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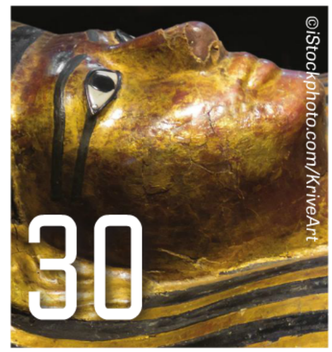
SSPC The Society For Protective Coatings
The Voice of SSPC: The Society for Protective Coatings

FEATURES



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SSPC Surface Preparation Standards Update

2015 was a busy year for SSPC Surface Preparation standards committees.

A revision of **SSPC-SP 1, Solvent Cleaning** was completed in March 2015. SSPC-SP 1 is used to specify removal of visible deposits of oil, grease and other soluble contaminants from metal surfaces before additional mechanical means of surface preparation are employed. All of the SSPC mechanical surface preparation standards require solvent cleaning to SSPC-SP 1 prior to performing any additional cleaning required by the project specification. Removal of heavy deposits of oil, grease and dirt is important because power tool or dry abrasive blast-cleaning can push these contaminants into the surface profile.


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Contractors should note that the 2015 revision of SSPC-SP 1 clarifies that "visible contaminants" are seen with normal or corrected normal (i.e. glasses) vision, but without use of any additional inspection equipment, such as ultraviolet light. A non-mandatory appendix added to the 2015 revision lists additional methods for verifying cleanliness that are not required unless specified in procurement documents. SSPC-SP 1 also requires that any solvent used must comply with local environmental safety and health regulations.

SSPC-AB 1, Mineral and Slag Abrasives was also revised in 2015. In addition to the existing requirements that are used by the abrasive manufacturer to qualify the abrasive, the 2015 revision clarifies that the contractor must perform field tests for oil contamination and conductivity. If the abrasive is only used once, it must be tested prior to use to ensure the media has not become contaminated in shipment or storage. If the media is recycled, the contractor must test the recycled material for conductivity and oil contamination every eight hours or every work shift, whichever period is shorter.

SSPC-AB 2, Cleanliness of Recycled Ferrous Metallic Abrasives, which is used to ensure that recycled ferrous metallic abrasive work-mix remains consistently clean and capable of providing the required profile throughout the duration of a project, was also revised in 2015. The revision has eliminated the requirement for field sieve testing of the abrasive to verify that excessive abrasive fines have been removed from the work-mix. Instead, the contractor must ensure that the profile created by the recycled work-mix continues to meet project requirements when tested in accordance with SSPC-PA 17, Procedure for Determining Conformance to Steel Profile/Surface Roughness/Peak Count Requirements. The test to determine the percentage of abrasive fines that was a requirement in the 2004 version of SSPC-AB 2 has been simplified and moved into a non-mandatory appendix.

The requirements for maximum lead content, freedom from oil and maximum conductivity level were not changed in the 2015 revision. However, the frequency for each of these tests has been clarified. Oil and conductivity testing are required once every 12 hours or work shift, whichever is shorter. The frequency of laboratory testing for lead content has been reduced from once per week to once immediately prior to first use.

The five joint **SSPC/NACE Wet Abrasive Blast-Cleaning Standards** were completed in 2015 and should be available in the first quarter of 2016. These standards combine elements of the existing standards for dry abrasive blast-cleaning with elements of the 2012 SSPC/NACE waterjet cleaning standards. The definitions of cleanliness for the steel surface immediately following wet abrasive blast-cleaning are identical to the definitions in the five dry abrasive blast-cleaning standards. However, because water is used to convey the abrasive onto the surface, a layer of flash rust will form on the cleaned steel as the water evaporates. Due to the varied tolerance of coatings for the presence of flash rust on the surface, it is important that the contractor know the maximum permissible level of flash rust that may be present on the steel immediately prior to the application of the protective coating, and how to assess how much flash rust has developed. The wet abrasive blast cleaning standards define four levels of flash rust: no flash rust; light flash rust; medium flash rust; and heavy flash rust. These definitions are based on the extent to which the flash rust obscures the underlying steel substrate, the ease with which it can be removed by wiping with a cloth and the amount of material that appears on the cloth after the surface is wiped.

As with the waterjetting standards and the dry abrasive blast-cleaning standards, the wet abrasive blast-cleaning standards also include information on materials and methods used to perform the cleaning process. For example, the water used must be free of contaminants that would affect the cleanliness of the prepared surface or the functioning of the pumps or other equipment. If the project specification includes requirements for non-visible contaminants, the water used for waterjetting must be free of impurities that could prevent the surface from meeting those requirements.

For further information on the 2015 SSPC surface preparation standards updates, as well as other SSPC standards, contact Aimée Beggs, SSPC standards development specialist, at beggs@sspc.org or 412-281-2331, ext. 2223. Beggs has been with SSPC for 36 years and has managed the SSPC standards development process since 1993.

SSPC Achieves ISO/IEC 17020 Accreditation

SSPC is pleased to announce that it has achieved accreditation from the ANSI-ASQ National Accreditation Board (ANAB) as a Type-A Inspection Body according to the requirements of the ISO/IEC 17020:2012 standard, "Conformity assessment – Requirements for the operation of various types of bodies performing inspection."

Specifically recognized were the SSPC Painting Contractor Certification Program (PCCP) and the following standard procedures.

- QP 1 – Standard Procedure for Evaluating the Qualifications of Industrial/Marine Painting Contractors (Field Application to Complex Industrial Steel Structures and Other Metal Components)
- QP 2 – Standard for Evaluating Painting Contractors (Removal of Hazardous Coatings from Industrial/Marine Structures)
- QP 3 – Certification Standard for Shop Application of Complex Protective Coating Systems
- QP 5 – Standard Procedure for Evaluating the Qualifications of Coating and Lining Inspection Companies
- QP 6 – Standard Procedure for Evaluating the Qualifications of Contractors Who Apply Thermal Spray (Metallizing) for Corrosion Protection of Steel and Concrete Structures
- QP 7 – Procedure for Evaluating Coating Contractors With Limited Work Experience
- QP 8 – Standard Procedure for Evaluating the Qualifications of Contracting Firms that Install Polymer Coatings, Surfacings, Linings or FRP Composites on Concrete and Other Cementitious Substrates
- QP 9 – Standard Procedure for Evaluating the Qualifications of Commercial Painting and Coating Contractors

ISO/IEC 17020 incorporates the same level of requirements for the organizational quality management systems as ISO 9001 and ISO/IEC 17000 series standards such as ISO/IEC 17021, "Conformity assessment – Requirements for bodies providing audit and certification of management systems," and ISO/IEC 17065, "Conformity assessment – Requirements for bodies certifying products, processes and services." ISO/IEC 17020, however, puts greater emphasis on organizational ability to manage impartiality and conflicts of interest as well as the technical competence of people, inspection processes and equipment.

Accredited inspection provides assurance of technically competent service and consistently reliable results, reducing costs and lowering risks. It is key in demonstrating that products, equipment, structures and systems meet required specifications. Governments and industries around the world are increasingly requiring use of accredited inspection services.

ANAB accreditation to ISO/IEC 17020 allows an organization to demonstrate integrity, reliability and technical competence as well as compliance with internationally recognized good practices. ANAB accreditation programs are based on the latest international requirements and are recognized by the International Laboratory Accreditation Cooperation (ILAC). ANAB accredited customers demonstrate conformance to the requirements outlined in the current versions of ISO/IEC 17020 and ILAC P15, Application of ISO/IEC 17020:12 for the Accreditation of Inspection Bodies. ANAB accreditation enhances competitiveness and allows access to global markets regardless of where the inspection body is located. ANAB management and technical staff assure high-quality service, integrity, independence, impartiality, confidentiality and customer service.

For more information about this accreditation, please contact Joe Berish, SSPC corporate certification specialist, at berish@sspc.org or 412-281-2331, ext. 2235.

SSPC Seeking Board of Governors Nominations

SSPC: The Society for Protective Coatings announced that it is currently requesting nominations for its Board of Governors in the categories of Facility Owner and Other Product Supplier.

The Facility Owner category is defined in the SSPC bylaws as "individuals who are employed by public or private sector owners of assets who are responsible for the maintenance of coatings of heavy or light industrial structures and surfaces."

The Other Product Supplier category is defined in the bylaws as "individuals who own, are employed by, or represent firms that manufacture or distribute equipment, abrasive or peripheral products for use in the protective coatings industry."

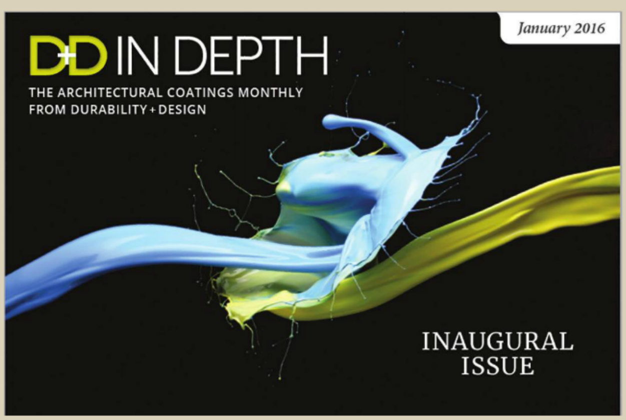
There are a total of four positions involved in the upcoming election. Each of the two aforementioned categories has one open spot and one spot with an incumbent candidate running for re-election.

All nominees must be SSPC members and meet the requirements on p. 5 of the SSPC bylaws, which can be found online at sspc.org. Self-nominations are not accepted. To nominate a candidate, SSPC asks that members submit a brief statement detailing the nominee's qualifications by March 1, 2016, to SSPC, Attn. Bill Worms, Executive Director, 800 Trumbull Drive, Pittsburgh, Pa. 15205; or via email to worms@sspc.org.

JPCL Publisher Launches *D+D In Depth*

Durability + Design, one of *JPCL*'s sister publications in the Technology Publishing Company network, is pleased to announce the launch of *D+D In Depth*, a new monthly digital publication for specifiers and users of architectural coatings and related materials.

The January issue was sent via e-mail to 80,000 readers, including architects, specifiers, facility owners, contractors and industry experts.



"*D+D In Depth* will provide technical feature content on topics important to the architectural coatings industry," said Harold Hower, *D+D In Depth* editor.

In all, 48 articles written by top industry experts are planned for 2016, Hower notes.

The articles will disseminate information on high-performance finishes that often require specialist knowledge about good technical practice in their selection and use. Examples of these high-performance and multi-functional materials include liquid-applied air barriers and flashings; reflective roof coatings; intumescents; fire-resistant coatings; and floor finishes in demanding environments.

D+D In Depth will cover the content areas of building envelope, color and design, decorative finishes, coatings technology, good

March Webinar Compares Performance Characteristics of Protective Coatings

A new, free webinar analyzing the performance and environmental properties of a variety of protective and marine coating systems will be available in March as part of the 2016 SSPC/*JPCL* Webinar Education Series.

"Performance Properties of Protective Coatings" will be presented by Ahren Olson of Covestro LLC on Wednesday, March 16, from 11:00 a.m. to 12:00 noon, EST. When selecting a coating for application it is important to identify the service environment, performance requirements and type of structure and substrate in order to achieve optimum performance. This webinar will provide an overview on performance requirements for coatings and linings used in industrial and marine service. It will describe the structures to which coatings are applied and discuss environmental issues and application methods. An overview of different coatings' performance properties will be examined. Coatings that will be discussed include acrylics (waterborne), alkyds, epoxies, polyurethanes, polyureas, polyaspartics and polysiloxanes. Participants will be eligible to receive credit from SSPC.

Ahren Olson is the marketing manager for corrosion protection with Covestro LLC in Pittsburgh, Pa. He has been with Covestro for 12 years, holding both technical and marketing positions in the area of protective coatings. Olson holds a Bachelor of Arts degree with a major in chemistry from The College of Wooster and is an SSPC Protective Coatings Specialist and NACE-certified Coating Inspector, Level 2. He is currently responsible for strategy development, implementation and business development for the protective coatings market. Olson was also recently profiled in *JPCL*'s August 2015 bonus issue, *Coatings Professionals: The Next Generation*.


Ahren Olson

Registration, CEU Credits

This program is part of the SSPC/*JPCL* Webinar Education Series, which provides continuing education for SSPC re-certifications and technology updates on important topics. SSPC is an accredited training provider for the Florida Board of Professional Engineers (FBPE), and Professional Engineers in Florida may submit SSPC Webinar Continuing Education Units to the board. To do so, applicants must download the FBPE CEU form and pass the webinar exam, which costs $25.

Register for this online presentation at paintsquare.com/webinars.

CORRECTION

An error on the cover of the January issue of *JPCL* mistakenly referred to Minnesota as "The Land of 1,000 Lakes." We apologize to our readers, primarily to those from the great state of Minnesota, for omitting 9,000 lakes.

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Now Buzzing on *PaintSquare News*...

Bridge Work Could Dry Niagara Falls *(Jan. 28)*

With a gushing flow visited by millions each year, it seems nothing could shut off the splash of Niagara Falls — except maybe bridge construction.

Officials in charge of the international falls and the park that surrounds them are considering a plan that will dewater the U.S. side of the world-renowned cascades. If ultimately approved, the American Falls could shut down — or at least have its flow diverted to the Canadian side.

"Dewatering is expected initially [to] be a tourism draw (a once-in-a-lifetime opportunity to see the falls and river channel without water)," according to a New York state-issued design report.

State officials have been moving to replace bridges built in 1900–1901 since 2004 when they were found to have deteriorated to the point where they were closed, according to the Niagara Gazette. Temporary bridges were built above the existing structures. Those temporary fixes have preserved pedestrian and bicycle access to Goat Island, but they lack the aesthetic appeal of the stone-faced originals and restrict views of the rapids, the report said. Meanwhile, the original bridges continue to crumble.

About 85 percent of the Niagara River flows over Horseshoe Falls on the Canadian side of the border, according to CNN. The rest of the river water goes over the American Falls in New York. To "dewater" the American Falls, officials would build a temporary cofferdam that would redirect the entire river flow to Horseshoe Falls, CNN noted.

"Dewatering is necessary for two reasons," the report said. "The existing 115-year old bridges need to be demolished. The river channel must be dewatered in order to demolish and remove the bridges.

"[And] the piers and abutments for the replacement bridges must be constructed 'in the dry,' to allow for safe construction procedures and to ensure that the new foundations are firmly anchored to bedrock."

According to the report, one scenario would be to leave the American and the adjacent Bridal Veil Falls dry for five months (August through December). The second would require a nine-month dry spell: from April through December.

Officials from the New York State Office of Parks, Recreation and Historic Preservation, Albany; the U.S. Army Corps of Engineers; and the state Department of Transportation agree that if a third option — to seal off the flow to the American Falls — is chosen, the project would not begin for several years, the daily newspaper said.

PSN TOP 10 *(as of Jan. 31)*

1. Bridge Work Could Dry Niagara Falls
2. Bay Bridge Leaks Get Low-Cost Fix
3. Offshore Fabricator Pays $20M for Shipyard
4. Seattle Tunnel Project Drills Ahead
5. Cold Eyed in Canada Bridge 'Split'
6. 3M Sues over Alleged Patent Infringement
7. At Work on the New Tappan Zee Bridge
8. Sinkhole Delays Seattle Tunnel Project
9. Giving Planes Coats of Many Colors
10. Keystone XL Owners Sue U.S. Government

WHAT'S GOT US TALKING

(PaintSquare News *Weekly Poll, Jan. 24-30)*

Drones are increasingly being used for bridge inspections; do you think drones are as effective at detecting bridge defects as people are?

Yes, they are just as effective and are better able to access hard-to-reach areas. **4%**

Yes, but humans will always need to interpret the data and take a firsthand look. **58%**

No, there's too much of a danger that they'll miss something important. **38%**

Rodney White: *"Drones can be useful to prevent accidents while inspecting precarious areas of a structure, reducing the chances of injury to a person, but there still must be a person operating the drone who knows both how to effectively fly the drone, and where to take the drone in order to observe problem areas."*

Murray Thessman: *"Drones are good for an overview but when it comes to concrete panels on structures, raking a hammer over the panel and listening for the 'drumminess' panels is often a stronger indicator than finding a crack (especially on exposed aggregate)."*

Glenn Viveiros: *"In this industry you need hands-on inspection. I've been in bridge painting for 30 years as a hands-on worker and a superintendent. There are many areas of the structure not accessible by drone — only the outside face of the structure would be viewed. There are many areas of the bridge that would be missed."*

On Comparing Organic to Inorganic Zinc Primers

WHAT ARE THE PROS AND CONS OF USING ORGANIC VS. INORGANIC ZINC PRIMER?

Larry Muzia
Exceletech LLC

Inorganic zincs (IOZs) offer a high level of galvanic protection as there is direct zinc-to-metal contact. In an organic zinc (OZ) the metal is bound in an organic resin and does not provide the same level of galvanic protection. OZs are easier to overcoat as they do not outgas, which may occur with an IOZ. IOZs can provide a high level of corrosion protection untopcoated, provided the environmental pH is within 5-to-10. IOZs require rigorous surface preparation and close adherence to dry-film-thickness specifications. They also require a minimum of 50-percent humidity to properly cure by hydration. Like any primer, no single zinc-rich type is best for all conditions.

Paiboonsak Saengsomboon
JT Marketing Co., Ltd.

They are both very good at corrosion protection and both provide a cathodic effect to steel surfaces. The difference between the two types, is first, that inorganic zinc performs in higher service temperatures (up to 400 C) while organic or epoxy zinc performs only up to 120 C; and second, that inorganic zinc can be used alone at specified thicknesses, for example, as a tank coating for some kind of chemicals, but organic zinc needs to have a topcoat. Neither of them is good as a primer for underwater areas due to high porosity and osmotic blistering.

