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October 8 – 11
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Features

INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

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GUEST COMMENTARY

Industry resources help extract top performance from your generators

Clyde V Maughan
President, Maughan Generator Consultants

Of the hundreds of components in a powerplant, large and small, the generator probably is the least able to be instinctively understood—and that scares some people. We understand what the major components do:

- Steam generators burn fossil fuel to release the energy it contains for converting water into high-pressure steam.
- Steam turbines use the energy in HP steam to produce rotational torque.
- Generators use the turbine's torque energy to make electrical energy.

But many of us on the deck plates are not clear exactly how the generator produces electric power. Even after 70-plus years of exposure, this writer does not know why the magnetic field of the rotor pushing on the counter magnetic field of the stator transfers energy across an air gap. Or why a conductor moving in a magnetic field makes voltage. Or why that voltage wants to move current and produce electrical energy.

We don't exactly know how all this works, but it does; we know how to generate electricity. And over the last 125 years we have learned how to do that better and better—but with increasing complexity.

We also know that in a powerplant with a failed turbine, an expert brought in to help can stand alongside that machine with half a dozen engineers, each of whom understands the turbine, and hold an intelligent discussion on why and how that turbine failed.

But if a generator has failed, the expert often cannot find one engineer at the plant who understands the generator—because of the machine's non-intuitive nature, its complexity, and its infrequency of failure. Furthermore, the "expert" himself may not understand the generator very well either. Thus, collectively, they may have no idea why a particular part failed in a particular way, or what to do to eliminate the problem.

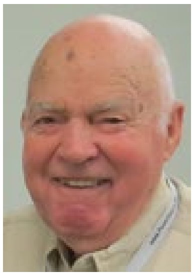
Is there a solution to this quandary? Well certainly no easy solution. But plant management may find one or more of the following suggestions helpful:

- The plant should have in-house access to an excellent engineer with training in the complexities of the generator. Primary resources for career development are industry conferences, seminars, and training courses—such as those conducted by the Generator Users Group, EPRI, Iris Power, Doble Engineering Co, and IzzyTech. In fact, IzzyTech's Isidor Kerszenbaum and Geoff Klempner will be conducting their annual technical seminar, "Large Turbo-Generators—Design, Operation, and Maintenance," in Irvine, Calif, October 22-26. Consider participating.
- Materials available online at no cost to support your training initiatives include the library on the website of the International Generator Technical Community, the seven-part webinar series on generator monitoring, inspection, and maintenance conducted by the author and available at www.ccj-online.com/onscreen, a cache of generator articles on the CCJ website, and the 2017 and 2018 editions of the Electric GENERATORS annual founded by the author (use the QR codes for easy access).

2017 2018

- Outside experts can be very helpful in failure diagnostics, establishing optimum corrective actions, and in training the in-house generator engineer. But be skeptical of any "expert" from any source if what you're hearing does not sound logical.
- In the event repairs are required, vet the crew and supervisory personnel to be sure they are well qualified for your project.

Finally, the generator is a complex machine. It likely is not fully understood by anyone. But if well designed and manufactured, and not mis-operated, it can be maintained to perform its necessary function reliably for decades. Critical to high reliability is a well-trained and wise in-house engineer.



Clyde V Maughan retired from active consulting in July 2018 at the age of 92. He spent 36 years with GE before "retiring" in 1986 to form the one-person consulting operation that bears his name. Much of the knowledge acquired during Maughan's 68-year career has been shared with the electric power industry though more than two score technical papers, more than a dozen articles in CCJ, webinars, his handbook, "Maintenance of Turbine-Driven Generators," dozens of seminars, and other avenues of communication.

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Annual meetings focus on O&M solutions to improve profitability, safety

The oldest gas turbines in the GE 7E fleet served by the 7EA Users Group are approaching a half-century of service. This fleet incorporates gas-turbine models MS7001A, B, C, E, and EA, numbering 1168 units at 216 plants worldwide in mid-2017. The first unit, a 52.9-MW, oil-fired MS70001A, commissioned by Long Island Lighting Co in 1971 at its Shoreham Plant, is still in service, now owned and operated by National Grid Generation LLC.

What all the stats suggest is that given today's topsy turvy generation world, the 2018 7EA Users Group meeting at the Hyatt Regency Orange County, Garden Grove, Calif, October 8-11, is the best place for owner/operators to find out what their colleagues are doing to meet demanding grid requirements and still turn a profit.

Presentations and discussion sessions will be replete with ideas and experience on strategies to accommodate must-take renewables, what upgrades others have found worthwhile for maximizing availability and starting reliability, when you should replace—not repair—parts, etc. You probably could sit down now and write dozens of questions you'd like answers to for helping to guide O&M strategies at your plant.

Do that!

Then use the list to justify your participation in the conference. Even if you get only a fraction of your questions answered, the financial benefit associated with making informed decisions could be enormous. Think of the meeting as *free* consulting.

The admission fee for users is only $250. Even after adding in transportation and hotel, the total cost is only a few dollars north of a thousand. Meals? Most of those are covered. No budget? That's no excuse for an opportunity like this; put off buying something budgeted until next year.

This is the 7EA Users' first meeting on the West Coast since Monterey in 2013 and travel is convenient. LAX is 35 miles from the Hyatt Regency, and the Orange County/John Wayne Airport only 13 miles away.

If you have never attended a 7EA Users Group meeting and have to do more "research" before you hop off the proverbial bubble, consider that last year's meeting in St. Augustine, Fla, attracted 100 users, in round numbers (about 40% by show of hands were first-timers), from six countries; 109 companies were represented at the vendor fair.

The 2018 conference agenda is available on the group's website at http://ge7ea.users-groups.com but it doesn't speak to the level of detail shared by both the user and vendor participants. You can get this by reading the report below.

Finally, consider perusing the user group's e-mail forum, moderated by Greg Carvalho of Simplified Technology Co, and easily accessible via the website. It contains hundreds of solutions of value. The first post by a user was July 28, 2003; same time last year the number of postings available to users topped 17,000.

Those who have participated in previous meetings sponsored by the 7EA Users Group might want to review the agenda: The conference format has changed. This year, GE Day is Monday and the widely valued annual presentation, "What We Are Seeing in the Fleet from Our Borescope Inspections," by Mike Hoogsteden, director of field services for Advanced Turbine Support LLC, moves to the first hour on Tuesday.

The editors believe this presentation alone is worth the registration fee—particularly for first timers. It brings you up to speed quickly regarding what's going on in plants like yours and what to look for during inspection and maintenance outages, and includes a review of the most relevant Technical Information Letters (TILs) issued by the OEM.

Consider that most users are "landlocked" at their plants and with the significant turnover in personnel these days a knowledge vacuum may exist at your facility. This and the other presentations will help you break that vacuum.

2018 Conference and Exhibition

October 8 - 11
Hyatt Regency Orange County
Garden Grove, Calif

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Dale Anderson, CT technician foreman, East Kentucky Power Co-op Inc
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Stay connected with colleagues via the user forum at http://ge7ea.users-groups.com.

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Inspection

A goal of every engine inspection is not to miss something that could contribute to a forced outage. Success requires qualified technicians equipped with the most sophisticated tools available and well connected to company experts with deep and applicable experience ready to help diagnose findings that may be unfamiliar to those at the plant site.

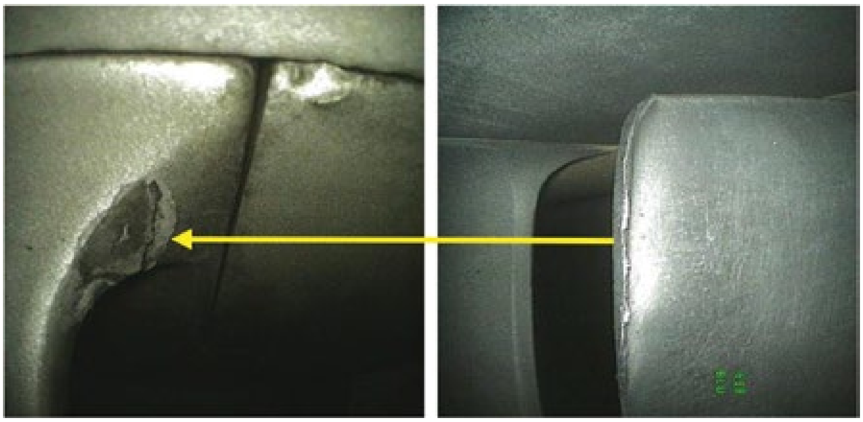
Mike Hoogsteden, director of field services, Advanced Turbine Support LLC, which inspects scores of GE E-class gas turbines annually, traditionally opens the 7EA Users Group meeting with the highly informative presentation, "What We Are Seeing in the 7EA Fleet during Our Inspections." This is of particular value to first-timers requiring an engine orientation lesson as well as a primer on what to look for and where during inspections to assure reliable service from the generating asset. The photos Hoogsteden presents are invaluable.

Pat Myers, the de facto leader of the 7EA Users Group steering committee before his retirement as plant manager of AEP's Ceredo Generating Station a couple of years ago, represented CCJ at the 2017 meeting and sat in on Hoogsteden's presentation. Now a consultant, Myers shares with clients his extensive knowledge on plant construction, maintenance, and operation gained over four decades in management positions at both gas and electric companies.

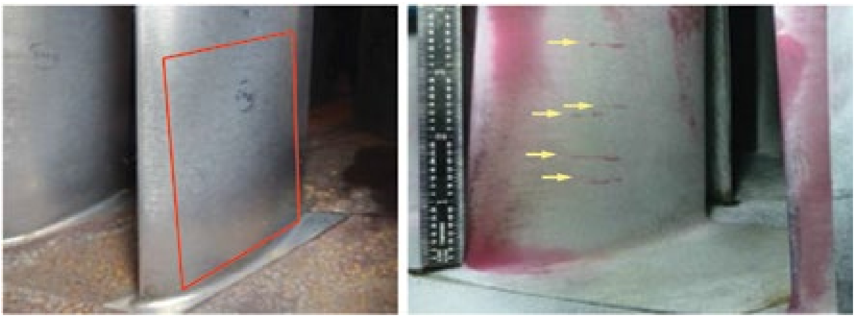
Hoogsteden opened his presentation by suggesting that owner/operators review Technical Information Letters (TILs) issued by the OEM for their engines, take notes, and bring their questions to the next user-group meeting. Colleagues and participating equipment/services providers, he said, are the best source of advice on what's important and what's not.

The five TILs at the top of Hoogsteden's list for 7EA users are the following:

- 1884, "7EA R1/S1 Inspection Recommendations," which addresses the need to inspect R1 and S1 airfoils for possible damage caused by clashing—the unwanted contact between the leading edges of S1 stator-vane tips and the trailing edges of rotor blades in the platform area.
- 1980, "7EA S1 Suction Side Inspection Recommendations," which advises users to inspect for crack indications on S1 vanes made of Type-403 stainless-steel, regardless of whether clashing damage is in evidence on S1 and R1 airfoils.



1. Clashing is defined as contact between the leading edges of stationary vane tips (right) and the trailing edges of rotor blades in the platform area (left)



2. "Area of interest" defined in TIL 1884 is outlined on stator vane at left. Dye penetrant inspection identifies cracks in an S1 vane at right

- 1854, "Compressor Rotor Stages 2 and 3 Tip Loss," which suggests blending and tipping to mitigate the impact on availability and reliability of R2 and/or R3 tip loss. This TIL supplements information provided by the OEM in the O&M manual provided with the engine.
- 1562-R1, "Heavy-Duty Gas Turbine Shim Migration and Loss," which informs users on the need to monitor the condition of compressor shims and corrective actions available to mitigate the risks of migrating shims.
- 1744, "S17, EGV1, and EGV2 Stator-Ring Rail and CDC Hook Fit Wear Inspection," provides guidance on the repair of dovetail wear and suggests hardware and software enhancements available to mitigate the potential risk caused by operating conditions that promote such wear.

TIL 1884. It took years for the OEM to address clashing in a TIL (Fig 1). Hoogsteden believes Advanced Turbine Support was the first company to alert the industry to this phenomenon—back in 2006. TIL 1884 was issued in spring 2013.

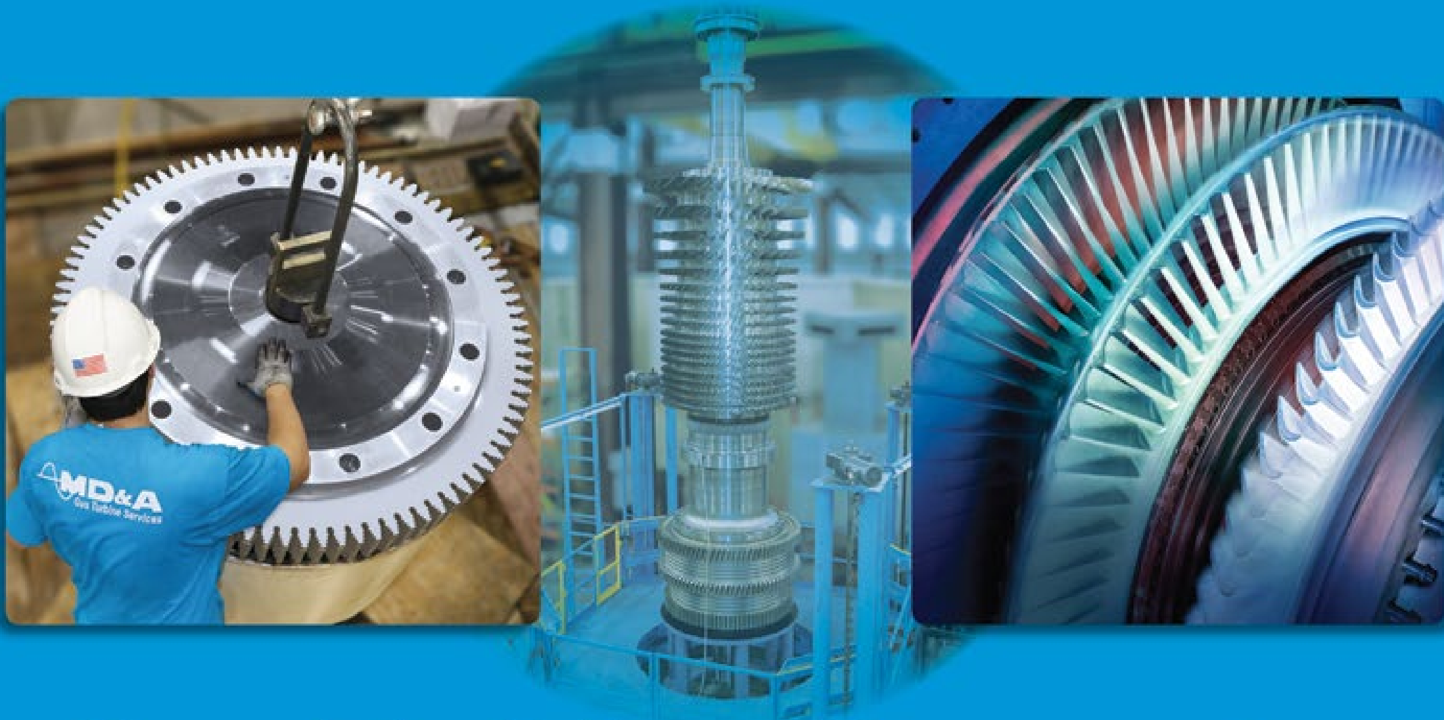
During the intervening years, Advanced Turbine Support worked closely with the user group, Myers on point, to share inspection data important to problem definition and solution. Developments in inspection technology contributed to a better understanding of first-stage findings and provided information of greater value for the resolution of issues.

TIL 1884 went beyond clashing, recommending the checking of stator vanes for cracking in the co-called "area of interest" (Fig 2). Lock-up of vanes in carbon-steel ring segments can cause higher-than-normal operating stresses, which the OEM says "reach a maximum on the suction side of the vane near the mid-chord location."

Hoogsteden's suggestion to mitigate the possibility of serious damage from clashing and cracking is to perform an in-situ eddy-current (EC) inspection on the trailing edges of all R1 rotor-blade platforms and the entire suction side of every S1 stator vane from platform to tip each peak-run season or every six months.

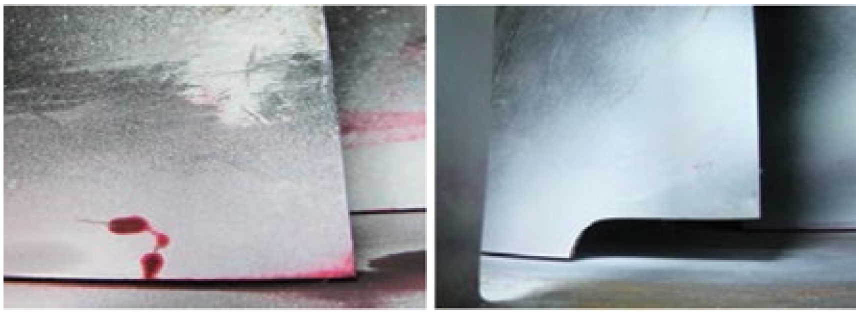
TIL 1980, issued January 2016, essentially is an "addendum" to TIL 1884, addressing S1 vanes installed in legacy 7EAs (1996 and earlier) made of Type 403 stainless steel. This material is more susceptible to mid-chord cracking than the GTD™ 450 alloy used in the manufacture of vanes since 1997.

TIL1980 recommends inspection by visible means or by fluorescent dye to reveal suction-side cracks that might be present. Hoogsteden mentioned in his comments on TIL 1884 that these methods are inferior to EC for this



3. Tip was liberated from this S1 vane. Such potential damage is not addressed in either TIL 1884 or 1980

4. Coil pins absorb vibration that can cause fretting wear in rows S17, EGV1, and EVG2. They are inserted in holes drilled half into the vane ring segment base and half into the compressor discharge case



5. Rotor-blade radial tip crack like that at left can be removed in-situ (first and second stages) in one shift as shown in the photo at right. Were the crack allowed to propagate, a tip liberation might have occurred, with consequent downstream damage

purpose. He added that if the vanes are coated, visible or fluorescent dye penetrant inspections may not be dependable, nor have an acceptable probability of detection.

Regarding the effectiveness of ultrasonic (UT) inspection for this purpose, if coating degradation—such as disbonding—occurs, the value of UT could be compromised.

TIL 1854, released in August 2012, informs owner/operators of E-class compressors about the blending and tipping of second- and third-stage rotor blades it recommends to mitigate the negative impact on availability and reliability caused by tip loss from heavy rubs and/or corrosion pitting.

The OEM says fleet experience and engineering analysis have concluded that compressor rubs can be caused by casing distortion that progresses over time, and by hot restarts initiated between one and eight hours after shutdown. The latter causes critical clearances to decrease. Corrosion pitting, by contrast, can create a local stress concentration that may result in tip loss via high-cycle fatigue.

Hoogsteden pointed out that although this advisory does not address first-stage rotor blades (Fig 3), they too can suffer tip loss and should be included in your inspection regimen. For R1 and R2 rotor blades showing signs of tip distress, Advanced Turbine Support recommends, at a minimum, a visible dye-penetrant inspection to determine if radial cracks have initiated. For R3 blades, the company suggests a minimum of a 360-deg roll with a close-up inspection of all blade tips at the same intervals.

TIL 1562, issued January 2007, is likely the most familiar of the advisories in this group of five because it is more than a decade old and shim liberation has been discussed frequently in user-group meetings and in CCJ and CCJ ONsite.

Hoogsteden recommends users develop a shim map for their compressors to identify locations where shims might have been installed, then audit those locations for shims remaining. The map should be updated after every inspection. Shims protruding from the case by less than one-quarter of an inch should be monitored regularly. When the shim protrudes into the flow stream one-quarter of an inch or more it should be removed or ground off.

TIL 1744, issued September 2010, said 7EAs operating at part load when ambient temperature is less than 40F are at risk for major damage caused by the lifting of 17th-stage vane segments—and EVG 1 and 2 as well. As the segments lift up they damage the hook fits and turn into the rotating blades.

A non-OEM repair procedure described at a user group meeting attended by the editors involved milling of the damaged slot to accommodate 18-in. inserts. They were installed in the upper and lower halves of the case to retain the new vane segments. The inserts are held in place with setscrews. The user describing the procedure cautioned against considering it a permanent fix because a root cause analysis had not been completed.

Another TIL 1744 solution comes from Rodger Anderson, DRS Power Technology Inc, well known to 7EA users for his widely used pinning mod to prevent shim liberation (TIL 1562). Here, Anderson uses compression coil spring pins to absorb vibration and arrest fretting wear of compressor vane ring segments in rows S17, exit guide vane 1, and EVG2 (Fig 4). As shown in the photo, the holes for the coil springs are drilled half into the base of the vane-ring segment and half into the compressor discharge case. To date, the procedure was said to have been implemented successfully on three 7EAs.

New capabilities. In closing, Hoogsteden brought attendees up-to-date on capabilities now at his company's disposal for in-situ repair of compressor components. Recall that only a few years ago, in-situ machining was generally confined to the first and second stages of the compressor (Fig 5).

Today, Hoogsteden said Advanced Turbine Support has been successful in developing and proving tooling for blending vanes and rotating blades deep into the compressor via the bell mouth. He showed photos of blending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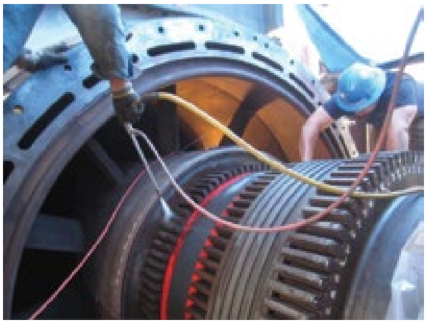
6. Eddy-current probe inspects dovetails for cracking, which could mean wheel replacement



7. Second- and third-stage turbine wheels are cleaned with denatured alcohol

on S11 vanes and R12 blades. The latter blend was about 1 in. along the length of the blade and about 300 mils deep.

Hoogsteden also mentioned that the company could cut off protruding shims deep into the machine by coming in through the back end of the compressor.

The learning never stops at user-group meetings. One of the discussions at Advanced Turbine Support's stand during the vendor fair focused on the presentation by a user earlier in the day who had discovered cracks in the 17th-stage vane slot during the replacement of blades on two units having between 550 and 700 starts (round numbers) and fewer than 3000 hours of service.

The cracks were found near where the flat-bottom slot transitions to a radius on the inlet end and were blended out. Typically, they were about 1 in. long and up to 30 mils deep; several cracks ran over the edge of the wheel by about 0.100 in. One of the units had crack indications on more than 90% of its slots; the other machine just had "many" cracked slots. Another user in on the discussion said he had observed similar cracks when replacing 17th-stage blades on his 7EA.

Hoogsteden said such cracks on the 7EAs appeared similar to those addressed by TILs 1971 and 1972 which covered cracking in F-class units designed with flat-slot-bottom dovetails in compressor wheels for stages 12 to 17. He commented that company technicians would add this to their list of things to look for when performing 7EA inspections.

User presentations

Presentations by owner/operators are the lifeblood of every user-group meeting. There is value in presentations by vendors, of course, but when a user colleague shares experiences, best practices, and lessons learned everyone listens—you can tell by the questions asked and the follow-on discussion generated.

There were five user presentations at the 2017 meeting of the 7EA Users Group. The editors were present for four as reflected by the summary notes that follow. The fifth was an overview by a utility engineer on his company's experience in converting its gas turbines to MkVIe control systems. To dig deeper, you can access the presentations on the organization's website at http://ge7ea.users-groups.com. You'll have to register if not already a member.

Dovetail coating in-situ

Dovetail wear and tear caused by excessive time on turning gear and operation at a TG speed conducive to damage is an annual agenda topic given the 7B-EA fleet's high percentage of simple-cycle engines required to be "on the ready" by grid operators (Fig 6). The pounding caused by bucket and wheel contact in the dovetail region with each revolution—so-called "bucket rock"—gets worse over time, as clearances open up.

The possible consequences of operating a unit with bucket rock include loss of sealing pins, loss of chrome carbide wear surfaces on shrouded buckets, slight radial rubs, overstressing of wheel dovetails, and possible twist-lock un-staking. The speaker suggested his colleagues take the following steps to correct bucket rock:

- First, install progressively larger bucket-shank seal pins.
- If wear exceeds the scope of correction by the largest shank seal pins, build-up the bucket dovetail by spraying with nickel aluminide (maximum recommended coating thickness is 15 mils). Note, too, bucket tip shrouds may need rebuilding of the chrome carbide wear area.
- Dovetail wear beyond the maximum restorable thickness on the bucket requires wheel replacement. However, the speaker did say that development projects are under way to identify a reliable wheel restoration technique.

The user presented a case history on the elimination of bucket rock in the first stage of his engine. First step was to check bucket gaps at four positions along the platform. Most were over the recommended limit of 180 mils specified in TIL 1049, "B- and E-class Gas-Turbine Wheel Dovetail Material Loss." Many were in excess of 0.200 in., one as high as 0.217 in. The TIL presents three options:

- Bucket dovetail spray modification.
- Wheel dovetail spray modification.
- Wheel replacement.

Additionally, the second- and third-stage turbine wheels were cleaned (Fig 7) and first-stage material loss was determined as specified in TIL 1049. Measurements were taken with gauge pins, slightly larger than the size called for in the OEM document—0.219 in. versus 0.21875. The

8. Bucket-rock measurements are taken with a dial indicator

9. First-stage wheel after grit blasting

10. Dovetails after coating with nickel aluminide to mitigate bucket rock

results all were within TIL limits, indicating the wheel had not reached end of life.

Bucket-rock measurements also were taken, using a dial indicator at the side of the platform while manually rocking the bucket to its limit and recording the total indicator travel (Fig 8). Rock recorded at 12 positions on the wheel ranged from 0.138 to 0.160 in. with the average 0.150. The speaker said he was told by a shop person with deep knowledge of rotors that 0.085-in. rock is the targeted value when spray coating a wheel.

The user's plant opted to spray-coat the first-stage wheel given the engine's current mode of operation with long periods on turning gear. Fig 9 shows the wheel after grit blasting, Fig 10 after coating with nickel aluminide to mitigate rock. Note that the spray repair took five shifts after buckets were removed; work was done with the rotor in place. New replacement buckets were installed after completion of the spray repair. Plant rates the project a success.

Rotor exchange program

Five of the six 7EAs at a 6 × 3 combined-cycle cogeneration plant serving an industrial facility were rapidly approaching the OEM's stated 200,000-hr maximum rotor life for its baseload frame engines. The machines, all manufactured in 1992, were steam-injected and had averaged 182,741 actual fired hours. The high-hours engine had 188,460 service hours.

The owner evaluated the three rotor-exchange options listed below, considering several vendors in the process.

- Purchase both turbine and compressor rotors as new.
- Purchase seed rotors (compressor and turbine) and refurbish based on fired hours of each unit.
- Basic seed-rotor (compressor and turbine) replacement.

GE was selected to provide the seed-rotor exchange program based on rotor availability, cost, refurbishment time, and technological expertise. Key points in the OEM's program were the following:

- Extend 7EA rotor fired hours from 200,000 to 300,000 and starts by 1500 to 5000.
- The OEM would provide two seed rotors, refurbish three of the plant's rotors, and provide a spare rotor with a storage container. Compressor seed rotors would be bladed, turbine rotors would have buckets supplied by the plant and installed at the GE shop.
- A 60-day schedule was planned for rotor refurbishment.

Work scope and other important details included these:

- Full teardown inspection using ultrasonic, eddy-current, mag-particle, fluorescent penetrant, and visual procedures, plus hardness testing.
- Replace compressor rotor blades in stages 14 to 17.
- Replace compressor turbine, and unit rotor assembly bolting.
- Inspect and repair dovetails in compressor wheels 14 to 17, stage-16 rabbet fillets, and stage-17 impeller blades.

Note that replacement of compressor stator blades and turbine buckets and nozzles were not included in the rotor exchange project. Any other deficiencies identified in the existing turbine and compressor rotors would be categorized as "extra work."

Project completion was planned for year-end 2017. At the time of the user-group meeting in October, the extra work—certainly of importance to anyone considering a rotor exchange—included the following:

- Field service charges for reaming of dowel holes and alignment of four units.
- The compressor for one unit was in bad shape and required this additional effort:
  - De-blading and re-blading of rows 1 to 13.
  - Patch-ring repairs on four rows.
  - Turbine rotor rabbet crack repair.
  - New turbine-rotor forward and aft stub shafts.
  - New second-stage compressor wheel.
  - New turbine wheels.
- An additional seed rotor made necessary by an unfit-for-duty compressor found in one unit.

One of the lessons learned: Don't expect things to go the way you planned on a project of this magnitude, even having experienced manpower and putting forth maximum effort. You likely will identify issues no one thought possible. Perhaps the biggest surprise here was the finding of excessive bucket rock on one of the turbines.

