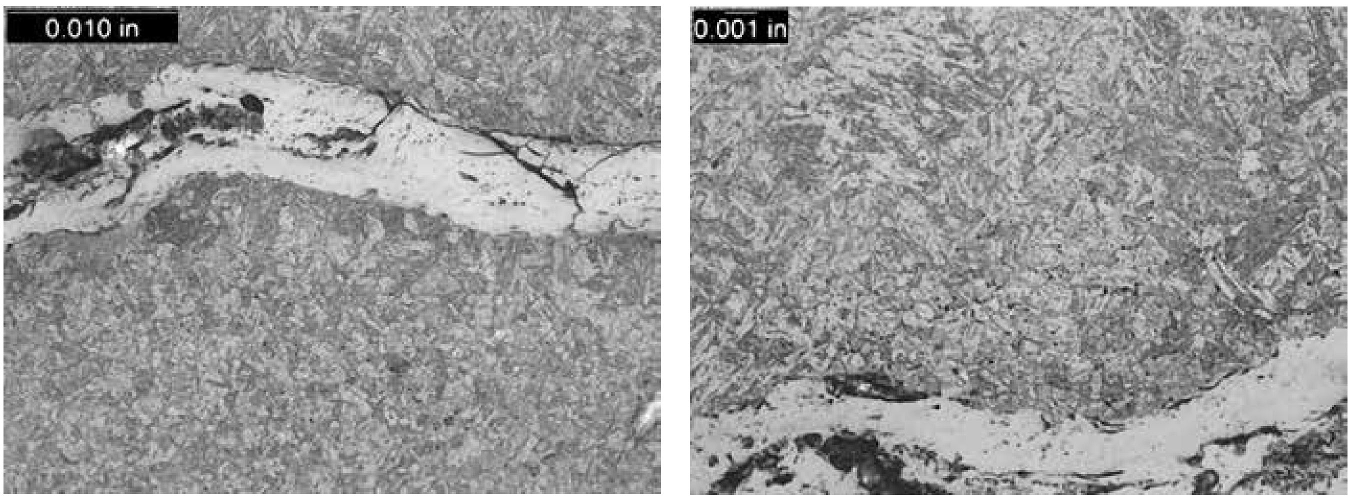


FIGURE 6. Views of the crack observed along the pipe-side toe of the RT plug. The crack was oxide-filled, and creep voids were observed alongside the primary crack (Etchant: Vilellas).

of several crack segments linking together; minor creep voids were observed adjacent to the primary crack. The typical microstructure observed in RT plug weld metal was the desired tempered martensite, and the average hardness was 234 HB, which is in the acceptable range.

CONCLUSIONS

The fact the low hardness values were confined to the bent pipe spool and were not in adjacent piping upstream and downstream of the field welds indicates the improper processing leading to low hardness and poor creep strength occurred during manufacturing of the bent spool, rather than during field erection. The large amount of swelling and creep voids observed in the window section clearly indicated that the "soft" pipe section was at the end of its useful life.

The leak occurred at the RT plug because of a local strain intensification created by the stronger RT plug in the "soft" pipe spool. If the RT plug had not been present, continued swelling would have eventually resulted in rupture of the base metal and a significantly greater release of high temperature steam.

This case study highlights the need for careful quality control and detailed verification of fabrication processes for creep strength enhanced ferritic steels such as Grade 91. If possible, that should be performed during the various steps of the fabrication and erection process, or as part of an in-service Grade 91 life management program.

In the present case, screening lifetime calculations to identify locations vulnerable to failure if in the "soft" condition would have identified this location as presenting high risk, and subsequent field hardness testing could have been timed to verify if the material was in the "soft" condition. This could have avoided the leak, lost generation time, and significant safety risk.

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STRUCTURAL INTEGRITY RECEIVES DISTINGUISHED RESEARCHER AWARD

Over the last several years, Structural Integrity (SI) has been actively supporting the Pipeline Research Council International's (PRCI's) industry research initiatives, providing expertise in advanced Non-Destructive Examination (NDE), fracture mechanics, and pipeline integrity. As part of these efforts, SI deployed a multidisciplinary team of experts from our Applied Technology, NDE Services, and Oil and Gas Pipeline groups. PRCI recognized SI for their contributions at this year's PRCI Research Exchange Meeting, where SI was the recipient of the 2018 PRCI Distinguished Researcher Award. This award is provided for the dedicated and distinguished service and scientific achievements that have enhanced the integrity, reliability, and environmental performance of the energy pipelines around the world. SI looks forward to continuing our commitment and support of PRCI in their aim at ensuring pipelines are the safest and most efficient means of energy transportation.

UPCOMING EVENTS

NEI Used Fuel Management Conference – Savannah, GA | May 1 – 3, 2018 | *Attending*

NAES O & M Managers Conference – Colorado Springs, CO | May 15, 2018 | *Exhibiting*

Condensate Polishing Sourcebook Review Meeting – Charlotte, NC | May 17 – 18, 2018 | *Exhibiting*

NEI Nuclear Energy Assembly Conference and Supplier Expo – Atlanta, GA | May 21 – 23, 2018 | *Exhibiting*

ANS Annual Meeting – Philadelphia, PA | June 17 -21, 2018 | *Attending*

Association of Rural Electric Generating Cooperatives Conference – Lanier Islands, GA | June 24 - 27, 2018 | *Exhibiting, Sponsoring*

EPRI NDE Tech Week – Clearwater Beach, FL | June 25 – 28, 2018 | *Exhibiting*

AGA Operations Conference – Washington, D.C. | June 25 – 29, 2018 | *Attending*

EPRI BPIG/SWAP Summer Meeting & Vendor Expo – Charlotte, NC | July 9 – 13, 2018 | Exhibiting

USA Executive Summit – Seattle, WA | July 17 – 20, 2018 | *Exhibiting*

AEP Go Forum – Columbus, OH | July 23 – 26, 2018 | *Exhibiting*

Nuclear Fuel Supply Forum – Washington, DC | July 24, 2018 | *Attending*