Usama Jacir
Cortec Middle East

My understanding is that you will get a higher utilization of the zinc galvanic properties due to the conductive nature of the inorganic binder, therefore better protection. A consideration in dry environments is the inorganic zinc's requirement for moisture to cure, making it harder to apply. In some of our regions, we have to actually force-cure it by spraying with water.

Ahren Olson
Covestro LLC

The pros of using IOZ over OZ include excellent galvanic protection, slightly better than OZ. IOZ can also be used untopcoated in the correct environmental conditions. IOZ has significantly higher heat resistance than OZ. The cons of using IOZ over OZ, are first, that IOZ requires humidity (moisture) to cure, typically above 50-percent relative humidity, which can be very problematic in the winter months for most shops; and also that IOZ typically requires a higher level of surface cleanliness (SSPC-SP 10 or greater). Additionally, IOZ tends to mudcrack when applied too thick, while OZ tends to be more tolerant of excessive film thickness. IOZ also requires a mist coat if it is going to be topcoated to prevent outgassing.

Todd Williams
Covestro LLC

There are several circumstances where inorganic zinc is a fitting choice over organic zinc for atmospheric service conditions. These include shop-applied coatings where zinc-rich primers are exposed to UV before applying the final coats and high-temperature applications. In all other scenarios, the possibility exists to use either organic or inorganic zinc and additional considerations must be taken into account. Oftentimes, inorganic zinc systems are specified because of slightly improved corrosion resistance obtained when applied under ideal conditions, versus organic zinc. The ideal conditions can be very different from a project's actual application conditions. Several recent papers have highlighted that prudent coating selection should be based on systems that have the best chance for success in real world conditions, not strictly upon the coating's performance. For example, inorganic zinc coatings require extremely clean surfaces (Sa 2½+) and humidity to cure, and if humidity is not present directly after application, the coating may not ever cure properly even upon re-exposure to moisture. Unless humidity can be controlled during dry application conditions, the results can be disastrous — the production schedule will be significantly slower than expected or curing will be insufficient, leading to cohesive coating failures in the field. Furthermore, application issues of inorganic zinc such as mud-cracking, dry spray, specialized application equipment and topcoat pinholing are not issues when using organic zincs. Because application errors are responsible for the majority of all failures, the performance benefits gained using inorganic zinc must be weighed against potential application errors, especially when inexperienced applicators are involved.

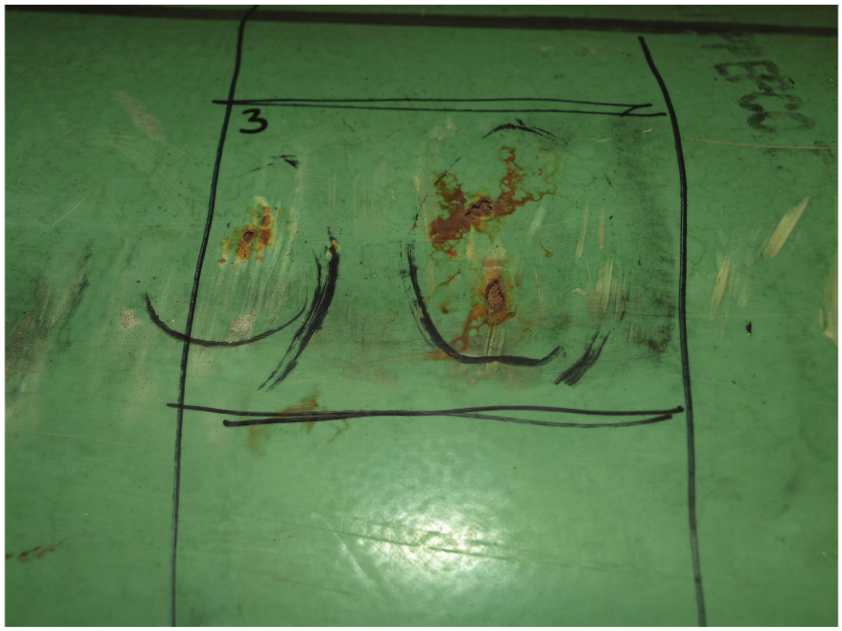

Fig. 1: Pipe section with pits marked for removal. All photos courtesy of KTA-Tator, Inc.

Corrosion in Less Than One Year is the Pits!

By Valerie D. Sherbondy, PCS, KTA-Tator, Inc.
Richard A Burgess, PCS, KTA-Tator, Inc. Series Editor

Section loss of pipe wall is of great concern in the pipeline industry. Reduced wall thickness due to pitting corrosion can adversely impact pipeline integrity; the results of which can be catastrophic depending on the product that the pipeline is transporting. In order to reduce the opportunity for corrosion, the use of protective coatings is often supplemented with impressed current cathodic protection (CP) systems to protect the pipe from corrosion, pitting and eventual perforation in the event of a breach in the protective coating system. In the instance discussed in this article, a pipe section that was excavated displayed severe pitting despite the application of a proven powder coating system and the installation of an impressed current CP system.

A section of pipeline needed to be excavated in a relatively small area to accommodate new construction in the surrounding area. The pipeline was buried and put into service only about six months earlier, so corrosion and coating failure were not expected. However, failure of the powder coating system and severe pitting was evident on the excavated pipe section. The pipeline owner was notified to witness the excavation and to examine the condition of the pipe.

After the initial section of pipe was excavated, additional lengths of pipe were exposed to determine the extent of the corrosion which was occurring in relatively deep pits that appeared randomly on the pipe sections in two areas. The other sections of excavated pipe revealed no visible corrosion. A section of the 24-inch pipe was removed and replaced (Fig. 1). From this section a smaller 15-by-48-inch section was delivered to the laboratory along with a copy of the specification governing the application of the powder coating.

Examination

Upon receipt at the laboratory the pipe section was cut into four small pieces that contained the corrosion pitting. The sections were examined using a digital microscope (Fig. 2, p. 16). Although there was some porosity within the thickness of the coating layer, it appeared near the metal interface, which is common. The application of the powder coating met the requirements of the specification with a porosity level of 1, as rated in the Canadian specification Z245.20-06, "Plant-applied external coatings for steel pipe" (Fig. 3, p. 16).

The coating thickness was measured using the same digital microscope. The thickness of the powder coating ranged from 15.2-to-20.2 mils in the seven areas measured. An example of the thickness is shown in Figure 4 (p. 17).

The thicknesses measured were within the specified range. The coating material was tightly adhered to the metal substrate, even adjacent to the areas displaying corrosion. A combination of scraping and chemicals had to be used to remove the powder coating and expose the underlying substrate. The roughness of the steel (created by the abrasive blast

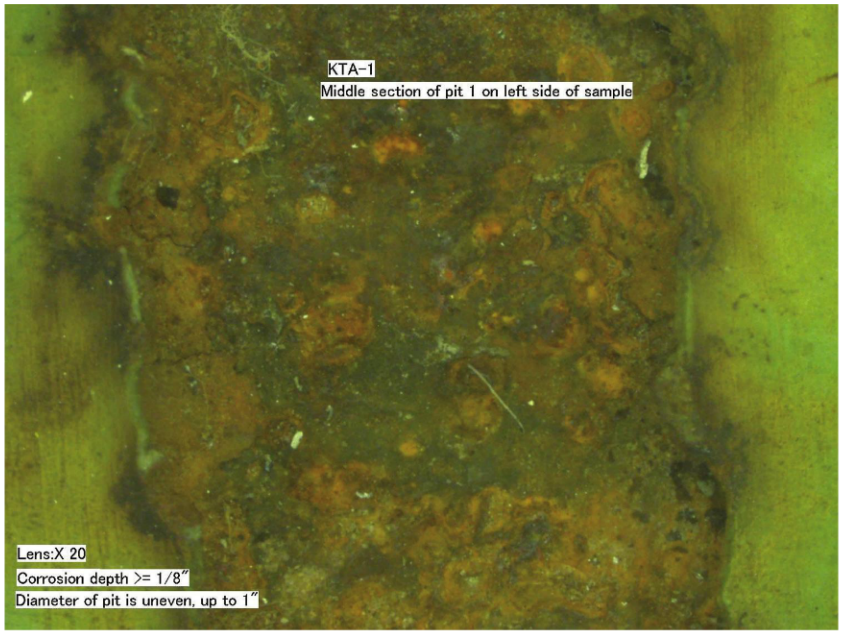

Fig. 2: Microscopic view of the pitting.

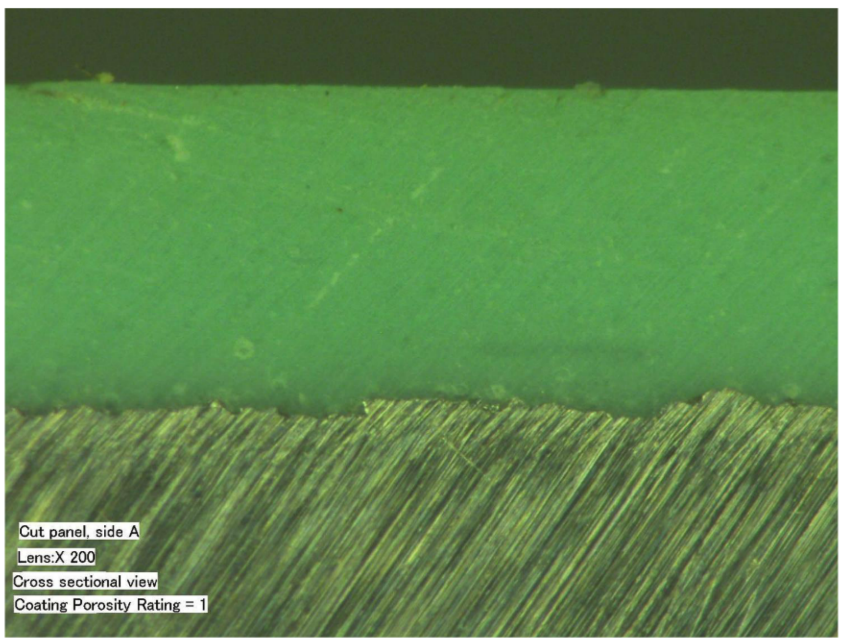

Fig. 3: Cross-section view taken away from pitted areas used for porosity rating.

cleaning process prior to application of the powder coating) was measured using replica tape and was approximately 3 mils, which was also within specification. The newly exposed metal surface was clean and shiny (Fig. 5, p. 18).

These initial findings were in contrast to the condition of the pipe in the pitted areas, especially considering the degree of corrosion and the depth of the pits noted on the pipe. The depth of the pits varied measuring up to 1/8-inch into the thickness of the

An example of the thickness is shown in Figure 4.

The thicknesses measured were within the specified range. The coating material was tightly adhered to the metal substrate, even adjacent to the areas displaying corrosion. A combination of scraping and chemicals had to be used to remove the powder coating and expose the underlying substrate. The roughness of the steel (created by the abrasive blast cleaning process prior to application of the powder coating) was measured using replica tape and was approximately 3 mils, which was also within specification. The newly exposed metal surface was clean and shiny (Fig. 5).

These initial findings were in contrast to the condition of the pipe in the pitted areas, especially considering the degree of corrosion and the depth of the pits noted on the pipe. The depth of the pits varied measuring up to 1/8-inch into the thickness of the ¼-inch-thick pipe, even though it had only been in service approximately six months.

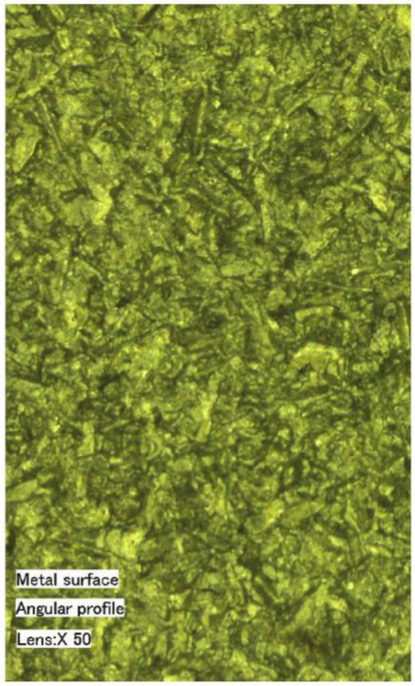

Fig. 5: Photo of metal surface.

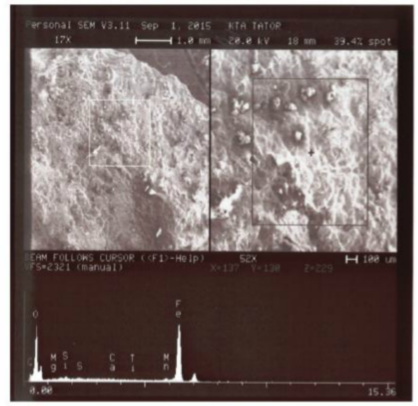

Fig. 6: SEM-EDS of surface.

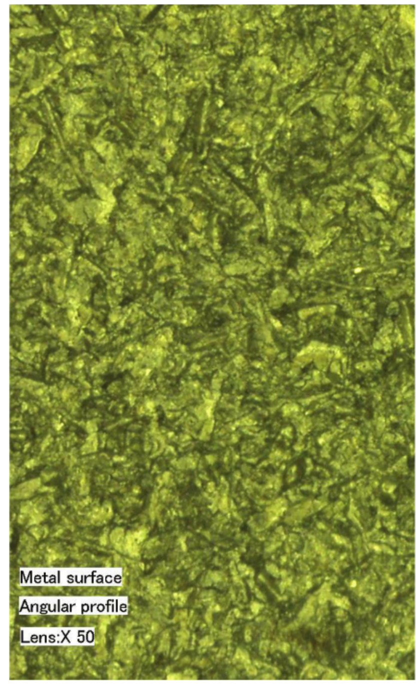

Fig. 5: Photo of metal surface.

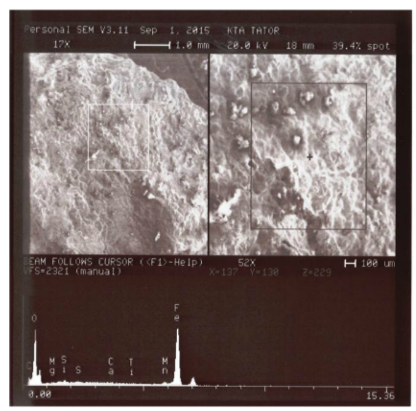

Fig. 6: SEM-EDS of surface.

Was the Powder Coating Cured?

While the application information supplied by the owner indicated that the proper bake time and temperature were followed. Differential scanning calorimetry (DSC) was performed to confirm the cure state of the powder coating. For this technique, small amounts of the material are heated and the reaction of the product to the heat is used to create heating curves and the glass transition temperature (Tg) can be determined from the heating curves. The glass transition temperature changes with the degree of

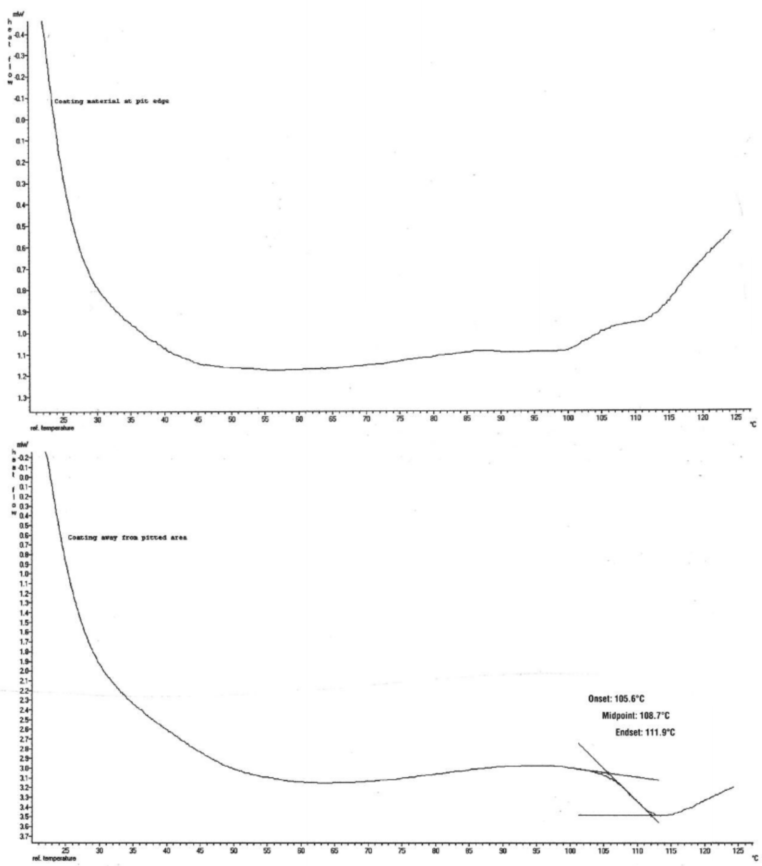

Fig. 7: The proper glass transition event is noted in the second of the heating curves, while the coating from the pitted area displayed no measurable glass transition (top heating curve)..

cross-linking of the material. Most powder coatings have an optimum glass transition temperature to achieve optimum properties of the coating material. If the glass transition temperature of the applied material varies from the stated glass transition temperature, it is an indication of improper cure during the post-application baking process.

Glass transition temperature results indicated that the coating material on the majority of the pipe section displayed a Tg that was within the temperature range expected for the properly cured material (Table 1, p. 17). However, there was some difference noted when the material was sampled at the spots where corrosion was occurring. The proper glass transition event is noted on the lower of the two heating curves, while an area that displayed no glass transition is portrayed in the top heating curve (Fig. 7, p. 19).

This was considered peculiar, since it would be essentially impossible to have small spots on the pipe where the bake conditions (i.e., temperature and dwell time) were different enough to lead to variations in cure. Rather, this seemed to indicate that the powder coating material was somehow being affected in these isolated areas, resulting in a change in the cross-link density after the pipe was put into service.