The GE shop reported this for the first stage and the turbine rotor was returned to the plant without buckets, the owner believing a new set of first-stage buckets would correct the problem. It didn't. Plan B was to have the new buckets coated to reduce the dovetail gap. But on further inspection, excessive rock also was found in the second and third stages. In the end, all three turbine wheels were replaced at significant extra cost.

A table presented by the speaker showed that the outage time projected for the unit with the wrecked compressor (last bullet point above), budgeted at 720 hours, would actually be about 4000 hours (unit overhaul had not been completed before the meeting). For the other engines, the actual outages wound up taking an average of 40% more hours than planned, in round numbers.

11. Bending of compressor blade reflects ice impact damage

R1 compressor ice damage

A Canadian user reported on a compressor ice damage investigation that was of interest to virtually all attendees (Fig 11). Keep in mind, ice can form in a gas turbine compressor at an ambient temperature above freezing. The speaker explained this with several slides on the physics of ice formation at the beginning of his presentation. He also discussed the various types of ice and how they differ. Specifically, precipitate icing— such as hail, ice crystals, snow, freezing rain—and condensate icing—such as rime, glaze (clear), and frost/hoarfrost.

If you're shaky on ice science, be sure to access this presentation on the 7EA Users Group website. It's easy to understand and you can become an "expert" of sorts in short order.

The user's root cause analysis focused on the following potential causes of ice damage:

- Plant staff did not verify the wash water system was positively isolated and drained after each compressor cleaning. The water wash procedure was updated to ensure positive drainage of the wash-water manifold.
- Inspections for leaks in the inlet ductwork and filter house were conducted, but no signs of water ingress were found.
- The anti-icing (AI) system did not prevent ice from depositing and

growing on air-intake surfaces. The details in the slides specific to the GE system are recommended viewing for anyone with a similar system and issues, and anyone planning on protecting his or her plant's gas turbines in this manner.

The AI portion of the presentation began with a description of the inputs to the control system (inlet temperature and humidity) used by GE de-icing logic to control the inlet bleed heat (IBH) charged with preventing ice formation. Problems identified included the following:

- Thermocouple noise, which was an easy fix by enabling a low-pass filter in the software (this is defaulted in normal control when the system is set up).
- Poor IBH valve control because of the installed position feedback on the positioner. An upgraded valve positioner solved this problem.
- Dew-point sensors were supplied by the OEM with the wrong range software. The instrument manufacturer corrected this by increasing the dwell time through the auto-purge sequence of the humidity sensor.

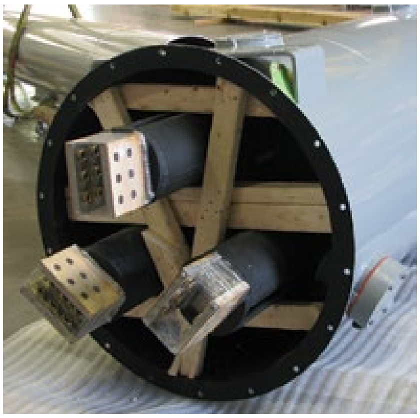
During the ensuing discussion it became apparent that the de-icing control provided by GE did not shut off until the ambient temperature rose above the set point—about 40F. The ambient temperature falling below the ice-formation temperature (too cold to carry moisture that would form ice) did not shut off the IBH (running at about 10%), regardless of how much colder it got. This results in a significant reduction in efficiency and output when operating at cold temperatures outside of the ice-formation physics.

Best practice: A user commented during the discussion that he and his colleagues had found a significant water entry point in the inlet ductwork. The bolting supplied during unit installation for clamping flange gaskets on the inlet "key" slot was bottoming out and not properly sealing the joint when the flange bolts were torqued. This permitted water entry into the inlet duct which could cause icing at low ambient temperatures.

Clashing update, rotor cracking

A user with perhaps more experience on clashing in 7EA compressors than anyone else in attendance reported that one of his affected units was retrofitted with GE's new-design S1 and S2 blades and showed no evidence of clashing after 42 fired starts in the last year. Photos revealed pristine airfoils.

He also reported R17 flat-bottom slot cracks on two 2001-vintage units. One had 2877 fired hours, 675 starts, and 24 trips, the other 2490 fired hours and 557 starts. The latter had indications of similar length in 51 of the 56 slots. Very little blending was needed to remove them.



12. Circular non-seg bus is robust as shown at the left with temporary wood supports for shipping. Interior view at right shows insulators

Roundtables

In 7EA Users lingo, "roundtable" is essentially a panel discussion. This differs from CTOTF™, where the term essentially means "session." Semantics aside, the 2017 meeting of the 7EA Users Group featured two two-hour roundtables, one on bus duct, the other on rotor life management.

The way these sessions are arranged, participating vendors are seated at the front of the meeting room, owner/operators in the audience. To begin, each of the vendors reviews its capabilities on the topic at hand and after introductory comments are completed the moderator, a member of the group's steering committee, ignites discussion and steers user questions to one or more of the panelists.

Bus duct

The Bus Duct Roundtable, chaired by Guy LeBlanc of First Energy Corp, featured these four vendor participants:

- Bruce Hack, Crown Electric Engineering & Manufacturing LLC.
- Jesus Davila, RMS Energy Co.
- Jeffrey Andle, Emerson IntelliSAW.
- Gary Whitehead, Electrical Builders Inc.

Snippets of information gleaned from both the introductory remarks

13, 14. Replacement non-seg runs from the generator (extreme right) to the circuit breaker at the center of the left-hand photo; it is shown entering the generator step-up transformer in the right-hand photo

15. Rectangular bus contributed to plant unavailability and was replaced with the circular non-seg shown in Figs 2 and 3

16. Thermal cycling causes bus-duct expansion/contraction conducive to joint degradation, water ingress, and failure

17. Mechanical rubbing of insulation at "choke points" leads to wear, tracking, and failure

made by each of the panelists and the open discussion are summarized in the bullet points below. For the most part, they reflect best practices and lessons learned.

- Traditional non-segregated-phase bus duct (a/k/a non-seg) failure events are far too frequent and often can become catastrophic. Recall that non-seg has all three phases in a common enclosure (Fig 12). In Fig 13, non-seg runs from the generator at the extreme right to the generator circuit breaker in the center of the picture and then to an auxiliary transformer (not shown). Fig 14 shows non-seg entering the generator step-up transformer.

  Traditional non-seg bus is made up of bolted rectangular sections—each section is a repetition of weak connections conducive to failure (Fig 15). Every bolted-section joint and bolted-conductor joint is a point where loosening can occur because of vibration and/or thermal cycling.

  In his opening remarks, Crown Electric's Bruce Hack noted that Westinghouse Electric Corp, which made both gas turbines and bus duct, understood the failure-prone problems of traditional non-seg when applied to gas-turbine applications and specifically developed circular non-seg bus duct (CNSB) to address these issues. Crown Electric is the direct successor to the Westinghouse CNSB design.

  Hack said CNSB is built just like isolated-phase (iso-phase) bus, except it is non-seg. Its welded aluminum housing has no sectional joints to fail, thereby protecting against all environmental conditions. Plus, it surrounds and supports Crown's extruded aluminum conductors, which are air-insulated, eliminating the need for sleeve insulation prone to rubbing, cracking, tracking, and in the extreme, failure.

  The conductors are supported by porcelain stand-off insulators, which may be optionally specified with a dew-point rating. Thus, potential heating issues related to moisture control are avoided.

  In bus-duct replacement projects, the circular non-seg often can mount right on the existing steel structural supports. To illustrate: The circular non-seg shown in Figs 13 and 14 was installed on the same steel that supported the Fig 15 rectangular bus that it replaced.

  Crown Electric's non-seg retrofits were given two-thumbs-up by multiple owner/operators, and they noted the more flexible inspection requirements for Crown non-seg compared to at least some alternatives.

- Moisture from condensation and/or water intrusion attributed to poor joint design and/or fatigue (Fig 16) is a catalyst for insulation degradation and associated tracking. Conductor insulation can rub at "choke points" and wear until tracking and failure occur (Fig 17).

- Traditional non-seg vendors generally recommend an 18-month minimum interval between visual inspections of all bus components. A typical inspection routine: Remove covers, inspect for tracking, look for insulation degradation, conduct hi-pot test, inspect terminals for condition and silver plating, check bolting for condition and proper torqueing, verify heat operation and condition, replace cover gaskets, and secure covers paying attention to attachment screws. Most attendees commenting on this topic said they have not performed inspections at the recommended interval.

After the roundtable concluded, Crown Electric's Hack told the editors that circular non-seg bus can go three to four times longer between inspections than other bus-duct designs. But he added the suggestion that users verify flex-braid bolted joints for tightness (Fig 18) on a three- to five-year basis (or whenever the GSU transformer is out of service for maintenance).

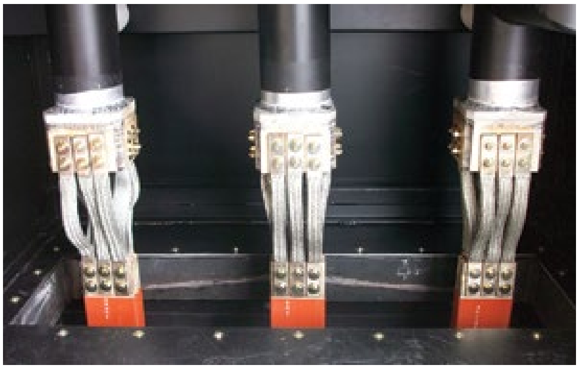
- Caution! Some cleaning chemicals will attack heat-shrink insulation. However, this is not a concern for air-insulated circular non-seg bus.

- Each time covers are opened, new gaskets should be installed and closure screws torqued to assure proper gasket compression.

- Early installations (pre-1990) used Noryl® insulation on bus conductors. It is a sleeve-type insulation that slides over the conductor; it degrades from the inside out. Noryl has a 20-year life expectancy with many locations far beyond that.

- Many installations have conductors insulated by an epoxy coating and many of those suffered epoxy cracking at installation. Given the large number thermal cycles the typical unit experiences today, cracking could be an ongoing issue.

- Heat-shrink tape used for conductor insulation—specifically 3M's 1990-vintage BBI 5—had a rating that was minimum for bus-duct installations. BBI 6 (1993) tape meets requirements.



18. **Every few years,** O&M personnel should verify flex-braid bolted joints are tight

19. **Tarps** are not reliable leak prevention gear

- Many non-seg bus vendors are out of business and parts either are not available or difficult to procure.
- Insulation materials degrade over time and with moisture exposure and condition should be verified by hi-pot at 75% of the factory test. A couple of panelists recommended that hi-pot testing be performed at mid-day because of moisture in the air. Crown Electric's Hack believes bus duct must work 24/7 and should be able to pass hi-pot any time of the day or night.
- Red GPO-3 panels get spongy over time and with moisture exposure will start to track and fail.
- EMI testing is effective in detection of tracking or partial discharge during operation.
- IEEE Standard for Metal-Enclosed Bus (C37.23) and Wet-Process Porcelain Insulators—spool type (C29.3) should be used as reference/guidance in inspection and testing.
- Most, if not all, installations have inadequate heating throughout the non-seg bus to prevent condensation inside the ductwork and on the conductors/insulation. Firm standards of heating flux are hard to obtain; in reality, requirements would vary from area to area across the country.
- Some users perform weekly IR scans of their non-seg bus to assure proper heater operation. Hack told the group, "Not necessary." Crown Electric's circular non-seg, he continued, does not need space heaters. Because they are an available option, in essence they become a belt and suspenders addition to a rugged design.
- Emerson IntelliSAW has installed remote temperature measurement and humidity measurement systems on several units; also, EMI sensors.
- Many users have installed water-intrusion prevention gear—from tarps (Fig 19) to elaborate rain hoods—over their non-seg duct. Not all mitigation efforts have been successful.

The discussion continues. The Bus Duct Roundtable was strategically arranged in the 2017 conference agenda, airing the morning before the vendor fair. This gave attendees the opportunity to follow up with panelists at their booths later in the day.

The first series of questions the editors asked Crown Electric's Hack had to do with replacing bus duct. It seemed to the editors this would be rare, but that's not so. Hack said Crown might do half a dozen replacement projects in any given year. He pointed out that powerplants, like other industrial/commercial facilities, are built "to spec" and no credit is given to the manufacturer of any equipment for doing more than the spec asks. If the parties agree that a component must work as specified for at least a year without issues and does, typically it gets a "pass."

Hack said his experience indicates that auxiliary equipment typically will meet owner/operator expectations for two decades the way powerplants are operated and maintained today. Given that the 7B-EA fleet has nearly 1200 machines, some of which are nearly 50 years old, leads one to believe a significant number of units may be candidates for overhauls/replacements of key components.

Assuming a nominal 20-year productive life for bus duct, perhaps the range of from 15 to 25 service years might be considered for evaluation purposes. That puts some of the many gas turbines installed during the "bubble" years of 2000-2004 in the "sphere of concern."

Keep in mind that bus duct was bought from the low bidder (perhaps no longer in business), and because it does not operate in a dynamically stressful environment not much attention is paid to it by an already overtaxed O&M staff. It's not unusual to learn that station personnel have never looked under the hood of bus duct at plants operating for 10 years.

A bus-duct failure can shut down your plant as quickly as the liberation of a compressor blade. If bus is problematic, consider its replacement during a planned outage to avoid the loss of revenue and a rush-service premium associated with doing the work at an inopportune time. Hack mentioned that well-planned replacement projects able to retain existing structural elements might cost less than seven figures.

When pursuing a retrofit project, remember that technology has advanced since bus duct likely was specified for your plant. Example: A couple of decades ago insulators were porcelain, but now you have a choice between the original dew-point rated porcelain and a cycloaliphatic alternative. You don't have to specify "replacement in kind," as it may not be the best choice today.

Unfamiliar with cycloaliphatic epoxy insulators? A quick Google search can bring you up to speed. But the CliffsNotes explanation is cycloaliphatic insulators have the strength of porcelain, or exceed it, and they are one-third the weight. Plus, they are dew-point rated. According to Hack cycloaliphatic insulators are equal to or better than porcelain in every electrical and mechanical characteristic that he is aware of.

Cycloaliphatic insulators are assembled in a manner that allows them to be made as drop-in replacements for porcelain. So-called skirts, the insulator components that when stacked resemble a pile of donuts, are retained by a very-high-strength center rod made of G10 material. Cus-

tomized aluminum castings top and bottom make the insulator the exact dimensions needed.

Hack tooted the Crown horn for a moment saying his company's insulators are reliable and long-lived because they are designed to handle more than four times the typical nominal operating voltage of 15 kV under extreme environmental conditions. To prove this point he showed videos of Crown's porcelain and cycloaliphatic insulators operating normally at 70 kV while being sprayed with water. Many insulators would short to ground under similar circumstances, he said.

Rotor life

The Rotor Life Roundtable, chaired by Tracy Dreymala of EthosEnergy Group, covered issues, procedures, and capabilities of life-extension programs. The following seven vendors participated with brief overviews of their companies' capabilities/activities, before Chairman Dreymala opened the discussion portion of the session:

- Scott Kennedy, Veracity Technology Solutions.
- Doug Sewell, Sulzer Turbo Services Houston Inc.
- Paul Tucker, FIRST/TBS.
- Hilary Magner, NRG Energy Services.
- Richard Rucigay, MD&A.
- Pete Miranda, Nord-Lock Inc/Superbolt Inc.
- Kale Dreymala, EthosEnergy Group.

With more than 400 7EAs expected to reach the end-of-life parameters established in GER-3620N (October 2017), "Heavy-Duty Gas Turbine O&M Considerations," within 10 years, this roundtable attracted a great deal of interest.

Snippets of information gleaned from both the company-capability overviews made by each of the panelists and the open-discussion segment of the program are summarized in the bullet points below.

- The opening remarks of Paul Tucker, FIRST/TBS, was indicative of the panelists' experience and the depth of knowledge accessible to the user attendees. Tucker said his company has been conducting end-of-life (EOL) inspections on gas-turbine rotors since 2007. The list includes: 10 Frame 3s, 31 Frame 5s, eight Frame 6s, 20 Frame 7s, six W251s, and four W501s. Roughly half of the rotors inspected were hours-based, half starts-based.

  Regarding the value of EOL inspections to engine owners, Tucker said FIRST/TBS's program had, by the time of the 2017 meeting, enabled the rotors examined to operate 4.7-million more hours and start nearly 200,000 more times.

  Concerning inspection results, Tucker reported that flaws were found in 17 of the 563 wheels/discs checked; 13 wheels were replaced in the 11 rotors requiring follow-on work. One-third of the 13 were compressor wheels.

- NRG reported having performed five rotor life assessments since 2013, with the lives of those rotors each extended by 100,000 hours.

- Veracity explained that current inspection techniques—especially phased-array ultrasonic, which provides 3D measurements of internal discontinuities—were not available when most engines in the 7B-EA fleet were ordered and almost all wheel forgings have discontinuities that have been present since manufacture. The new capabilities for mapping internal flaws can provide engineers data to help calculate remaining life going forward.

- There is no "industry standard" available to vendors that perform rotor life-extension programs. Each establishes its own process, guidelines, and disposition documentation—typically based on an in-house engineering evaluation and experience.

- A user asked, "How long can a rotor's life be extended?" The vendors answered in many different ways, perhaps best summarized as "It depends."

- Tucker shared his opinion that if wheel inspections reveal proper metallurgy and internal flaws are "cleared," a rotor likely is good to run indefinitely, provided surface creep is monitored. You are not going to find a "birth defect" flaw after a detailed inspection, he said. Other vendors suggested 100,000 hours as the life-extension norm, but again there is no industry standard to validate this claim. A user commented that a rotor with a 200,000-hr extension had been shipped from the OEM's Greenville shop after its EOL inspection.

- Vendors typically unstack the compressor, remove the last four stages of blades (usually damaged in the process), and perform detailed wheel inspections during their EOL evaluations. Most panelists recommended a complete compressor wheel inspection to get a 150,000-hr life extension.

- A user asked the roundtable panelists to address a comment attributed to the OEM earlier in the day that the GE standard (in its rotor life-extension program) was a mandatory replacement of the aft compressor stub shaft. One panelist commented that he had seen a rotor recently returned from a GE inspection that did not have the aft stub shaft replaced. All on the roundtable panel did not believe a mandatory replacement was required.

- A user asked which turbine wheels have defects. The roundtable vendors said they have found defects in all stages from time to time.

GE Day

To say that developing and organizing content of interest and value to owner/operators of a gas-turbine fleet as large and diverse as the 7B-EA is challenging would be trite. It is a Herculean task. Be mindful that the 1168 engines in this fleet (the OEM's number in fall 2017) serve in simple-cycle, combined-cycle, and cogeneration systems, operate on multiple fuels, may be anywhere from less than one to nearly 50 years old, generate from about 52 to 90 MW depending on the model and year of manufacture, and are fighting to remain relevant and profitable in a variety of electricity markets in a rapidly evolving industry.

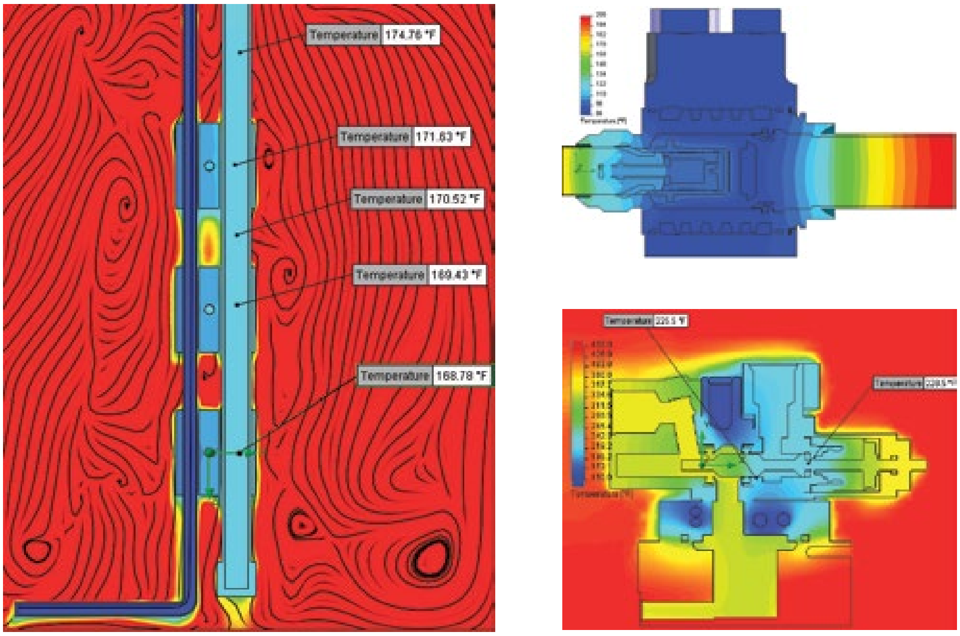
Consider too that customers are demanding more from their services partners, and while the 2017 program focused on the core engine, it included total plant considerations (Fleet360* in GE's lexicon) involving the steam turbine, generators, HRSGs, environmental control, digital solutions, and balance of plant. Additionally, cybersecurity and regulatory initiatives.

Tall order.

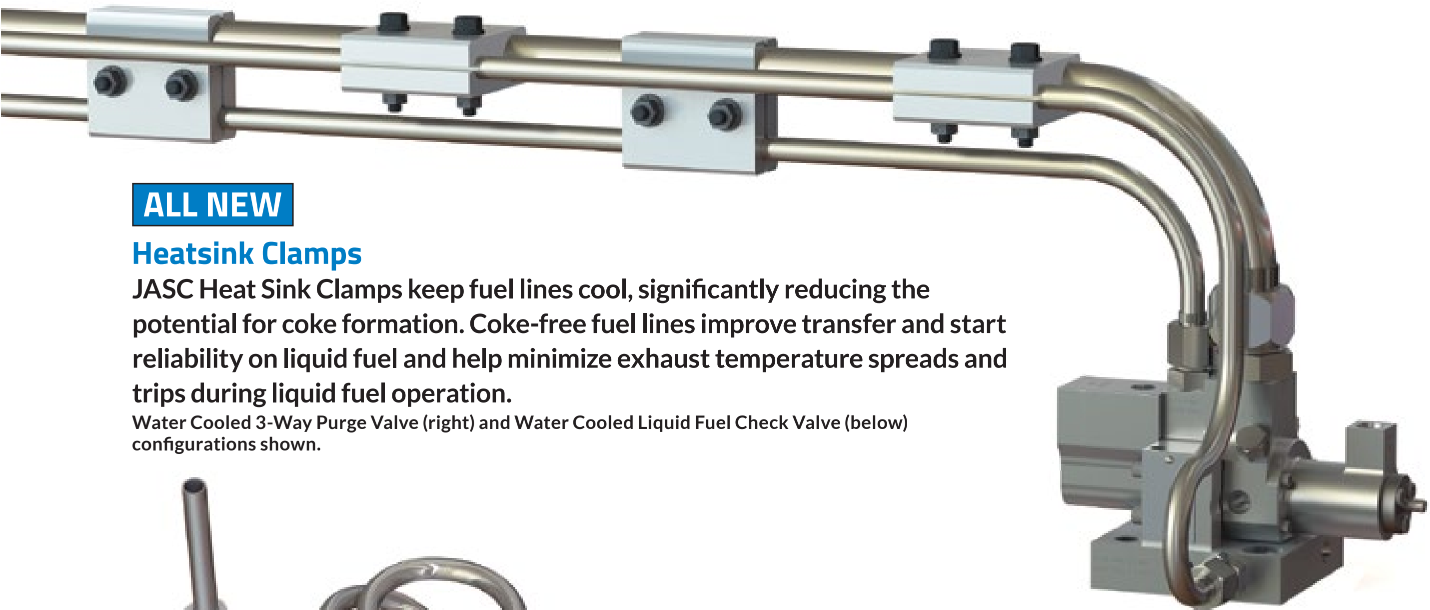
GE brought its A-team of subject matter experts—at least 20 by the editors' count—to St. Augustine to present, answer user questions, and conduct roundtable discussions during breakout sessions. It's impossible to do justice to the OEM's contribution in a summary here of only 1500 words. The highlights, in the eyes of the editors, are presented below. If you want to dig deeper, the first place to look is in the presentations section of the 7EA Users Group website (ge7ea.users-groups.com); be prepared to sign up if you're not already registered. For

Maximum Reliability

Water Cooling Technology Provides Increased Operating Intervals Between Liquid Fuel Runs



Thermal analysis shows the affectiveness of active cooling (*left*: fuel lines with heat-sink clamps installed, *top right*: water cooled liquid fuel check valve and *lower right*: water cooled 3-way purge valve).

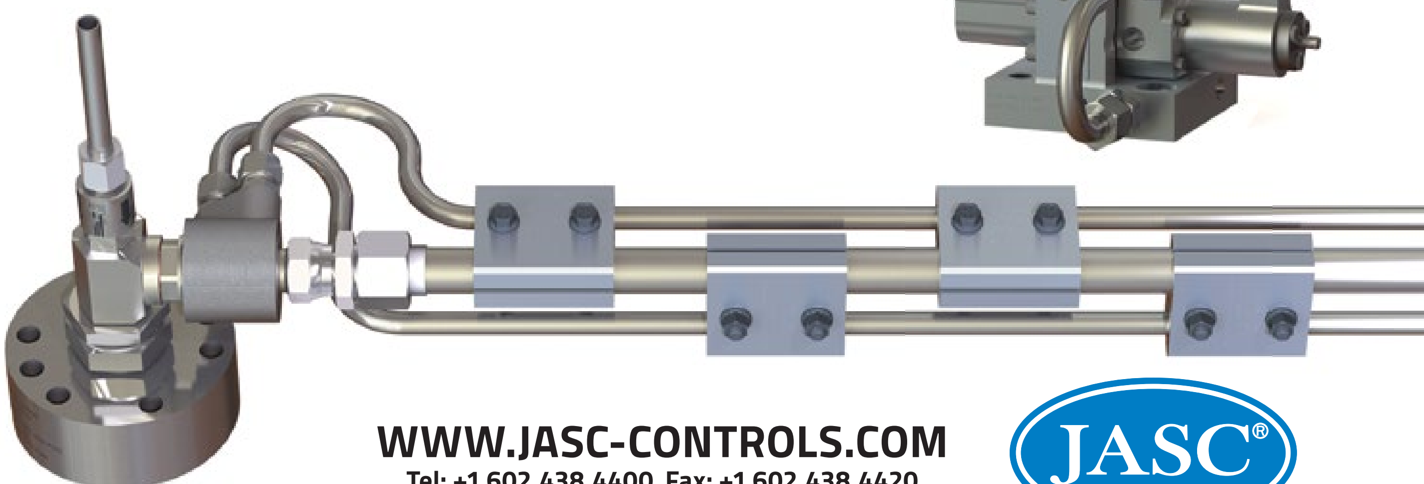


ALL NEW

Heatsink Clamps

JASC Heat Sink Clamps keep fuel lines cool, significantly reducing the potential for coke formation. Coke-free fuel lines improve transfer and start reliability on liquid fuel and help minimize exhaust temperature spreads and trips during liquid fuel operation.

Water Cooled 3-Way Purge Valve (right) and Water Cooled Liquid Fuel Check Valve (below) configurations shown.



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more information, reach out to your plant's customer service rep.

Perhaps the two most significant announcements made during GE Day, which began after morning coffee Tuesday and ran until OEM's "Open House" (dinner and exhibition) at 5 pm, concerned GE's revamped field-service operation and a change in the rotor maintenance-factor calculation.

Field services. Regarding the first point, the OEM essentially severed its field-service employees from GE employment in August 2017 and allowed most of them to interview for positions in its wholly owned subsidiary, FieldCore, which aggregated the field-service resources from GE Power Services and Granite Services International Inc—at least that's the way the editors understand the organizational changes. Note that Atlantic Plant Maintenance, a wholly owned affiliate business of GE Power Services that provides craft labor in the US and Canada, was not rolled into FieldCore.

The users were told during the GE-sponsored evening reception that they should continue to contact their regular GE rep to arrange for field-service support. Billing will continue to be directly through GE to the customer. The FieldCore regional GM addressing the group said his organization would continue to provide quality field-service support to/for GE while driving down costs.

There was significant chatter among users during coffee breaks regarding the shift to FieldCore. As you might expect, most of the discussions were negative: Change is difficult for most people to accept without at least some grumbling. Attend the 2018 meeting of the 7EA Users Group in California, October 7-11, to learn more about the transition of field services to FieldCore and how its processes are changing to better suit the customer.

Forced cooling. Shortly before the 2017 meeting, GE published Revision N to its "Heavy-Duty Gas Turbine Operation and Maintenance Considerations (GER 3620)," introduced nearly three decades ago. It generally is recognized as the company's "bible," providing frame owner/operators guidance on O&M tradeoffs for the company's engines.

It's important for users to obtain a copy of this document (access via Google) and to keep up with future revisions—you never know what surprises it may have. In Revision N, the change creating the most concern among owner/operators is believed to be the one related to the impact of forced cooling on the rotor maintenance factor.

It states that should an operator force-cool a unit after operation, there will be a 4× impact on the maintenance factor for that start. An OEM representative said this applies to E-class units and defined forced cooling as cranking a gas turbine (after a start/run) for an *extended* period of time at more than 60 rpm. "Extended" was not defined in terms of hours.

Also said was that the maintenance-factor calculation for forced cooling had to be "back calculated" in determining "factored starts" for rotor maintenance actions.

Owner/operators of legacy E and EA models with cranking turning gears (versus ratchet-type turning gears) and cranking speeds above 60 rpm to avoid bucket-rock damage should take a deep breath: A significant addition to the number of factored starts will occur.

Until now it has been "routine" for many plants to force-cool their gas turbines to reduce the time required for maintenance outages and offline compressor washing. This new calculation suggests operators might want to rethink their cooldown procedures. Also, staff at affected plants should review operating logs to determine how the new calculation impacts their rotor-inspection schedule. Presentations at various user-group meetings indicate a two- to three-year planning phase may be required and it's possible you're now late getting started.

More bad news: The unit trip factor is now 2×.

NERC requirements. "Responding to NERC MOD and PRC Standards" was another presentation containing information you might not want to be reminded of, but necessary. It covered the required testing and model validation required to comply with standards that would be July 2018 enforceable. Obviously, that date has already passed. So if some of what follows comes as a surprise to you, it's a good idea to learn quickly and bring your plant up to current requirements.

The first part of the presentation focused on testing that should be conducted to understand the capability of your equipment and to get the most from it. This is an important step to assure full compliance with NERC standards. The speaker reminded that manufacturer "design" may have a wide range of "normal" and retuning of controller settings or retrofit of late-model digital controllers may result in significant deviation from "book ratings."

Additional benefits of testing include the following:

- Recognition of deviations, enabling a refinement in tuning.
- Better coordination with protection systems.
- More effective training of staff because of testing at the bounds of control—that is, non-normal operating modes.

NERC model validation standards reviewed were these:

- MOD-025-2, "Verification of Generator/Plant Real and Reactive Capability." Requirements include verification of the maximum continuous real power output and lagging and leading reactive power outputs; calculation of transformer losses; analysis of test results and manufacturer's stated limits; submission of data reporting forms; documentation of auxiliary load consumption.
- MOD-026-1, "Verification of Dynamic Models and Data for Generator Excitation Control and Plant Volt-VAr Control Functions." Requirements include submission of an excitation control system description, and of an approved model for the generator, exciter, power system stabilizer, and plant volt/VAr controls. Plus, verification that the model simulation matches the response from a disturbance.
- MOD-027-1, "Verification of Dynamic Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions." Requirements include submission of a description of the governor and load control system, and of an approved model for the governor and plant active power controls. Plus, verification that the model simulation matches the response from either a significant disturbance or an online speed governor step test.

So much for the details. To learn more about applicability and timing of the model validation standards, access the presentation on the 7EA Users Group website. Keep in mind that the generation owner is responsible for model validity; also that one size does not fit all: applicability differs in the East, WECC, and Ercot, as does the timing of compliance.

Typical tests were profiled by the presenter and test-equipment requirements were defined, followed by analysis and reporting requirements. If you feel overwhelmed after reviewing all the things you're responsible for beyond safety, top availability, high starting reliability, low heat rate, etc, you can turn to GE Energy Consulting for help. The short promotional section of the presentation mentioned this group has tested more than 1500

units and has experience with all major OEM equipment.

Technical Information Letters. A review of the latest TILs is always of value. It's easy to miss communications on these important missives during busy periods. The four TILs highlighted at the 2017 meeting were these:

- TIL 2046 describes DLN1 purge-valve operating issues (potential gas backflow into the wrapper) and actions to mitigate them.
- TIL 2028 provides control settings for Reuter Stokes flame sensors. Be aware that false flame detection is possible if the threshold is set too low, resulting in unburned fuel delivery.
- TIL 2025 addresses dry GE Reuter Stokes Model FTD325 flame-scanner false indication on shutdown.
- TIL 2044 addresses dry GE Reuter Stokes Model FTD325 flame-scanner false indication while offline.

A session on typical B- and E-class rotors revealed the following findings:

- R-17 compressor vane migration has been attributed to staking variability. A new standardized method of staking has been implemented. It notches the R17 vane near the center of the wheel and wheel material is moved into the notch on the vane.
- TIL 1049 regarding history and recommended checks for wear on turbine-wheel dovetails was discussed. Repair personnel were reminded to check platform gaps, and if they are "out of band" then perform a "pin check."

Vendor presentations

Presentations by suppliers expose users to new technologies and solutions for improving unit performance and personnel safety, providing valuable perspective on topics of importance. At the 2017 7EA Users Group meeting, 27 companies interfaced with owner/operators from the podium. There was GE Day (p 20), the Bus Duct Roundtable (p 14), the Rotor Life Roundtable (p 20), and more than a dozen individual presentations. Plus, the vendor fair brought users face-to-face with more than a hundred product/services providers on Wednesday evening.

Steering-committee members know how sensitive their colleagues are to sales pitches, so presentations are invited, then vetted to eliminate more than expected horn-tooting. Inviting experts to address specific topics minimizes duplication of subject matter and expands the learning experience.

Subjects covered in last year's vendor presentations included the following: gas-turbine inspection (p 6), DLN-1 troubleshooting, controls issues, fuel systems, training, generator circuit breakers (p 28), rewinding of generators, coupling best practices, exhaust-plenum improvements, control-system tuning, generator diagnostic, air filters, and actuator overhaul.

Quite a lineup for sure and what you can expect at the 2018 meeting. Register today at http://ge7ea.usersgroups.com. Short summaries of several 2017 presentations selected by the editors for coverage are below. To dig deeper, and to access other PowerPoints, visit the user group's website. You'll have to register if not already a member.

"Troubleshooting DLN-1 Primary Re-Ignitions," *Mitchell Cohen, Turbine Technology Services Corp.*

Mitch Cohen, one of the industry's leading experts on the DLN-1 combustion system, always has been ready to share his considerable knowledge with 7EA owner/operators. CCJ has been covering Cohen's presentations since he spoke on DLN-1 basics at the 2007 meeting of the 7EA Users Group in San Francisco. To access, visit www.ccj-online.com and use the search feature provided. If you are new to the industry and the DLN-1 you might want to begin there; it's a valuable backgrounder.

At the 2017 meeting in St. Augustine, Cohen spoke to the causes of primary re-ignition (PRI) and how to mitigate this operational anomaly. Operators should be concerned about primary re-ignition, he told the group, because it can move the engine out of emissions compliance; plus, extended lean-lean operation causes excessive heating of the venturi in the combustion liner and incurs a 10× maintenance factor (TIL-1443 R2).

Cohen listed the following as possible causes of primary re-ignition:

- Spontaneous, unexpected ignition source in the primary zone—such as lube oil, hydrocarbon liquids in fuel gas, distillate in dual-fuel machines, and combustible matter in air (dry grass, for example). The speaker identified several common materials that might be drawn into the inlet duct through breaches in inlet filters or ductwork, or accidently left inside the machine during an outage, with auto-ignition temperatures below the compressor discharge temperature.
- System instability—fuel, air, combustion dynamics; or an instability induced by faulty or mis-calibrated instrumentation. Cohen said PRIs after transfer from liquid fuel are relatively common. A possible remedy: Implement a temporary, higher-pressure purge in primary and lean-lean mode after fuel transfer.

He also mentioned that wiring problems in the Mark V cabinet (so-called wire whiskers) are known to have spuriously energized the ignition transformer, thereby causing re-ignition. Plus, don't overlook the possibility of a faulty P-2 transmitter: It can cause a hiccup in speed-ratio-valve control.

The most common cause of PRI during fuel transfer was said to be improper timing of purge valves. The specified opening time is 35 ± 5 seconds. Slow opening minimizes load and temperature spikes, while rapid opening (8.5 seconds) expels residual transfer fuel unevenly and in a slug-like manner causing a large load spike and high exhaust spread. The latter triggers the spark plug to fire, transferring to lean-lean extended mode.

- Powering up of spark plugs, initiated by control-logic response to an alarm/fault condition such as high exhaust spread, thereby igniting a combustion source in the primary zone. Bear in mind that DLN-1 spark plugs cannot be retracted and that insertion depth is critical. Check the depth after a maintenance outage. Inserting a plug too far will burn up the tip and the spark plug will act as a glow plug to re-ignite primary fuel during the fuel transfer process.
- Sub-optimal tuning.

"Considerations for the Rewind of Highly Cycled 7A6 Generator Rotors," *W Howard Moudy, National Electric Coil.*

Howard Moudy is a frequent presenter at user-group meetings and generally held in high esteem by owner/operators both for his knowledge of things generator and his willingness to share what he knows. Over the last several years, Moudy's 7EA User Group presentations have focused on a variety of concerns with the 7A6 generators typically married to the 7EA, including the following:

- Stator failures traced to housing leaks.
- Stator-winding partial discharge.
- Rotor main lead failure.
- Stator endwinding looseness (dusting and greasing).
- Rotor-turn insulation migration.
- Rotor copper elongation and foreshortening.

The speaker moved quickly through his review to allow maximum time for coverage of the requested topic:

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Young & Franklin's proven line of Electric Products are drop-in replacements of OEM supplied valves and actuators for DLN and Diffusion gas systems

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DCS data can pinpoint avoidable, damaging thermal transients in HRSGs

Heat-recovery steam generators (HRSGs) are sometimes ignored by personnel at plants powered by GE Frame 7 E-class gas turbines—primarily 7Bs, 7Es, and 7EAs. The 7EA Users Group, with which you are most familiar, focuses on "things engine," leaving solutions for other major equipment—including HRSGs and steam turbines—up to others.

There are more boilers and steam turbines serving in plants with Frame 7 E-class GTs than you might imagine. At the 2017 7EA Users Group meeting, GE said the fleet totaled 1168 engines, with about two-thirds of those in simple-cycle service. About half of the remaining machines are in cogen systems. Another 140 units are integrated into combined cycles, the remainder mostly drive compressors in LNG plants. Given this information, the editors put the number of HRSGs supporting the 7B-EA fleet at about 325; two-thirds of those are in the US.

Perhaps the best open source of practical O&M problem-solving information on boilers is the *HRSG Forum with Bob Anderson,* which meets next at the Hilton Orlando, July 22-24, 2019. This meeting will bring you up to date on HRSG issues and solutions worldwide given the Forum's affiliation with user groups in Australia/New Zealand, Canada, Europe, and Russia. Plus, Anderson, a respected and active industry consultant specializing in boiler work, brings first-hand insights to *Forum* discussions based on the scores of HRSG surveys he has conducted around the globe.

Anderson told the editors that HRSG owners and operators, in particular those affiliated with plants built prior to and during the gas-turbine "bubble" (2000-2004), often traced pressure-part failures—superheater/reheater tubes and steam-pipe girth welds, for example—to attemperator overspray. A common root cause: Controls configured as a simple feedback loop instead of the cascade control scheme typically required, and operator intervention by lowering the attemperator setpoint.

Anderson recalled that a few years ago, after many operators had improved their control logic, he noticed leaking spray water when an attemperator was supposed to be out of service and believed that was causing most of the trouble. Anderson found many attemperators with chronic and/or severe leaking problems used valve-protective logic that opened and closed the block valve each time after and before, respectively, the control valve opened and closed.

The intention of this "master control valve/martyr block valve" logic was to protect the seat in the expensive control valve from damage caused by opening and closing against the high differential pressure across the valve. In other words, let the block valve take the damage in an attempt to protect the control-valve seat.

Anderson has for years been telling anyone who would listen (including attendees at the 2018 *HRSG Forum*) that use of such logic in a unit where the attemperator comes into and out of service frequently ensures the block valve's seat will be damaged quickly, allowing leak-by. Damage to the control valve's seat then occurs because the block valve can no longer isolate it from high differential pressure. The large number of leaking attemperators Anderson has found doing the HRSG surveys mentioned earlier supports this hypothesis.

He suggests that owners use the following "master block valve/martyr control valve" logic to avoid wear and tear on valves serving in cycling units: Open the block valve once during unit startup when the gas-turbine exit gas temperature increases to about 950F and leave the valve open until EGT decreases to 950F during shutdown.

The improved logic assures the block-valve seat will remain sound, protecting superheater/reheater tubes, headers, and piping from damage far more costly to repair than control-valve seats. Anderson believes owners will not see significantly higher maintenance costs on their control valves because their tight shutoff is not critical *provided* the block-valve seats are protected.

At the recent *HRSG Forum,* Anderson urged users to periodically review DCS data to see when their valves are opening and closing and to see if there is any leakage.

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rewinding of highly cycled 7A6 generator rotors. You can come up to speed on the subjects listed above with simple keyword searches in the online archives of CCJ and the International Generator Technical Community Forum (www.generatortechnicalforum.org).

Moudy set the stage for his presentation with this brief introduction:

- The rotor is the primary generator component most affected by cycling.
- Many generators, the 7A6 in particular, were not designed for cyclic operation.
- Rotational forces, or cyclic loading, can fatigue rotor components—especially those not designed for cycling.
- Rotor endwindings not designed for cyclic operation can be modified and rewound to better withstand this demanding service environment and provide long-term reliable operation.

The last bullet point was the segue to Moudy's 2017 presentation. Key points he made:

- 7A6 rotors are experiencing issues in the rotor main lead, and cracking of the 90-deg right-angle-turn joint assembly of the coils, because of fatigue attributed to cycling. First step in avoiding a forced outage: Have a qualified technician borescope the main leads of your generators—regularly.
- NEC reported having a coil-forming process to avoid the 90-deg right-angle turns on coils by forming a bend in the copper to eliminate the right-angle joint.

The speaker also mentioned migration of rotor-winding turn insulation because of insufficient bonding, noting the potential value of borescoping for identifying possible issues. Plus, he said poor design of the end-turn blocking contributed to copper elongation and foreshortening issues.

Finally, Moudy suggested that users read IEEE C50.13 to learn more about the terminology used in lifecycle investigations and better understand what their machines are capable of in terms of start/stop cycles, in baseload and peaking service, etc.

"7EA Marriage Flange Load Coupling Hardware Solution," *Pat McCormack, Riverhawk Company.*

Pat McCormack spoke to hardware issues associated with the 7EA marriage flange (turbine to compressor) and load coupling, and proven solutions. For example, marriage-flange bolting often is difficult to remove because of galling. Galled threads cause the hardware to seize, requiring that the bolts be cut off, which can add to outage time. Turnaround costs are increased as well because new hardware is required.

Recommended solution: Use hydraulically stretched bolting for the

marriage coupling to eliminate galling. Tensioned studs were said to be reusable because no damage occurs to the threads even after multiple installation and removal cycles. Improved rotor balance is another reported benefit; plus, stud design provides a convenient location for balance weights.

Tensioning tools also were covered in the presentation. For the 7EA, the load-coupling and marriage-flange tensioner are one in the same. The company developed a new, lighter-weight tool for easier handling.

Given the age of many machines in the fleet, McCormack said legacy tooling can be modified to permit marriage-coupling assembly with the new bolting.

The speaker also mentioned a solution for couplings requiring fitted bolts. The details: A sleeve is machined to the ID of the coupling hole (less a clearance). The bore of the sleeve is tapered and the bolt has an OD matching the sleeve taper. As the bolt is tightened, the sleeve expands to take up the clearance for a size and size fit between the coupling and bolt assembly.

"Overheat Detection in Air- and Hydrogen-Cooled Generators," *Christopher Breslin, E/One.*

You don't have to sit through many presentations at a meeting of the Generator Users Group to realize these machines often do not get the love they deserve. Forced outages occur more frequently than you'd like to believe, typically because there's no one at the plant with a good understanding of how generators work, what inspections and maintenance they require to keep them operating reliably, and how to tell when problems are on the horizon.

This situation likely will get worse before it gets better because the relatively few generator experts in the power-generation community are retiring at an alarming rate, staff sizes are shrinking at virtually all plants, and the need for generator training can get a big "huh?" from owners without an O&M background.

Christopher Breslin discussed the importance of condition monitoring in protecting generators.

Operational risks increase as generators age and staff experience declines, he told the users. OEMs typically include the following condition monitoring tools with their equipment: temperature sensors to identify overheating indicative of insulation failure, overload (over-current) protection, vibration monitoring to warn of shaft/rotor imbalance, and hydrogen purity to alert about a possible safety issue.

But there's still more monitoring equipment available to help mitigate risk, including: fiberoptic accelerometers to indicate end-turn vibration, partial discharge (PD) to warn of stator insulation breakdown, flux probe to identify shorted rotor turns, radio frequency (RF) to find arcing, dew-point sensor to track moisture level, and the generator condition monitors (GCM) offered by the speaker's company for hydrogen- and air-cooled generators.

The GCM, Breslin said, can warn of back core burning, shorted rotor turns, foreign material, mechanical vibration, hot spots, and blocked rotor cooling. Several slides explained how the GCMs (one for hydrogen-cooled generators, one for air-cooled) work. What the GCM does is detect the sub-micron particles created during overheating and arcing; their numbers increase exponentially when those events occur.

An ion chamber is ideal for detecting sub-micron particles in hydrogen-cooled generators because their cooling systems are closed-loop. The solution is not so simple for air-cooled generators which can have open cooling systems. Their detectors must be highly sensitive, yet immune to false alarms created by the omnipresent dust and dirt in the atmosphere. Access Breslin's presentation for details.

"7EA Exhaust Plenum Improvements," *Gary Martin, Cust-O-Fab Inc.*

Benjamin Franklin reportedly said, ". . .in this world nothing can be said to be certain, except death and taxes." To that it's safe to add "and gas-turbine exhaust system problems," especially in cycling units more than about 20 years old and installed in areas with high humidity.

Knowing that one day you'll probably have to make extensive repairs to your 7EA exhaust system, or replace same, it's important to keep current on companies in the business of repair and upgrade and what they're offering. Gary Martin's presentation highlighted the exhaust-plenum improvements offered by COF Specialty Services, including the following:

- Double-sealed wing door.
- Forward and aft flex-seal insulating collar.
- Drainable liner floor.
- Full floating internal liner design.
- Cold-flange design between components.
- Material upgrade for flex seals.
- Ability to install the exhaust plenum with turbine rotor and aft diffuser in place.

It's difficult to understand these improvements without looking at the drawings Martin showed the group. The editors recommend accessing a copy of the presentation on the 7EA Users Group website to better understand COF's design.

20. 15-kV switchgear overheated and was destroyed by a very hot fire. It vaporized this cubicle as well as a couple of others. Plant was down for 21 days to replace the three cubicles affected, considered a rapid turnaround given project complexity

21. Nameplate for generator main breaker reveals F.C.—for forced cooling—after the continuous current rating of 5000 amps

Generator main breakers

At the 2016 meeting of the 7EA Users Group, Bruce Hack of National Breaker Services LLC presented on the benefits of using his company's Citadel product line to mitigate problems with circuit breakers that several owner/operators were dealing with. After his presentation, the steering committee met with Hack to discuss ongoing issues with breakers

supplied by a particular switchgear manufacturer and installed on many 7EAs. He offered to look into the group's concerns, provided he could visit plants with breaker issues and get the details first-hand.

Through the 7EA Users Forum, Hack identified three users willing to let him visit their facilities and to discuss their challenges. At the first plant he visited, he found the breaker's nameplate rating slightly lower than the known current output of the generator. Overheating did not seem to be an issue with the operations personnel so the matter was rested after being pointed out to the plant engineer.

Racking, alignment, and secondary contact issues also were identified. They were of major concern to the operations department because it had disabled the breaker's use during previously needed times. The issue appeared related to insufficient/improper floor support under the breaker cubicle section. This likely would be attributable to the switchgear outdoor-house manufacturer and/or the original design team.

The remaining two plants on Hack's list had the same 5000-amp generator main breakers—on paper. Although their nameplates said they were the same they were anything but. Hack's survey revealed they were so different it was not possible to interchange them. Anyone trying to buy one of these as a spare for the other would be deeply disappointed at the first rack-in attempt, he said. Specifically, the cell floors varied, and the interlock positions and secondary block designs were not the same.

Heating issues had dogged both plants since COD. Additionally, some of the breaker problems that arose over the years, discussed by Hack in his 2017 presentation to the 7EA users on the results of his plant visits, included the following:

- Racking mechanism issues.
- Primary clusters, secondary disconnect alignment anomalies.
- Floor interlocks.

Overheating of generator main breakers was a consistent and major issue. Fire-hazard and personnel safety concerns always are paramount to any plant owner (Fig 20); plus, the potential for a plant trip and expensive forced outage can completely negate the value of a peaking unit. One plant installed thermal monitoring instrumentation as an advanced warning system, the other had multi-ton air conditioners blowing on its breakers to keep them cool.

Two questions that came to mind:

- Why live with the overheating problem?
- Why are the breakers overheating in the first place—is the equipment defective? The short answer is "no."

Hack reported there was no "maintenance" money available to replace the breakers. There were requests for "capital" money, but accounting "rules" prevented using it to correct issues with problematic breakers. A wholesale upgrade and change out would have been required.

The long answer has to do with commercial considerations. Fig 21 shows that the equipment is rated for 5000 amps (continuous), but there's an "F.C." that follows that information—for forced-cooled. In all probability, this was the most cost-effective offering the OEM could incorporate into the total plant package "at the time." Whether the components and designs pushed their limits is an open and ongoing debate.

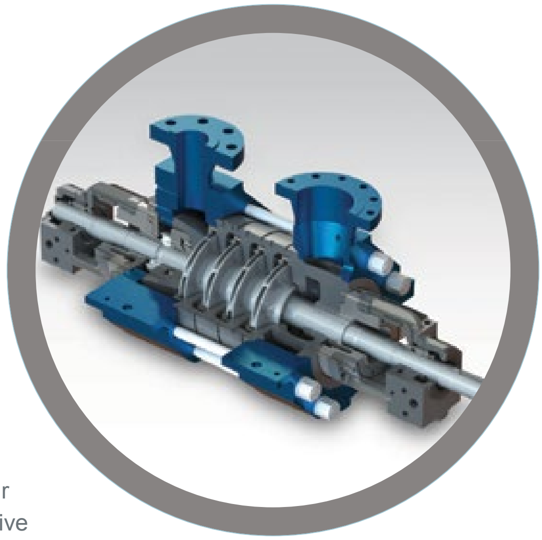
Undoubtedly, Hack said, the design did not provide the sort of belt-and-suspenders safety margins that gets a plant 30 to 40 years of highly reliable, maintenance-light service. No one would have wanted an entire plant to depend on the operation of a few small fans and an auxiliary a/c system to keep breakers from overeating if it could have been avoided.

Hack dug deeper with a back-of-the-envelope calculation. He measured the lower stem of the vacuum interrupter at about 1 in. diam, meaning the conductor cross section was about 3.2 in.^{2}. A conservative rule-of-thumb suggests a maximum current flow of 1000-1200 amps/in.^{2} for this breaker, which means it's about 1200 amps less than the 5000-amp nameplate without forced cooling.

As Hack pointed out, "at 5000 amps you're running a toaster in the middle of your circuit breaker. If you wick away the heat fast enough, you can keep things within limits. But the better solution is to simply use a properly rated, self-cooled 5000-amp breaker if at all possible."

Hack's conclusion: A better vacuum interrupter and properly paired mechanism design is needed for this breaker to be specified for 5000-amp service. As is, he believes it should not have been used above about 3600 amps, self-cooled.

A solution Hack suggested was a fixed-mounted breaker—specifically a bolted-to-the-bus Citadel breaker that has line and load air-break disconnects with an integral, interlocked grounding switch. It would eliminate the stab failure issues and provide an air-break switch with grounding for lock-out/tag-out isolation. Racking out generator breakers for maintenance activities is an issue for almost all 7EA locations. CCJ



Hot topics: risk-based inspection, corrosion under insulation, water chemistry

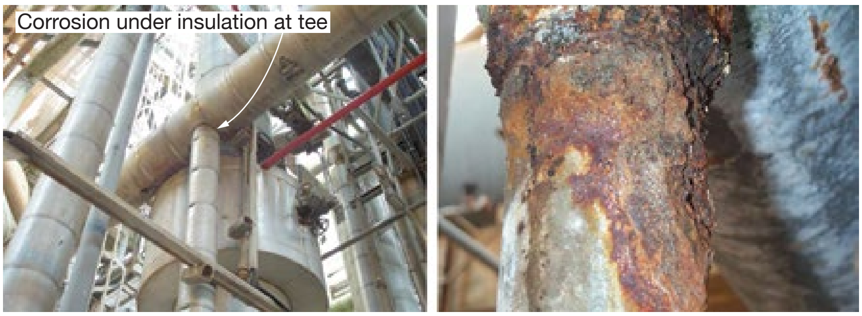
By Steven C Stultz, Consulting Editor

At the end of 2017, participants at the Australasian HRSG Users Group Conference and Workshops in Australia were welcomed to the 10th annual meeting. Of all the HRSG groups outside the US, AHUG has the second longest history, behind only IMechE in the UK.

The shared purpose of these groups: Provide interactive forums where owners, operators, manufacturers, service providers, consultants, and others with an interest in HRSG systems and equipment meet to learn from others while sharing their knowledge and experience. All meetings feature a combination of carefully selected technical presentations and facilitated discussions and debate.

The world's most trusted experts share their knowledge at these events, helping to tie together both local and global concerns, innovations, and forward-looking ideas. It's the openness, the sharing of thoughts and experiences, that generates the momentum for these groups and their in-depth looks at projects, technologies, and most of all, owner/operator success.

And for those closer to home, the *HRSG Forum with Bob Anderson,* entering its third year, collects the ideas and discussions, consolidating a truly world view within North America.



1. Atmospheric corrosion of carbon and low-alloy steel is hidden under insulation

Common challenges, market forces

The first open-floor question: "Many European countries, the US, and Canada continue to install large pockets of renewable generating capacity (primarily wind and solar). This has caused the need for faster and sometimes more frequent startups of combined-cycle units. Is this also the experience within Australasia?"

The assertive answer: "*Yes!*" It's a global movement with common challenges.

Renewables are a force in Australia. In New Zealand, flexibility also has been needed to accommodate the abundance of hydroelectric and geothermal units. Plants in this region of the world have learned for many years to be flexible with operations and pay close attention to cycle chemistry. Specific local plant reports would provide depth throughout the AHUG meeting.

So we have a universal truth, global concerns that strengthen annually.

As a participant, we listen to new as well as tutorial technical details. The fundamentals are there for a reason and are worth stressing to all colleagues at each event. But we also carry away some Rules of Thumb, the things that seem to work. And we pick up a few golden nuggets—experiences that our colleagues face and try to overcome. Discussions are frank and open. All of these elements have both immediate and lasting value.

Below is a selected review of the November 2017 meeting in Sydney.

Risk-based inspection

The Cockburn Power Station in Western Australia is a 240-MW site with a 160-MW gas turbine, 80-MW steam turbine and dual-pressure HRSG, commissioned in late 2003.

Cockburn averages 150 starts per year in two-shift operation. A recently implemented risk-based inspection (RBI) program allows the plant to better incorporate both targeted maintenance and safety into its operations. (RBI has become a familiar theme in all regional meetings.)

Inspections in Australasia commonly find corrosion under insultation, signs of corrosion fatigue in the HP drum, and corrosion within the closed cooling systems.

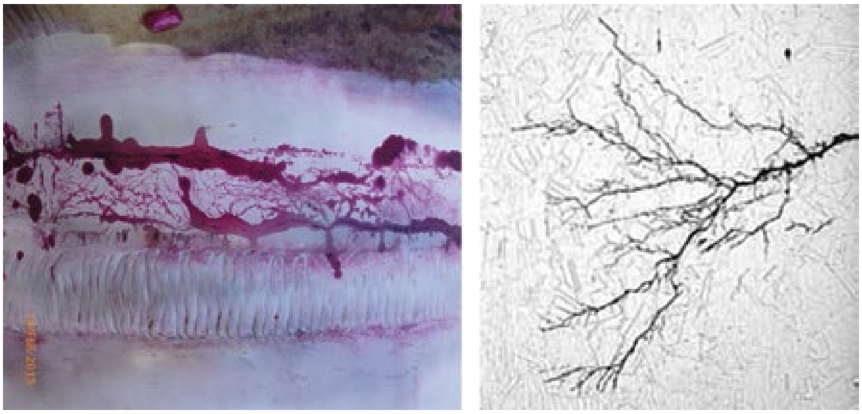
Desuperheater instability was discovered in the past year at Cockburn, using methods discussed in detail at the 2016 AHUG meeting.