What about Surface Contamination?

Elemental examination of the surface for contamination was the next step in the investigative process. However, in order to examine the surface, the coating (that was very well adhered to the steel) had to be removed. Smaller sections (strips) cut from the pipe were placed in a freezer to cool the metal to -40 C. The individual sections were removed and a press was used to quickly bend the strips over a narrow mandrel. The rapid, forced bending at a cold temperature caused the material to release cleanly from the surface.

The newly exposed metal was then analyzed for elemental variations using a scanning electron microscope (SEM) outfitted with energy dispersive X-ray spectroscopy (EDS) (Fig. 6, p. 18). This technique is not as sensitive as some other techniques for examination of surface contamination, but since the coating was so tightly adhered it was difficult to expose the larger surface areas that are required when employing other surface analysis techniques.

The elemental scans did not reveal the presence of high levels of chloride or sulfur that may be associated with salt contamination. These scans confirmed that the surface was clean prior to application of the powder coating.

What Does High pH Indicate?

The pH of water placed inside one of the pits revealed an alkaline condition. Since the pipe section had been handled and the pH condition was not reproduced by other pitted areas, this was hardly compelling evidence but was considered a clue nonetheless. In hindsight, measuring the pH in the pitted areas in the field, before the pipe was handled, would have proven valuable. Interestingly, areas subject to cathodic disbondment typically produce an alkaline condition.

Do We Have Probable Cause?

The results of the laboratory analysis in conjunction with admittedly circumstantial evidence led to the opinion that the cause of the aggressive pitting was most likely stray current corrosion.

The corrosion was considered severe, due to the short time of service.

This was of great concern to the owner, so a site visit was performed by an investigator to determine if any more information about the service environment could be uncovered. The investigator was able to discover several interesting pieces of information.

First, while an impressed-current CP system was in place, it was not being monitored. The initial setting was "standard" and may not have been appropriate for the conditions at that site. Second, there were tanks with impressed-current CP systems nearby and power lines were present in the area where most of the severe pitting was occurring. All of these external influences can adversely impact the effectiveness of the cathodic protection intended for the pipe. Monitoring the CP system and noting the areas of higher or lower resistance can help to prevent stray current corrosion. The installation of a monitoring system for the impressed-current CP system was discussed with the owner to determine the changes in the current density and attempt to offset the effect of the stray currents. Additionally, some degree of isolation from the other sources was deemed necessary for the temporary protection of the pipeline.

Finally, the quality and consistency of the backfill was discussed. Changes in the backfill material can alter the resistance of the soil surrounding the pipe, and changes in temperature of the material within the pipe can change the requirements of the cathodic protection along the pipeline. These variations can initiate corrosion in small defects that would typically be protected by the CP system. The resulting small areas of intense corrosion due to variations in current density would appear similar to pitting caused by stray currents.

About the Author

Valerie Sherbondy is the technical manager for the analytical laboratory for KTA-Tator, Inc., a consulting and engineering firm specializing in industrial protective coatings. Sherbondy has been employed at KTA since 1990 and has provided laboratory support for the investigation of hundreds of coating failures and coating testing programs. She holds a B.S. in chemistry from the University of Pittsburgh and is an SSPC-certified Protective Coatings Specialist, a member of the American Chemical Society (ACS) and a committee chair for NACE International.

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INSPECTION EQUIPMENT

BY ALISON B. KAELIN, CQA, ABKAELIN, LLC

As many of you know, I spent the 1980s in the field as an air pollution control engineer/regulator, and later as a consultant training and monitoring field abrasive blast cleaning and painting projects especially related to lead. I gradually moved from the field to the office and starting focusing more on specifications, reports, standards and quality documents and procedures related to lead, environmental, health and safety, project management, coatings, equipment calibration, steel fabrication, non-destructive testing and other areas related to the coatings industry. In 2012, since starting my company, I find myself back in the field as well as in the office. I have gained a new appreciation of the different perspectives and interpretations that can lead to communication breakdowns in the coatings industry.

This column will provide commentary on wide-ranging, coating-related topics from the perspective of office workers (owners, designers, manufacturers, consultants, regulatory personnel) and field workers (contractors, workers, QC/QA personnel). The goal will be to identify potential disconnects and viewpoints between the office and field and sometimes, office-to-office and field-to-field.

INSPECTION EQUIPMENT

Almost everyone associated with the painting industry has some form of inspection equipment. But how do we select it and know that it's providing accurate data,

TABLE 1: VARIANCES IN EXAMPLE READINGS

Parameter	QC Data	QA Data
Dry Bulb (Air Temperature)	99 F	95 F
Wet Bulb	NA	91 F
Depression (t-t')	NA	4 F
RH	84 %	86%
Dew Point	90 F	90 F
Surface Temperature	100 F	101 F
Difference (ST-DP)	10 F	11 F

especially when our measurements can result in loss of production, stopped work or non-conforming conditions?

Inspection equipment should be selected to assure accuracy of the measurements being taken. Common expectation is that it be selected based on the potential range or measurements, degree of accuracy necessary to assure conformance, the intended conditions and ease of use.

EQUIPMENT ACCURACY

Owners, consultants and specifiers establish measurement acceptance criteria as part of specifications but rarely define the desired accuracy level of the equipment to be used. This can lead to erroneous measurements and results, and conflicts in the field.

For example, a specification requires daily QC and QA testing of air and surface temperature, relative humidity (RH) and dew point. It states that "Abrasive blast-cleaning operations shall not be conducted under the following conditions:

a. The relative humidity exceeds 85 percent.

b. The surface temperature is less than 5 F above the dew point."

It mandates the use of thermometers with ranges between 10 and 100 F but provides no other guidance on the type of equipment to be used or its required accuracy.

Similar requirements exist for the temperature of the storage area and the application and cure of the coatings. In fact, temperature, relative humidity and dew point are among the most important measurements made during the surface preparation and coatings processes.

ROOM FOR ERROR

Following the example, in the field, both the QC and QA representatives have equipment that meets the specification. However, the QC representative performs measurements using a properly calibrated electronic psychrometer and obtains ambient readings. He reports that the conditions meet the specification and abrasive blast-cleaning can proceed.

The QA representative performs measurements using a properly calibrated sling psychrometer, psychometric charts and an infrared surface temperature gage. He determines that the RH is non-conforming and issues a non-conformance report (NCR). Work is delayed for four hours until conditions are acceptable (Table 1).

How can their readings be so different when both gages were calibrated?

Accuracy describes the difference between the measurement and the actual value of the items being measured, sometimes referred to as uncertainty. Every instrument has a stated accuracy identified by the manufacturer. It is based on how the measurement is derived (for example, by a direct reading or a sensor), the conditions of use, and the equipment being used according to the manufacturer's instructions and under specific conditions of use. Accuracies between different types of equipment that measure the same thing can vary dramatically.

For example, most sling pychrometers have a stated accuracy for +/- 1–2 F and +/- 5-percent RH of the reading. Most electronic pychrometers have accuracies around +/- 1 – 2 F and +/- 2-percent RH of the reading. In the previous scenario the actual RH (based on the accuracy of the respective equipment) would be in the range of:

QC (2 percent) = 82-to-86-percent RH

QA (5 percent) = 81-to-91-percent RH

The most commonly used surface temperature gages (spring-loaded, infrared and electronic) also have significantly different accuracies.

Spring-loaded thermometers often report their accuracies as "2 percent of the full scale." If an instrument has an accuracy specified as a percentage of full scale then the error will have a fixed value no matter what the temperature is in the range. This means that at 50 F, it would read at +/- 1 F error and at 200 F, the error would be +/- 4 F.

Electronic contact thermometers have accuracies of 0.5-to-1 F of the reading. The errors tend to be lower (.5 F) at lower temperatures but get larger (closer to 1 F) as the temperature increases. Infrared (IR) thermometers can have accuracies ranging from 1 F to 5 F of the reading.

EQUIPMENT USE AND OPERATING ERRORS

Do you know how to use that new equipment you just bought? Do you understand the limitations for use and factors that affect accuracy? Let's look at some of the instruments we just discussed.

The accuracy of the handheld IR thermometer is primarily determined by the distance-to-spot ratio (D/S). This ratio is the size of the area being evaluated by the IR thermometer as it relates to distance. For example, an IR thermometer with a D/S of 8-to-1 used to measure a 2-inch spot would need to be held at a maximum distance of 16 inches in order to achieve the stated accuracy. More importantly, using IR thermometers on shiny, polished or reflective surfaces (like blasted steel or stainless steel) can result in significant error since the surfaces have low emissivity which means they will tend to read higher. Most importantly, IR thermometers only read the surface temperature and therefore should not be used to measure mixed coatings.

For sling psychrometers, the physical location of the test and the amount of time spent whirling or blowing air over the wet bulb directly has an effect on the accuracy of the reading. The sling should be whirled rapidly for 20-to-30 seconds, stopped and quickly read — the wet bulb first because it will begin to change when the air movement stops. The test should be repeated until three consecutive wet-bulb readings equal the lowest reading obtained. Sling psychrometers should be used in the shade and can be affected by wind. They cannot be used to measure RH at near or below freezing (32 F). Accuracies can be affected by insufficient wetting, poor fit or contamination of the sock.

Electronic psychrometers may require about 30 minutes of time in the location of measurement to adjust to higher RH. If they have been stored at a low RH or not used for a while, the device may have to be exposed to a damp cloth to read higher humidity levels. Some electronic thermometers are not recommended for outdoor use, such as field painting.

Surface temperature measurements should be taken where the work is to occur and take into account the direction of the sun or heat source on the surface. The probe or thermometer should remain in contact with the surface for two-to-three minutes to stabilize.

Also check liquid thermometers frequently for liquid separation, which is generally the largest single cause for the failure of thermometers.

If separation occurs, it can sometimes be corrected by getting the liquid to run down. This can be accomplished by holding the thermometer in an upright position and gingerly tapping the stem above the separation against the palm of your hand. As you gently tap the thermometer, observe the liquid above the separation until it breaks away from the wall of the capillary and runs down to join the main column. If this cannot be corrected, the thermometers should be replaced.

Any thermometer or associated probe that relies on contact with the surface can be affected by contamination.

VERIFICATION

Since we use so many thermometers, we can periodically verify (not calibrate) them by laying them all under a towel in an area where the temperature is relatively stable and there is no wind. Allow the thermometers to stay under the towel for about 30 minutes to reach consistent conditions. After 30 minutes, uncover them and read the temperatures as quickly as possible. Temperatures should all be within the stated accuracies of each thermometer. If not, the thermometer may need to be replaced.

Regardless of the thermometer, any temperature measurement will be affected by direct sunlight or shade and wind and can even be affected by the structure and nearby equipment through conduction and radiation. Prior to taking measurements, all thermometers should be exposed to the environment they will be used in for sufficient time to allow them to stabilize.

While we've examined thermometers, the same principles apply to other coating and test instruments. The message here is pretty simple. Office personnel, consider what levels of accuracy and types of equipment you really need and specify accordingly. Verify that appropriate equipment is accurate and is used in accordance with the manufacturer's instructions. Field users, look at your equipment, pull out the manufacturer's manual and read it. Go online to the manufacturer's website and learn about accuracies and limitations of use. Do you know the accuracy and range of use? Are you using the right instruments and are you using them properly? Clarification of expectations and proper

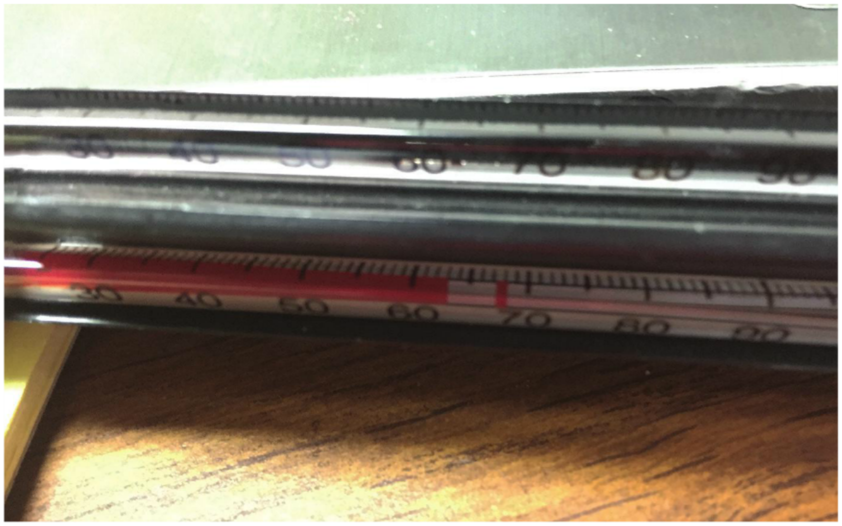
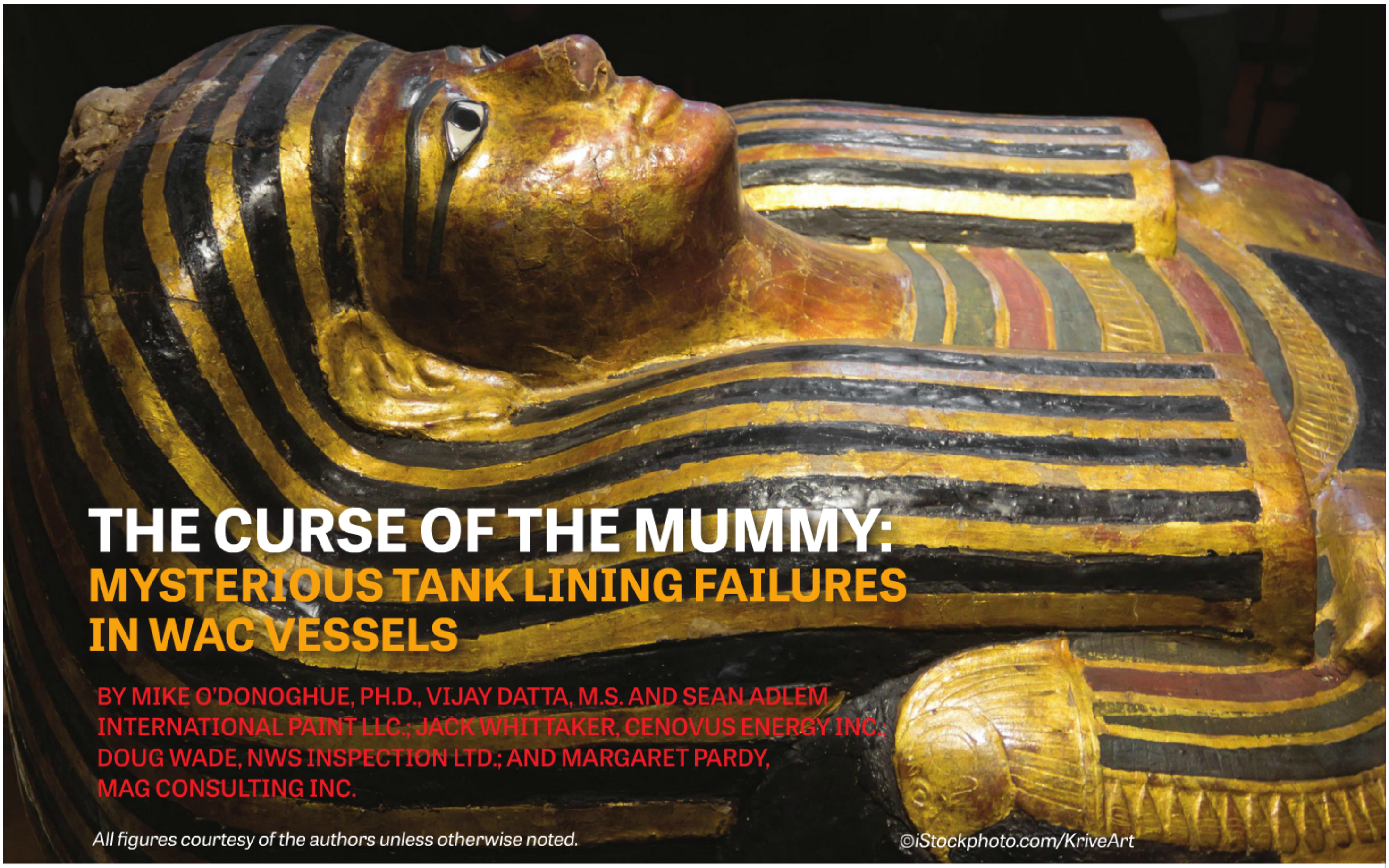


Photo courtesy of the author.

verification and use of instruments can reduce problems that may arise later during a project.

ABOUT THE AUTHOR

Alison B. Kaelin, CQA, has more than 25 years of public health, environmental, transportation and construction management experience in the coatings industry. She is the owner of ABKaelin, LLC, a provider of OSHA training, quality assurance, auditing, consulting, and related services to the protective coatings, construction, fabrication, and nuclear industries. Kaelin is a certified quality auditor and a NACE-certified Coating Inspector. She was a co-recipient of the inaugural SSPC 2014 Women in Coatings Award, a 2012 *JPCL* Top Thinker, a 2012 *JPCL* Editor's Award Winner and an SSPC Technical Achievement Award winner in 2005. Kaelin is also a *JPCL* contributing editor.



THE CURSE OF THE MUMMY: MYSTERIOUS TANK LINING FAILURES IN WAC VESSELS

BY MIKE O'DONOGHUE, PH.D., VIJAY DATTA, M.S. AND SEAN ADLEM INTERNATIONAL PAINT LLC.; JACK WHITTAKER, CENOVUS ENERGY INC.; DOUG WADE, NWS INSPECTION LTD.; AND MARGARET PARDY, MAG CONSULTING INC.

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This article outlines discoveries made from forensic work to unravel epoxy lining failures in several water treatment weak acid cation (WAC) vessels. In previous work by authors Mike O'Donoghue and Vijay Datta, a forensic investigation of several costly tank lining failures was presented as analogous to an archeological dig wherein anticipation and wonder mounted as the investigation unearthed and unwrapped a "chemical mummy"[1]. By no means did the latter reveal its secrets easily. In that particular study the authors peeled through the metaphorical wrappings, utilizing progressively more sophisticated analytical techniques to get to the heart of the mystery. Often sidetracked, and led into unexpected dead ends, the investigation was akin to a journey into the depths of an Egyptian Pharaoh's tomb.

The "dig" exhumed third-party independent testing of several linings at elevated temperatures in chemical immersion, scrutiny of the epoxy lining chemistry and application processes, and compared the severity of real-world service exposures inside a WAC vessel with accelerated laboratory testing chosen to simulate WAC service conditions.

Would the present study prove to be similar? Or would a different type of mummy be discovered in another, and altogether different, series of tank lining failures. The answer was soon to be discovered in the Canadian oil patch where attention was focused on boiler feed water.

In the treatment of steam assisted gravity drainage (SAGD) boiler feed water, WAC and strong acid cation (SAC) ion-exchange vessels play an important role in the treatment of process fluids and demineralization of water to generate steam. The service conditions in WAC vessels are more aggressive than those in SAC vessels, with typical SAGD operating temperatures in excess of 93 C (200 F), operating pressures of 40-to-60 psi and a weekly regeneration protocol that consists of approximately 1.5 hours of acid treatment (6-percent hydrochloric acid, HCl) followed by 1.5 hours of caustic treatment (5-percent sodium hydroxide, NaOH).

The ion-exchange resin beds in the WAC vessels are not considered overly aggressive when compared to the aggressive regeneration conditions. WAC resins have a carboxylic acid (COOH) functional group and are produced by copolymerizing acrylic acid with divinylbenzene as a cross-linking agent[2,3].

Due to the severity of the conditions in WAC and SAC vessels, high-performance linings must be carefully selected and carefully applied. The expectations are that the linings in WAC vessels should afford corrosion protection for at least 10 years.

WAC AND SAC FLOW PROCESS

The WAC and SAC vessels both contain a cationic resin. The WAC resins are regenerated with acid and caustic whereas the SAC resins are regenerated with acid only. While HCl and NaOH are stored onsite at concentrations of 36 percent and 50 percent, respectively, during the regeneration steps the concentrations are adjusted to 6 percent for HCl and 5 percent for NaOH. During regeneration, both the acid and caustic injection steps are about 30 minutes each depending upon the plant load. Throughout the run time of the WACs, about 153,000 cubic meters (5.4 million cubic feet) of materials are used compared to some 20,000 cubic meters for the SAC vessels.

A flow meter is used to determine the discharge rate of the dilution water, caustic and acid used in the regeneration process. While the distributed control system (DCS) makes a calculation to ensure the right concentration of chemical reagents are used, engineering is currently trying to verify that the DCS calculation is correct given that there is no pH feedback in the system to ensure that the right concentration of chemicals is present during regeneration.

In the case of a WAC vessel, regeneration consists of backwash, acid injection, dilution, caustic injection, dilution, and finally a rinse. In contrast, for a SAC vessel, regeneration consists of backwash, acid injection, acid dilution and rinse. Once the hardness of the water starts to rise on the discharge of the exchanger vessel, the latter is taken out of service and regenerated.

It is important to note that while no temperature measurement is directly incorporated into the process loop, the requirements of the process dictate that produced water should be 80 to 85 C (176 to 185 F). The temperature of the influent brackish water is about 10 C (50 F). According to site engineers, if the process runs properly it is unlikely that there would be much temperature variation of the produced water.

RUBBER LINING FAILURES AND LABORATORY TEST PROGRAM

In early 2003, a 1-inch-thick chlorobutyl rubber lining was shop-applied to the carbon steel internals of four WAC vessels, A through D. Within five years, the linings in WAC vessels A, B and C prematurely failed due to disbondment of the liner from the vessel substrate. This was a far cry from the expectations that the lining would provide good corrosion protection for at least 10 years. Even worse, by the first year's inspection of WAC vessel D, the internal lining had failed which was evidenced by pieces of the disbonded liner fouling or plugging drain lines and pipe valving. This was not the mode of failure seen prior to 2003, when rubber linings had literally been torn off of vessel shells, thought at that time to be the absence of air snubbers on pneumatic isolating valves which would otherwise have slowed down the reaction of the valves and alleviated the piston effect. Hence, air snubbers were installed along with differential pressure transmitters (the latter detected plugging in the process loop when hydrocarbon carry-over-contamination became excessive) for the WAC vessels lined in 2003.

Given the premature failure of chlorobutyl rubber lining failures in WAC vessels, an accelerated testing program was designed by the owner and a third-party independent laboratory to find linings capable of withstanding the immersion service conditions and protecting the low carbon steel of WAC vessel internals.

Following discussions with certain manufacturers, several industrial linings were chosen from a range of chemistries including:

- liquid- applied solvent-free epoxies;
- liquid-applied solvent-borne epoxies; vinyl esters (with and without glass- flake);
- polysiloxiranes; and
- baked phenolics; and
- rubber linings.

Importantly, the original rubber lining that failed prematurely in WAC vessels was used as a control in the accelerated laboratory test program with the expectation that it would fail as it had in real life in-service conditions. Both one-coat and multi-coat systems were either field- or shop-applied according to manufacturer's instructions.

The owner and third-party independent laboratory agreed that while the real-life and cyclical regeneration cycles occurring in WAC vessels were not easy to replicate, a reasonable compromise would be to evaluate the candidate linings in a static exposure of 28 days to fluids present in the WAC process[4]. In this way, a 28-day laboratory exposure at a slightly higher temperature was considered to be the rough equivalent of 168 in-service regeneration cycles, or 3.2 years of service in both acidic and basic media. In addition, 10-percent HCl and 10-percent NaOH were used in the laboratory to try to simulate a somewhat more aggressive immersion media than those media experienced in the field, namely 6-percent HCl and 5-percent NaOH (counter-intuitively, a 5-percent caustic NaOH solution is more aggressive towards a lining than a 10-percent NaOH solution). A sample of the produced oil and produced water from a Canadian oil patch site was used in the accelerated laboratory testing.

The performance of the linings was evaluated based on a suite of tests consisting of knife adhesion, pull-off adhesion, impact resistance, impedance, blistering and color change. Slight swelling was evident in some of the coatings after completion of the testing. In the case of the rubber linings, the performance was assessed based on evidence of softening, swelling and retention of adhesion.

SOLVENT-FREE EPOXY (SFE 1): BEST IN TEST

Table 1 (p. 33) shows the laboratory test results for a solvent free epoxy, SFE 1. It can be seen that SFE 1 performed well in acidic, basic and process fluids, and retained excellent adhesion, hardness, impact resistance and barrier properties. Figure 2 (p. 35) show the pre- and post-test coated coupons of SFE 1. The photos in Figure 3 (p. 38) show that superficial chemical attack occurred on the surface of SFE 1 accompanied by minute blisters. Aside from two baked phenolic linings that also performed well, the remaining eight linings failed in immersion in one or more of the media. Failure was deemed to occur with cracking, swelling and blistering.

As expected from the outset, the control rubber lining failed. It did not fail in the hot acidic or basic media, but rather in the hot produced oil and produced water process fluid.

Based upon the best-in-test criteria in the accelerated 28-day immersion test in the laboratory, SFE 1 was selected by the owner as the WAC replacement lining for the previously failed chlorobutyl rubber lining.

The object of the research had been accomplished whereby a promising candidate lining had been found to replace the prematurely failed rubber lining. As a result, the WAC vessels were taken to coating shops for relining.

APPLICATION OF SFE 1 IN WAC VESSELS

Surface Preparation

A pre-blast to SSPC-SP 5/NACE No. 1, "White Metal Blast Cleaning" was achieved in each vessel using green diamond 20/50 abrasive media (< 5 ppm chlorides), one 750-CFM compressor and a #7 nozzle. The surface profile in each WAC vessel ranged from 3.4-to-3.8 mils. Chloride ion detector tubes were used to quantify the initial chloride levels on the steel surface. Chloride levels were found to vary from 10-to-150 µg per cm^2.

Fig. 1: A WAC vessel in service in the Canadian oil patch.

Prior to coating application, the coating manufacturer of SFE 1 required surface chlorides to be less than 3 µg per cm^2. Therefore, excess chlorides were removed by power washing at 80 C (175 F) and 2,500 psi with a proprietary cleaning solution diluted 4-to-1, and then power rinsing the steel substrate. Final chloride levels were less than 3 µg per cm^2 following one wash and one or more power rinse.

A final sweep/blast to SSPC-SP 5/ NACE No. 1 was again achieved in all WAC vessels. Dust assessments were completed in accordance with ISO 8502-3, "Preparation of steel substrates before application of paints and related products — Tests for the assessment of surface cleanliness —Part 3: Assessment of dust on steel surfaces prepared for painting (pressure-sensitive tape method)." A Class 1 level was attained where particles could be visible under 10-times magnification but not seen with normal or corrected vision.

Application

The SFE 1 had a short pot life of approximately 15 minutes at room temperature and was therefore applied using plural component spray equipment. Generally, the temperature of the base component varied between 38 C and 46 C (100 and 115 F) and the convertor temperature was 29 C (84 F). Post-cure of the epoxy lining was completed by the applicator during the evening, or overnight.

Dry-Film Thickness (DFT)

The target DFT for the one-coat application of SFE 1 was 30-to-40 mils. The DFTs in the WAC were close to the recommended range with isolated areas as high as about 70 mils. Due to a low DFT, the manway throat in one of the WAC vessels was sanded and recoated by brush and roller (with the recoat window exceeded).

THE MYSTERIOUS LINING FAILURE OF SFE 1

Expectations were high for long-term field success using SFE 1 because the

TABLE 1: PREQUALIFICATION IMMERSION TESTING AT 90 C OF SOLVENT FREE EPOXY, SFE 1 IN 10% HCL, 10% NAOH AND PROCESS FLUIDS

Sample	Phase	DFT (pre-test mils)	DFT (post-test mils)	Adhesion Parallel Scribe	Adhesion (psi) ASTM D4541	Blistering ASTM D714	Color Change (TM0185)	Log Impedance @ 0.1 Hz (ohm*cm^2)	3.0 J Impact
101	Control	39.7		ND	963			ND	Pass
102		34.2		A	ND			11.3	
103	Acid	41.1	41.4	B	ND	<#8M	Moderate	10.6	Pass
104		38.7	40.6	ND	1124	<#8M	Moderate	ND	
105	Base	46.2	46.3	A	ND	<#8D Surface	Very Slight*	10.8	Pass
106		43.1	43.6	ND	1149	<#8D Surface	Very Slight*	ND	
107	Process	35.1	35.1	HC-C W-B	ND	<8#D Bottom	Slight**	HC-11.2 W-11.2	Pass
108		43.8	43.2	ND	753	<#8D Bottom	Slight**	ND	

*Color changed from bright green to dark green. Otherwise no other visual effect. Blisters appear to be on the surface of the coating only. Blisters are not cracked and not wet inside.

**Coating appears stained from bitumen, not discolored. Light brown/yellowish tinge. No other visual change. Very small blisters are visible only at bottom edge of panel (e to 6 mm from edge). Blisters are only at the very top surface of the coating. Blisters are tough and mostly full of coating (almost like overspray), but less dense than the non-blistered area. Blisters are not cracked and not wet inside.

ND – not done; HC – hydrocarbon phase; W – water phase

Surface preparation: SSPC-SP 5/NACE No. 1; surface profile 3-to-5 mils; 1 coat field applied; cured for 7-to-8 hours followed by a post cure of 6 hours

Swelling: post-test DFT – pre-test DFT

TABLE 2: PRE-QUALIFICATION ADHESION TESTING OF SOLVENT FREE EPOXY, SFE 1

Lining	Sample #	Test Location	Adhesion ASTM D4541 (psi)	Average Adhesion (psi)	Standard Deviation (psi)	Location of Separation (ASTM D4541)
SFE 1	1a	Control		963	44	
		Top	968			2% cohesive, 98% glue
		Middle	917			5% cohesive, 95% glue
		Bottom	1,005			2% cohesive, 98% glue
	1b	Acid		1,124	302	
		Top	1,016			30% cohesive, 70% glue
		Middle	891			35% cohesive, 65% glue
		Bottom	1,466			30% cohesive, 70% glue
	1c	Base		1,149	46	
		Top	1,171			98% cohesive, 2% glue
		Middle	1,096			100% cohesive
		Bottom	1,180			100% cohesive
	1d	Process		753	90	
		Top	649			100% glue
		Middle	796			100% glue
		Bottom	813			100% glue
		Bottom				

laboratory test indicated that at least a three-year performance could be obtained. Lamentably, however, reality dashed those expectations in less than two years.

The first of four WAC vessels lined with SFE 1 was examined revealing blistering and extensive cracking. Then, one by one, the other three WAC vessels were examined with the same result — blistering and cracking of the lining. The photos in Figure 4 (p. 39) are representative of the coating degradation, and the pattern of lining failure in each vessel was almost identical. So, what was the chemical mummy that caused the coating problems? Just how bad was the lining failure? Was this a coating failure in the classic sense[5-7]? Numerous questions arose. As in the authors' previous "Curse of the Mummy" investigations, would it be necessary to employ

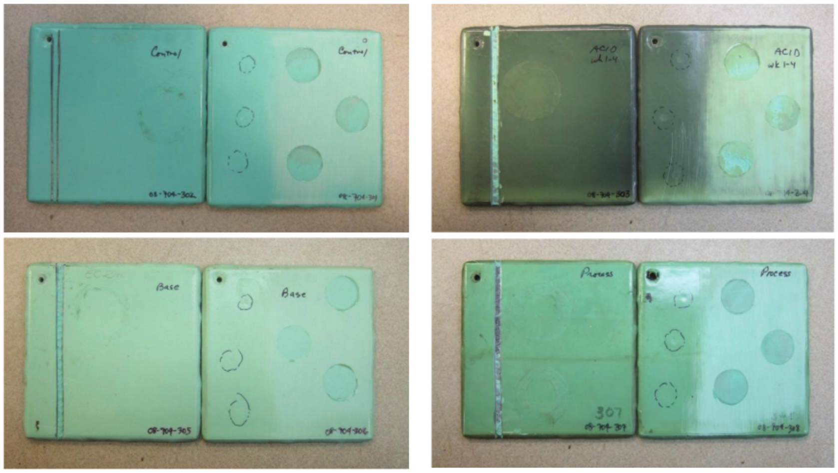

Fig. 2: Prequalification testing of SFE 1.

a multitude of high-tech analytical techniques in order to determine the cause of the problem or, importantly, would the root cause be far more obvious[8-10]?

FAILURE ANALYSIS

Observations in the WAC Vessels

Manway Throat

The blisters on the manway throats of the WAC vessels were dome- or crescent-shaped, intact and extensive.

Upper Head

The upper heads of each WAC vessel were extensively blistered with more than 20-percent of scale-type or small crescent-shaped blisters with a few of them opened to expose bare metal.

Shell

Each WAC vessel had approximately 30 percent of the coating blistered (scale-type, or small crescent-shaped). Blistering was dense, particularly on the lower part of the shell, which extended just below the weld for the shell/head transition. More blisters were opened on the lower areas of the shell than on the upper areas.

Bottom Head

In three WAC vessels, approximately 5 percent of the coating had blistered. The majority of the blisters were located near the

TABLE 3: WAC VESSEL A — APPLICATION OF SFE 1

WAC Area	Average DFT (mils)	High DFT (mils)	Low DFT (mils)	Stripe Coat	Remarks
Manway Throat	24.0	35.0	18.0	N	
Upper Head and Upper Shell	38.0	50.0	24.0	N	
Nozzles	29.0	45.0	21.0	N	Brushed and rolled
Bottom Head and Lower Shell	29.0	54.0	15.0	Y On Brackets	Heavy corrosion on lower shell and head

Original surface preparation before SFE 1 application:
- Upper and lower half of vessel were abrasive blasted and coated separately
- Abrasive = Green Diamond 20/50 NACE No. 1/SSPC-SP 5
- Residual Cl^- = >10 – 40 µg/cm²
- Powerwash and rinse with cleaning solution at 80 C and 2,500 psi
- Following wash, residual Cl^- = <3 µg/cm²
- Surface profile measured 3.5-to-3.6
- ISO 8502-3 Class 1 for dust level on substrate
- Material Temperature: Base 115 F Convertor 85 F
- Manway throat was low in DFT, sanded and additional coating applied by roller.
- Post-cured for 3-to-4 hrs @ 150 F

TABLE 4: WAC VESSEL A LINED WITH SFE 1 AFTER 2 YEARS SERVICE

WAC Area	Average DFT (mils)	High DFT (mils)	Low DFT (mils)	Blistering (%)	Remarks
Manway Throat	23.0	34.0	17.0	100%	Dome shaped, intact blisters
Upper Head	27.0 – 42.0	47.0	27.0	20%	Scale shaped blisters, few open
Shell	25.0 – 43.0	51.0	25.0	30%	Scale shaped, denser on south side and lower areas of shell. More opened on lower areas of shell. Brackets on shell more affected by blisters than in C and D
Bottom Head	18.0 – 39.0	43.0	18.0	5%	Scale shaped located near shell/head weld and floor brackets

weld for the shell/head transition and on the bottom areas where brackets were located.

On the bottom head of the fourth WAC vessel, 100 percent of the coating had blistered with small scale-type (or small crescent-shaped blisters) seen near the weld for the shell/head transition. Large crescent-shaped blisters on the bottom areas of the head were observed where the brackets were located. In two of the WAC vessels the lining was heavily discolored.