The 2017 presentation introduced many added topics (seals and at casing penetrations, expansion joints, etc) the plant has faced because of challenging and changing operational trends:

- More time in layup (little use in summer).
- Winter peaking operation.
- More days between starts.
- Constant standby.

Why RBI? The main risks to the HRSG at Cockburn are from fatigue and corrosion. As Keith Newman of Synergy explained, "If you understand where your risks lie, you can spend your money on the things that matter."

Problems were appearing with:



2. Stress corrosion cracking of austenitic stainless steel (Types 304 and 316) is easy to identify

3. LP drum level transmission pipe corrosion (above)

4. Swanbank E Power Station in Queensland was returned to service from dry storage (right)

- Feedwater piping—HP pipe, LP pipe, and HP drain pipe.
- HP drum—cracking on attachment welds and on internal surfaces of both downcomers.
- Galvanic corrosion in the condenser (seawater cooled).
- Desuperheater overspray.

This status presentation triggered active discussions and thoughts on solutions. Desuperheater liner replacement is being considered, but repair is a near-term option if the crack does not enter the pressure parts. Penetration seals and corrosion of carbon-steel rings were discussed, along with repair/replacement issues. Fabric penetration-seal retrofits and isolation valves were covered also and would be explained in later presentations.

The RBI concept was openly examined including the ability to incorporate major events into the RBI calculation. Cockburn currently uses Microsoft Excel. Maintenance planning is with SAP, guided by the RBI analysis.

This presentation served as a real-world introduction to both RBI and much of the meeting agenda.

Hidden dangers

Corrosion under insulation (CUI) was a topic in several case studies. CUI is atmospheric corrosion—a/k/a rusting of carbon and low-alloy steels (Fig 1). For stainless steels this leads to stress corrosion cracking above 140F (Fig 2). The main problem remains this: there is not yet a method of inspecting with the insulation in place. And this is not unique to the power industry. It is a significant concern within the global refining industry as well.

Five case studies were reviewed by Charles Thomas of Quest Integrity.

With insulation removed, inspection of carbon steel can be visual. Inspection of stainless is both visual and with dye penetrant. At highest risk are the small-bore lines, most with thin walls, and dead legs that cool down away from the main vessel. But a plant cannot remove all insulation, and therefore, "Inspection techniques to identify CUI (without removing the insulation) are the current holy grail of the inspection industry."

Case studies were presented on LP drum-level transmission pipe (Fig 3), HP vent line, pipe bend low points where water pools, and the discovery of stress corrosion cracking under support plates.

The underlying message: look carefully.

Lengthy discussions followed on inspection techniques and methodologies including guided wave, radiography, eddy current and thermal imaging. The general agreement was the need for a risk-based approach: "Manage by targeted inspection of at-risk areas."

An interesting thought was generated during the discussions: If insulation is not required, don't replace it. Perhaps consider also installing rain covers on the pipe bridge for plants with horizontal, exposed runs.

Swanbank E

For the past three years, participants have reviewed the status and details of Stanwell Corp's 375-MW Swanbank E Power Station in Queensland (Fig 4). The plant was withdrawn from service on Dec 1, 2014, and placed in dry storage after operating with an average 97.5% reliability.

Site labor was reduced to a caretaker team, and comprehensive cold storage and preservation of all systems was implemented.

Major storage risks, typically, are corrosion of water/steam components and corrosion under insulation. Acid dew point corrosion on the HRSG gas side was a concern, as were gas and steam turbine corrosion. Stanwell's full storage with dehumidified air has ensured few issues other than rainwater ingress (some corrosion under insulation).

Safety valves were found to have a few problems with debris. Some were overhauled due to cracks in casing, primarily attributed to missing insulation.

The unit was returned to service shortly before the conference. Operations will be reported at the next AHUG meeting in Brisbane, Nov 13-15, 2018.

Those pesky millennials

One presenter at the *HRSG Forum with Bob Anderson* in Houston this year called a large group of HRSGs *millennials*, meaning those built in the late 1990s and early 2000s. In Sydney the presenter keyed into those in the 2000 to 2005 range, stating that even those are getting close to half way through their original design life. The common message is the need to do thorough and accurate life assessments of all components and systems, and to understand the overheating mechanisms in these aging units (Fig 5).

Non-pressure parts can be a major concern:

- Liner plates in inlet ducts (at risk at 1200F).
- Liner materials in firing ducts (oxidation and thinning at 1500F).
- Tube ties—chrome steel and Type-304 stainless steel plate.
- Gas baffles.
- Type-304 duct-burner materials.

Many units are experiencing the need for new inlet-duct liner systems because of fatigue cracks in Type-409 stainless steel liner plates and bolting systems (Fig 6). Fatigue strength is temperature-dependent and above 1020F it decreases sharply for Type 409.

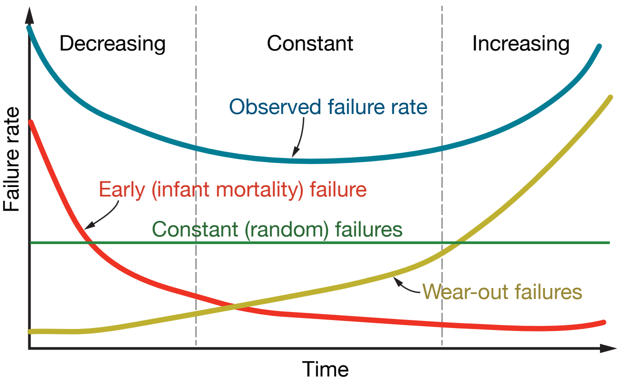
Duct burners themselves must be carefully monitored.

Superheater and reheater tube ties are traditionally Type-304 plate materials located downstream of the duct burners. These are subject to fatigue cracking, increasing the risk of failures—including tube vibration and fin damage. In the case example, normal thickness of $7/16$ in. had been reduced to less than $1/8$ in. (Fig 7). Standard causes are poor turbine exhaust distribution and poor burner fuel distribution, or both. Monitoring can be done using firing-duct view ports. Flames should never make contact with the tubes, and glowing red components indicate excessive temperatures (1500F).

Loose or missing tube-bank baffles also were discussed. Baffle reinforcement systems are available and were described by Lester Stanley, HRST Inc. He said, "If the baffle system keeps failing you need to redesign it, but it's very important to keep it in the system." This led to an interesting exchange on missing or damaged baffles producing the following Rule of Thumb: Operating without the baffles should never be an option, because of downstream heat damage.

The presentation then switched to pressure parts and covered:

- Tubes.



5. Failure rates of aging HRSGs

6. Fatigue cracks found in Type-409 liner plate

7. Type-304 plate materials downstream of duct burners must be thick enough to prevent damage

- Headers.
- Link pipes (between tubes and headers).
- Steam outlet piping.

Examples concentrated on overheating as the cause of damage. Overheating would become a common theme in the meeting, and in the workshop on the final day.

During discussions, proper oxide analysis was also discussed, and would also be addressed in the workshop.

Stanley's presentation offered several takeaways, including:

1. Perform careful visual inspections to find early clues on overheat risk locations, then monitor these areas. One critical activity should be to both maintain and use the burner view ports. One failure noted was attributed to site personnel "getting lazy."
2. Analyze performance (both low load and full load) and compare predicted versus actual performance.
3. Use performance assessment results to analyze remaining life (then manage the remaining life carefully).

Always worth repeating

Barry Dooley, Structural Integrity Associates Inc, commonly addresses these meetings on the importance of HRSG cycle chemistry control and flow-accelerated corrosion detection. He did so in Sydney. Key items are repeated here, for ongoing emphasis.

- Instances of under-deposit corrosion (hydrogen damage) are increasing globally, especially in HP evaporators.
- FAC is an ongoing issue, in the same locations and situations spanning the past 15 years.
- Owner/operators need to concentrate on the known repeat cycle chemistry situations:
  - High corrosion product levels.
  - HP evaporator deposits.
  - Failure to chemically clean when needed.
  - Lack of instrumentation by international standards.
  - Lack of carryover control.
  - Inadequate shutdown protection.
  - Air in-leakage.
  - Contaminant ingress.
  - Failure to challenge the plant's status quo (policies, procedures, and action/inaction decisions).

As another Rule of Thumb, David Addison principal, Thermal Chemistry Ltd (New Zealand) stressed that "A fully optimized chemistry program should mean almost no loose iron anywhere in the cycle."

Thermal transients

Bob Anderson then presented a brief update on thermal-transient issues. Nearly 30 key items were tracked over a 10-year period for 51 plants includ-

ing gas turbines from five OEMs, steam turbines from nine OEMs, and HRSGs from 18 OEMs. The trends were interesting.

One focused question: For tube failures, is there an active root cause program in place? Positive response but luke warm, going from 0 plants previously to only 10% of them today.

For superheater/reheater drain issues, responses were better. Drain pipe sizes being large enough improved from 0 to 56%, drain pipes sloping continuously downward improved from 0 to 31%, and blowdown vessels being below SH/RH elevation improved from 11% to 49%.

For attemperators, avoiding overspray actually declined from 75% to 71%. Ensure leaking spray water will drain before entering tubes improved from 32% to 54%. Routine hardware inspection program use improved from 11% to 22%.

Instances of exceeding a prudent HP-drum ramp rate during startup improved by decreasing from 33% to 28%.

Here was an interesting question: In a perfect world, how do you manage the thermal stresses of rapid shutdown and startups because of increased cycling (use of renewables)? One answer: Control the shutdown to bring the SH steam temperature closer to saturation. This means slowing the GT shutdown. An interesting caution: But be careful; you may run into emissions limits.

Specific to the drain issues, effective draining during startup as confirmed by use of DCS data for superheaters improved from 22% to 44%, but for reheaters declined from 75% to 71%. Having drains open during GT purge improved from 33% to 57%.

Use of a reliable condensate detection system improved from 0 to (only) 8%.

8. F-Class plant in Middle East produces more than 2000 MW

Ultrasonic condensate detection

The goal here is to detect and remove condensate from superheaters and reheaters to prevent damage to coils and other equipment in the steam path. This reduces damage from tube metal failures, stretching and bowing of tubes, and a host of related issues.

The industry has extensive experience using ultrasonic meters to measure flow. One application to detect condensate uses this same method, although calibrated differently to distinguish condensate from steam.

The example used in Sydney was derived from an EPRI R&D project, managed by Competitive Power Resources using Flexim ultrasonic flow metering equipment.

The system is being used by Nooter/Eriksen on two new HRSGs, incorporating properly set slope and pipe size on all systems, and ultrasonic liquid detection sensors to control the drain valves.

Once condensate is detected, drain piping and valves must be able to remove the condensate while preventing release of live steam. This is a severe service system with large pressure drops and flashing liquid.

The master/martyr valve system was discussed: the master valve is opened first and closed last. The purpose is to maintain reliable shutoff tightness of the master valve by using a sacrificial martyr valve, which is required to throttle.

An early implementer of this system has had 16 systems in service for two years using their original ball-type drain valves. While adequately draining the superheater, ball valves open and close repeatedly during startup and will not have acceptable durability. This plant is currently working to replace the ball valves with modulating valves using the EPRI control algorithm.

Full details on valves, pipe sizes, and headers were presented. Options for drain pots and valve types were also given. Operational challenges were reviewed and discussed.

Middle East case study

Thermal Chemistry's Addison presented cycle-chemistry challenges with a new-build combined-cycle project in the Middle East. The Persian Gulf location means very hot and humid summer conditions. The subject plant was commissioned in 2014 at 2000 MW with F-class gas turbines firing 100% gas or distillate. Bypass stacks were included for open-cycle operation.

HRSGs are triple-pressure with feedforward LP evaporators. Site has five gas turbines (two 2 × 1 and one 1 × 1 combined cycles). Seawater cooling is used (titanium-tubed condenser) with no condensate polishing, and pulse chlorination on cooling water. The plant (Fig 8) is designed for flexible operation (part of year baseload, then part load and partial plant operation).

P11 and T11 are used in critical FAC locations.

Commissioning water chemistry was as follows:

- Feedwater/LP evaporator—AVT(R), ammonia/amine, and carbohydrazide.
- IP/HP evaporator—phosphate treatment with vendor sodium phosphate blends.
- All chemical dosing—manual control. No automation.
- Feedwater pH target—8.8 to 9.2.
- Evaporator pH target—9.1 to 9.6.
- Chemical vendor prescribed program.

Addison carefully reviewed the steam and water sampling and analysis systems, based on non-OEM-approved system integration. Critical issues include:

- Sample-line sizes too large.
- Non-OEM flow cells.
- Sequencers not working correctly—loss of sample flows.
- CACE analyzer resin columns installed incorrectly (upwards flow) plus threaded connections (no quick connects).
- Tight spacing—limited maintenance access and no room for additional analyzers.
- Lack of air-conditioned space—impact on analyzer performance and maintenance.
- Non-compliant with IAPWS minimum analyzer levels for a plant of this type.


umicore
Catalysis
Smarter catalysts: two in one
Better emissions compliance
Clean air is our business. The GTC-802 (NOx/CO-VOC) "Dual Function" catalyst will help your plant meet stricter emission standards while improving performance and profitability. GTC-802 combines two catalysts in one, delivering both superior NOx reduction and outstanding CO and VOC oxidation. Lowest pressure drop, near zero SO2 oxidation and reduced ammonia slip add up to improved heat rate, increased power output and fewer cold-end maintenance issues. GTC-802 is positioned downstream of the ammonia injection grid in the same location as the current SCR catalyst. As an added benefit, the catalyst allows direct injection of liquid ammonia or urea in place of the traditional vaporized ammonia.
http://secc.umicore.com

The plant meets only 80% of the IAPWS minimum instrumentation levels. If the O/S analyzers are taken into account, this drops to 60%.

There is no automation for the dosing systems (manual once per day testing). The plant is constantly over/under dosing and chemists are not dedicated to the area.

The chemistry laboratory onsite is set up primarily for fuel and environmental water analysis and is physically separated from operations and engineering. Experience is low, and documentation levels are poor and, at least in part, technically incorrect.

Layup and storage procedures are poor. HRSGs are left wet without nitrogen capping, partially drained down, for weeks at a time. Steam turbines are left with no protection. DHA equipment at site has never been commissioned. Outside of key summer (high demand) months, the plant is in flexible operating mode. Multiple GTs/HRSGs are out of service, recallable on short notice.

Commissioning was poorly managed with major delays. Commissioning documentation and procedures were poor.

HRSG makeup rates are extremely high. The water treatment plant has operated in overload to ensure makeup demand is met (42% over design). Startups and flexible operation increase the water demand even more.

FAC is a problem, as shown in Fig 9. Even with P11 in the LP evaporator, FAC was detected (also in IP evaporator and HP economizers). FAC was attributed to the plant's initial AVT(R) program with reducing agent, low feedwater and LP evaporator pH, and low IP evaporator pH.

Condenser tube-leak risk is high (no leak detection analyzers) and condenser spill return is directly back to the site demin tank—a major risk of contaminating all units if one leaks.

Improvement activities include the following:

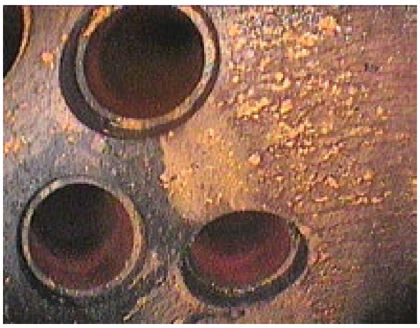
1. High makeup demand. Focus on identification and fixing/replacing leaking HRSG valves, and improve treatment plant maintenance practices.
2. Low feedwater/evaporator pH. Undertaking correct dosing; running pumps/chemicals at correct levels.
3. FAC in HRSGs. Halt reducing-agent dosing, increase feedwater pH to 9.8 with ammonia, increase HRSG evaporators (IP/HP) pH with tri-sodium phosphate (TSP); implement condensate polishing program.
4. Analyzers O/S. OEM training of technicians, increase priority on defects and repairs, correct setup issues, and begin additional analyzer project (sodium in condensate, etc).
5. Condenser. Future change to spill/return setup (to raw water tank), and increase in risk awareness
6. Chemistry management. Rewrite chemistry manual and procedures to align with IAPWS Technical Guidance Documents, phosphate dosing with TSP only, improve chemistry management, ongoing development of chemists.
7. Layup and storage. Develop procedures; push to commission DHA equipment.

Film-forming substances

Day Two ended with an update on film-forming substances—specifically GE application experience in HRSGs—by Justin West. Various updates have been covered recently by CCJ.

This presentation highlighted developments by summarizing significant differences between modern FFAs and older filming-amine technology:

- Higher volatility over wide steam-cycle pressure/temperature range versus ODA.
- Strongly absorbed and highly persistent surface film.



9. Active two-phase FAC in LP drum

- Lower tendency to form unwanted deposits and combinations with corrosion products versus ODA.
- Equally hydrophobic and difficult to formulate aqueous product solutions.

In the examples given, chemical cost reduction was achieved by utilizing a new pH target, neutralizing amine technology, and improved pH control. A vacuum-pump-drain pH reduction was achieved by using organic amine technology. The pH went from above 10.5 to 9.2-9.3 by replacing ammonia and eliminating the need to divert from the wastewater sump.

In the case described, lower corrosion/iron transport in both cycling and continuous operation was achieved.

The bottom line continues to be this: A great amount of research has been completed and progress made, but there remains a lot more to be done.

Materials issues workshop

The third day of the meeting featured a workshop on materials issues in HRSGs. Topics included a review of P91 damage mechanisms, premature failure of a P91 superheater tube, and creep-fatigue life predictions of P91.

Some presentations were specific to the region, based on Code AS/NZS3788. Others were more global.

Metallurgical perspectives on overheating (Thomas) compared ferritic steels (deformation and creep) with the more expensive inclusion of alloying elements, reviewing potential benefits. Strengthening was covered in detail, including oxidation and creep life.

Overheating discussions led to life assessments and a variety of proven inspection techniques including ultrasonic, EPRI algorithms, accuracy, and results. Cautions were given leading to a discussion of an "integrity operating window." The bottom line on asset integrity management:

1. Ensure safe operating limits are understood, and
2. Have plans in place to react to overheating.

This was followed by an in-depth discussion on oxide growth and exfoliation in HRSG superheaters and reheaters with Dooley at the front of the room. He included steam-turbine deposits related to HRSG component materials, and various "oxide morphologies."

Coming up

At AHUG 2017, nearly 30 presentations were included, complemented by pre-submitted subjects, a panel session on attemperation, and open-floor questions and discussions. The AHUG 2018 event will be similarly intense, November 13-15, at the Brisbane Conference and Exhibition Center. Review the agenda and register at www.ahug.co.nz.

The third annual *HRSG Forum with Bob Anderson* will be held in Florida's Hilton Orlando, July 22-24, 2019. In addition to two days of carefully selected on-point presentations and facilitated discussions, the 2019 *HRSG Forum* will include a full-day workshop on Makeup Water Treatment. As with the international HRSG conferences that Anderson helps organize, everyone interested in the design, operation, and maintenance of HRSGs and their support systems is urged to attend. For more detail, visit www.HRSGForum.com. CCJ

Sharing HRSG technology globally benefits users

Technical presentations and discussions at the recent (mid May) European HRSG Forum (EHF2018) in Bilbao, Spain, validated several agenda topics under consideration for the 2019 *HRSG Forum with Bob Anderson* in Orlando, July 22-14 (www.HRSGforum.com). The fifth annual EHF attracted 72 participants from 16 countries. Dr Barry Dooley of Structural Integrity Associates Inc, who chaired the meeting as he had done previously, considered the event "highly successful."

While design codes, operating paradigm, and economic drivers may vary geographically, the technologies important to HRSG success (materials, water chemistry, etc) are global. Hence, the value in sharing experiences worldwide cannot be overstated. The EHF, supported by the International Assn for the Properties of Water and Steam (IAPWS, www.iapws.org), is conducted in association with the *Australasian HRSG Forum* (AHUG) and the US-based *HRSG Forum with Bob Anderson* (www.hrsgforum.com).

The Bilbao meeting featured 28 presentations, a panel discussion on attemperation, and a workshop on HRSG materials aspects. The highly interactive forum incorporated new information and technologies related to HRSGs, case studies of plant issues and solutions, and open discussions among users (18 owner/operators were represented in Bilbao), equipment suppliers, and industry consultants.

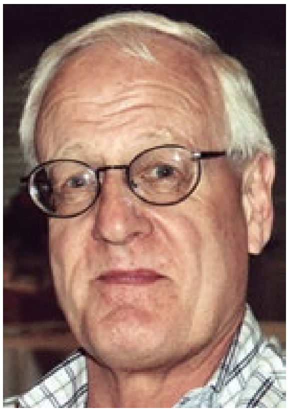
Dooley, and Bob Anderson of Florida-based Competitive Power Resources, both members of CCJ's Editorial Advisory Board, participated in EHF2018 and compiled the following meeting highlights:

- International updates were provided on HRSG cycle chemistry, instrumentation, and FAC—including a review of recent IAPWS Technical Guidance Documents (TGD) in these areas. One TGD receiving considerable attention was "Application of Film Forming Substances (FFS). . . ." You can download this and other TGDs at no cost from www.iapws.org.

Anderson

- Another high-interest area with no geographical boundaries: HRSG thermal transients associated with attemperators and superheater/reheater drain management.

- A presentation discussing the impact of gas-turbine hot-gas-path and controls modifications on HRSG performance stressed the need to evaluate these impacts before executing any mods. Of particular interest was the ability to use the Variable Load Path mod on Frame 9FA engines to eliminate long-standing problems with attemperator performance during startup. Anderson and at least some members of the *HRSG Forum* steering committee believe the VLP mod could benefit some US plants with 7FA machines and are weighing its inclusion in next year's program.



Dooley

- Two presentations focused on the value of using historical HRSG operating data to identify areas requiring attention to assure future reliability.

- How renewable generation in combination with large-scale energy storage may impact gas-fired generation. Of particular interest were the details of high-capacity battery evolution and future possibilities. This is another subject under consideration for the *HRSG Forum's* 2019 program.

- A highly informative technical panel on attemperators with discussion among Panel Chair Anderson, Emerson/Fisher Valve's Justin Goodwin, IMI-CCI's Juan-Luis Dias, and Uniper Technologies' Dan Blood. Dooley said the subject matter was on-point and discussion was driven by attendee interest areas and questions. Expect this and/or a panel on bypass systems at the 2019 *HRSG Forum*.

- The group's first specialist workshop on HRSG materials focused on the following:

1. The history of development of Grades 23 and 91 and their evolution—including the pros and cons of how ASME has regulated these materials and what can be expected of their performance going forward.
2. Oxide growth and exfoliation in superheaters and reheaters. This information was particularly helpful for determining the degree of overheating in legacy HRSGs and for predicting oxide formation and exfoliation in HRSGs being designed for higher steam temperatures.

Informal discussions among attendees indicated some of the leading thinkers on exfoliation of steam-side oxide believe the ASME Code permits the use of T91 and P91 above what might be the safe long-term oxidation temperature. The bottom line here is that owner/operators should expect an increase in solid particle erosion and superheater and reheater tube failures

in legacy units. Attend the 2019 *HRSG Forum* to learn more on this critical subject.
3. Metallurgical examination should be the first stage in a root cause analysis of HRSG tube failures.

- The importance of cycle chemistry in combined-cycle plants was covered several presentations, including these:
1. The latest guidance from IAPWS.
2. The use of so-called Repeat Cycle Chemistry Situations for identifying future damage/failure.
3. Examples of good plant-chemistry control practices.
4. The importance of managing, vetting, and validating cycle-chemistry alarms to assure that the most important alarms are not missed. Anderson considers this an important topic with practical information not generally thought about by O&M personnel. It's penciled in on the preliminary program for the 2019 *HRSG Forum*.
5. The application of film forming substances for combined-cycle plants and how to identify hydrophobicity.

- Repowering with gas-turbines was discussed by two presenters. One offered experience with dry cooling systems.

- Case studies reviewed performance of dry-ice blasting and pressure-wave technology in removing external tube deposits.

- Latest experience with gas tightness and movement of penetration seals.

- Anderson presented case studies on how to identify and remedy the root cause of premature erosion in HP turbine-bypass pressure control valves. Severe erosion is caused by opening the bypass valve prematurely during startup. Such erosion also may be caused by wet steam ingested by the valve when depressurizing the HP system via the bypasses during pressurized layup. Discussed too were damaging thermal transients in high-energy steam piping when operating the bypasses during pressurized layup.

- Extensive discussion and information on the optimal approach for HP-drum-to-downcomer cracking.

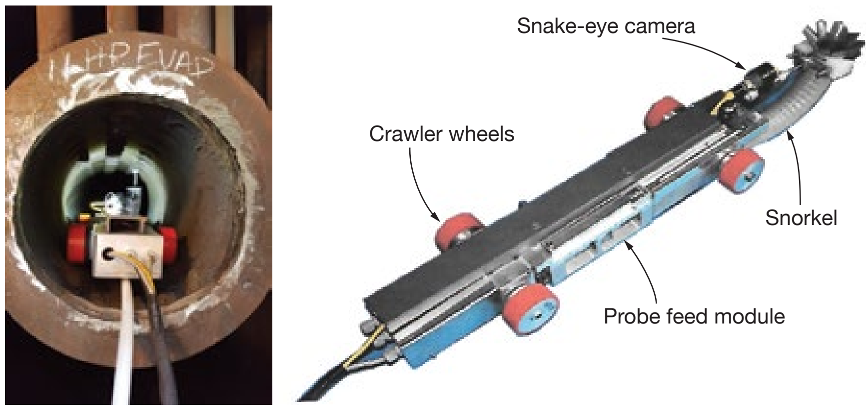
- New technologies, including the latest HRSG designs for the Chinese market and the use of UV for treating boiler makeup. CCJ

NDT innovations showcased at HRSG Forum

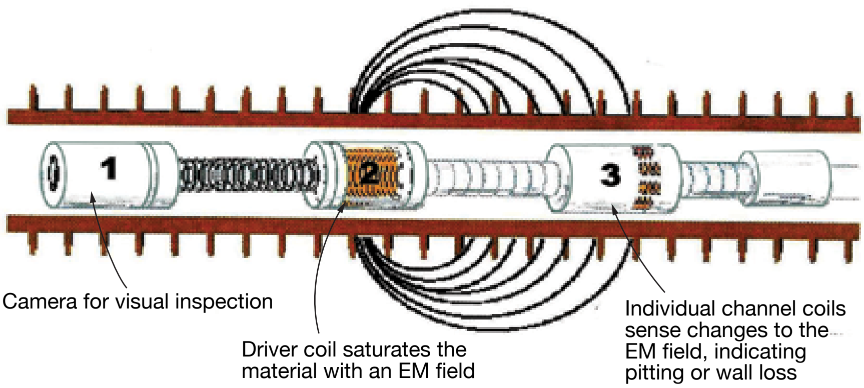
Innovations, looks forward, and disclosure of new ideas were hallmarks of the second annual *HRSG Forum with Bob Anderson,* held earlier this year in Houston (CCJ 1Q/2018, p 63). TesTex Inc, Pittsburgh, Pa, was there with a collection of ideas including its proprietary remote field electromagnetic technique (RFET) equipment (Fig 1).

For internal tube inspection, TesTex has developed and operates this proven method for accessing the finned tubes through the headers. Forum participants could not only see the system and watch it operate; they could touch it.

With the internal access tool inserted, a flexible RFET multichannel probe head is inserted into each tube (Fig 2). The probe includes a camera, a driver coil that saturates the material with an electromagnetic field, and eight individual pick-up coils that sense changes to the field, indicating pitting or wall loss. Results are shown both visually and graphically, and recorded.



1. Internal access tool positions the probe head in Fig 2 in the boiler tube



2. Probe head travels up through boiler tubes to identify any pitting or wall loss

The probe is inserted into the vertical tubes and pushed upward to the top header. It captures readings and video images as it is inserted into and retracted from each tube. The flexible multichannel system travels at 2 to 3 in./sec, collecting 480 samples per channel per second, at a frequency of 15 Hz.

"Assuming the conductivity and magnetic permeability of the tube are constant, any variations in wall thickness at the two coils cause a change in the phase and amplitude of the received signal," explained Shawn Gowatski, manager of the company's solutions providers group. "The multiple pickup coils allow detection of small localized anomalies."

To enable the probe to complete the 90-deg horizontal-to-vertical bend, the current header ID minimum is 5.25 in. There is no maximum ID limit. Current header-to-header tube length limit is 70 ft.

TesTex has been working with RFET since 1987.