There was very little difference between the lining failures in each of the WAC vessels except that coating degradation in the lower heads of two vessels was much worse than in the other two vessels. The nozzles had also blistered in each vessel and blistering was more extensive on the throats nearer to the shell.

DETERMINATION OF BASE-TO-CONVERTER MIX RATIO OF SFE 1

In order to ensure that the applicator had mixed the two components of SFE 1 in the proper ratio, a small chip of SFE 1 was field-retrieved from WAC vessel B. The base-to-converter mix-ratio was then determined by microanalysis. The amount of carbon, hydrogen and nitrogen in the chip were determined from a microanalysis and the percentages compared with those of SFE 1 prepared and cured in an oven at 90 C (194 F) in the laboratory with mix-ratios of 1-to-1, 1.5-to-1, 2-to-1 (correct ratio), 2.5-to-1, and 3-to-1. Since nitrogen-based curing agents (various amines) are present in the converter and not in the base component, the nitrogen concentration in the mixed coating varies significantly with mix ratio.

Given the SFE 1 coating samples have some degree of heterogeneity; each sample was analyzed in duplicate, except for the 2-to-1 sample and coating chip, which were analyzed in quintuplet. Uncertainty in the measurements was 2 percent of the concentration.

From a nitrogen analysis, the mix ratio of the failed SFE 1 lining was the correct 2-to-1 of base to converter. Therefore, the two components of the SFE 1 lining had been mixed properly by the applicator (for the WAC vessel from which the coating chip had been retrieved).

ATR-FTIR of SFE 1 Coating Chip and Control

A small portion of the same SFE 1 chip used for mix-ratio determination was analyzed by scraping the sample surface before attenuated total reflection-Fourier transform infrared spectroscopy (ATR-FTIR) analysis. A sample of SFE 1 was prepared in the laboratory and used as a control in a comparative ATR-FTIR analysis.

The analysis was performed using an FTIR main bench with an attached FTIR microscope. The transmission spectra were acquired by taking 32 scans at 4 wavenumber (cm^{-1}) resolution for both background and samples. The ATR spectra were acquired using a slide-on ATR microscope attachment with a Germanium element and a sampling area of approximately 100 microns. The ATR spectral acquisition consisted of 128 scans at 4 cm^{-1} resolution for both background and samples. The data analysis was performed using software. All peak positions are stated in wavenumbers.

The control sample spectrum contained several peaks (1509, 1607, 1244, 1181, 827 cm^{-1}) that were diagnostic for Bisphenol A epoxy resin. The spectrum for the coating chip of failed SFE 1 was essentially the same with the exception that it had one major peak at 985 cm^{-1}, which could be indicative of the presence of silicate.

DISCUSSION

Epoxy Chemistry of SFE 1

There were several important reasons why SFE 1 was submitted for prescreening for WAC service in the independent laboratory test. Firstly, the lining had performed extremely well in the manufacturer's in-house hot immersion tests in 5-percent, 10-percent and 20-percent HCl at 90 C, where the pH was less than 1. Secondly, SFE 1 had a long and admirable track record in acid storage. Thirdly, SFE 1 possessed caustic NaOH resistance of up to a pH of 14, a feature shared with many epoxy linings. Fourthly, in unpublished work the authors had also amassed considerable data that showed SFE 1 could withstand immersion temperatures of up to 177 C (350 F) and 250 psi in autoclave tests relevant to other oil patch vessels such as separators and treaters. Interestingly, SFE 1 was a Bis A-Bis F epoxy phenolic and not a three-dimensional epoxy novolac with higher functionality and higher cross-link density.

On the downside, it was known that to be successful in hot non-oxidizing acid service (for example, hydrochloric acid), SFE 1 had to be applied to an SSPC-SP 5/NACE No. 1 metal surface with an angular profile of 3-to-5 mils. Lesser prepared surfaces resulted in SFE 1 failure in the laboratory tests. Additionally, given that SFE 1 was a high-build epoxy with a short pot life, another critical requirement for its successful application was the proper use of plural-spray equipment. Qualified applicators had to ensure that the specified film thickness of 30-to-40 mils DFT would be applied in a single-coat application. Unfortunately, the complex geometry of WAC vessels made the latter extremely difficult to achieve. Furthermore, if insufficient SFE 1 was applied, its propensity to amine blush and its rapid curing characteristics could prove deleterious in terms of being recoated to acquire the specified film thickness. While SFE 1 was a high-performance and rapid-curing lining, and performed best-in-test in the WAC qualifying testing, it was nonetheless a difficult coating to apply properly in a WAC vessel with a complex geometry.

At first glance these considerations indicate that a thin-film, air-drying epoxy with superior wetting characteristics would have been preferable. A discussion of single-coat, thick-film and solvent-free epoxy technology vs. multi-coat, thin-film, solvent-borne epoxy systems has been presented elsewhere[11,12]. While the authors often prefer the use of multi-coat, solvent-borne novolac epoxy systems for high-temperature applications in the oil patch, such linings rarely possess outstanding mineral-acid resistance at 90 C.

Fig. 3: Surface blisters on SFE 1 in prequalification testing.

This was borne out in the prescreening laboratory tests.

After two years of service in the four WAC vessels, the cracking in SFE 1 evidenced around what appeared to be dry blisters could reasonably suggest that a plasticizer in the film had been driven off, excessive tensile stress had developed and stress dissipation occurred by the film cracking. With a brittle thermoset like SFE 1 there will be a higher modulus, less elongation and at elevated temperatures, the potential of cracking. It was clear that in many instances the cracked blisters then probably formed by cohesive separation in the film because of the in-service conditions.

It is necessary to consider the chemistry of SFE 1, its prequalification performance for 28 days in the accelerated laboratory static immersion tests at 90 C, and its real-life performance in the cyclic immersion–cyclic chemical environment of WAC vessels.

Application Considerations and Field Observations

Third-party inspection reports showed that each WAC vessel had been properly abrasive blasted to SSPC-SP 5/NACE No. 1 white metal with a 3-to-4 mil angular profile. Chloride levels were less than 3 µg per cm^2 prior to coating application after treatment with a water-based proprietary cleaner (removed by power washing at 2,500 psi).

The application appeared to have been carried out well in each WAC vessel after application teething difficulties had been overcome in the first WAC vessel coated.

After less than two years in service, dry blisters were found in the SFE 1 lining that extended down to the substrate. The blister distribution is per Table 4 (p. 36) in one of the WAC vessels. These results typify those found in the WAC vessels at-large.

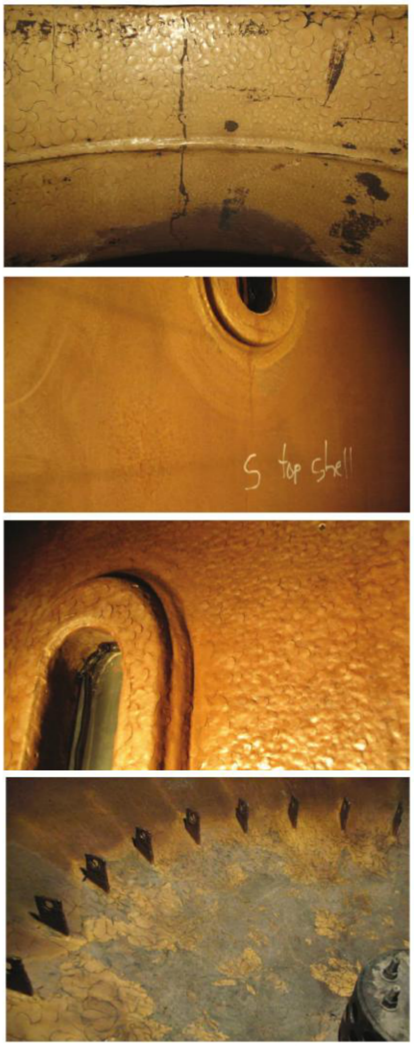

Fig. 4: Photos of SFE 1 in WAC vessels after two years of service.

Blistering occurred on non-pitted areas as well as pitted areas, and even in the lining that had been applied at the correct specification of 30-to-40 mils DFT and at markedly higher DFTs. In either case, no blister liquids were discerned or available for extraction.

In the first WAC vessel it took three separate applications of SFE 1 before the lining was correctly applied.

A coating inspector noted that the SFE 1 was higher than the specified film thickness in certain areas, especially in the lower head regions of two WAC vessels (approximately 70-mils DFT). It can be speculated that loss of plasticizer at elevated temperatures in SFE 1 could lead to high internal cohesive-curing stresses and cracking of the lining (in a WAC vessel where the film thickness was typically in the correct 30-to-40 mil DFT range, the lining still cracked).

Laboratory vs. Field Conditions

The original laboratory immersion testing to evaluate lining candidates for WAC vessels was carried out for 28 days in static and constant stress conditions of 90 C and 10-percent HCl, 90 C and 10-percent NaOH, and 90 C and produced oil/produced water. These conditions were markedly less severe than if a cyclic test (i.e., with cyclic stress) had been chosen to simulate the real-world environment of the WAC units.

Interestingly, only two coatings passed all three of the static tests. Lining SFE 1 passed all three tests. Even then the SFE 1 apparently had some miniscule blisters in the acid test. In retrospect, a cyclic exposure test regimen would have been more appropriate. At best, the laboratory results indicate that SFE 1 would be acceptable based on static immersion conditions, but the authors contend that those results could not be extrapolated to indicate that SFE 1 would survive long in a cyclic WAC environment. Significantly, even the third-party independent laboratory commented that their test results suggested SFE 1 "was acceptable for the aggressive WAC conditions, although the life expectancy could be shortened due to the severe regeneration conditions."[4]

Realistically, handling extremely aggressive real-life immersion in a cyclic chemical environment of 6-percent HCl, boiler feed water, and 5-percent sodium hydroxide (pH 0.2-to-13) and temperatures of 90 C minimum and perhaps 120 C, is too difficult even for the best-in-test SFE 1 epoxy lining. The authors suspect that no epoxy lining will handle this service for any significant length of time. Thus far two years have been obtained with SFE 1 in these vessels and based on much less aggressive laboratory test criteria. In fact, two-to-four years may be the best that any epoxy lining can provide.

In the lower head regions of two of the WAC vessels it was found that the DFT was about 70 mils (compared to the maximum of 40 mils) and pronounced blistering and cracking of the SFE 1 lining had taken place. In contrast, in the lower head regions of the other two WAC vessels where the DFT was close to the maximum specified then the blistering and cracking was much less. Therefore, in this region of the WAC vessels there was a correlation of blistering as a function of DFT. No such correlation was found in other areas of the WAC vessels.

No correlation was found between the extent of SFE 1 lining degradation and steel areas that had previously been heavily corroded or pitted, or the heat pattern during accelerated cure where over or under heating could have compromised the coating.

So all things considered, the bandages were off! The "mummy" was revealed for what it was — a somewhat inadequate laboratory testing regimen for indicating the long service life of a lining in WAC vessels. The mystery appeared to have been solved and the curse of the mummy laid to rest. In contrast and in previous work, the mummy was slow to release its secrets. In this work, however, the mummy was soon discovered without resort to a plethora of analytical techniques.

CONCLUSIONS

The curse of the mummy that caused the solvent-free epoxy SFE 1 lining failure in WAC vessels is most likely the overly severe real-world immersion conditions in WAC vessels

The original laboratory test where SFE 1 ranked best-in-test did not simulate real-world immersion conditions where a repeated cycle of highly acidic, highly basic, and process fluid media impact the lining on a regular basis. Lab tests did not correlate at all with real-life service

In some instances SFE 1 blistered and cracked in real-world conditions at both the specified film thickness and double the specified film thickness.

Interestingly, SFE 1 continues to afford protection in the WAC vessels. There is little evidence of corrosion being observed in the vessels.

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JPCL

INDUCTION HEATING FOR COLD WEATHER PREHEATING AND POST-CURING OF LIQUID EPOXY COATINGS ON GAS PIPELINE GIRTH WELDS

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PHOTOS COURTESY OF PG&E

In 2013, Pacific Gas & Electric Company (PG&E) did not have a specific standard or guidance for selection, application and inspection of cold weather, field-applied coatings on transmission piping when the pipe surface temperatures went below 50 F (10 C). In November of that year, unusually cold weather hit northern California. Night temperatures were below freezing, which caused the pipe surface to be below the 50 F minimum necessary to cure the approved epoxy coatings.

At this time, the application procedure consisted of enclosing the work area and using space heaters to raise the ambient temperature sufficient to increase the pipe temperature. This approach was costly and cumbersome, and resulted in cure times of 6-to-10 hours or more. With these long cure times, construction crews could not quickly backfill the pipelines, and corresponding construction production rates were slow and costs high.

COLD WEATHER COATING CHALLENGES

A fundamental challenge of applying traditional two-component, epoxy amine pipeline coatings at low temperatures is the slowing of curing reaction as the pipe temperature decreases. If the temperature drops below a minimum threshold, the reaction will cease completely. The curing process may restart when the temperature increases, but other issues associated with the interrupted cure may prevent the

Fig. 1 (Left): Induction heating equipment set up for demonstration at PG&E Applied Technology Services facility.
Fig. 2 (Above): PG&E personnel participating in the demonstration at PG&E Applied Technology Services facility.

coating from achieving the optimum coating properties. Epoxies can be effectively applied in cold weather by preheating the pipe, and force-curing the applied epoxy.

At low temperatures, the applicators will need to deal with changes in coating characteristics. As the temperature decreases the coating will become more viscous (thicken). The chemical composition of a coating will determine its freezing point, but typically a coating containing solvent will freeze below the freezing point of water. Two-component materials will be harder to mix when they have a higher viscosity. Some coating manufacturers require that the coating be stored and mixed at higher ("normal") temperatures. A higher-viscosity coating will become inherently harder to apply and application techniques may become limited to trowels. A higher-viscosity

Fig. 3: Induction heating system mounted on a vehicle for use in pipeline right-of-way.

coating will not sag as quickly as it might normally; if attention isn't paid to achieving the proper wet-film thickness, sags may develop after the applicator has completed the work. In extremely cold temperatures, attire will be necessary to reduce risks associated with low-temperature environments such as hypothermia and frostbite, and this can interfere with the applicator's productivity.

LOW-TEMPERATURE COATING

Aside from enclosing and heating the environment with space heaters, two general solutions are available for coating pipe at low temperatures — heating the pipe and applying a traditional epoxy or applying an alternative, non-epoxy coating material at lower temperatures. Subsequent to extensive research and testing, PG&E concluded that heating the pipe and applying a traditional epoxy amine coating was the best solution in this case.

INDUCTION HEATING

Following extensive research and testing, PG&E selected an induction heating system that uses an induction blanket wrapped around the pipeline. The system is an adaptation of an induction heating system that is commonly used in the pipeline industry for welding preheat and/or stress relief.

Induction heating involves heating a conductive metal using coils of electromagnets and alternating current electricity. The alternating current produces eddy currents within the substrate and the internal resistance produces heat. As electronic power sources using inverter technology have become much smaller and more efficient, induction heating has become better suited for field use. In addition, flexible coils have been developed which make induction heating equipment easily adaptable to a variety of shapes and configurations.

Air-cooled induction heating systems have been specifically designed for preheating applications up to 400 F (204 C). In the case of induction heating blankets for girth weld coating on existing fusion-bonded epoxy (FBE) coated pipe, the maximum temperature is controlled to 180 F (82 C) in order to prevent damage to the existing FBE. These systems can be operated in manual modes where power output is applied to a part for a specified length of time or in the temperature-controlled mode where the power output is automatically adjusted to maintain a specified temperature at a sensor location on the pipe.

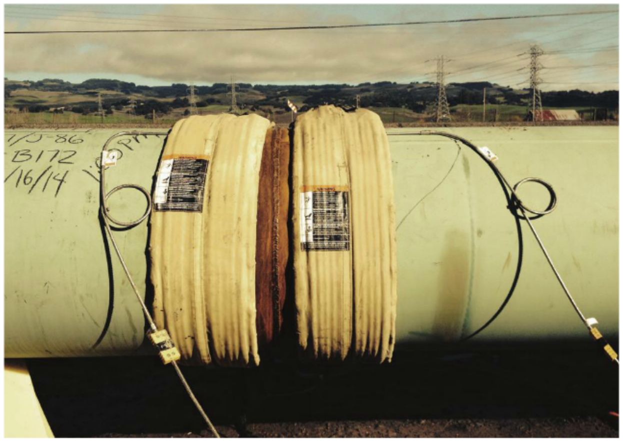
Fig. 4: Induction heating blankets installed adjacent to girth weld.

provide feedback on field use of the system. Several sections of FBE-coated pipe were brought to ATS facilities to allow the induction heating equipment manufacturer to demonstrate the system. Figure 2 (p. 45) shows observers during one of these demonstrations. PG&E engineering and ATS personnel collected data on the heating and cooling rates under different combinations of pipe diameter, blanket spacing and system control settings. Based on the data collected and input from the observers, a draft procedure and plan was prepared for field demonstrations.

Air-cooled blankets are available for pipe diameters from 8-to-60 inches (20-to-152 cm). A disadvantage of these systems is that the blankets may get the surface dirty where they contact the pipe. To avoid contaminating the cleaned surface and curing coating, the operator should develop a heating strategy and exercise care when handling the blankets. Induction heating provides the optimum QA/QC for preheating and coating as the entire pipe wall can be heated and precise temperature of the pipe surface can be controlled throughout the entire process. In addition, the induction heating system also allows the pipe heating to be continued during the post-cure process, permitting the coatings to be cured in approximately one hour. Short cure times are desirable since they decrease the time to backfill. Precise temperature control or post-cure heating cannot be attained using propane preheat systems.

Laboratory Demonstrations

The system was demonstrated on girth weld coatings at the PG&E Applied Technology Services Laboratory (ATS). Figure 1 (p. 44) shows the equipment in the ATS facility for the demonstration, during which a range of PG&E personnel were brought in to observe the process, learn how to operate the equipment, collect data on heating efficiency, and (because this lab allows for operation of equipment on 20-foot sections of pipe),

Field Demonstrations

After the demonstration at ATS, the first of several field pilot projects was performed during a 24-inch line installation near Petaluma, California. The induction heating equipment can be mounted on a vehicle for easy access along the pipeline right-of-way (Fig. 3, p. 45). Before surface preparation, the induction heating blankets were placed directly on, or immediately adjacent to, the girth weld area (Fig. 4). Thermocouple (temperature) probes underneath the middle of each blanket were used to ensure the pipe temperature remained below the temperature set point, with the coating applicator able to adjust the blanket spacing and induction heating control temperature (below 180 F) based on site conditions. Ambient temperature, wind, pipeline conditions and other variables will affect heat transfer from the pipe, and thus the optimum adjustment of the induction heating system.

Once the area underneath the blankets has been warmed to the desired temperature and recorded by the temperature probes (typically taking several minutes), the heating blankets may be moved so they do not get damaged during surface preparation (Fig. 5, p. 48). The blankets may be energized during surface preparation to ensure continuous heating of the pipe during the blasting process.

Once the surface was prepared and inspected, the induction blankets were placed as close as possible to the edge of the coating application area without interfering with the work. With induction heaters in place, the epoxy coating was applied in accordance with standard practices (Fig. 6, p. 48).

The induction heaters may remain in place as required for adequate cure. Figure 7 (p. 48) shows the time to backfill as a function of temperature for two PG&E-approved liquid epoxy coatings for buried pipeline. Note that both manufacturers indicate a minimum cure temperature of 40 F (10 C). By maintaining the pipe surface temperature above 100 F (254 C), the time to backfill can be reduced from over 10 hours to less than one hour. This expedited cure results in shortened construction time, less impact on the public and reduced project costs.

During the laboratory and field demonstrations, data was collected to understand the effect of induction heating on the pipe. Figures 8 and 9 show some of the data from the field demonstration. Induction coils quickly raise the temperature of steel in their immediate vicinity. Figure 8 (p. 48) shows temperature data with a 3-inch blanket spacing. Note that it takes five minutes to heat the center section of that pipe to 160 F (71 C) with the blankets controlled at 180 F. Once the blankets were removed, the pipe temperature remained above 140 F (60 C) for an additional five minutes.

Steel surfaces several inches away from the induction coils can take considerably longer to heat and will not reach the same temperature as the steel under the coils. Figure 9 (p. 50) shows that with an 11-inch spacing between the


Fig. 5: Abrasive blasting of the heated girth weld. Note that blankets have been moved to avoid damage.


Fig. 6: Heating blankets are reinstalled for coating application and cure.

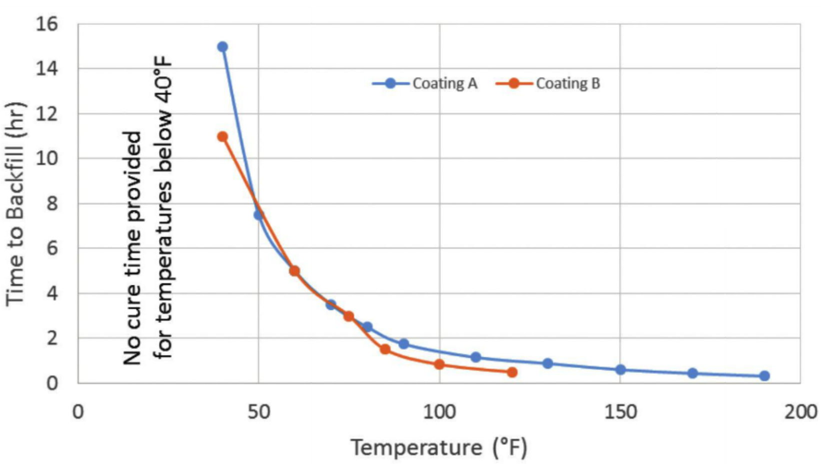

Fig. 7: Time to backfill versus temperature for approved liquid epoxy coatings.

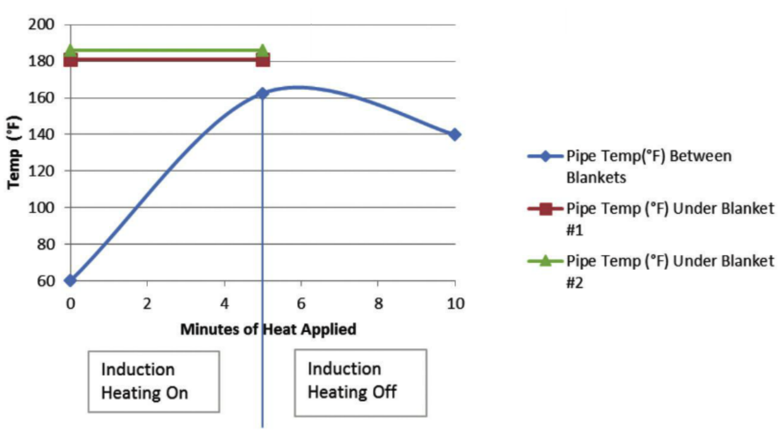

Fig. 8: Pipe temperature profile with 3 inches between induction heating blankets.

blankets, the weld only reached 140 F. Obviously these temperature profiles will be affected by the ambient temperature and other factors such as airflow and pipe product temperature.

The data demonstrates how pipe temperature can be adjusted through spacing of the blankets and adjustment of the temperature control under the blankets. Adjusting these parameters allows the coating applicator to control heating in various pipe configurations and ambient conditions. During the PG&E testing and pilot project, the optimum conditions were determined to be 11-inch spacing between blankets and 180 F temperature control set point under the blankets.

AN ALTERNATIVE PIPE-HEATING PRACTICE

PG&E's new standard practice for coating pipelines when the pipe surface temperature is below 50 F involves preheating the pipeline prior to surface preparation and coating application. The company also tested and allows use of propane torches as a preheating alternative in situations where induction heating is not available or not practical. Open propane flame heating is also a common preheating method used in pipeline construction. Propane torches are used in welding to preheat the pipe to between 250 F (121 C) and 400 F. Lightweight, rugged portable heating torches are available with capacities in excess of 200,000 BTU/hour at 2,000 F. Open-flame heating

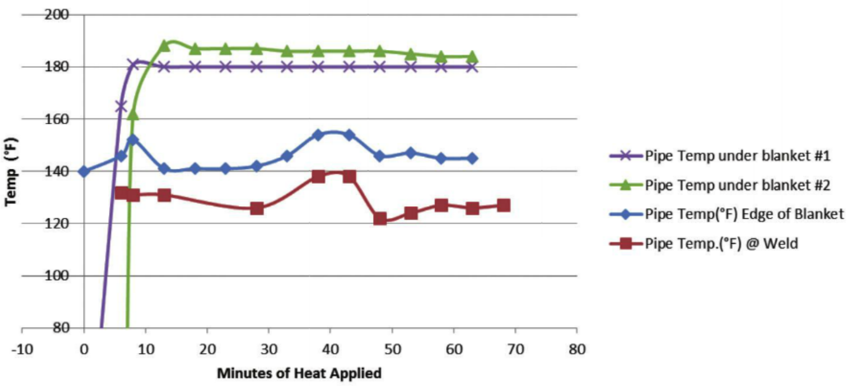

Fig. 9: Pipe temperature profile with 11 inches between induction heating blankets.

is generally inefficient because the heat energy in an open flame is lost heating air surrounding the targeted area. Inconsistent heating and hot and cold spots can also occur when there is inefficient heat transfer within the part. This can result in inconsistent coating quality.

At extremely low temperatures, propane torches become difficult to use and storage tanks/cylinders may need to be warmed for proper operation. There are also safety issues anytime anyone works with an open flame. Workers must be careful not to ignite flammable sources that may also be on the jobsite. In addition, propane heating has a limitation in that it cannot be used to post-cure epoxy coatings. Therefore, this method is considered a second alternative to the induction heating system.

SUMMARY AND CONCLUSIONS

PG&E has determined that the optimum approach for cold weather coating application on girth welds is to use the existing approved epoxy coatings with induction preheat of the pipe to above 50 F during surface preparation, coating application and cure. As a second choice, preheating can alternately be achieved with propane torch heating if the induction preheat system is not available at jobsites.

PG&E is now successfully using this pilot standard for cold weather coatings. The first of several sets of induction heating equipment has been purchased. Personnel have been trained in induction heating procedures and propane heating is also available for use.

The system was demonstrated on girth weld coatings at the PG&E Applied Technology Services Laboratory and also during several 24-inch line installations near Petaluma, Calif. as a pilot program. Based on the data gathered and success of the demonstration, PG&E has an accepted process for heating with induction blankets when coating girth welds in cold weather.

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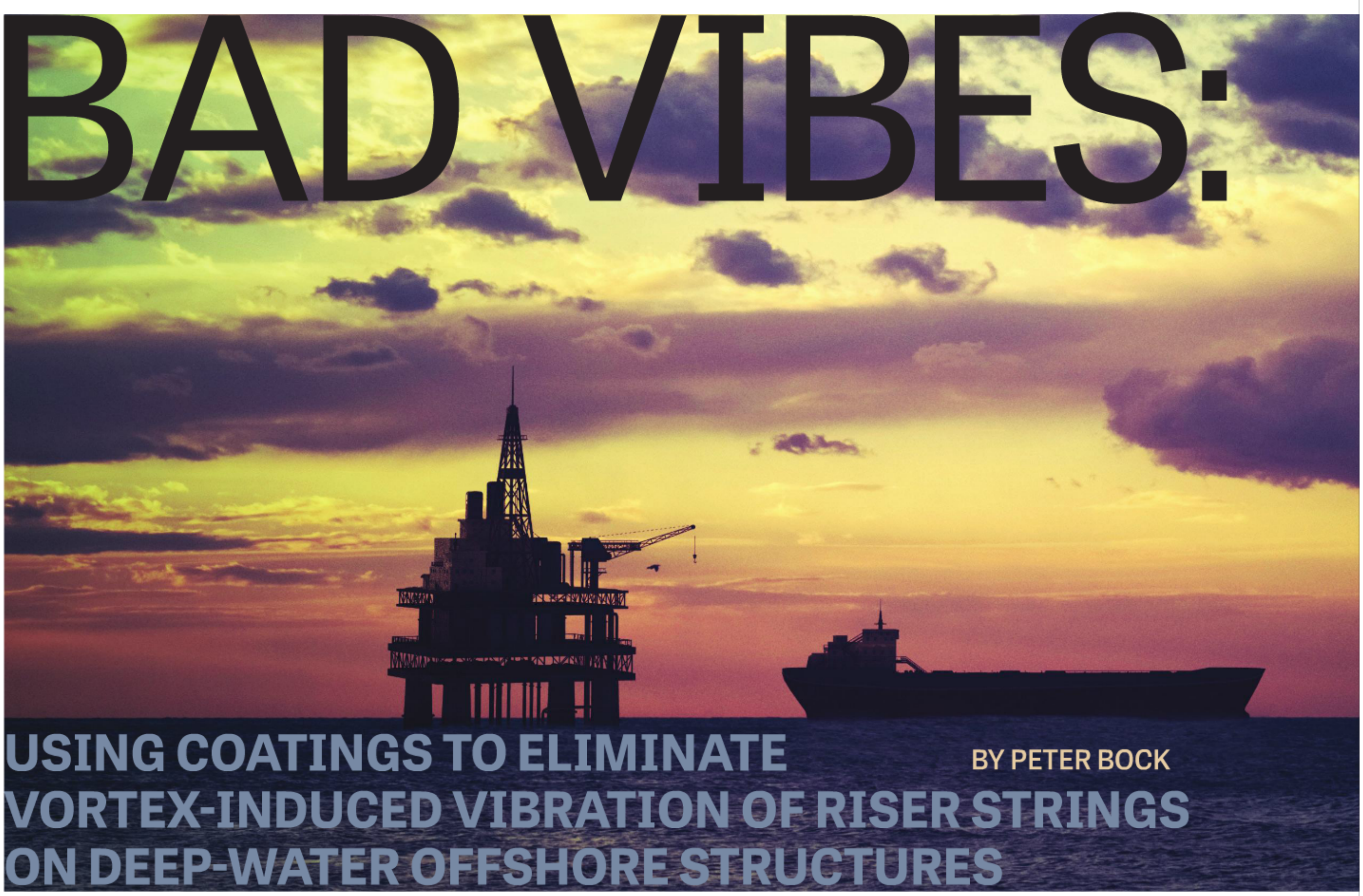
Images courtesy of the author unless otherwise noted.

On an offshore oil production platform, it is the riser pipe which brings produced oil from the wellhead on the seafloor to the production platform at the surface. Equipment on the platform separates produced oil and natural gas, and removes unwanted byproducts including water, carbon dioxide, other gases, sand and particulate matter. The separated oil is then sent ashore by pipeline or transferred to a shuttle tanker for delivery ashore

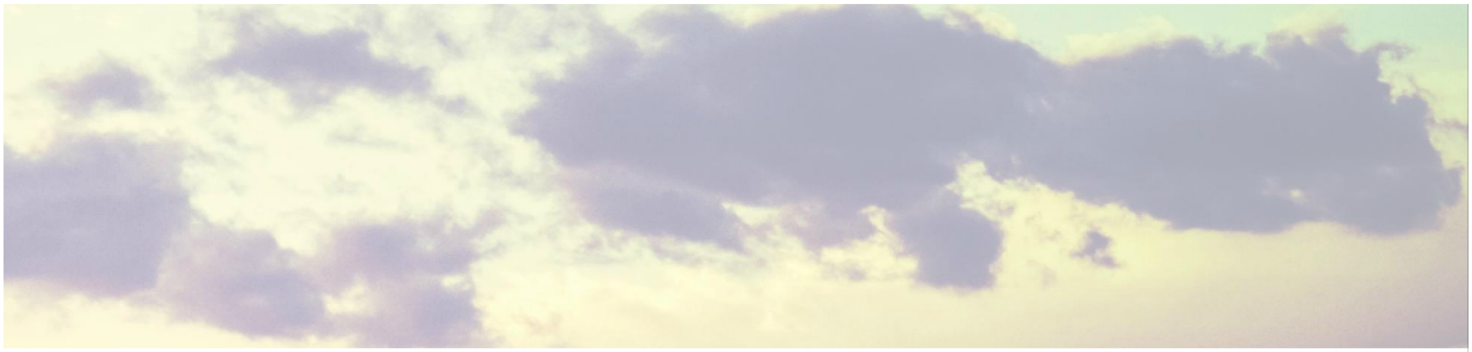
Shallow-water production platforms in the Gulf of Mexico actually stand on legs reaching to the seafloor, where they are secured by piles into the seabed. The riser piping is usually near the center of the structure and is held rigidly by its own strength and by the surrounding fixed leg structure. Deep-water structures can be actual floating platforms and are held exactly in place by anchors or other methods. The riser pipe string may be the only solid direct connection between the seafloor and the floating production platform. Movement of the platform from wave action or tidal forces is compensated by flexible joint connections in the riser string. But when the rigid support of legs on the seafloor is removed and the length of the riser string increases for structures in deep water, a new insidious force comes into play — VIV, or vortex-induced vibrations, which can crack joints in the riser string or rupture the riser pipe itself, causing a potentially disastrous oil spill.

BAD VIBES:



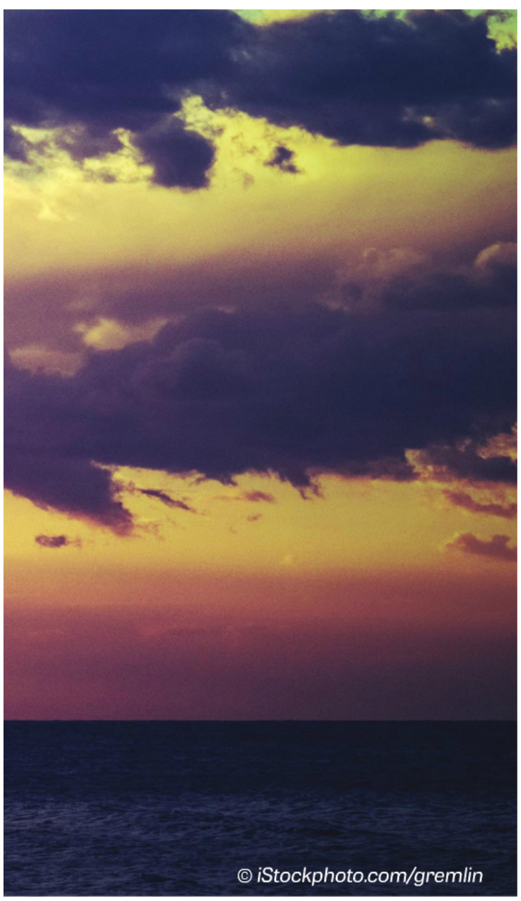
USING COATINGS TO ELIMINATE VORTEX-INDUCED VIBRATION OF RISER STRINGS ON DEEP-WATER OFFSHORE STRUCTURES

BY PETER BOCK



WHAT ARE VIV?

An engineer's definition from fluid dynamics describes VIV as a set of vibrations created by an irregular external fluid flow in a body immersed into that fluid flow. A small-scale version of VIV forces on offshore riser pipes can be demonstrated by putting a tube or cylinder (like a soft drink can) into water and moving the can through the water at right angles to its axis, which simulates tidal or wave motion on a real-life fixed riser. As the soft drink can is moved, water flows around it and is slowed when in contact with the can (or riser) surface. This slower boundary layer of water doesn't want to follow the curvature of the can but has also become separated from the main tidal or wave flow, which is not affected by the can or riser. Distribution of water pressure around the circular object may be uneven, allowing vortices to form asymmetrically and creating uneven lift forces, diagonal to the water flow. Unlike symmetrical wave action, these asymmetrical vortices can cause uneven and unpredictable vibrations in the can or riser pipe, eventually leading to cracking or failure of the riser. VIV are found in many areas of engineering design and are usually a major consideration in the design of ocean structures.