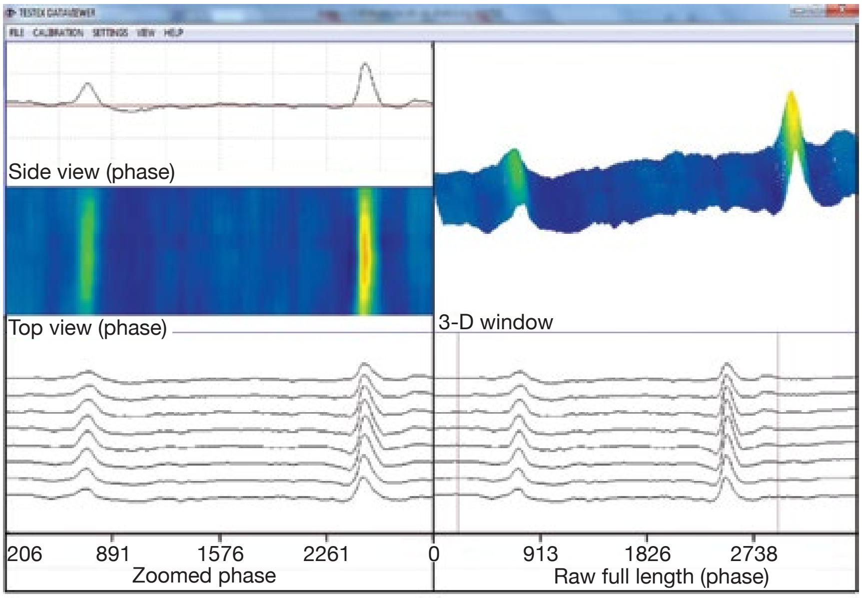
Also on display was the proprietary low-frequency electromagnetic technique (LFET) system. With this, TesTex personnel can examine HRSG finned tubes from the exterior to detect and quantify internal pitting, wall thinning attributed to flow-accelerated corrosion, and other damage issues. The signal penetrates the tube through the fins to identify any tube wall thinning or irregularity.

"This hand-operated system is used for the leading- and trailing-edge HRSG tubes. A two-person crew can examine approximately 1,000 linear feet of tubes in a shift," explained Gowatski. The technology is also used on tube walls and sections of large fossil-fired utility boilers.

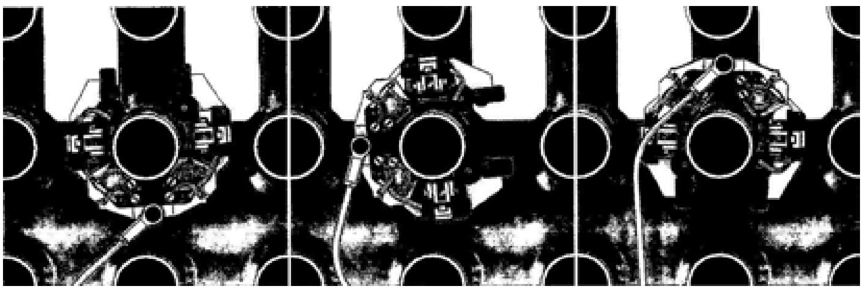
The hands-on demonstration at the *HRSG Forum* featured a 2-in.-OD carbon steel tube, 0.150-in. wall thickness, with 0.75 in. fins. Two 0.5-in.-diam pits had been machined on the inside tube surface (30% and 60% deep). Three output views were presented: side-view phase plot, top-view simulated color B-scan, and 3-D window (Fig 3).

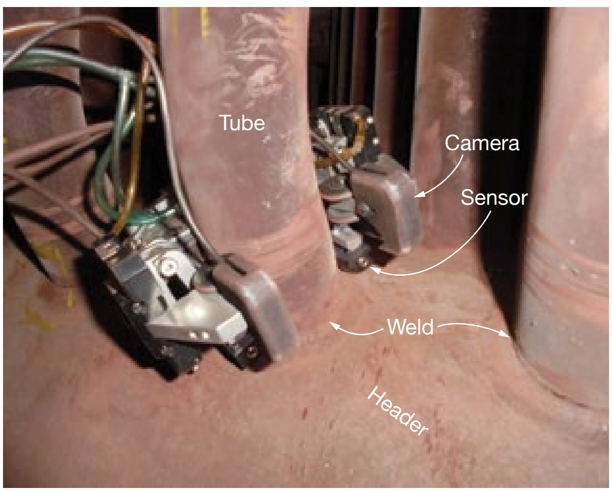
LFET inspections are designed to locate and identify pitting, general wall loss, caustic and phosphate gouging, corrosion cells, hydrogen damage, microbiologically induced corrosion attack, flow-accelerated corrosion, cracking, erosion, and manufacturing defects.

Also of interest at the *HRSG Forum* was the balanced field electromagnetic technique (BFET) inspection for tube-to-header welds. Customized *claws* (Fig 4) hold sensors and cameras as the assembly moves circum-



3. Waveform display confirms 30%- and 60%-deep pits from a calibration standard





4. Customized claws hold sensors and cameras as the assembly moves circumferentially around the weld to detect cracking, lack of fusion, porosity, etc (above)

5. Arm claw traverses the full 360 deg of the tube-to-header weld (right)

ferentially around the weld. Results detect and confirm any cracking, lack of fusion, porosity, or other defect.

This is used for header diameters of four in. and larger. The claws are able to examine the tube-to-header welds for tube diameters of 1.5 to 2.5 in.

These claws traverse 360 deg of the tube-to-header weld (two coils spaced 180 deg apart) and include two cameras for visual inspection and recording (Fig 5).

The arm claw can examine the first two rows from the access point. A crew is able to inspect approximately 200 welds per shift. Electromagnetic sensors assess the tube-to-header welds in an HRSG without any surface preparation. "Our clients like the fact the claw is able to examine 360 deg around the tube to header weld and they do not have to perform any sand blasting," said Gowatski.

TesTex provides NDT products and services for both ferrous and non-ferrous components. Clients include fossil and nuclear power generation, chemicals, and refining, among others. The company also performs corrosion-under-insulation inspections. CCJ

Effingham

Foam inserts prevent air flow through offline gas turbines

Challenge. When gas turbines (GT) are shut down for extended periods in Georgia, the high humidity and natural draft through the HRSG creates problematic condensation on tube fins. Rusting occurs, especially when water is still present in the tubes. Ultimately, excessive tube fin rust creates a resistance to exhaust flow through the HRSG and GT back pressure increases, reducing turbine output.

Solution. Staff investigated adding stack dampers, duct balloons, and compressor inlet foam inserts to minimize air flow through the HRSG. The most effective option would have been stack dampers, but their upfront and ongoing maintenance costs were significantly higher than those for the alternatives. The duct balloon was an interesting and feasible option; however, the time and manpower required for balloon deployment and removal militated against its selection at Effingham.

The most economical and effective solution for Effingham: The high-density, custom-fitted foam inserts, shown in Fig 1, which prevent air flow through the compressor and HRSG. Cost of the inserts for both turbines was under $9000; no maintenance is associated with this application.

The inserts were labelled for each unit for inventory purposes. A LOTO is placed on the unit when the inserts are installed to ensure accountability. Once the inserts are removed and counted, a shift supervisor performs a close-out inspection of the GT inlet.

Results. GT wheel-space temperatures remain above 150F—90% longer using the inserts versus not installing them for a weekend shutdown. Also, HRSG internal temperatures remain above 100F 40% longer with the inserts.

This trapped heat helps minimize condensation on HRSG piping and components. Once the HRSG temperatures are low enough and a dispatch is not expected the HRSGs are drained. This practice should help reduce corrosion of the HRSG tubes and minimize performance issues.

Installing inserts on Friday following a shutdown saves fuel and increases revenue by allowing faster ramping when the units are restarted on Monday. This is based on less time needed to warm components and quicker steam formation because HRSG drums and piping retain heat longer.

Project participants:
Mike Sears, Marty McDaniel, and Chris Hofer

1. Custom-fitted inserts of high-density foam prevent air flow through the compressor and HRSGs when the gas turbine is on a weekend shutdown or longer

Effingham County Power

Owned by The Carlyle Group

Operated by Cogentrix

525-MW, gas-fired, 2 × 1 combined cycle located in Rincon, Ga

Plant manager: Nick Bohl

Streamlining I&C learning

Challenge. Effingham's web-based I&C training program is supported both by a training bench with various plant instruments for hands-on experience and a supervising subject-matter expert. The plant SME is responsible for training technicians on the software and the test and monitoring equipment they will use on a daily basis.

Unfortunately, the web-based training program included outdated monitoring and test equipment which was not plant-specific, delaying the qualification process because of a lack of reference material and available training lessons.

Without reading the actual O&M manuals there was nothing in place to prepare technicians for hands-on training or instrumentation calibrations. And without actual test equipment and monitoring-device training there was limited reference material. Once the technicians were qualified they had to rely on their notes and read the O&M manuals to complete their required proficiency training.

Solution. The I&C SME developed a list of what technicians need to know to become proficient in calibrating Effingham's instrumentation. This information in hand, the web-based training courses were evaluated for their applicability to the plant's mission. The most pertinent courses were grouped into eight modules.

Fourteen PowerPoint presentations were created to train individuals on plant-specific instrumentation, calibration equipment, calibration software, and proper calibration techniques. These presentations were reviewed by other qualified I&C techs for content and effectiveness and then added to the eight web-based training modules to form a structured plant-specific I&C fundamentals training program.

Exams were created to help reinforce the knowledge learned. Job performance measures (JPM) also were developed to evaluate the technician's ability to perform calibra-

tions on various monitoring devices. Since the SME uses these JPMs to certify the technician's abilities, each individual is evaluated using the same standard.

Progress of the technicians can be tracked via the web-based program. They are also issued a qualification card so they understand the goals for each module.

Results:

- The streamlined program covers more areas of I&C, producing better-trained technicians.
- The self-guided reference materials allow the technician to build confidence and education to ask the right questions. This helps both the SME and the qualifying technician.
- The training bench allows technicians to practice calibration techniques online or offline rather than in the plant which minimizes the possibility of lost generation.

Finally, as new test equipment is purchased, training presentations and exams are developed and implemented. The training program is continually evaluated for its content and ability to train plant personnel. Since Effingham owns the training program it can be revised as needed at minimal cost.

Project participant:
Cheryl Hamilton

Outage management improves with delegation of job leads

Challenge. In the past, contractors interacted only with the maintenance supervisor and/or shift supervisor when onsite for outages. This created bottlenecks because each contractor needed to meet with the same one or two individuals to receive plant support—such as having LOTOs in place, preparing hot-work permits, inspecting work areas, retrieving parts and materials for the job, etc.

Significant man-hours were wasted while each contractor waited its turn to speak with the one or two management personnel conducting the outage. Since Effingham's outages are necessarily brief, staff discussed ways to streamline the process and maximize contractor productivity.

Solution. Once the maintenance supervisor has awarded the job to the contractor, a technician is assigned as the contractor's job lead. The technician typically is selected based on his or her subject-matter expertise. This is important for the technician to adequately support the contractor and to understand the basic job scope.

The expectation is for the two parties to communicate by phone or email prior to the outage to discuss the job and how it will be completed. Once the job lead understands the scope of the job, the plant can prepare for the contractor's arrival.

Onsite, the job lead and contractors meet and the job lead ensures the safety orientation has been completed. The job lead is responsible for ensuring the LOTO is walked down with the contractor and if there are any discrepancies, they are resolved prior to the workers signing onto the LOTO. If any confined-space or hot-work permits are required, the job lead makes sure they are in place each day the contractor is onsite.

The contractor and job lead meet daily onsite to discuss the day's plan and job status. If the contractor needs any parts or materials, the job lead is contacted and those items are delivered to the job site. The contractor doesn't lose man-hours searching for help, it just contacts the job lead to get the needed support to complete the job on schedule.

Results. This practice was beneficial while conducting a major outage in 2016, in which Effingham had over 350 contractors onsite. When the contractors arrived onsite, they exchanged phone numbers with their job leads (if they had not done so already), and when assistance was needed, it was necessary to make only one call and never leave the worksite.

Project participants:
Nick Bohl, Howard Beebe, and Bob Kulbacki

Proper greasing of equipment

Challenge. To reduce motor repair costs and avoid possible lost generation, plant had to improve its method for greasing large frame motors. Effingham's local motor repair shop reported that several motors sent for repair had little to no grease in their bearings.

Typically, all bearings were receiving the same amount of lubricant; however, lubrication should be based on bearing size and the manufacturer's recommendations. A system of greasing bearings that took into account these differences was necessary.

Solution. The proper amount of grease for any given motor or bearing was found by using the motor and bearing manufacturers' data sheets, in addition to information available on the motor data plate. Nameplate data on most motors include bearing identification numbers which can be cross-referenced to reveal bearing size, configuration, and lubrication requirements.

Personnel also measured the output of the plant's grease guns by weighing the grams per pump to determine how many pumps per gun it would take to achieve the recommended amount of grease per application. Once they knew how much grease the gun applied per pump, staff calculated how many pumps it would take to provide the required amount of grease in any application. Labels then were affixed to the grease guns to provide the information required by technicians performing the lubrication PMs.

Technicians stamped stainless steel tags with the lubrication infor-

2. Tags made by plant personnel give the equipment number and type and amount of grease required

mation and attached the tags to the motors with stainless steel chains. These tags give the equipment number and type and amount of grease required (Fig 2).

Results. When performing operator rounds, a technician discovered that a cooling-tower fan motor had some bearing noise. He added grease based on the old method of one to two pumps from a grease gun. Several technicians then researched the amount of grease recommended by the bearing manufacturer. As a result of their investigation, more grease was applied and the problem was resolved—reinforcing the belief this was the method to implement.

After obtaining data for all bearings at the plant, metal tags were made and attached to components. Technicians inspected the tags to assure readability and accuracy.

Since implementation, technicians have performed several greasing PMs. Having the type and amount of grease required posted on the equipment provides a back up to ensure the correct grease is added. Also, having the metal tags installed on the equipment, the operators have a quick reference as to how much grease to apply. Having all this information on the equipment saves time and ensures the proper type and amount of grease is used.

Project participant:
Kris Brackbill

Standardizing data on fire extinguishers benefits recordkeeping, compliance

Challenge. Date of manufacture is required on fire extinguishers, but there is no standard format or location for the date among manufacturers. Some are labeled on bottom, some have the information mixed with other data in code on the bottle, and some have the date on the printed label, which fades and peels in outdoor applications. Identification of manufacture date is required to establish requirements for six-year inspections and periodic hydro testing mandated in NFPA regulations.

Solution. Personnel contacted various manufacturers to identify the location and format of the manufacture date on their extinguishers. Embossed metal tags were added to each fire extinguisher on the hose or neck, identifying the later of the date of manufacture, date of last six-year inspection, or date of last hydro test. Date information also was added to the fire-extinguisher inspection checklist for annual inspections, to aid in identifying periodic maintenance requirements (Fig 3).

Results. Benefits are ease of inspection and recordkeeping, simplified maintenance procedure, and assured compliance with applicable NFPA requirements. Labor cost also is reduced because it's now easy to find this information when performing monthly and annual fire-extinguisher inspections. Plus, budgeting is more accurate knowing when the fire extinguishers will be serviced.

Project participants:
Don Johnson, Richard Blankenship, and Byron Sewell

3. Clear labeling of date of manufacture on fire extinguishers is important

Oil labeling

Challenge. Plant was having difficulty maintaining labels on secondary oil containers. The markings were fading or the labels would come loose and fall off because of contact with the oil. This is important to avoid contaminating oil used in other equipment. Cross-contamination can lead to premature wear or even catastrophic failure of equipment.

Because several different oils are used in the plant, a procedure was needed to ensure the correct oil was added to each piece of equipment. In the past the auxiliary operator would look up which oil was required when finding a low oil level during rounds. Plant needed a way to ensure the correct oil was added; also to expedite the process to ensure bearings were lubricated properly.

Solution. Each type of oil was given a specific color code. Based on the lubrication list, each component was painted the designated color at the oil addition port. Secondary containers also were painted to identify the corresponding oil. Since these containers were used for only one type of oil, a laminated tag was attached to the handles so the oil could be stored and used as needed (Fig 4).

The technicians do not have to clean containers prior to use because the labels are securely attached, and the contents properly identified, minimizing waste. Cross-contamination of oils is avoided by verifying that oil is added to the proper secondary containers by reviewing the labels.

Technicians use the preventive-maintenance work order and lubrication chart to verify the proper oil needed for the equipment. Having the ability to match the color of the container to the equipment is a good back-up check.

Results. The laminated labels can withstand getting oil on them and still be legible. They will not fall off because of contact with oil. The color code gives a visual identifier to the technicians in the plant when filling plant equipment.

Waste also is reduced because the secondary containers are labeled adequately and oil can be stored in them until needed. In the past, the plant was required to empty all contents and wipe containers out before storing them. This contributed to additional costs for disposing of unused oil and for the absorbents needed to properly dispose of waste oil.

Project participants:
Don Fludd, Mark Gunter, and Robert Lancaster

4. Color coding of both oil storage containers and fill ports on equipment (yellow, right) helps to identify a specific lubricant and avoid cross contamination through misapplication

Monthly P&L report helps keep budget current, accurate

Challenge. A method was needed to ensure the plant stayed within budget for controllable costs. By reviewing each transaction for the month, staff can ensure accounts are charged correctly, reclassified if not. It also is necessary to justify why monthly and yearly variances are favorable or unfavorable. This information is recorded in the plant's monthly operating report so management and investors can track financial activity. A snapshot of upcoming expenses also is provided monthly so the funds are made available.

Solution. Each month the plant receives a budget variance report and posted transaction report from accounting. After entering the data from the budget variance reports into an Excel spreadsheet, the data are reviewed by the operations, safety, and administrative departments. Each department puts comments on the spreadsheet to explain significant variances between actual and budget—favorable or unfavorable.

Next step is to review the posted transaction report to verify that all transactions are classified to the correct account. Errors are reported to accounting for reclassification. Once all transactions are reviewed, they are compared to the budget to verify timing of the charge and how it compares to the budgeted amount.

This practice was developed to ensure the plant stays within the budget for controllable costs. It also is used for input to the monthly operating report and as a forecasting tool for budgeting and to provide accounting a snapshot of upcoming expenses.

Results. This is a success in several areas. Plant staff reviews their accounts monthly to determine if they are favorable or unfavorable compared to monthly and yearly budgeted amounts. The monthly review also ensures that all transactions are charged to the correct account, and if a discrepancy is found, it is corrected.

The monthly report also is helpful in preparing next year's budget and for determining if budgeted amounts for each account should be increased or decreased. Comments recorded on the review spreadsheet should be consistent with any changes contemplated.

Project participants:
Bob Kulbacki, Jobie Sewell, and Lori Middleton

The importance of cleanliness

A clean ball is a happy ball

By **Brian Hulse,** BDHulse Consulting Services LLC

At some point in time, everyone who is anyone, from Arnold Palmer (photo) to Mahatma Gandhi, has made a quotable statement regarding cleanliness and/or hygiene. It's never a controversial topic.

Back in the 1840s, a Hungarian physician named Ignaz Semmelweis (1818-1865) demonstrated scientifically that hand-washing could drastically reduce the number of women dying after childbirth while he was director of the maternity clinic at Vienna (Austria) General Hospital.

There was a scientific argument behind what your mom said: "Wash your hands!" It's been a household staple ever since.

Today, working on LM-engine-equipped powerplants, we come into contact with all kinds of different chemicals and materials, and occasionally have no alternative but to get a little dirty. We may take the time for a quick wash-up—especially if we can feel some kind of reaction taking place on our skin—but sometimes we just press on and worry about it later.

A "well-run" powerplant will have MSDSs (Material Safety Data Sheets) available to personnel on all of the appropriate materials, but the truth is that they are rarely read before we work with a material—likely never read at all—unless something "bad" happens. Most often, they sit neatly captured in a clearly labeled binder that is in an easily accessible location. Sometimes, the binder is in a dedicated holder, attached to a wall with bright signage indicating exactly what it is. And, nine times out of 10, there will be a heavy layer of dust on the top, unless it's been out for updating.

And yet, with mother's words (and our safety manager's) ringing in our ears and all of the needed information at hand, we press on. We succumb to the pressure of time. We just don't have time to go back to the break room (or wherever) and clean up. The job has to be finished, readings taken, boiler blown down, RO back-flushed, etc. There's always something more important than washing your hands.

When I was in the US Navy, working for the first time with LM (and Allison) gas turbines on a Spruance-class destroyer, I got one of those "life lessons" that one does not forget quickly. I had been aboard ship for about three and a half years when I came down a ladder in the engine room and there at the bottom was one of my shipmates. . .on the deck plates. . .experiencing some kind of seizure.

I called for help and, while it was en route, I tried to keep him from hurting himself as he jerked spasmodically. I didn't know what was happening or what else to do. He had never (to my knowledge) had this happen before. Finally, the corpsmen showed up and, since we were in our home port, he was taken to the base hospital.

It turned out that he had "synthetic oil poisoning." There are several chemicals contained in the oil that can cause harm. Some of them are trans-dermal (they can go through your skin) and the body doesn't metabolize them, so, they build up in your system over time. My shipmate's hygiene practices were particularly poor when it came to working with the oil (he didn't wash after contact, he didn't immediately change clothes when they became soaked, etc). Because of that, and his system's specific sensitivity to the chemicals, he had a nervous system reaction that resulted in the seizure. Since the build-up in his system couldn't be removed, he lost his MOS (Military Occupational Specialty) code and could no longer be in the machinery spaces of the ship.

Although the MSDS would lead you to believe that synthetic oil (as well as many other chemical compounds) is relatively safe, there are hygiene warnings/recommendations sprinkled throughout the text. It's also important to know that everyone is different. Some folks can eat jalapeno peppers and some can't. Some can tolerate more of a certain chemical and some can't tolerate hardly any of it at all.

As plant managers and supervisors, it's critical for us to always have our teams' best interests at heart. We have to *make* time for personnel to take care of themselves—wash up, change clothes, and whatever else is needed to keep them healthy. It's always best to err on the side of conservativism. It won't hurt to be overly cautious, but it may hurt to be in a hurry.

We all have safety meetings, and we all are always on the hunt for new—and applicable— topics to discuss. Reading an MSDS or two at each safety meeting is not a bad thing to incorporate. You won't get through the whole binder anytime soon, but you may spark enough interest to get folks looking at it proactively a little more often.

Take a tour through your bathrooms, break rooms, whatever facilities you have for personal hygiene. Take stock of what's available for everyone to use. Make sure it's up to your standards—what *you* would want to use if *you* had to clean up after a shift or a spill or working on the gas turbine. If you don't see something you'd like, chances are it's not going to be that expensive or difficult to correct the deficiency. Do it, and let everyone know you've done it. Not only may they use it, but they will appreciate your efforts in looking out for their health and safety.

Be aware and observant. If you see one of your folks coming in from a job or in the process of doing one and they have signs of some exposure that concerns you, *say* something. Let them know you're concerned and that you'd like them to get cleaned up as soon as practical. Yes, it's inconvenient, and yes, it might hold things up a bit, but again it sends the message that you're serious about their safety.

Building the *better* mouse trap

It's an age-old quest—building the *better* mouse trap. The US Patent Office has issued over 4400 patents for mouse traps although, paradoxically, only about 20 of them have ever seen any commercial success.

This would lead one to think that *better* is a term that needs more specific definition. Smaller? Easier to operate? More mice out of service per minute of trap service? Cheaper? Limited contact with the eradicated mouse? What is *better*?

When it comes to the air that LM-series gas turbines ingest, *better* focuses on three critical areas:

- Cleanliness.
- Temperature (45F to 65F usually is optimal).
- Direction (gas turbines don't like directional disturbances of the air at their inlets).

When it comes to plant owners, they're usually looking to keep expenditures down, but they budget for maintenance and are willing to look at reasonable improvements to their existing equipment. With that in mind, let's agree that the third area, "direction" is off the table. Design of the inlet-duct structure is what it is. The engine has run with it to date and is none the worse off for it. It could likely be redesigned and improved, but the effort and costs would be unacceptably high.

Cleanliness

So what about cleanliness? How can cleanliness be improved without busting the maintenance budget or incurring significant capital costs?

Gaskets. Man-doors, hatches, structural flanges all have gaskets that deteriorate over time. Once the gasket fails, untreated air can enter the duct. Filtration and/or temperature control may be adversely affected. Inspect gaskets regularly and fix them promptly when discrepancies are found.

Filters. There are times when the critical drivers of operational excellence (cost, vendor alliances, logistics, quality, product performance, product availability, etc) get out of whack. We may have sacrificed too much product performance for some other driver. If the product isn't performing, it doesn't matter how easy it is to get or how cheap it is. It's not doing the job, and that is unacceptable. Make sure your product priorities are right.

Theory of operation. Without getting into redesigns or rebuilding, take stock of your current theory of operation versus your actual operating environment. Things change. Certain site elements may have not been taken into consideration that have now become apparent. Your EPC contractor may have bought the generic duct offering with no site-specific options to save money, or out of ignorance.

Example: You may benefit from adding a pre-filter element to your high-efficiency filters. This may not only improve cleanliness, but may extend the life of your high-efficiency filter elements. If you're in a marine environment, you may benefit from the addition of demister pads at the front of the duct.

Conversely, you may benefit from the *removal* of a feature. In one case, the O&M team I was on dropped the overall differential pressure of the duct 0.5 in. H_2O by removing a set of inertial separator panels that we found to be ineffective in our environment.

Preservation. Maintaining the integrity of structural surfaces—especially downstream of the high-efficiency filter elements—is critical. Rust and failing coatings are your (and your engine's) enemy. Doing spot repairs is perfectly acceptable, but you have to ensure you're doing it right.

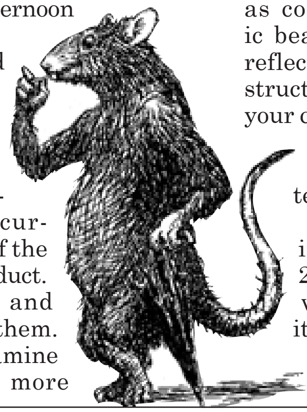
Engines are sensitive to a lot of materials. For instance, they don't like zinc, a common element in many primers used to protect steel surfaces from corrosion. Unlike regular paints or epoxies which resist corrosion by forming an impermeable barrier between the metal and atmospheric moisture, zinc-rich primers provide corrosion protection by electrical means: The zinc and the steel form a tiny electrical cathodic cell that protects the steel at the expense of the zinc. Of course, the zinc primer also provides a little "barrier" protection as well.

However, these same properties react poorly with the engine's gas-path surfaces, so zinc-rich primers should be avoided. The best advice is to contact the duct manufacturer and get a primer/paint spec from them.

Instrumentation. Keeping instruments calibrated seems like a no-brainer, but in this case it is a special challenge. Pressure and differential-pressure instruments typically measure very small quantities. The structure has a habit of vibrating because of air buffeting around inside. Instruments are mounted to the structure. Vibration can wreak havoc on them, sometimes actually shaking apart the instruments. Check them regularly.

Temperature instruments may be affected by what side of the duct structure they're located on (catching morning or late afternoon sun).

Don't be afraid to suggest additional or more accurate instruments to refine your understanding of what's occurring in each step of the process inside the duct. Build credibility and a database with them. Being able to examine the process at a more granular level may help justify work orders or even capital expenditures.



Temperature

Controlling inlet air temperature has a direct effect on the horsepower output of your engine. Keeping the air going into the machine in that "Goldilocks" range of 45F to 65F will help the engine perform at its best. If we have a mechanical means to do this installed (chiller, evap cooler, fogging, etc) in the duct, all the better, but there are a couple of tricks we can use to our advantage when we don't have the mechanical means at our disposal.

Coatings. Several high-tech coatings are commercially available (such as coated polymer stacks, ceramic beaded polymers, LO-MIT high-reflective coatings, etc) that reduce structural heat absorption. Much like your car sitting in the direct sunlight, duct structures often are quite a bit hotter than the ambient air temperature.

Theoretically, a metal surface in still, dry 77F air can reach 248F. Because of the variables in wind, humidity, sun angle, etc, it usually maxes out somewhere between 95F and 122F. Still, that's a lot of heat available in

the structure to bring the temperature of the air inside up. The next time you're getting ready to paint the exterior of the duct, investigate the use of one of these coatings on the sides and top of the duct.

Lagging. An old friend from the steam world, the concept of lagging—or insulation—of the duct has proven successful. However, depending on the site environment, the cost of ongoing maintenance may be prohibitive. Coatings may be a better solution in all but the driest of climates. If your duct does have a mechanical means of temperature control installed, enclosed, or shielded insulation should be considered on the external structural surfaces between the introduction point (chiller coils, evap-cooler panels, etc) and the front of the gas turbine. It's a low-cost way of ensuring you get all of the "goodness" out of the system.

Gaskets, preservation, instrumentation. Everything that was said above in these three areas can be equally applied to temperature control. Thus, their importance is not just doubled, but is raised by a magnitude. Keeping up in these three areas is nothing but pure goodness as far as your gas turbine is concerned.