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As major oil companies developed and set production platforms in deeper and deeper water in the Gulf of Mexico, their engineering staffs determined that even the relatively mild wave action and slight currents in the Gulf were enough to cause VIV once the length of the riser string exceeded certain depths. They then developed an elegant and workable system to prevent the effects of VIV on their production platforms' riser pipe strings.

The dry-land, onshore equivalent of VIV is wind action on very tall, very slim smokestacks or vent pipes. A standard engineering solution is to weld a horizontal spiral spine around the entire length of the stack or vent pipe. The spiral spine stiffens the pipe and also acts as a wind deflector, changing and dispersing the direction and strength of the wind. Oil company offshore engineers came up with a similar solution for riser strings and VIV.

A spine could not be welded to the riser pipe, so there would be no strengthening, but fiberglass covers with a horizontal spiral spine molded into them could be clamped over the outside of the riser pipe structure, and it would dissipate the vortices caused by tidal, current or wave action, thus preventing VIV. Computer simulation and laboratory testing determined the ideal curvature and length of the spiral spine, and a fabricator was found to make a number of small test pieces.

THE GLITCH

The waters of the Gulf of Mexico are a veritable Cajun gumbo of food for sea slime, algae and barnacles. Fertilizer runoff from Midwestern farmers comes down the Mississippi River, along with industrial and human waste residue. Dozens of other nutrients enrich a food chain which fortunately includes oysters, shrimp and crabs at its top end, and unfortunately, also barnacles. Year-round sunlight and warm water temperatures encourage everything to grow on surfaces as far down as sunlight penetrates, typically about 100 feet in Gulf of Mexico deep-water areas, even where particulate mud from the Mississippi River no longer clouds the water.

Sea slime, algae and barnacles love to stick to relatively smooth but porous surfaces such as fiberglass. In less than six months in the Gulf, the elegant spiral-spined fiberglass cover test pieces were shapeless globs of barnacles growing on top of barnacles, with a layer of algae at the bottom, tightly adhering to the fiberglass. This destroyed the original spiral-shaped fins' ability to reduce VIV.

A SOLUTION THROUGH COATINGS

The engineers appealed to a large global manufacturer of marine coatings to come up with a solution, but being engineers, they had some specific requirements which seemed somewhat unrealistic. The paint company should supply a coating system which would prevent marine growth from changing or obscuring the shape of the plastic riser covers for 10 years without requiring anything more than an in-place, underwater, low-pressure water wash. The coating system also had to have no adverse effects on the environment.

Fig. 1: Prepared surfaces of the riser covers had to be 100-percent checked with low magnification, and filling in pinholes was a process similar to final preparation of auto body panels in a body and fender shop before application of the first coat of paint.

Antifouling coatings are normally used on ship-hull bottoms to prevent growth of slime, algae and barnacles. The three most common types of antifouling coatings are biocide, self-polishing biocide and nonbiocide foulant release systems (NBFRS). The biocide antifouling coatings release a poison from the surface of the coating, killing marine growth that tries to settle there. As the biocide is depleted, the antifouling effect stops. Self-polishing biocide coatings use water action from the hull's motion through the water to remove thin layers of surface, exposing fresh biocide poison and thus extending the usable life of their biocide. The NBFRS contain no poison. These coatings use a silicone or fluoropolymer resin which creates a flexible non-stick surface. Slime and algae literally wash off the NBFRS-coated surface whenever the ship moves. Biocide antifouling coatings have a useful life of three-to-five years. The NBFRS theoretically have an endless service life, but on ship hulls, impact and abrasion can easily damage and remove the relatively soft coating, limiting its useful service life.

Fig. 2: As a test of effectiveness, the fiberglass fabricator prepared a single half-shell, which was then blasted and coated, to be shipped offshore for a test on an actual riser in the Gulf of Mexico.

Fig. 3: What had for months been a one-off test program came to take over an entire building, as abrasive sweeping and coating of the riser cover half-shells expanded into a multi-year, multi-million-dollar assembly-line project.

Fig. 4: An entire yard crew was trained in the special abrasive sweeping and coating application requirements of the project, and close quality control was maintained cooperatively by all the parties involved.

Fig. 5: Special plywood housings were fabricated for the smaller-diameter riser covers, as much to prevent damage to the NBFRS antifouling as to be sure the covers floated if they went overboard from the back deck of a supply boat.

Fig. 6: Larger-diameter covers were shipped standing on edge on a flatbed truck, and were laid flat on the back deck of the supply boat to prevent damage to the applied coating.

Because of the engineers' environmental restriction and requirement for a 10-year service life, NBFRS was the only antifouling system that could be recommended. Impact and abrasion damage would not be a problem, even over 10 years, but a riser string doesn't move; would there be enough water movement from wave and current action around the riser pipe strings to keep the surface clean?

There was also a very limited track record regarding application of the NBFRS to fiberglass surfaces. Since the NBFRS sticks to itself only slightly better than algae stick to it, proper application of the multi-coat system was critical to assuring long-term adhesion. Shipyards and drydocks had experience applying NBFRS to aluminum and steel ship hulls, but not to small fiberglass pieces. A large Houston-area onshore painting contractor offered to do some prototype coating testing. They had very little experience with ship hull work or with NBFRS, but a great deal of experience with coating fiberglass surfaces. Since the riser covers were relatively small pieces, to be shop-fabricated and shop-coated before installation, the contractor would simply treat the process as a new type of coating system, rather than as antifouling.

Fig. 7: After having been abrasive swept, stub riser cover pieces, too short for the pipe racks, were coated on the back of a shop trailer.

TEST APPLICATION

The first hurdle was surface preparation. As the riser covers came from the fiberglass fabricator, the exterior surfaces were glossy smooth. The NBFRS required a low anchor profile and a proprietary epoxy primer coat for application on aluminum or steel hulls. Abrasive blasting the riser covers with conventional abrasives destroyed the gel coat surface, exposed the layers of glass beneath, and left an unacceptably rough finish after priming. Several weeks of testing found a very fine abrasive which textured the gel coated surface just enough without cutting into the glass fiber beneath.

Even with light abrasive sweeping using the very fine abrasive, pinholes and bubbles in the gel coat were exposed. When such defects were primed with the recommended epoxy, unacceptable craters or blisters developed. Prepared surfaces of the riser covers had to be 100-percent checked with low magnification, and filling in pinholes was a process similar to final preparation of auto body panels in a body and fender shop before application of the first coat of paint (Fig. 1, p. 56).

Additional testing and a close reading of the NBFRS Product Data Sheets and SDS determined that the gel coat on the riser covers and the recommended epoxy primer were similar enough to each other that the epoxy primer could be omitted, and the second (silicone) coat of the three-coat NBFRS could be applied directly to the abrasive-swept, gel coat surface of the riser covers. Testing confirmed that the silicone NBFRS second coat adhered well to the abrasive-swept gel coat, and there was actually less of a problem with craters and blisters.

There was no reliable laboratory test method to determine whether there would be sufficient water movement to keep the NBFRS coating free of marine growth on the deep-water riser pipe strings. The only answer was to mount a section on an actual riser in the Gulf and observe it for a period of time.

The fiberglass fabricator prepared a single half-shell with the proper diameter for the riser on the selected production platform (Fig. 2, p. 56). The coating contractor abrasive-swept the half-shell, filled in all the craters, and then applied the second and third coats of the NBFRS. The coating supplier inspected the work and approved it; the end user's coating specialist also checked the work and approved it; and even a couple of the design engineers came out to the jobsite and took a look. The finished half-shell was packaged to prevent shipping damage and trucked to the owner's shore base in Morgan City, Louisiana to be put on a supply boat and delivered to the production platform, where a diving contractor would install it.

Two weeks later, there was a call from offshore; the diving contractor was on the structure, ready to install the half-shell, but couldn't find it. A series of frantic phone calls to the shore base finally got the head dispatcher: "Oh, that weird plastic thing. It fell off the back of the boat. It doesn't float."

Another series of weeks passed while the replacement half-shell was fabricated, coated and shipped offshore. This time it arrived without problems and was installed on the riser. And then everyone waited. When the divers went down a month later, the half-shell was so clean it almost glowed. The test was considered a success, and purchase orders were issued for complete sets of half-shell covers for all of the company's deep-water production platform risers. The fiberglass half-shells would be coated with the NBFRS antifouling to a depth of 100 feet on each of the riser pipe strings. Below that, there is not enough sunlight to promote barnacle growth; the covers were still needed to prevent VIV-induced damage, but their shape would not be distorted by a covering of slime, algae and barnacles.

The paint contractor's job was to coat the top part of each set of riser covers. What had for months been a one-off test program on a table at the side of the contractor's blasting-painting yard came to take over an entire building, as abrasive sweeping and coating of the riser cover half-shells expanded into a multi-year, multi-million-dollar assembly-line project (Fig. 3, p. 56). An entire yard crew was trained in the special abrasive sweeping and coating application requirements of the project, and close quality control was maintained cooperatively by the contractor, the coating supplier, and the end user's paint expert (Fig. 4, p. 56). Even some of the design engineers came out again to the paint facility to check on the progress of the project.

Special plywood housings were fabricated for the smaller-diameter riser covers, as much to prevent damage to the NBFRS antifouling as to be sure the covers floated on the off chance that they went overboard from the back deck of a supply boat. (Fig. 5, p. 56). Larger-diameter covers were shipped standing on edge on a flatbed truck, and were laid flat on the back deck of the supply boat to prevent damage to the applied coating (Fig. 6, p. 58). There were no serious problems encountered during the whole project.

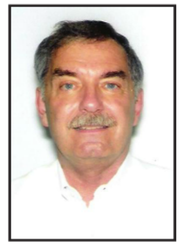
Unfortunately, all good things must come to an end. Even before the last of the NBFRS-coated riser covers had been installed offshore, a new, engineered castable plastic compound was discovered, which had most of the surface characteristics of the NBFRS coating. Testing proved that the surface of this plastic would resist the growth and adhesion of slime, algae and barnacles almost as well as the NBFRS coating.

The new plastic, which entirely replaced the fiberglass and NBFRS-coated riser covers, was frightfully expensive, of course, but making riser covers out of it was a one-step straight casting process. The fiberglass covers required gel coat and chopped fiberglass in the mold at the fabricator's shop, then abrasive sweeping, inspection and repair of craters, and two coats of the NBFRS coating at the paint contractor's shop (Fig. 7, p. 60). Material cost, labor and time involved were all in favor of the new plastic, so much so that below the 100-foot level, where the barnacle resistance was not needed, the new plastic covers were still less expensive than the fiberglass ones even without the NBFRS coating.

Today the NBFRS coating system continues to be used on underwater portions of metal equipment on deep-water production platforms where a growth-free surface is required — monitor heads, electronic sending units, and covers which divers occasionally have to open for inspection or repair. None of these involve VIV, only the need to stay growth-free, and the size and number of them is very small compared to the original riser cover project.

The VIV-reducing riser cover project has gone into the books as one of those rare occasions when an elegant engineering solution offshore required an equally elegant, almost unique, coating solution to make it a success.

ABOUT THE AUTHOR



Peter Bock is a petrochemical coatings consultant and CUI specialist, based in Houston. He is a U.S. Air Force veteran and holds degrees from Tulane University and the University of Northern Colorado. Bock has 38 years of management, technical service, inspection and sales experience in oilfield and petrochemical heavy-duty coatings, in the United States, Canada, Mexico, Venezuela, Indonesia and Taiwan.

Bock has experience with on- and offshore production, drilling and workover rigs, shipyard work, natural gas and LNG, pipelines, terminals, refineries and chemical plants. He is a recognized expert on carbon steel passivation and corrosion under insulation, and teaches annual courses on corrosion under insulation.

Bock is a past-president of NACE New Orleans Section and of the Houston Coating Society. He is a NACE-certified Coating Inspector (Level 3), has been published in a variety of industry journals and has presented papers and symposia at the SSPC, PACE, NACE and NAI conferences, as well as at many regional and local coatings and corrosion control events. He is also a *JPCL* contributing editor. ***JPCL***

Images courtesy of Naval Research Laboratory

DEVELOPMENT OF MATERIALS AND PROCESS METRICS FOR HIGH-PERFORMANCE ABRASIVE BLAST SURFACE PREPARATION

BY ROBERT KOGLER AND LAURA ERICKSON, RAMPART LLC

Protective coating systems provide the primary corrosion protection for assets in sea water. They are defined as a specific combination of surface preparation and coating material applied under specified conditions to a specific structure. Over many years, the paint industry has focused considerable resources toward the formulation, performance testing and fine tuning of coating materials. These efforts have produced outstanding results through implementation of advancements such as single-coat, ultra-high-solids paint for tanks, and by sharpening and implementing aggressive requirements in quality assurance and specification documents. Far less emphasis has been placed on understanding and refining the details of surface preparation and the effects of variations in these details on the subsequent performance of sea water immersion coatings. However, it is generally accepted that improper or inadequate surface preparation is a major contributor to real-world coating failures. This area is ripe for coating system quality and performance gains.

Dry abrasive blasting remains the workhorse for achieving high-quality surface preparation for application of coatings. This article details the effects of both the operational parameters of abrasive blasting and the measurement techniques used to characterize abrasive blasted surfaces. The goal of this study is to relate blasting parameters to the resultant surface preparation, characterized beyond current limited visual

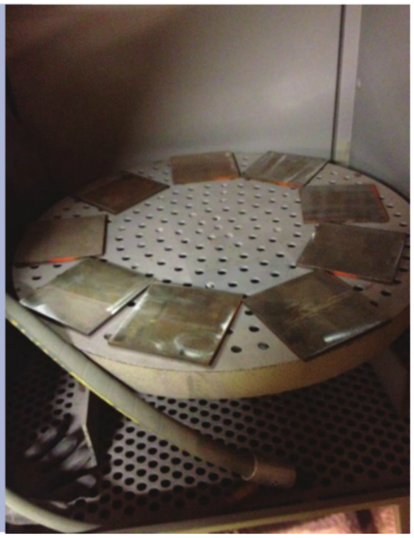


Fig. 1: Panels arranged for blasting in glove box blasting cabinet.

and one-dimensional profile standards, including parameters such as surface peak height density and profile height. The output of this study will be data that characterizes the impact of variables associated with abrasive blasting materials and process control parameters on the resultant surface morphology. In addition, the ultimate goal of the work is to relate coating performance to measureable surface profile details in order to characterize the important factors associated with surface morphology and ultimate coatings performance.

The primary variables studied include:

- Abrasive type;
- Abrasive size;
- Blast pressure at the nozzle; and
- Type of substrate (strength of steel).

Additionally, the work is assessing the impact of variables such as production rate, dwell time and nozzle standoff distance by blasting larger steel sample plates. These results will be analyzed and reported at a later date.

Specifications for abrasive blasting surface preparation have been technically stagnant for decades. These specifications refer to primarily qualitative measures of visual cleanliness (SSPC-SP "X" standards) coupled with single-point, semi-quantitative measures of average surface profile using replica tape/micrometer devices (as per ASTM D4417). These standards provide the data necessary to discriminate acceptable from unacceptable surfaces for coating application in a gross sense; however, they are inadequate for defining the high degree of surface preparation required to achieve the next step in long-term quality and performance the Navy seeks for critical coated areas. Others have addressed similar questions in recent years with useful results produced[1, 2]. The study by Roper, et. al., provided a glimpse into the potential importance of going beyond present simplistic approaches to profile characterization, showing a direct relationship between peak height density and coating adhesion[3]. As early as 1982, Fultz studied the differences in measurements obtained using various available techniques and measurement approaches. In this work, he reported a lack of success in determining a definitive mathematical relationship to convert between the various measurement techniques studied[4]. Additionally, Fultz found difficulty in defining a relationship between coating adhesion and surface profile. Beitelman's work examining the effect on particle shape of multiple recycling passes for steel grit also provides significant lessons and direction for the subject project[5]. His use of metalized coatings — with adhesion particularly sensitive to surface characteristics — shows a path to coatings testing to determine cause and effect.

TECHNICAL APPROACH

Two separate strengths of steel panels were used for testing, notionally 50 ksi (50,000 psi) and 100 ksi (100,000 psi).

Table 1: Grits Tested

Grit Type	Grit Size (per label)	Grit Size in Inches (weighted avg. as measured)
Coal Slag	Medium	.043
Coal Slag	Fine	.032
Steel Grit	G25	.029
Aluminum Oxide	24	.0275
Steel Grit	G40	.020
Garnet Vendor #1	30/60	.011
Garnet Vendor #2	30/60	.008
Mineral Abrasive (garnet by-product)	80	.006

Nine 6-by-6-inch panels of each grade of steel were blasted in a controlled, glove-box cabinet set up for once-through use of the grit size and type selected for that set (Fig. 1, p. 65). Each set of panels was blasted using both 100 psi and 80 psi (measured with a needle gauge at the nozzle) using a #6 straight bore nozzle. Several different grit types were tested and are listed in Table 1. All of the abrasives represent materials which can qualify as "equivalent" for use under the present Military specification (MIL-A-22262B, Abrasive Blasting Media Ship Hull Blast Cleaning).

Test panels were blasted using once-through capture of the spent abrasive. Grits were sieved for size characterization prior to and after one pass of blasting to assess breakdown of the various grits after a single pass on the steel.

Blasted panels were measured for profile referring to SSPC-PA 17 for guidance (Procedure for Determining Conformance to Steel Profile/Surface Roughness/Peak Count Requirements) and using three different methods in parallel to compare results: ASTM D4417 (Standard Test Methods for Field Measurement of Surface Profile of Blast Cleaned Steel), Methods B (single point micrometer measurement), C (replica tape), and ASTM D7127 (Standard Test Method for Measurement of Surface Roughness of Abrasive Blast Cleaned Metal Surfaces Using a Portable Stylus Instrument). Additionally, both 2-D and 3-D microscopy was used to quantify the surface morphology of the various panels.