Thus, by taking advantage of the maintenance budget you've been allocated, leveraging some new technologies, and applying modest amounts of capital judiciously, you can take the mediocre mouse trap you already have in your back yard and turn it into a lean, mean mouse killin' machine. In other words, a much "better" mouse trap. CCJ

About the author

Brian Hulse has spent his 40+ post-college years dealing with gas turbines from many perspectives. These include the US Navy, EPC, O&M (owner and third party), asset management, component repair/reverse engineering/manufacture, mobile powerplant packaging, and depot MRO management.

Today, the former Western Turbine Users Inc board member is an independent consultant, sharing his expertise on safety, O&M, quality control, financial accountability, and team-building with leading owner/operators. Hulse's deep technical experience underpins his work in the development of depot-level work scopes, conduct of root-cause failure analyses, guidance on plant audits and best practices, and as an expert witness.

River Road

River Road Generating Plant

Owned by Clark Public Utilities

Operated by General Electric

250-MW, gas-fired, 1 × 1 combined cycle located in Vancouver, Wash

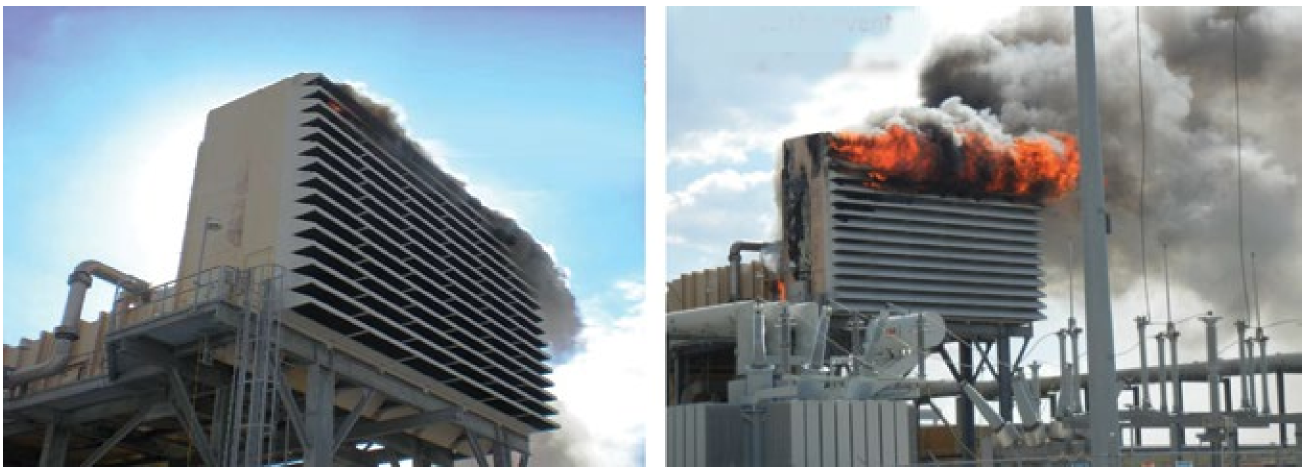
Plant manager: Todd Gatewood

Retrofit air-inlet filter house for emergency egress

Challenge. River Road Generating Plant (RRGP) was built in 1996-1997. The legacy four-level air-inlet filter house was installed with no emergency egress. During outages, personnel occupy the filter-house space during filter removal and replacement. Fleet experience has demonstrated that filter media and the dust collected by the filters can be highly combustible (Fig 1).

Had a fire started, the only escape path was via internal ladders from one platform level to another, then through a 2 × 3-ft manway exit on the lowest level. This represented a significant safety issue for anyone involved in the filter replacement process, the control room personnel directly adjacent to the filter house, and the personnel in the office space below.

The challenge was to determine the best method of egress, taking into consideration the limitations presented by the existing structure—including office space directly below the filter house. The entire RRGP team was involved in brainstorming sessions. Some ideas were rejected outright because of code or practicality considerations—including emergency zip lines and doorways on each platform with access to a "fire pole."



1. Once a filter-house fire starts it's virtually impossible to extinguish without extensive damage. The materials it contains—including air filters, and in most cases, evaporative cooling media—are highly combustible. Photo at the left shows a smoldering fire and blistering paint. Only seven minutes later, the fire was raging (right). Within 10 minutes of first noticing the fire, plant personnel reported the entire filter house was ablaze

The decision was made to proceed with a project that included cutting doorways at each level, plus an external platform and ladder arrangement in combination with an intumescent coating on the interior wall and doors of the filter house (sidebar). The challenge was designing and building a structure to suit the plant's safety needs while designing around existing structures below the filter house (Fig 2).

2. The external platform and ladder arrangement for rapid evacuation of the filter house was assembled on the ground in sections (left) and lifted into place (right)

Solution. Following an extensive fire safety code and structural engineer-

How intumescent coatings work

Intumescent coatings, often referred to as intumescent paint, are a passive method of fire resistance. They consist of a series of chemicals suspended in a binder. When the binder is exposed to heat it begins to soften, which allows the suspended chemicals to react and release a vapor that creates a foam. Carbonization occurs and the foam solidifies into a black insulating material that helps keep doors and the escape structure, such as that shown in Fig 3, relatively cool.

ing analysis, a custom emergency egress was designed, pre-fabricated, assembled, and installed (Fig 3). This reduced the personnel concern regarding rapid egress. The retrofit external platform and ladder assembly eliminated the safety hazard of the internal "trap door and ladder" access system supplied with the original filter house.

Results. A process failure-modes effects analysis (FMEA) was completed. Prior to the retrofit, the total risk priority number (RPN) was 784. Following completion of the retrofit, the RPN was reduced to 150—a reduction in RPN of 81%.

Project participants:
Todd Gatewood, plant manager
Ken Roach, maintenance manager
Steve Ellsworth, shift supervisor
Terry Toland, energy resources manager

3. Emergency escape tower has landings on each floor of the filter house, making it easily accessible through the doorways installed

Hermiston

Self-perform combustion inspections

Challenge. The days of having long-term service agreements (LTSAs) that coexist with power purchase agreements (PPAs) are vanishing. Many of these contracts in older facilities have expired or are approaching expiration. Private-equity firms with stakes in these plants are looking at maximizing their returns on the assets.

Strategic independent power producers (IPPs), such as Hermiston Generating Plant (HGP), would like to strike a balance between short-term return and long-term sustainability, while keeping critical infrastructure in a healthy condition. Given parent company support, the greatest impact on returns managed at the plant level is major maintenance. Developing a major maintenance strategy that positively impacted fixed costs was the challenge.

Solution. Shortly after HGP's LTSA expired with the OEM in 2016, the plant experienced a combustion issue in one of its two gas turbines. A borescope inspection revealed damaged diffusers on several fuel nozzles. Plant management contracted a third-party technical advisor (TA) to assess the issue. Because of time constraints, management decided to "self-perform" the outage. Nine fuel-nozzle assemblies were replaced in three shifts using four O&M technicians under the guidance of a TA.

The cost saving was significant and prompted HGP to contemplate performing all future combustion inspections with in-house labor.

To implement an in-house outage program, the following considerations had to be evaluated:

- Safety.
- Training.
- Cost.
- Schedule.
- Experience.
- Tooling.
- Parts availability and sourcing.
- Reliability.

Safety. By using plant personnel, many safety issues were avoided. Staff already had a solid working knowledge of "site specific" safety procedures, policies, and issues. Addressing job-specific hazards was HGP's primary objective. Job hazards included, but

1. Hermiston Generating Plant performed two CIs with four O&M technicians, one third-party millwright, and a third-party TA in seven shifts

2. Project participants: Tim Hevrin, outage manager (far right) and the outage team of Joe Wedding, Danny Picard, Dennis Morris, and Jeremy Parker (l to r)

3. Portable crib for the tools recommended in GEK 107535 was designed by and for the O&M techs on the outage team were not limited to, rigging and fall protection, already a focus in pre-outage classroom training. These outage operations are monitored closely by a third-party TA and HGP management during disassembly/reassembly. HGP's safety approach resulted in zero accidents and zero near misses during both CIs.

Training. Prior to the 2017 outage season, HGP engaged a third-party to conduct a 40-hr training program on combustion inspections with the outage team. Operators were instructed in the following:

- Gas-turbine theory.
- Rigging.
- IGV calibrations.
- Torqueing.
- Parts function and familiarity.
- Specialty tool usage.
- Inspection and maintenance guidelines from GEK 107535.
- Quality control and assurance.

Cost. Combustion-inspection costs vary among vendors—ranging from about $140k to $170k each (not including the cost of hardware, consumables, or parts refurbishment). Note that no crane costs are incurred at HGP because the plant was constructed with overhead cranes. HGP performed two CIs with four O&M technicians, one third-party millwright, and a third-party TA in seven shifts at a cost of $51k per CI (Fig 1). Plant realized a median cost saving of $114k per CI.

Schedule. Self performing outages allows more schedule flexibility. Plant management is able to shift the outage schedule without costly contractor penalties or contractor unavailability. Outages may be moved slightly depending on real-time market opportunities. The facility is also able to immediately address forced-outage situations rather than waiting for contractors to mobilize.

Experience. HGP has a tenured staff with very little turnover. Combustion inspections are performed every 8000 to 8800 operating hours. During outages, all O&M technicians are assigned to the maintenance department (with the exception of two control room operators). A select group of O&M techs were permanently assigned to the outage team, which meets regularly to discuss ways to mitigate risk and improve overall outage performance (Fig 2).

Morale. Staff's ability to successfully perform planned and unplanned outages has fostered a higher level of confidence, knowledge, and self-reliability among plant personnel.

Tooling. HGP constructed a portable crib for the tools recommended in GEK 107535. The trailer was designed by and for the O&M techs on the outage team (Fig 3). Equipped with tooling, consumable parts, office space, and break amenities, it is staged adjacent to the turbine compartment during outages.

Parts availability and sourcing. By self-performing, HGP is not restricted to using specific vendors. Purchasing is able to negotiate more reasonable costs and decreased lead times. HGP also carries a large inventory of spare parts. With the familiarization of turbine maintenance, each member of the team is able to quickly identify and procure parts as needed.

Reliability. Strict QC policies and second checks were implemented to prevent oversight. Since implementing the self-performed CIs, the facility has achieved an EFOR of less than 1% and a starting reliability greater than 98% (201 successful starts in 204 attempts) through the end of 2017.

Results. Every aspect of the self-perform CIs had a positive impact. All future CIs at HGP will be performed by plant personnel. Management is currently evaluating the need for TA services during the next CI.

Minnesota River

Upgrades to non-segregated bus duct help prevent faults

Minnesota River Station

Owned by Minnesota Municipal Power Agency

Operated by NAES Corp

43-MW, dual-fuel, simple-cycle peaking facility located in Chaska, Minn

Plant manager: Bob Burchfield

Challenge. Two electrical faults occurred on a 13.8-kV bus within five years (Fig 1). In both incidents, the solid copper bus and ductwork sustained extensive damage, resulting in lengthy forced outages. Figs 2 and 3 show the burned red insulator boots and damaged metal duct covers at the fault location.

During the first incident, the team coordinated with the OEM and determined that the section of bus where the fault occurred had insufficient heating. Plant installed two new heaters and scheduled more frequent inspections.

Five years later, a fault at a different location required a more extensive investigation and more robust defense. Both events had occurred during conditions of extreme humidity with heavy rainfall and dew points above 73F.

A third-party engineering firm determined that the bus was designed for relative humidity of 95%. However, relative-humidity levels routinely exceed 95% during the spring and summer months in the region. Ductwork is vented to atmosphere through small screened holes, exposing the bus to ambient weather conditions.

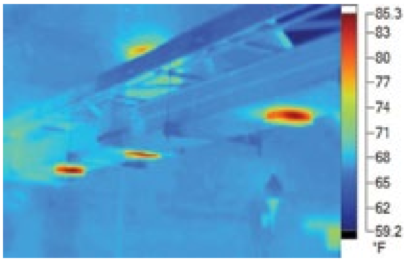
1. Two electrical faults occurred on this section of 13.8-kV bus duct within five years

2, 3. Burned insulator boots (left) and damaged duct cover (below) at the fault location

While making repairs after the second incident, staff noticed that the OEM had modified the replacement parts. The red insulating boots now had the tie-wraps at the sides rather than on top (Fig 4). Previously, they had allowed moisture accumulating on the upper cover to drip into the seams and onto exposed copper bus. The OEM had also modified the metal duct covers to create more overlap, particularly on the corners.

After the plant had completed repairs with improved OEM parts and added another space heater, the insulation readings still remained below acceptable values. Infrared imagery revealed that the heaters added negligible heat to the actual duct (Fig 5). Staff also noted that the new heaters purchased from the OEM were installed inside the duct with minimal clearances from the bus, apparently to make them more effective.

4. New-design insulating boots have tie-wraps at the sides rather than on top



5. Infrared image shows heaters added a negligible amount of heat to the duct

6. Throttling valves and flow meter assure equal air flow at each injection point

Solution. After heating the bus for a prolonged period following repairs, technicians found that phase-to-ground resistance readings remained below acceptable limits. They injected dry air overnight using a makeshift regulator and hose, which significantly improved insulation and permitted the bus to be energized safely.

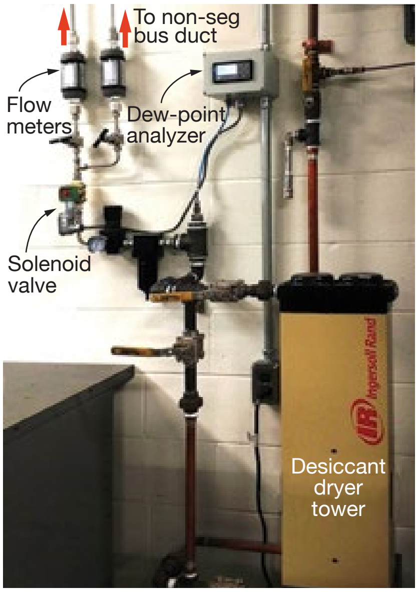
Given the success with this arrangement, technicians designed a dry-air supply system for permanent installation and wrote an operating narrative explaining multiple safeguards and interlocks to prevent over-pressure and use of a permanent dry-air injection system to prevent moisture entry. The slight positive pressure created by injecting air, they noted, is an added benefit of the injection system.

Staff learned from the repair contractor that many sites in the region had experienced similar failures, and in some cases, simply doubled the number of space heaters as a corrective action. However, Minnesota River ruled out the "additional heaters" option because the OEM's new locations for space heaters inside the bus provided less than 4 in. of clearance between the bus and ground. As the IR images showed, the heaters were less than effective at increasing the temperature inside the duct, even at that proximity.

To be on the safe side, the technicians' proposed air-injection system was reviewed by a qualified third-party engineering firm and by management. Injection of dry air typically is reserved for isophase bus ducts, so there were concerns about applying this solution to a non-segregated bus duct—especially since non-seg bus covers are fastened with screws and not necessarily designed for positive pressure.

Recall that isophase bus duct generally is constructed of welded tube with only one conductor per duct.

In their narrative, the technicians explained how they would provide equal flow to each injection point using instrument throttling valves and a flow meter to measure the incremental air-flow increase at each injection point (Fig 6). At the same time, they confirmed low pressure with sufficient air flow by observing a small amount of the air exiting the duct from each vent/drain hole.



7. Dryer tower was added to serve the non-seg bus duct exclusively

8, 9. Air is injected at each space-heater box located below the bottom bus cover; dry air enters the bus duct through the perforated holes above the heater (left). If any heater circuit trips the current draw will drop by 1 amp (right)

The following three-pronged approach was taken to prevent water from entering via the supplied-air system:

- The team recognized that any malfunction of a regenerating dryer tower could allow water to enter the instrument air piping from the air compressors. Technicians didn't completely trust the installed plant dryer tower, so they proposed adding a tap to the top of the instrument-air receiver tank plus another dryer tower dedicated solely to the non-seg bus duct (Fig 7).
- Staff also procured and installed a dedicated dew-point analyzer and programmed it to shut off the air-supply solenoid at a predetermined set point. The normal dew-point temperature downstream of two dryer towers is very low, so a conservative shutoff set point of 0F was selected. Part of the logic in being this conservative was that the dew point remains relatively constant in the new system, so a change of any appreciable amount could indicate a problem.
- Air is injected at each space heater box located below the bottom bus cover; dry air enters the bus duct through perforated holes above the heater. If water reaches this box from the air supply, it has a last chance of removal through the bottom screened hole (Fig 8).

The sheer size of this particular bus factored into our solution. The ducting measures approximately 200 ft long and consists of three different sections. It is heated by 25 space heaters powered by two separate 120-V circuits; each heater draws slightly more than 1 amp.

The team procured and installed a current monitoring device. If any heater open-circuits, the current draw will drop by 1 amp (Fig 9). If an entire heater circuit trips, the new panel will display a loss of current. An alarm was not provided because a thermostat periodically will shut off heaters at 95F and this would cause nuisance alarms.

Results. The dry-air injection system has been in place for two years. During a series of severe storms last year that brought heavy rains, 80- to 100- mph winds, and many days of high relative humidity there was no arc-tracking and no evidence of moisture intrusion. Phase-to-phase and phase-to-ground insulation resistance readings remain much higher than pre-installation values.

A nationally recognized bus contractor wrote a highly favorable letter acknowledging the system's benefits and the ingenuity of plant technicians. Staff needs more time to fully determine the new system's effectiveness, but if it had not been in operation during last year's extreme weather, another electrical fault likely would have occurred.

Project participants:

I&E technicians Mike Pavek and Bill Schrot

Maintenance technicians Bob Flicek and Steve Gare

Water-wash program gives year-round benefit

Ontelaunee Energy Facility

Dynegy

580-MW, gas-fired, 2 × 1 combined cycle located in Reading, Pa

Plant manager: John Goodman

Challenge. A new powerplant with no leaking valves and latest-technology equipment generally doesn't have to be concerned with losing a few points in its heat rate. Add 15 years of operation and that measurement of plant efficiency takes on a whole new meaning. One of the best ways to keep efficiency as high as possible is to maintain the equipment in the best possible operating condition. For gas turbines, that includes a clean compressor.

Like many other plants powered by gas turbines, Ontelaunee Energy Facility relies on springtime offline water washes to regain compressor efficiency losses. Offline water washes would show remarkable improvement, but as the turbine ran, the compressor would foul and efficiency would slowly creep downward. Determined to find a way to maximize efficiency longer, Ontelaunee began an online water-wash program.

Initially, the program focused on performing water-only rinses three times a week. Result: Efficiency did not decrease as quickly as before. However, once temperatures began to drop in the fall, the water-wash skid was winterized and remained out of service unit the annual offline wash in spring.

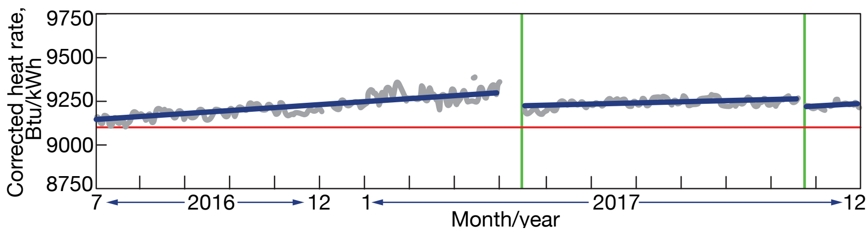
Solution. In 2017, Ontelaunee decided to make the online water wash program more robust. This included performing online water rinses daily and online soap washes weekly. Both the rinses and washes were conducted in accordance with OEM recommendations. This compressor cleaning program gave good results, efficiency remaining close to what is was immediately after an offline water wash.

However, staff was concerned about the wintertime, when ambient temperatures would drop below the suggested minimum washing temperature. The OEM's water-wash procedure has a recommendation for using anti-freeze, either ethylene glycol or propylene glycol. But past experience with glycol-based anti-freeze was that it had a negative effect on combustion turbine emissions. Not wanting to risk an emissions exceedance, the plant sought a different solution.

Ontelaunee planned to install an inlet bleed heat (IBH) system to combat air-filter clogging which could occur during snow events. With the PJM implementing a "capacity performance" segment, penalties for forced outages and derates attributed to filter clogging became a major financial concern. In 2016-2017, the IBH system, designed by PSM, was installed. The immediate benefit of preventing filter clogging was realized, but staff saw a possible additional opportunity for performance improvement.

Results. Personnel reasoned that if the IBH system could raise inlet scroll temperatures to prevent bellmouth and Row 2 compressor-blade icing, it might increase the air temperature enough to continue online water rinses in cold weather. It did. Today, anytime the ambient temperature is above 35F, IBH can raise the inlet temperature enough to permit an online water rinse. This allows the water-wash program to continue year-round, enabling the plant to maintain a competitive heat rate.

Project participants:
Adam Sensenig, plant engineer
Bret Pardew, production manager



Degradation of baseload heat rate has been slowed at Ontelaunee by the plant's robust online water rinse and wash program

Green Country

2018 Best Practices Award
BEST OF THE BEST
CCJ COMBINED CYCLE Journal

Green Country Energy

Owned by J-Power USA

Operated by NAES Corp

801-MW, three gas-fired 1 × 1 combined cycles located in Jenks, Okla

Plant manager: Danny Parish

Design hazardous-spill response plan for worst-case scenario

Challenge. Nearly all plants have a plan for addressing hazardous spills. Many, like Green Country Energy (GCE), have a comprehensive spill-prevention control and countermeasures plan that identifies areas where spills could happen, as well as appropriate responses to them. The challenge is to develop a plan which takes into account the site, weather, and staffing conditions that would be present at the time of the event.

A successful plan is one that can easily and quickly be executed by anyone at the facility. It should require very few steps to complete and ensure the safety of those involved. Plus, it should deal effectively with any spill—small or large.

At GCE, personnel have worked to improve the plant's plan so it meets all the criteria mentioned above. In the process, however, staff began to identify obstacles fundamental to the success of other engineering necessities.

To illustrate: A modern, well-designed facility typically would engage with civil engineers to design flow paths and drainage channels that direct rainwater quickly to storm-water drains to prevent site flooding during heavy-rain events.

But many facility drainage systems take rainwater quickly to underground piping systems, never to be seen again onsite. These well-designed and engineered systems actively work against the ability to properly manage a spill. Site spill plans must take this into account.

At GCE, any spilled material would enter the storm-water system swiftly, leaving very little time to contain the spill. During a major rain event, that time would be reduced even more. We had to assume that storm water would be present during a spill and incorporate that into our control plan.

Another thing considered in creating a sound spill plan was the design of containments and containment drains. At GCE, transformer containments all have administratively controlled drain valves. Following a rain event, operations personnel visually inspect the water in the containments to ensure there is no oil or other contaminants. They then open the drain valve, which allows rainwater to flow to the oily water separator.

Some sites—not ours—have position-indicating valves (PIVs) for these drains that visually indicate whether the valve is closed or not. It is critical to keep containment drains closed during normal operations so that, in the event of a spill, the containment can do its job.

At GCE, the lack of position indicators on underground containment drain valves created an opportunity for an administrative error. Thus, the plant's plan required continuously visible indication on these valves so the operations team could ensure that they stayed closed at all times.

Another major consideration for GTC was that, during evenings and weekends, only three employees man the entire 20-acre site. One stays in the control room, and the other two split their time between equipment rounds, readings, small maintenance projects, and other operations duties. This dictated that the plant's spill plan had to be easily and safely executable by no more than two employees.

Recap: Goal was to develop a spill response plan to address each of the issues identified and give project owners the peace of mind that, in the event of a spill, the plan could be executed quickly and mitigate any risk of non-permitted process waters leaving the site.

Solution. GCE has a back-flow preventer at the Arkansas River discharge location that provides an isolation point for all of the water flowing from the plant (Fig 1). The challenge was to find a simple, cost-effective means of installing a positive closing device at this point.

Staff decided on an I-beam strongback with a modified handwheel designed to put positive closure pressure on the back-flow flap. Technicians designed and engineered this device using scrap material and parts from an old valve.

The largest expense was the rubber sealing material placed between the cast-iron flap and the 48-in. pipe lip. To ensure that any employee could close this valve, a platform with a slip-resistant grating and handrails were installed to allow safe access in any weather (Fig 2).

1, 2. Back-flow prevention flap before addition of new features is at left; below with strongback beam and handwheel added to apply pressure to the flap. Slip-resistant grating and handrails allow safe, convenient access

The drain-valve indicator issue was addressed by replacing all gate valves with one-quarter-turn butterfly valves. Extension handles then were fabricated to assure quick, easy valve operation. The handles are retractable to eliminate any trip hazard (Fig 3). The positions of the valves now can be seen at all times, allowing the operations group to ensure all drains are opened only during rainwater draining events.

3. Retractable butterfly-valve handles indicate whether valve is open or closed while eliminating a trip hazard

Results:

- GCE's spill response plan can be executed by any employee, in any type of weather, in less than five minutes.
- The back-flow valve handwheel can be accessed safely at any time.
- Valve positions on containment drains are clearly visible and easily operated for maintenance activities.
- Plant continues to use floor-drain covers, absorbents, dikes, dams, and diversions to mitigate small spills—but only after the back-flow flap has been closed.

How to excavate safely in high-risk areas

Challenge. Safety is a core value at Green Country Energy (GCE) and identifying opportunities for safety improvement projects is a big part of what staff does on a daily basis. Many of these are simple to execute. Some take a little more time and planning; occasionally personnel face a safety-improvement opportunity that seems impossible to implement. Such was the case with installing protective bollards around the plant's natural-gas supply.

Staff identified the need for bollards early on because the gas line is located at the plant entrance. Delivery trucks pass within 10 to 15 ft of it, and vendors, contractors, and other visitors pull into the administrative parking areas and then back up next to the line. The odds of someone hitting it are not great, but if they did, it could be catastrophic.

Plant personnel collaborated on a design. The bollards would consist of 8-ft lengths of 6-in.-diam steel pipe set vertically in the ground to a depth of 3 ft, then filled with concrete and painted bright yellow. If a truck or other vehicle were to make a navigational error near the gas line, the bollards would both protect it and minimize negative consequences to personnel and equipment.

The plant has many similar bollards to protect other equipment—such as the bulk hydrogen storage tank and fire hydrants. Most of these were installed during construction, some were added later.

Locating the bollards was complicated. A review of underground drawings showed the gas line came out of the ground right next to the plant's gas chromatograph. Also, a storm-water drain was located just east of the line and a series of conduit runs were just to the north for conveying gas flow-meter and chromatograph data to the control room.

In addition, the bulk hydrogen line to the generators was routed through that area. Then there was the plant ring road alongside the gas line. If the bollards were moved far enough away from the gas line to clear all of these obstacles, they could pose more of a hazard to plant mobile equipment and personnel than the gas line itself.

The risks associated with any sort of conventional excavation appeared to outweigh the safety value of the bollards. Hand-digging in this area looked all but impossible because of the hard clay and rock. Result: The project was considered too risky to undertake and was put on hold for several years.

Solution. In 2017, plant management recommitted to installing the safety bollards around the gas line. After researching possible work-arounds, Badger Hydrovac Services was engaged to excavate the foundation holes.

Badger relies on high-pressure water to loosen the soil, rock, and clay while simultaneously using a vacuum pipe to pull the loosened material out of the hole. This approach was effective and did not damage any underground cable, conduit, concrete, piping, or other critical equipment (Fig 4).

Results. Badger's excavation was fast, safe, and cost-effective. GCE now has a fully protected gas line (Fig 5).

But unexpected things have a way of turning up when excavating in an industrial setting. This project was no exception. When digging the final bollard hole in a location that had no known obstacles, a buried pipe was found. It turned out to be the control-room sewage lift station line and was not on any of the drawings. Hydrovac spared the plant a messy and expensive outcome, reinforcing staff awareness that all excavations involve risk.

Project participants: The entire GCE staff.

4. Hydrovac system makes holes for bollards with minimal impact to existing infrastructure (left)

5. Bollards protect gas line at plant entrance (below)

Tight project control, capable craft personnel spell success for triple major

The MS5002, designed specifically for mechanical-drive applications in process plants and on pipelines, is a durable fuel-flexible machine capable of accommodating a wide range of demanding operating requirements. More than 500 of these two-shaft, four-bearing prime movers have been installed worldwide since the engine's introduction in 1970. They can be found in desert locations, offshore, in the arctic, etc.

There are five models in service: A, B, C, D, and E. Shaft power has increased over the years as it has for other frames. The A series develops about 26,000 hp in a simple-cycle arrangement (the regenerative cycle is an alternative), while the E version introduced in late 2007 is rated more than 45,000 hp.

The engine is valued by owner/operators for its efficiency over a wide range of speeds and loads as well as for its simple design (sidebar), which permits onsite maintenance and inspection (including majors) without the need for specialized tooling or service-shop assistance. Large process plants may have a dozen or more of these units in service.

One such facility producing LNG took three of its MS5002D compressor drivers out of service early in 2018 for major inspections. The overhauls were conducted simultaneously by Power Services Group, Cape Coral, Fla, and completed successfully within the allotted 25-day window. This article, based on information shared by PSG Project Manager Mark Sherrill, does not cover any of the process-compressor work done at the same time.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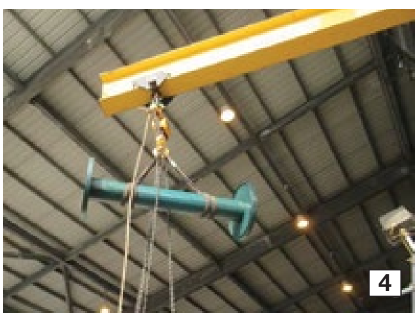
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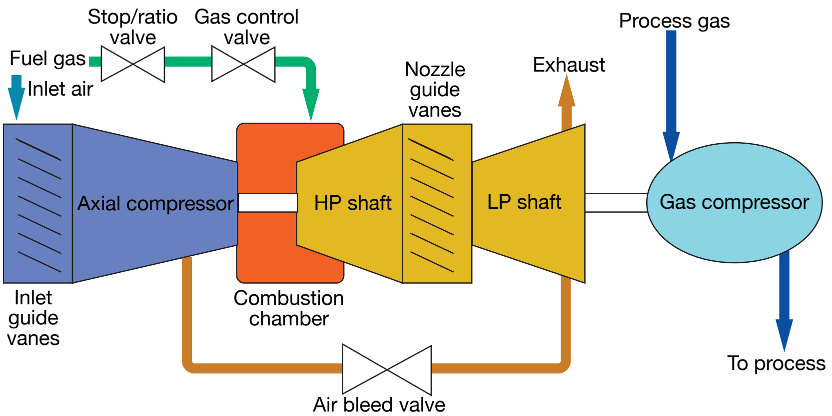
MS5002D design highlights

The simple schematic describes this two-shaft frame engine. The HP shaft is shared by a 17-stage axial compressor and a single-stage turbine. First-stage nozzles are air-cooled, those in the second stage are of the variable-angle type. A single-stage turbine on the LP shaft turns the driven equipment—a compressor in this case.

Twelve combustion chambers, capable of burning a variety of gaseous and liquid fuels, are contained within a single wrapper. A DLN option is available.

Finally, a central lube-oil system supplies clean, cool fluid to lubricate both the gas turbine and the driven equipment—plus provide oil for compressor seals, if required.



The PSG team, led by Sherrill, provided management and technical expertise to perform the majors on the three engines, built in 2004-2005; they entered commercial service in fall 2007. Fired hours among the three at the time the overhaul began ranged from 88,000 to 92,000 in round numbers, emergency stops from 86 to 134, and fired starts from 133 to 177.

The scope of work included major inspections of the load and accessory gearboxes, and auxiliary systems and components, in addition to the gas turbine. Support startup also was part of the contract. The PSG team, consisting of 52 turbine mechanics, four welders, 13 foremen, 12 supervisors, and two technical directors, worked two 12-hr shifts. They were supported by four dozen non-PSG instrument techs and others.

Outage snapshot

PSG's senior outage personnel arrived onsite four days before the mechanics to complete the training required and make sure the turbine deck was properly scaffolded for the project (Fig **1**. That complete, a pre-outage meeting was held with PSG supervision and mechanics to review the scope of work, identify key issues, and develop a "team approach" for the project. The outage started on January 22 with an all-hands safety meeting and walk-down of the LOTO (lock out/tag out).

To keep the project on schedule, PSG management provided the customer a daily status report reviewing accomplishments, work-forecasted action items, concerns, etc. Work lists also were developed daily based on critical-path activities requiring attention. They helped to maintain continuity of tasks being performed.

The gas turbines, located outdoors and under roof, are enclosed by sound-attenuating walls and roof sections. There are permanent overhead cranes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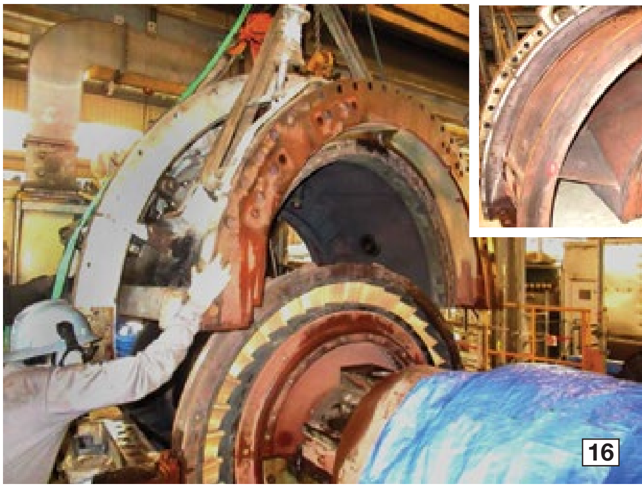
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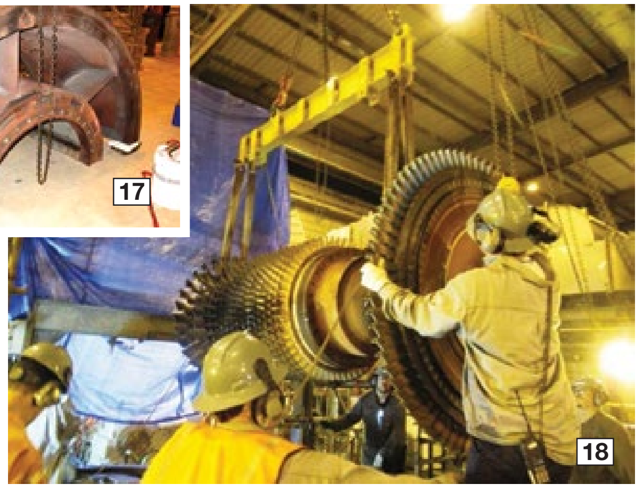
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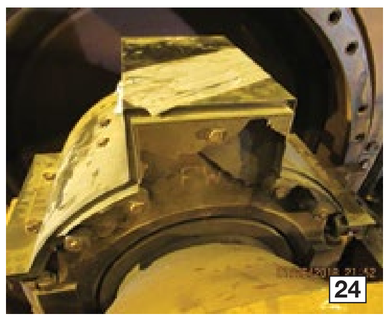
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onsite. Work began on all three engines in parallel with disassembly of roof-mounted ductwork **2** and removal of the roof panels **3**. Inlet and exhaust expansion joints were unbolted and collapsed to facilitate removal of the inlet 90-deg elbow and exhaust-duct transition section.

While this work was underway, the load **4** and accessory **5** couplings were disassembled and alignment fixtures **6** were installed to take the necessary readings. After the exhaust section **7** and inlet-ductwork **8** and cooling-air piping were removed, the package enclosures were disassembled to gain access to the turbines **9**. Cooling-air fans were removed **10** and their motor bearings were replaced.

Next, combustion-system hardware **11** and the wrappers **12** were removed. Components replaced: fuel stop valve **13**, fuel nozzles, can covers, crossfire tubes, and liners. All cases from the inlet bellmouth to the exhaust diffuser **14** were rigged and picked (upper halves of the compressor **15** and turbine **16** cases, and exhaust frame **17** and diffuser) allowing removal of the HP **18** and LP **19** rotors.

NDE inspections of the exhaust case and diffuser were performed; no indications were found. After the rotors were lifted off their bearings and transferred to storage coffins **20** for shipment to the owner's repair facility, compressor stator vanes **21** were replaced. Refurbished rotors were installed for the next interval **22**.

IGV gears **23** and vanes, and the first- and second-stage shroud blocks, were replaced. Severe damage was


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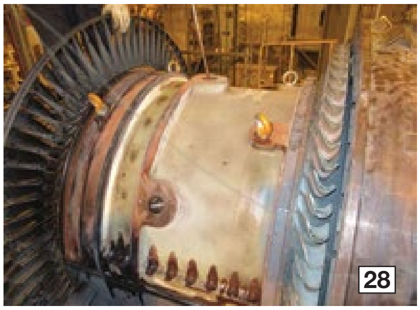
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found on the No. 2 bearing heat shield of one unit **24**. This was the first time the second-stage shroud blocks had been removed. Nuts were welded **25** to the individual blocks and had to be driven out with a 20-lb sledge hammer **26.** Newer-style shroud blocks with honeycomb inserts **27** were installed on two gas turbines, the third was replacement in-kind. One of the MS5002s required a new diaphragm **28** and first-stage support ring **29.**

Load gears on two machines were disassembled and inspected by representatives from Texas-based Lufkin Industries, with PSG support **30.** New radial bearings were installed in both gearboxes. Finally, the three accessory gearboxes were disassembled and inspected by representatives of Germany's Flender AG, owned by Siemens. Radial bearings were replaced in the three units. The main lube-oil pump was replaced with a new one **31**.

Restarts of the overhauled gas turbines occurred on February 14 and 15, right on schedule and incident-free except for a hiccup on one unit. That machine was shutting down on high compartment temperature. Root causes:

- Lifting eye holes were blowing hot air; issue was attributed to the combustion–cover mod made during the outage.
- Loose crossfire-tube flange set.

Simple fixes were made and the bad behaviors were corrected.

Reflecting on the triple major, Sherrill, a member of the 7EA Users Group steering committee back in his plant days, mentioned a few best practices that he thought might help industry colleagues:

- Have at least two air-powered chipping hammers on hand for each machine to facilitate removal of shroud blocks.
- For your gas turbines, only use heavy-duty, metal-free Never Seize.
- Recommended sealant for horizontal and vertical casing joints is Loctite 5972. CCJ

Recognition program salutes five companies

The European Turbine Network (ETN Global) launched a Best Practices program late last year, with assistance from CCJ, and recognized five companies for their accomplishments in the areas of Workforce Development/Knowledge Management and Environment, Health, and Safety (EHS) at the non-profit membership association's Annual General Meeting in Bucharest (Romania), Mar 14-15, 2018.

ETN Global (https://etn.global) brings together the entire value chain of the stationary gas-turbine (GT) technology community (power generation and mechanical drive) worldwide. Its 110 members from 23 countries include power-generation and oil-and-gas companies, OEMs, and the providers of services and equipment that support them, as well as universities and consultancies. The challenges and concerns of users are addressed in committees and working groups.

One of the main benefits provided by ETN Global is the opportunity for members to increase their technical knowledge through interactions with peers (Fig 1). The Best Practices program is one way to share information of proven value. All members can participate (not just owner/operators as in CCJ's program). The ETN program is directed by Christer Bjorkqvist, the network's managing director, and Pascal Decoussemaeker, chairman of the organization's Asset Management Technical Committee.

Companies recognized for their accomplishments in workforce development and knowledge management were ConocoPhillips (global), Exxon Mobil (Usan FPSO, Nigeria), and GE's O&M Center of Excellence (Switzerland). ConocoPhillips Australia (Darwin LNG), Sutton Bridge Power Station (owned by the UK's Calgon Energy Ltd and operated by GE O&M), and Neste Oil Porvoo Refinery (Finland) were applauded for their EHS programs.

Workforce development, knowledge management

Transfer knowledge among the company's plants worldwide

Challenge. How to ensure and accelerate organizational learning from individual experiences.

Solution. Knowledge-sharing networks were introduced in 2006 with core teams having at least one representative from each business unit. One such network was "Rotating Equipment." Engineers company-wide with rotating-equipment responsibilities were encouraged to participate. The core team hosts regular teleconferences to share experiences globally. A SharePoint site was created for network members to post questions, share successes, etc. Each member receives daily or weekly updates on the site's activity.

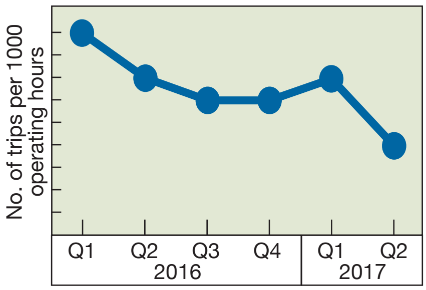
Outcome. There has been unprecedented sharing of knowledge across business units and country borders. Such networking has contributed to a real sense of comradery among those involved and has identified engineers expert in resolving particular types of challenges encountered at operating units.

Identify best practices for performance improvement

Challenge. Improve fleet reliability, currently not meeting expectations.

Solution. Implement an aggressive, proactive, and systematic program to identify and address reliability issues using company's the existing support system, which consists of an asset machinery/reliability engineer and

1. Christer Bjorkqvist, ETN Global's managing director, opens the organization's annual general meeting in Bucharest, Romania, where Best Practices Awards were presented for the first time



2. Reliability of the OEM's gas-turbine fleet increased dramatically over the last year and a half thanks to an aggressive, proactive, and systematic program to address O&M issues

site resident field-service tech (the core team) in collaboration with the OEM's gas-turbine technical staff. Important to success is to have clear ownership and stewardship of each issue from identification to closure.

Establishing well-defined objectives is the first step. For the example provided in the Best Practice submittal to ETN, the owner/operator stated the following:

- A given process train must not experience more than six trips annually.
- A process train is not allowed more than two open reliability issues at any one time.
- The amount of time from issue identification to finalization of an action plan should not exceed one month, absent any special circumstances.

Methodology for issue resolution includes the following steps:

- Create an inventory of all known reliability issues for each process train.
- Understand and classify each issue identified.
- Capture, understand, and address any suspected emerging threat—such as a step or frequency change. Proactive surveillance is critical to this effort.
- Conduct an aggressive review of issues and progress. Examples: The core team should review operating status daily. A fleet performance review should be conducted weekly with the asset O&M team.

Outcome. The initiative commenced in May 2015, and through June 2017, having better visibility of onsite issues and more proactive ways of dealing with them contributed to a 38% improvement in gas-turbine fleet reliability (Fig 2).

Increase fleet reliability by halving trips through awareness, full-circle knowledge-sharing

Challenge. Avoid interruption of the power-generation process in a fleet of

3. Stop Work authorization cards (front at left, back at right), signed by the plant manager, empower employees and contractors to take action against unsafe behaviors

4. Stop Work poster, signed by lead contractor managers and safety reps, reinforces the message that unsafe practices will not be tolerated

47 powerplants (total of 32,800 MW) across 19 countries.

Solution. First steps taken by the contract operator was to create an awareness among its management personnel of potential trip indicators, openly share issues faced and lessons learned among the sites served, and deliver engineered solutions to the powerplant teams fleet-wide. To transfer information expeditiously, a notification process was established and a weekly call is conducted to share experiences among the sites and the operator's O&M Center of Excellence (COE).

Solutions developed by the OEM's engineers to mitigate issues identified are shared with the sites for implementation via so-called O&M Instruction Letters. Results then are reported back to the COE and distributed network-wide, thus creating an ongoing loop of knowledge-sharing between COE experts and O&M teams in the field.

Outcome. Within 18 months of program implementation, trips fleet-wide had been halved.

Environment, health, and safety

Tooling certification and proper use

Challenge. Avoid repetition of an EHS incident related to tooling during the replacement of an HP turbine rotor. The incident was attributed to a tool malfunction and lack of awareness concerning associated risks. The tool and manpower associated with its use were hired from the OEM.

Solution. Purchase tooling to have better control of its certification and use, while also ensuring proper procedures are followed.

Outcome. Sharing of knowledge gained across the company's business units and country boarders.

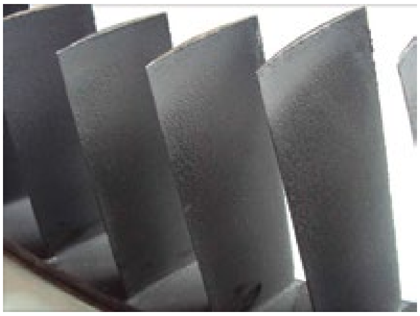
Stop-work authority

Challenge. Empower all personnel onsite to stop work if concerned over any aspect of a job's safety or quality requirements.

Solution. A "Stop Work" program is in place across all GE business units. At Sutton Bridge, the safety campaign was extended to include subcontractors. Also, management recognized that simply talking about the program in meetings was not sufficient. To reinforce the message, a more permanent reminder was created. Stop Work authorization cards (Fig 3), signed by the plant manager, are given to all personnel onsite. They are the size of a typical credit card and made of a similar durable material. A Stop Work poster, signed by all lead contractor managers and safety reps, also was created to reinforce the message (Fig 4).

Outcome. Increased awareness.

Anti-fouling treatment maintains gas-turbine performance without washing



5. Impact of a harsh coastal environment shows on compressor blades above that were not washed prior to major inspection after 40,000 hours of service. Positive impact of coating applied to compressor blades which had operated for 38,000 hours without washing while using F7/F9 inlet air filters is below

Challenge. Reduce fouling-related degradation of gas-turbine performance caused by a harsh coastal refinery environment containing salt, dust, soot, etc. No online or offline compressor washing was performed to mitigate possible engine tripping and other problems during restart, environmental aspects of water use for washing, and the cost of demin water, detergent, and spent wash-water transportation and disposal.

Solution. Compressor blades were coated with an anti-fouling treatment from United Services Sweden AB, said to be long-lasting and have low-friction properties, during a major overhaul in April 2012 (Fig 5).

Outcome. No noticeable fouling-related degradation after 38,000 hours of operation without washing while using F7/F9 inlet air filters. CCJ

Tuxpan II and V

CCC Tuxpan II and V

Owned by Electricidad Águila de Tuxpan and Electricidad Sol de Tuxpan

Operated by NAES Corp

Tuxpan II: 500-MW, dual-fuel, 2 × 1 combined cycle located in Tuxpan, Veracruz, Mex

Tuxpan V: 500-MW, gas-fired, 2 × 1 combined cycle located in Tuxpan, Veracruz, Mex

Plant manager: Jorge Gamel Esparza Cárdenas, PE

Outage safety benefits from community outreach program

Challenge. The people who live in the communities around the Tuxpan plants are a critical resource for the company. Management is concerned that citizens know what to do in an emergency and how to deal with safety-related issues encountered in their daily lives.

Solution: Develop safety training programs for people living near the company's facilities and for "safety watchers" to assist plant personnel during outages. NAES implemented the core safety training program for 80 residents. It was conducted by personnel with extensive experience in industrial safety; participants completing the program received a certificate.

Lessons were presented on how to use a safety harness, what to do in an emergency, firefighting, CPR, types of fires and fire extinguishers, hazard and risk identification, differences between hazardous and urban wastes, PPE, crane and forklift inspection, etc.

Four groups of about 20 participants each were trained in one month (Fig 1). Goal was to increase knowledge of safety issues and to ensure a good relationship with stakeholders. The top performers in the community training program were invited to be part of a group of safety observers who would participate in the Tuxpan II fall outage by supporting NAES management in the supervision of contractor personnel.

Prior to the outage, the safety observers were trained to monitor specific issues. When the outage began, the safety watchers, supervised by the NAES HSSE team and training personnel, were divided into groups—first in day and night shifts, then in key areas (Fig 2).

Watchers had the task of giving safety recommendations for each act or unsafe condition detected, first addressing the worker to correct it, then the contractor's safety supervisor to prevent it from happening again, and finally the NAES supervisor to integrate the incident into the safety statistics to improve or control it.

Results. Excellent results were obtained with the safety watchers; they helped the HSSE team avoid a lost-time incident during the 35-day outage. Here are the stats:

- Good practices cited, 115.
- Drug and alcohol tests, 6796. There were 10 positive results for alcohol, three for drugs.
- Unsafe acts and conditions reported, 233.
- Near misses, 6.
- Safety inspections conducted, 192.
- Minor first aid (health issues, headaches, flu, etc), 139.
- First aid (safety issues), 2.
- Medical treatments, 1.
- Lost-time incidents, 0.
- Incidents closed, 232.
- Average number of persons onsite during the daytime, about 360.
- Average number of persons onsite during at night, about 100.

Project participants:

Jorge Gamel Esparza Cárdenas, PE, plant manager
Leonel Rosas Maitret, PE, production director
Jonathan Carballo Alonso, PE, technical assistant
Odilón Cruz Salomón, PE, HSSE supervisor

1. Each of the four training classes had about 20 participants from communities in the vicinity of Tuxpan plants

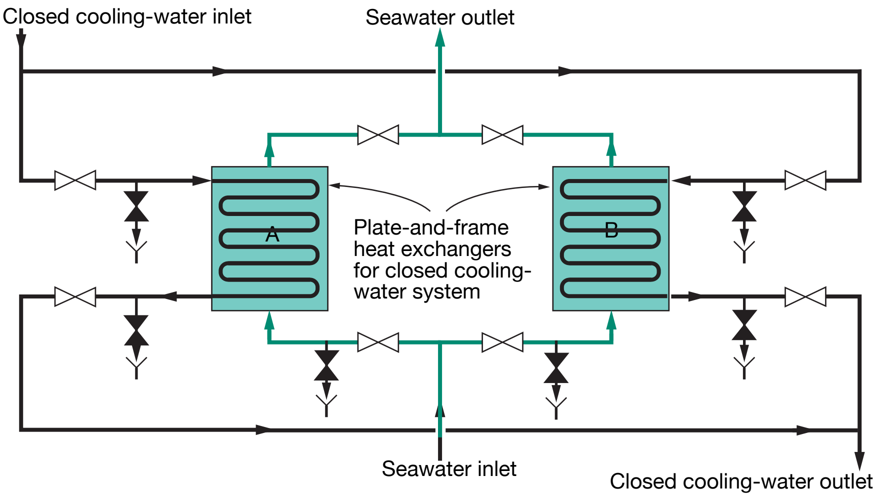
2. Safety watcher monitoring proper crane use

Backwash plate-and-frame heat exchanger to boost performance

Challenge. The OEM's operating procedures provide NAES a safe way to isolate the closed-cycle plate-and-frame heat exchangers for cleaning when heat-transfer surfaces are fouled and cooling duty cannot be maintained. However, these procedures require mechanical disassembly of the exchanger and washing each plate in turn because the backwash procedure provided was not effective.

Solution. Objective of the new procedure implemented by NAES is to wash the exchanger without disassembly, taking advantage of the same seawater pressure used for cooling in an inverse way. Benefit of backwashing is that it extends the interval between manual cleanings, thereby reducing the cost of maintenance by about $30,000 annually.

Note that the wind and currents at the plant's coastal location affect the amount of dirt carried by seawater into the heat exchangers. In a typical year, cleaning would be required 10 to 15 times. Today, backwashing is initiated only when the temperature of the closed-cycle cooling water rises to the point where cooling becomes inefficient.



3. Backwashing of heat exchangers helps maintain top performance of the closed cooling-water system

Results. The following backwash procedure was developed by plant personnel (Fig 3):

The first step is to drain the heat exchanger. Stepwise:

- Close the seawater inlet valve to the heat exchanger (Fig 4).
- Close the seawater outlet valve (Fig 5).
- Open the seawater drain and empty the heat exchanger completely (Fig 6).
- Close the closed-cycle-water inlet valve to the exchanger (Fig 7).
- Close the closed-cycle-water outlet valve.
- Open the closed-cycle water-side vent valve (Fig 8).
- Open the closed-cycle water drain and empty the heat exchanger.

Second step is backwashing:

- Constantly open and close the seawater outlet valve shown in Fig 5.
- Leave the seawater drain open, so dirt is removed from the exchanger during this process.
- Open the seawater inlet valve, leaving the drain open to eliminate any remaining dirt.
- Repeat this maneuver as many times as necessary until the drain is clean.
- Refill the heat exchanger and return it to service.

Project participants:

Jorge Gamel Esparza Cárdenas, PE, plant manager

Leonel Rosas Maitret, PE, production director

Erasmo Casados Marcelino, PE, operations manager

4. Closing heat exchanger's seawater inlet valve

5. Closing the seawater outlet valve

6. Open drain line confirms when heat exchanger is empty

7. Shutting the closed-cycle water inlet valves to the heat exchangers is part of the process

8. Opening the vent valve in the closed-circuit water system is an important step

Tests of safe start with gas fuel in the GT

Challenge. The "Tests of Safe Start with Gas Fuel in the Gas Turbines" have as an objective to assure reliable starting and to avoid delays in the commissioning of the turbines, verifying the correct physical operation as well as the logical response of the main valves involved in starting and operating the engines.

Solution. The safe-start tests are conducted on the following valves:

- Fuel gas system.
- Pressure control.
- Main flow control.
- Pilot pressure control.
- Fuel gas vent.
- Turbine fuel-gas shutoff for protection against gas-turbine overspeed; plus confirmation of overspeed trip reset.
- High-pressure bleed.
- Low-pressure bleed.

Results. Conducting these tests has allowed the detection and correction of abnormal variations in response of the valves to control logic, physical abnormalities of movement, and other situations in a timely manner for correction before turbine start. Deadtimes have been reduced, failed starts avoided, and turbine damage prevented.

Project participants:
Jorge Gamel Esparza Cárdenas, PE, plant manager
Leonel Rosas Maitret, PE, production director
Erasmo Casados Marcelino, PE, operations manager

1. The first GT for power generation in the US was relocated from host Belle Isle Station to GE Schenectady in the early 1980s

2. Wolverine Power Supply Co-op's STAG 105 looks almost new after 50 years of service

The future is nothing without the past

By Dave Lucier, PAL Turbine Services LLC

Gas turbines and I have been "connected" almost since these machines were first used to generate power in the US. I'm not exactly sure when I learned we were inseparable, but the early 1960s sounds about right, after being introduced by the mechanical engineering faculty at UMass Amherst.

Only a few years earlier, in June 1949, Oklahoma Gas & Electric Co launched the gas-turbine era on this side of the Atlantic by starting up a 3.5-MW unit at the utility's Belle Isle Station (Fig 1). I was in grammar school then and didn't know anything about gas turbines; however, it is significant (to me, at least) that I've been around since the beginning and have enjoyed the ride.

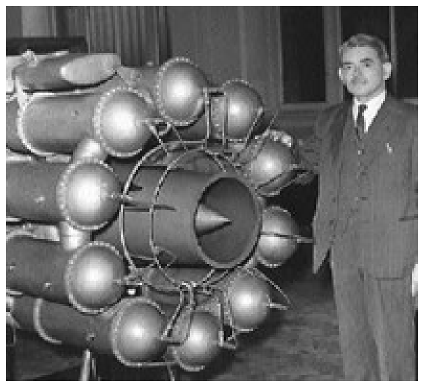
What's interesting about Belle Isle is that the gas turbine was part of a combined cycle; it was not a simple-cycle machine as you might have expected. Also interesting was that this and other early combined cycles married GTs and conventional boilers, most often the gas turbines substituting for forced-draft fans. At Belle Isle, the oxygen-rich exhaust gas was used for preheating feedwater.

The first pre-engineered combined cycle integrating the Brayton (gas turbine) and Rankine cycles (HRSG and steam turbine) was installed by the Ottawa (Kans) Municipal Electric Dept in 1967. This 11-MW single-shaft unit, powered by a GE Frame 3 is still in service today. About a year later, when I graduated from the GE field engineering program (see previous article, p 34), the first STAG™ (for STeam And Gas) combined cycle equipped with a Frame 5 was started up by the Wolverine Electric Power Supply Co-op Inc in Cadillac, Mich (Fig 2). This unit, also still active, was rated 21 MW.

A step back, across the pond. The turbojet engine came into prominence just as World War II was ending. Renowned British design engineer, Sir Frank Whittle, developed an engine in the post war period that is reminiscent of early GE multi-combustor gas turbines (Fig 3). GE and others were looking for applications for this new technology in the late 1940s and Whittle was known to have conferred in Schenectady during the war. Soon thereafter came the Frame 3 gas turbine.

There were at least three obvious commercial applications for gas turbines: planes, trains, and automobiles. Companies like Pan American World Airways, Trans World Airlines, and British Airways were looking to expand into global air travel, which would require jet engines for long distances—such as New York to London, Paris, and Rome. The Boeing 707 of the early 1960s and the hump-back 747 of the early 1970s, spurred companies—including GE, Pratt Whitney, and Rolls Royce—to meet the demand for jet engines.

Union Pacific Railroad experimented with gas turbine/generators on about 50 locomotives operating in the West, beginning in 1948 (Fig 4). Power



3. Sir Frank Whittle's multi-combustor engine was the forerunner of GE's 100-MW "gatling gun" gas turbine which didn't gain traction among utility customers

4. The Union Pacific had several locomotives powered by gas turbines in the 1950s

5. Jet One roadster is believed the first car powered by a gas turbine

6. Second place went to the Granatelli GT racer in the 1967 Indy 500

was generated for the drive motors on the wheels. Although successful in the open spaces, the high-frequency whine from the compressors soon became unacceptable when passing through cities and towns. Compressor noise attenuation technology came much later, when gas turbines were applied to land-based powerplants.