Following surface characterization, the panels were painted with an array of typical Navy primers. Adhesion testing per ASTM D4541 (Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers) was performed to attempt to differentiate coating adhesion based on surface profile parameters. For longer-term testing, panels will be exposed to test environments to identify any performance

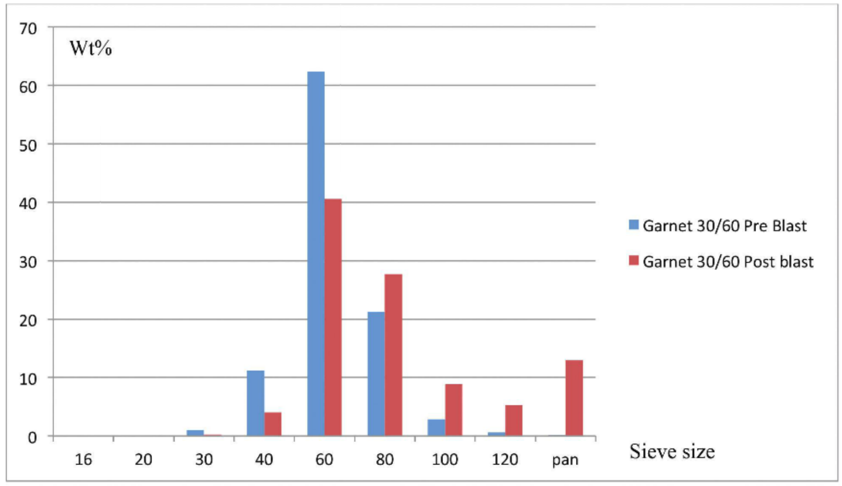


Fig. 2: Initial and post-blast size average distribution of garnet grits.

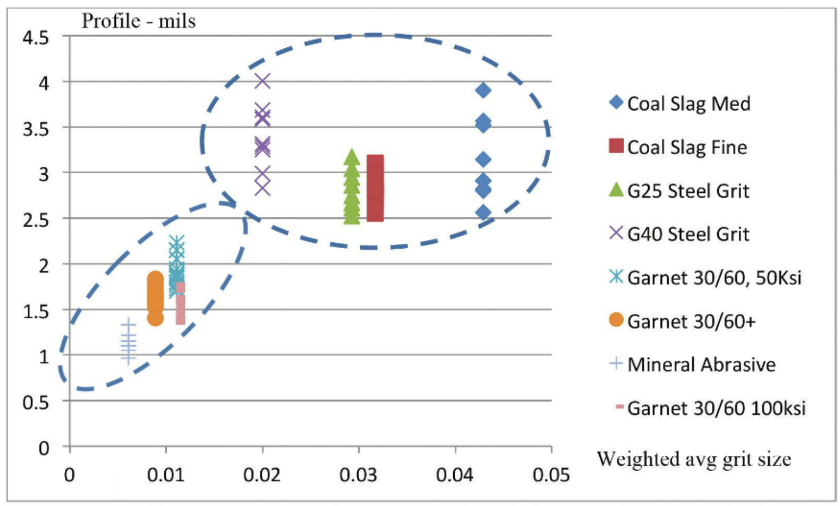


Fig. 3: Mean grit size relationship to profile.

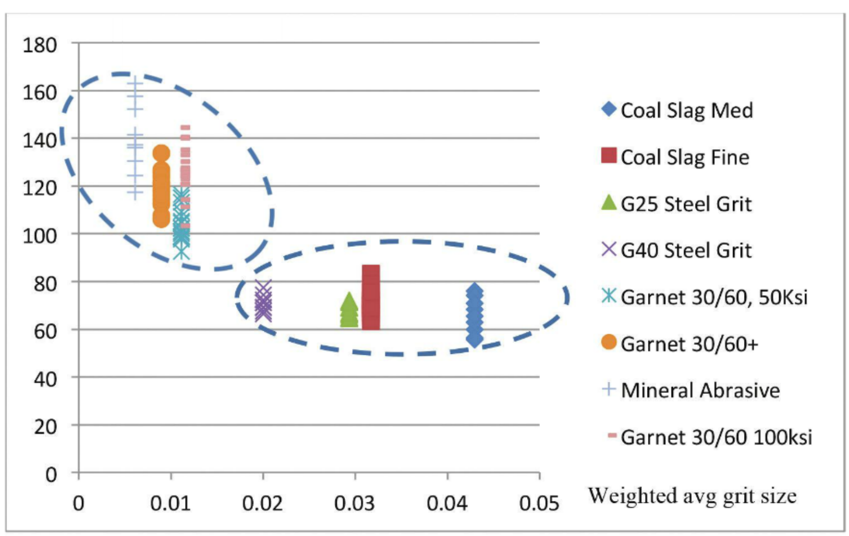
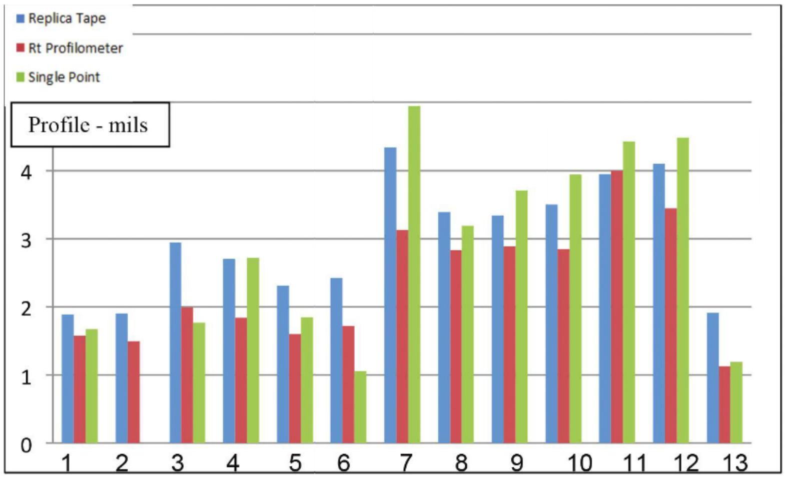


Fig. 4: Mean grit size relationship to peak count per inch



1. Hard rock Garnet 3060 100ksi/100psi
2. Hard rock Garnet 3060 100ksi/80psi
3. Hard rock Garnet 3060 50ksi/100psi
4. Hard rock Garnet 3060 50ksi/80psi
5. Alluvial Garnet 100ksi/100psi
6. Alluvial Garnet 100ksi/80psi
7. Coal Slag Med 50ksi/100psi
8. Coal Slag Fine 100ksi/100psi
9. Coal Slag Fine 100ksi/80psi
10. Steel Grit G25 100ksi/100psi
11. Steel Grit G40 100ksi/100psi
12. Steel Grit G40 50ksi/100psi
13. Mineral Abrasive Fine

Fig. 5: Profile Depth Method Analysis

differences that arise due to the different surface profiles for each panel, the results of which will be reported at a later date.

RESULTS

Grit Size Analysis: Pre- and Post-Blasting

Figure 2 (p. 66) shows average results from sieve sizing for 30/60 garnets obtained from two vendors. These two materials were sized similarly but not exactly the same, so average sizes are presented here. After one pass, these garnets both showed breakdown below a 100 mesh of approximately 20 percent. This is encouraging when considering the possibility of systematically recycling mineral grits to reduce waste streams in the future.

Surface Profile Results

Preliminary analysis of the surface profile data indicates that the primary controlling variable of surface profile is the mean size of the grit used for blasting (Fig. 3, p. 66). Additionally, an inverse relationship between mean grit size and number of peaks per inch is observed, as seen in Figure 4 (p. 66). The resultant relationship between profile height and number of peaks per unit length measured is also clear.

Profile measurement varied depending on the specific technique used. The replica tape typically provided a measurement that was higher than the stylus and the single-point micrometer (by 0.5-to-1 full mil), although sometimes the single-point measurements had a higher average than the replica tape.

SUMMARY

The subject testing shed light on several key results regarding abrasive blasting materials and process parameters (Fig. 5, p. 68). Abrasive size was found to be a primary driver in the resultant surface profile depth and peak density of the blasted surface. For mineral abrasives, larger peak counts were observed, but a lower peak height profile resulted in comparison to steel and slag abrasives. For larger slag and steel abrasives, peak density remained constant while profile varied between 2.5-to-4 mils. Other abrasive material and process-related parameters may play a role in resultant surface profile, but over the operating parameters studied, these factors did not play a contributing role.

The various measurement techniques for surface characterization employed in this program all provided useful data, but the linear profilometer provided more dimension and value than did the single-point micrometer and replica tape with similar inspection time and effort. It is recommended that both peak density and peak height (profile) continue to be evaluated in terms of characterizing surfaces.

The relationship between surface profile to coating adhesion proved more difficult to quantify. Simple pull-off adhesion testing (ASTM D4541) does not provide a sufficient means for characterizing differences in the expected performance of similar coatings applied over varying surface morphologies. This aspect of performance testing for surface discrimination is still being actively explored.

ACKNOWLEDGMENT

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ABOUT THE AUTHORS

Bob Kogler, principal with Rampart LLC (www.rampartdc.com), has been a corrosion and durability engineer for his entire professional career. He has worked extensively for the U.S. Navy and the U.S. Federal Highway Administration managing and executing corrosion and coatings technology and research efforts for the past three decades. Kogler's work has spanned from the laboratory to field testing, to development of specifications and standards, to implementation and oversight of coatings and corrosion technology applications for infrastructure and marine system owners. He is a past-president of SSPC and is currently on the Standards Review Committee.

Laura Erickson, principal with Rampart LLC, has worked in technology development and implementation for the U.S. Navy for the past decade. She has extensive experience developing innovative corrosion protection technologies and test protocols for various ship and weapons systems. Erickson is also a subject matter expert in the development and management of corrosion control policy methodologies on a Navy-wide and platform-wide level. She has recently been the lead on ship cathodic protection design and Navy coatings testing and selection application programs.

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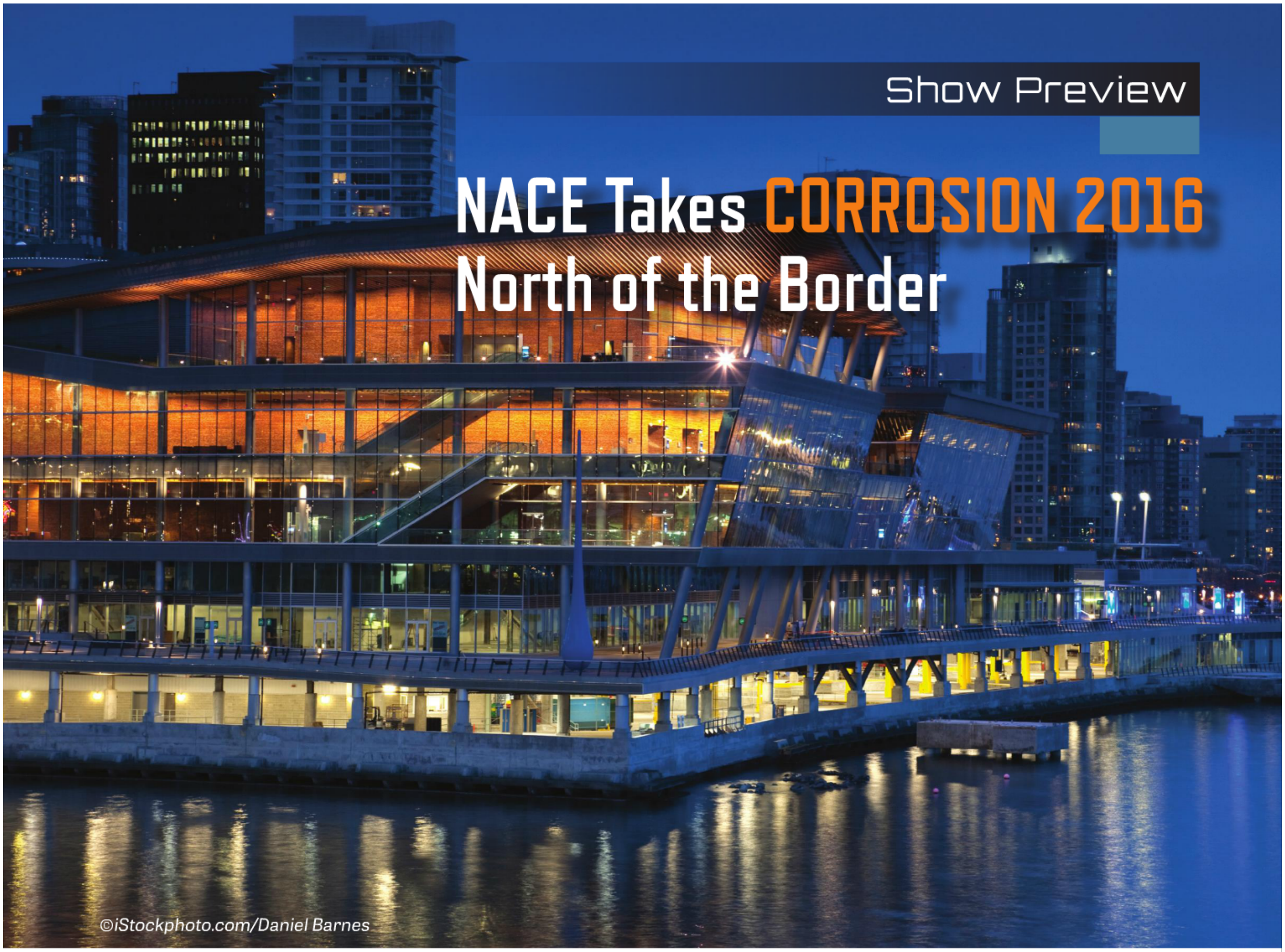
NACE Takes CORROSION 2016 North of the Border



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NACE International's annual conference and exhibition, CORROSION 2016, will take place March 6 to 10, 2016 at the Vancouver Convention Centre in Vancouver, B.C., Canada.

According to NACE, this year's event is expected to attract more than 5,500 corrosion professionals from over 60 countries, as well as more than 400 companies exhibiting their products, technology and services. CORROSION 2016 will also feature more than 1,000 hours of technical symposia, forums and meetings from 15 unique industry and technology tracks, including cathodic protection; coatings; oil and gas exploration and production; pipelines, tanks and underground systems; and energy generation, transmission and distribution.

The following meetings, events and technical sessions scheduled for CORROSION 2016 may be of interest to protective coatings professionals.

All information is current as of press time. For complete information on CORROSION 2016, visit the official conference website, www.nacecorrosion.org.

SUNDAY, MARCH 6

"NII Specialty Board for Protective Coatings," 11:00 a.m. to 1:00 p.m.

"NII Specialty Board for Pipeline Coatings," 1:00 to 3:00 p.m.

"Threaded Fasteners: Coatings & Methods of Protection for Threaded Fasteners Used with Structural Steel," 1:30 to 2:30 p.m., 2:30 to 3:30 p.m.

"Coating Conductance," 3:30 to 5:30 p.m.

MONDAY, MARCH 7

Plenary Lecture: Ken Tator, KTA-Tator, Inc., 8:00 to 8:45 a.m.

"Oil and Gas Production — Nonmetallics and Wear Coatings (Metallic)," 9:00 a.m. to 1:30 p.m.

"High Temperature Issues and Materials for the Process Industry," 1:00 to 4:00 p.m.

"Cathodic Disbondment Test for Coated Steel Structures Under Cathodic Protection," 3:00 to 4:00 p.m.

TUESDAY, MARCH 8

"Testing of Nonshielding Property of Pipeline Coatings to Cathodic Protection," 8:00 to 10:00 a.m.

"Coating, Polyolefin Resin Systems: Review of NACE SP0185-2007," 8:00 to 10:00 a.m.

"Coating Application on Exterior Surfaces of Steel Railcars," 9:00 to 9:30 a.m.

"Maintenance Overcoating of Railcar Exteriors," 9:30 to 10:00 a.m.

"Surface Preparation by Encapsulated Blast Media for Repair of Existing Coatings on Railcars," 10:00 to 10:30 a.m.

"Guidelines for Qualifying Personnel as Abrasive Blasters and Coating and Lining Applicators in the Rail Industry," 11:00 to 11:30 a.m.

"Coatings Under Insulation Material Testing Procedure Recommendations: Discussion," 1:00 to 3:00 p.m.

"Coating Thickness Measurement, Methods, and Recording — Specific to the Railcar Industry," 1:30 to 2:30 p.m.

Revision of NACE SP0592, "Application of a Coating System to Interior Surfaces of New and Used Rail Tank Cars in Concentrated (90 to 98%) Sulfuric Acid Service," 2:30 to 3:00 p.m.

WEDNESDAY, MARCH 9

"Standard Practice for Evaluating Protective Coatings for Use Under Insulation," 8:00 to 10:00 a.m.

"Oil and Gas Coating Technology Symposium (Day 1)," 8:00 a.m. to 5:00 p.m.

"Oil and Gas Production — Nonmetallics and Wear Coatings (Metallic)," 9:00 a.m. to 12:00 noon

"Guidelines for Data Collection and Analysis of Railroad Tank Car Interior Coating/Lining Condition," 9:30 to 10:00 a.m.

"Land Transportation: Information Exchange on Corrosion and Coating Related Issues," 10:00 to 11:00 a.m.

THURSDAY, MARCH 10

"Oil and Gas Coating Technology Symposium (Day 2)," 8:00 a.m. to 3:00 p.m.

"Inhibitors — Vapor Transported (VCI) and Surface Coatings and Rust Preventives," 8:00 a.m. to 4:00 p.m.

"Soluble Salt Testing Frequency and Locations on Previously Coated Surfaces," 1:00 to 3:00 p.m.