The gas turbine also had some success in automobile applications. The first GT-powered auto I'm aware of, the Jet One roadster (Fig 5), was introduced in the early 1950s in England. Poor gas mileage was an early issue for those wanting to drive long distances. It wasn't until the regenerative cycle was refined for auto applications did the idea of a gas-turbine-powered car become more acceptable. However, compressor whine was objectionable to most, as GT cars passed by street observers.

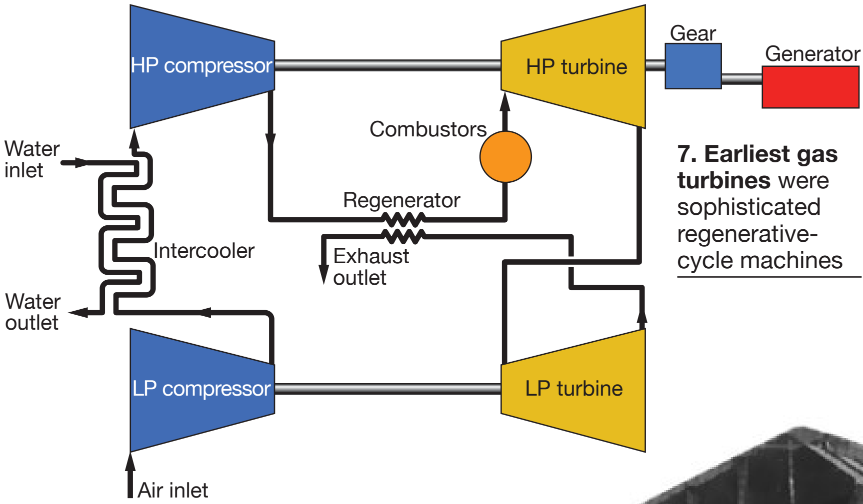
On the oval, the Granatelli-sponsored gas-turbine race car nearly won the Indianapolis 500 in 1967 (Fig 6). A failed part in the transmission (nothing to do with the engine) took it out of contention after leading nearly the entire race. Nevertheless, it didn't win the race and few people remember just how competitive the turbine-powered car was. One reason is that the rules were changed the following year, so the turbine cars couldn't meet the displacement requirements versus piston engines.

The first "peakers." In the small Vermont town of Rutland, circa 1951, three innovative Frame 3 gas turbine/generators were installed in a building on the west side. For this to be the location of a very complicated cycle was interesting. Perhaps GE wanted these machines located only a few hours from the Schenectady manufacturing facility.

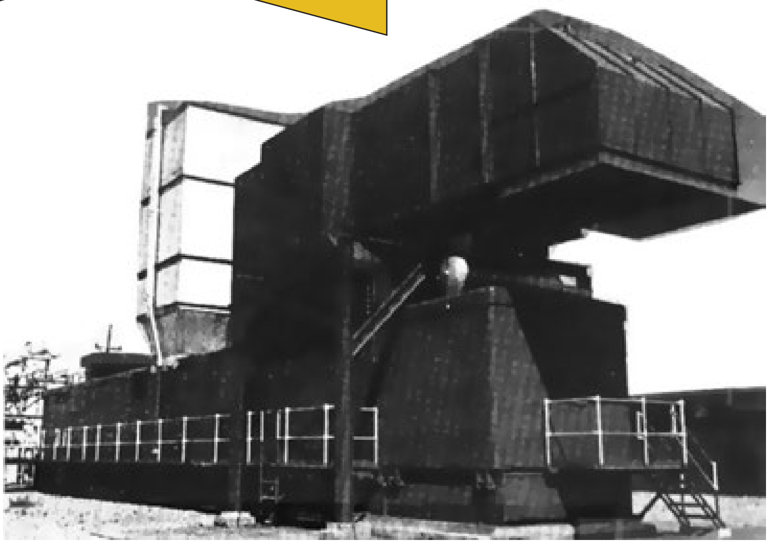
Rated only 4 MW each, the intercooled, regenerative-cycle, two-shaft engines with fuel regulator controls would start on No. 2 distillate oil and transfer to a heavier fuel oil during operation (Fig 7). When the final unit was retired in the early 1990s, owner Central Vermont Public Service Co gave me the original Young & Franklin fuel regulator, instruction books, installation photos, and operator log books to preserve for posterity. They are among my industry "treasures."

The first "bubble." In the early 1960s, GE was selling only a handful of Frame 5 so- called "package power plants" annually. Then came the Great Northeast Blackout, Nov 9, 1965. By decade's end, the OEM was shipping over 100 units per year from Schenectady, as the power industry recognized a good (and necessary) product for black-start, emergency, and peaking applications.

Installation time was short once a



7. Earliest gas turbines were sophisticated regenerative-cycle machines



8. Package Power Plant, MS5001L, dates back 50 years

flat foundation with rebar and anchor bolts was poured and cured. Some units became operational within a few months. Case in point: An installation that I supervised in Vietnam in 1971, made power with two MS5001L (Fig 8) gas turbine/generators in less than three months!

Back in the US, larger gas turbines were desired, but GE didn't have one—yet. Instead, the OEM sold Frame 5s in two- and four-unit power-block configurations to electric utilities from Brooklyn to San Diego. A few examples: Chicago's ComEd bought 68 units, New York's ConEd 48, Washington's Potomac Electric 16, and San Diego Gas & Electric eight. ComEd put its units around Chicago and in nearby towns, Potomac Electric installed its GTs to provide emergency power for the Capitol and White House.

Unique among these early projects was the 32 ConEd Frame 5s installed on four barges in Gowanus Bay—factory-assembled and pretested. Each eight-unit barge was equipped with a control house, power transformer, and black-start capability. The 32-engine installation could deliver 622 MW when operating on distillate oil with 95F inlet air. Four captive 1-million-gal fuel-oil barges moored to the turbine barges enabled full power production for 50 hours with 40F ambient air.

After the blackout, utilities were asking for gas turbines with a 50-MW rating. It took GE another five years to develop and manufacture the first Frame 7A in Schenectady. This prototype was sold to Long Island Lighting Co. Problem was the Frame 7 didn't have a diesel starting engine, so it wasn't a black-start machine. Nor was it capable of "dead-bus" starts. But it did approach the desired targeted output threshold.

Subsequent Frame 7B, 7C, and 7E gas turbines were made at GE's new facility in Greenville, SC, beginning in the early 1970s. Frame 5s were manufactured in Schenectady into the late 1980s.

In 1978, GE-Schenectady developed the Frame 6B, looking to capture an emerging co-generation market. Those applications were located near a "steam host"—a plant requiring steam for process. Once the pressure dropped to a useful level (say 200 psig), it was used in the host's process. Pressure reduction often was accomplished using a small steam turbine/generator, adding to the plant's electric production capability. Cycle efficiency approached 50%.

9. PLC-based GEMAC developed by PAL is an option for plant owner/operators that can't justify a full-blown controls upgrade

The GE control systems of post-war decades were mechanical-hydraulic-pneumatic, using Young & Franklin's fuel regulator. This product survived for 20 years and still remains operational at many sites today. Temperature controls by Hagan were used in the early years; the GEMAC electro-pneumatic system was applied in 1966.

Incidentally, one of several upgrades that we developed for legacy gas turbines is the PAL GEMAC replacement system (Fig 9), based on modern PLC technology, for plant owner/operators that can't justify a full-blown controls upgrade. National Grid opted for this compromise upgrade at two Long Island sites, Consumers Energy on three units in Michigan.

Electronic control systems evolved in the early 1970s with the advent of GE's Speedtronic™ Mark I. Later in the decade, the Mark II version came along with more analog and digital electronics (fewer relays). The Mark IV entered the market in 1978, with its triple modular redundant (TMR) concept, opting for two out of three voting processors and redundant key sensors. TMR remained a staple for Mark V in the early 1990s, along with the human machine interface (HMI). The Mark VI was next; the Mark VIe is favored today.

The introduction of the dry, low-NO_x (DLN) combustion system demanded more sophisticated controls and turbine exhaust monitoring for verification. Upgraded combustors on the early Frame 7E and EA units accomplished this.

Many innovations came with the development of DLN. Compliance with EPA directives was the main challenge in the evolution of the technology in the 21st century. As for increasing turbine "firing" temperature for more power output, three factors made this possible: better turbine metallurgy, ceramic coatings, and internal air cooling of turbine nozzles, buckets, and shrouds. CCJ

AIG upgrades slash ammonia consumption, tube fouling

Managing a powerplant for top performance can be a thankless task. You always seem to be at odds with those controlling the purse strings who don't fully understand how generating assets work. So you write a business case to illustrate that a better balance sheet would be possible were a given upgrade funded. You're a good employee, focused on doing all you can to help the company.

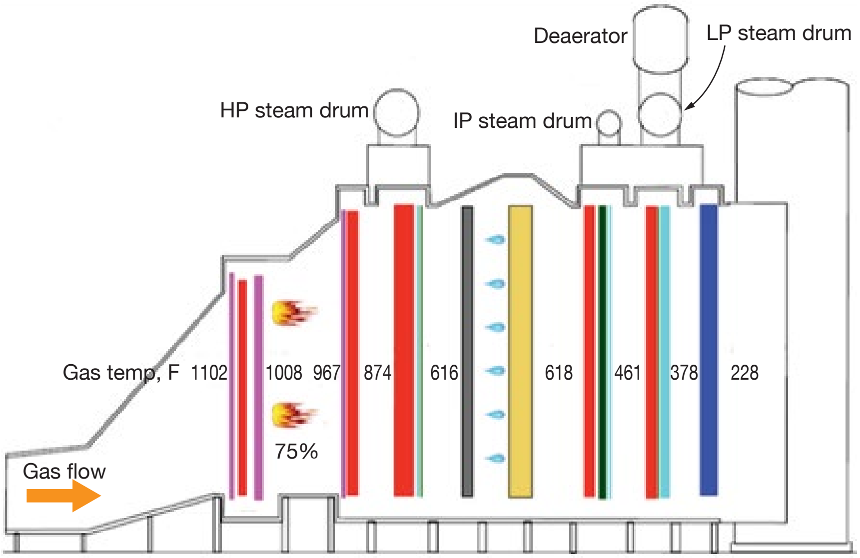
Difficult to get attention the first time you float an idea up the "chain of command." You hear things like "we have several projects ahead of yours," "we have projects that produce higher returns on our investment dollars," "we're focusing on operational risks now and your plant will run reliably even if it's not at top efficiency," "we're planning on operating your plant only during the summer run season going forward," etc.

Important not to lose heart. Resubmit your idea with each year's budget until it gains traction. There's a better-than-even chance it will be implemented if the positive supporting assumptions used in your analysis have not changed and/or the plant is not sold during the gestation period.

Case in point is a 2 × 1 combined cycle powered by W501FC+ gas turbines that had experienced a high exhaust-gas pressure drop through its HRSG's fifth modules since plant startup in 2000 (Fig 1). The fifth module includes the LP evaporator, IP economizer, and HP economizer sections. There was one change in ownership over the years.

Each of the HRSGs is equipped with an oxidation catalyst and SCR to keep CO and NO_x emissions within permit limits. The gas-only plant's continuous full-load rating is 480 MW with duct firing at a maximum ambient temperature of 120F and 15% relative humidity.

The majority of the fouling in Module 5 was occurring in the LP evaporator section, the tubes contacted first by exhaust gas flowing through the module. Cause of the high pressure drop was ammonium bisulfate (ABS) deposition in the tube bundle, caused by high local ammonia concentrations that pass through the SCR in those areas (slip). Ammonia, as a 28% aqueous solution, is injected at a rate of 150 lb/hr at plant design operating conditions.



Module	1	2	3	SCR catalyst	4	5	6
ΔP actual, in. H_2O	3.85	0.73	1.71	3.34	2.15	6.79	1.87
ΔP design, in. H_2O	3.0	0.7	2.2	2.2	2.3	2.1	0.9

1. HRSGs serving a 501FC-powered 2 × 1 combined cycle experienced rapidly increasing pressure drop in Module 5 (LP evaporator/IP economizer/HP economizer) following annual cleaning with dry ice. Fouling by ammonium bisulfate was attributed to ammonia reagent bypassing the SCR catalyst

The HRSGs were cleaned annually by dry-ice blasting, but the pressure drop quickly increased after cleaning, from 2.1 in. H_2O (clean condition) to 6.8 in., or more. Fig 1 gives typical data taken from the plant DCS when Module 5 was experiencing high gas-side pressure drop attributed to fouling. Fig 2 is typical of the ABS fouling found in Module 5 of both HRSGs.

2. Ammonium bisulfate fouling of finned tubes in Module 5 reduced heat transfer and increased pressure drop through the tube bundle

Incentives for mitigating ABS deposition include the following:

- Extend the interval between tube cleanings, reducing cost.
- Reduce gas-turbine backpressure, thereby increasing output and revenue. The nominal 5 in. H_2O increase in pressure drop through

Module 5 was costing this plant, in round numbers, between about 1 and 1.5 MW in output.

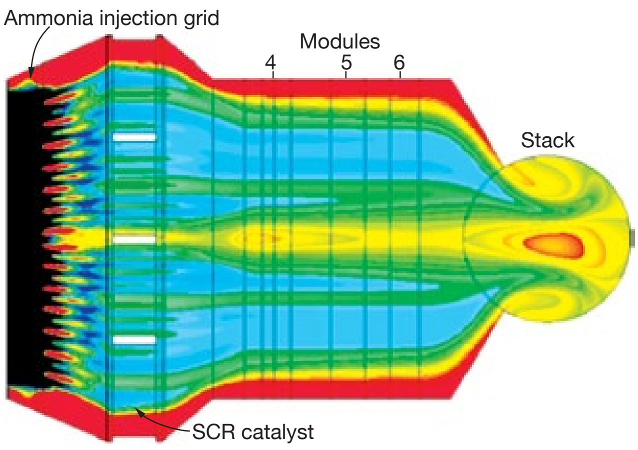
Concord Environmental was contracted by the plant owner to tune the ammonia injection grid (AIG) with the expectation that improving ammonia distribution across the SCR would eliminate the fouling problem. Bill Gretta, PE, senior VP/engineering director, would lead the company's effort.

However, AIG tuning alone failed to improve the ammonia distribution. Physical changes in the HRSG were necessary to reduce ABS fouling downstream of the SCR.

Concord Environmental developed a computational fluid dynamics (CFD) simulation of the entire HRSG to determine the cause of the poor ammonia distribution. Gretta said the company also was tasked to develop and implement the necessary design changes once the root cause of the fouling was determined.

Reduction in ammonia flow attributed to AIG replacement and baffle additions

Parameter	Unit 1	Unit 2
Ammonia flow before retrofit, lb/hr	161.2	164.9
Ammonia flow after retrofit, lb/hr	140.1	147.6
Reduction, lb/hr	21.1	17.3

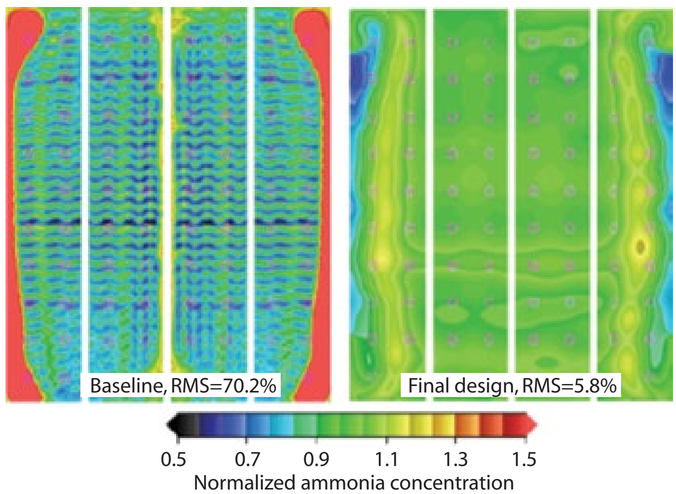


3. CFD results confirmed the poor ammonia distribution measured in the field. They showed that the AIG design itself was creating the poor distribution, as indicated by the high concentrations of ammonia (red) along the sides of the catalyst bed in this plan view

CFD identifies problems. Without delving into the complexities of the full-system CFD model, suffice it to say that detailed contour plots of exhaust-gas temperature, pressure, velocity, and ammonia distribution were developed throughout the entire HRSG—including the AIG grid. The model found that although the velocity distribution was quite uniform at both the CO and SCR catalyst inlets, the ammonia distribution was very poor at over 70% RMS—well beyond the goal of 10% RMS—at the inlet to the SCR catalyst.

The bottom of the CO catalyst support structure was of a design that allowed large areas of recirculation. Ammonia quickly collected there and along the sides of the HRSG where the casing expands and additional areas of recirculation existed. These two regions cause the ammonia to be "pulled" in and stay concentrated near the bottom and vertical walls before being propagated downstream into the SCR catalyst. Such problems typically are caused by

4. New AIG lances and baffles as installed. Note that the original structural penetrations were unchanged although the AIG was moved 3 ft upstream



5. Ammonia distribution across the vertical face of the SCR catalysts compared for both the baseline case and final design. Red shows sections with ammonia bypass, the darker color regions with poor ammonia mixing. Figure at left is the vertical cross section of the flue shown in Fig 3

too few injection holes in the AIG and the lack of mixing of the ammonia and the flue gas (Fig 3).

Concord Environmental's CFD modeling confirmed that ammonia was concentrating heavily along the side walls as well as in the top and bottom corners of the catalyst bed. However, the CFD model revealed that the AIG design itself was creating the poor distribution with high concentrations along the sides of the catalyst. The AIG supplied with the HRSG was located 4 ft downstream of CO catalyst, in a section of the HRSG casing expanding towards the SCR catalyst.

The solution was to move the new AIG 3 ft upstream so the revised AIG centerline was 1 ft downstream of the CO catalyst (the gray module immediately upstream of the AIG in Fig 1) in a uniformly spaced arrangement. CFD modeling also showed that adding mixing baffles to the upstream side of the newly located AIG greatly improved local mixing. The lance penetrations through the HRSG casing remain unchanged thus causing a jog in the AIG lances in the upstream direction. This eliminated the need to modify any external piping (Fig 4).

Mixing of ammonia downstream of an AIG is highly dependent on the local turbulence level in the gas; thus the holes in the new grid are spaced over its entire 33-ft length. Plus, all holes point directly downstream, unlike those in the original design. The turbulence level downstream of the fine-pitch CO catalyst is very low; the new baffles greatly improve ammonia mixing.

In addition, there was a large wall at the base of the CO catalyst bed which created a large recirculation zone along the floor. The CFD model was used to design plates that were added around the perimeter of the CO catalyst to direct exhaust flow directly into the AIG and avoid sneakage along the sides, top, and bottom into those recirculation zones.

With the addition of AIG mixing baffles and CO catalyst ducting baffles, gas flow from the CO catalyst now flows uniformly into the AIG injection area. When compared to the baseline AIG pressure drop, the new design added only 0.2 in. H_2O. More importantly, the final CFD design reduced the ammonia velocity distribution to 5.8% RMS, well below the design goal of no more than 10% RMS (Fig 5).

Accelerated construction. Concord Environmental was awarded the design, supply, and installation contract for removing the old AIG and installing the upgrades after the CFD modeling report was completed and the results presented to the plant owner in early October 2017. However, the owner had earlier scheduled a plant outage for Nov 1-14, 2017, so there was less than a month available to design and fabricate the new AIG and baffles, select, and mobilize the contractor at the job site, and complete installation.

Concord selected a non-union contractor based on its experience and ability to meet the project's compressed schedule. The new AIG tubes and baffles were quickly fabricated by one of company's preferred fabrication shops, arriving onsite October 30.

By that time, the contractor had mobilized onsite and had completed the demolition and removal of the old AIG. Construction crews worked two 12-hr shifts to complete the AIG upgrades on both HRSGs on schedule. Installation of the new AIG and baffles was completed November 13, one day ahead of schedule.

Operating data after startup. After the outage was completed, initial startup data showed significant reduction in ammonia flow, which translates into reduced localized ammonia concentrations (table).

Ammonia usage has decreased by 15% to 25% depending on load, and pressure drop in Module 5 has held steady for the past six months based on station instrument readings. The result has been a reduction in plant operating cost through the reduction of ammonia usage, avoiding the operating efficiency loss experienced with ABS fouling of Module 5, and will greatly reduce the future cost to clean the ABS from Module 5 tubes. CCJ

ISO 16890, a new global test standard, facilitates comparison of alternative filters

There's a new test standard for evaluating the efficiency of HVAC and industrial air filters—Classes G1 to F9. ISO 16890, which completed an 18-month phase-in period in June 2018, is the first uniform filter standard for the world, Jason Tiffany, a product development engineer in the Gas Turbine Systems unit of Donaldson Company Inc, told the editors.

"Efficiency" refers to the percentage of particulates a filter actually captures. Until now there were two very different regional standards for air-filter efficiency: ANSI/ASHRAE Standard 52.2 in the US and EN779 in Europe. Users in Asia and the Middle East referenced both standards, as well as others. While 52.2 and 779 aim to measure similar performance criteria, Tiffany said, they do so in disparate ways that defy comparison.

Efficiency conversion tables have been guesswork at best, he added, making it difficult for both suppliers and users of filters to communicate effectively in an increasingly global industry. The introduction of an international standard for efficiency and dust-holding capacity relieves at least some of this confusion.

Tiffany noted that ISO 16890 is not simply a change in measurement language, as in metric versus English. Rather, it's a way the test is conducted and product ratings are determined. The methodology aims to better represent actual dirty air in the outside environment and report how well various filters clean it.

The new standard focuses on classes of particulate matter (PM) to align with concerns of the World Health Organization and Environmental Protection Agency, and similar national organizations worldwide, regarding hazards to human health. Specifically, Tiffany continued, ISO 16890, measures the average capture of particulates with diameters in these three ranges:

- PM1 or ePM1, from 0.3 to 1 µm.
- PM2.5 or ePM2.5, from 0.3 to 2.5 µm.
- PM10 or ePM10, from 0.3 to 10 µm.

Filters qualify for one of these efficiency classes if they demonstrate, on average, at least 50% efficiency. If a filter fails to achieve 50% collection efficiency in *any* category, it is designated as "coarse." A filter's efficiency rating is reported next to its classification—PM1-65%, for example. It's a straight-forward rating system. Note that the stated efficiency is rounded down in 5% increments. This means that if the test results showed 67% capture, the stated number would be 65%.

Also important: ISO 16890 recognizes that an electrostatic charge on new filters can provide an initial performance advantage that dissipates over time. The test procedure assures comparison of alternative filters on a level playing field this way:

1. Measure the efficiency of the clean filter as supplied.
2. Condition the filter to eliminate the electrostatic charge.
3. Measure the efficiency of the clean, conditioned filter.
4. Calculate the efficiency as the average of the conditioned and unconditioned filters. Important: To qualify for a certain PM classification, *both* the conditioned and unconditioned filters must achieve a minimum 50% efficiency.

The table, which compares filter ratings by test standard for Donaldson's Spider-Web® product line found in many gas-turbine applications, illustrates the value of the new performance standard to owner/operators (photo). Using the EN779 standard, which uses only one particle size (0.4 µm), all the filters listed in the first column appear to have the same performance.

In the US, ASHRAE 52.2 tests a variety of particulates, but its weakness is an imprecise rating scheme. MERV (Minimum Efficiency Reporting Value) ratings from 1 to 16 are meant to correlate with performance—the higher the number the more efficient the filter. However, some data have shown a negligible difference in real efficiency between filters rated MERV 8 and 11, and a big performance jump between MERV 11 and MERV 13.

Comparing filter ratings by test standard

Donaldson Spider-Web® filter	EN779	ASHRAE 52.2	ISO 16890
Duratek	F9:2002	MERV 13	PM1-60%
Duratek XP	F9:2002	MERV 15	PM1-80%
Synthetic	F9:2002	MERV 13	PM1-60%
Synthetic XP	F9:2002	MERV 15	PM1-80%
Synthetic XP2	F9:2012	MERV 15	PM1-85%

Tiffany points out that the ISO rating method is designed to be more accurate and provide absolute values, rather than a relative scale. Note the better performance of the XP2 filter compared to the XP filter. Both the EN and ASHRAE tests rated them equal. The additional information allows a user to justify spending more for the XP2 filter if its better performance was of commensurate value to the plant.

Users are not likely to abandon MERV or EN779 ratings overnight. Tiffany believes there will be a gradual conversion to the new standard as equipment tests are completed. Donaldson, for example, will continue to classify its filters under all major rating schemes until ISO 16890 becomes predominant in the market.

Tiffany summed up the main benefits of the new standard this way:

- Users are able to compare filters on an apples-to-applies basis, even those made in different countries. The ISO standard gets everyone speaking the same language and helps companies collaborate across borders.
- ISO 16890 mimics real-world environments better than ASHRAE and EN—especially regarding outdoor air. Plus, the ISO reports are easier to interpret. Selecting a filter for a given climate, application, or cost is simpler.
- The new test will bring reported test results in the industry up-to-date. To earn an ISO rating, manufacturers have to get their filters retested—a significant investment. By buying an ISO-rated filter, a customer is assured its efficiency has been verified since the end of 2016. By contrast, a MERV rating could be 15 years old. CCJ

Duratek gas-turbine inlet filter performed well in ISO testing

BUSINESS PARTNERS

Departure of industry leaders accelerates

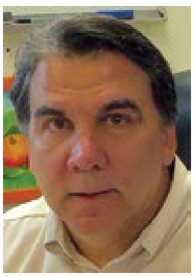
For several years, a topic of discussion at virtually every user-group meeting attended by the editors was that the industry is ageing rapidly and retirements are near at hand. The question, "Who was going to fill the shoes of the talented managers, supervisors, and O&M personnel heading for the exit?" was asked over and over again.

There were answers, of course, but few in a position to do something about the coming exodus of the industry's most experienced were really listening and fewer still seemed willing to act on what they heard and knew in hearts should be done.

The obvious answer to some who manage the financial services firms that are a dominant force in the electric generation sector today was to reduce staff in lock step with departures. Nothing wrong in managing with a sharp pencil, but there comes a point when you're cutting muscle and bone, not fat. It takes significant commitment and effort to steer clear of that reef.

The first guidance on how to prepare for the coming sea change the editors remember was offered about a decade ago by a pair of industry leaders, Rich Evans and Dr Robert Mayfield. They weren't the only ones, to be sure, but both were plant managers who clearly saw the handwriting on the wall, were sensitive to the need for continuing personnel development, and were active participants in two of the industry's most vocal users groups.


Evans


Mayfield

Both Evans and Mayfield began by reaching out to colleagues via CCJ's Best Practices Awards program. In 2005, Evans was plant manager of Wolf Hills Energy, a six-unit aero peaking facility, and among the first award recipients. In the first 10 years of the recognition program, Mayfield's 3 × 1 F-class Tenaska Virginia Generating Station, earned more awards than any other plant in the nation.

Their unrelenting commitment to the industry and its people is without question. A decade ago, Evans was on the CTOTF™ executive committee as the vice chair for power systems. He was the driving force behind the user group's initiative to identify and attract promising technicians and engineers to the gas-turbine sector of the industry and to make sure there were career rewards in place to retain them.

To get the proverbial ball rolling, he developed and chaired an interactive forum with a panel of true experts in generation-plant management to help guide those wanting to listen.

Mayfield, by contrast, has been a passionate speaker at 7F, CTOTF, and Combined Cycle user groups meetings on workforce development through Career and Technical Education programs. Plus, a frequent lecturer and author on knowledge management initiatives to guide plants on how to retain what their employees have learned on the job.

Mayfield's contributions to the industry were recognized by the Combined Cycle Users Group during its annual meeting at the end of August in Louisville where he received the organization's 2018 Individual Achievement Award.

The user groups provided the forums for discussion and helped the industry plan for the transition, but little that is visible has been done to develop new talent in a meaningful way—except possibly at a few companies managed by power professionals. Given that retirements to this point have occurred at what might be considered a relatively manageable rate, what about the next couple of years?

In July 2018 alone at least three key industry contributors said goodbye: Paul Tegen of Cogentrix Energy Power Management LLC, Joe Schneider of NRG Energy, and John Demcko of Arizona Public Service Co. Others have told the editors they'll be gone by year-end or a couple of weeks thereafter—including Evans.

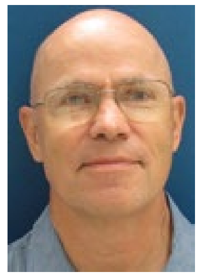
As you read though the biographical snapshots saluting the July departures ask yourself how the industry can absorb such losses—particularly in a time when the OEMs are laying off thousands, small shops are closing up, and leadership is in short supply. To minimize the chaos, what incentives should be offered to talented personnel to cope with the pain?


Tegen

Paul Tegen was chief combustion turbine/I&C engineer at Cogentrix. He served as the Westinghouse roundtable chair at CTOTF in the early 1980s, then teamed up with Bill Wimperis, Bill Barras, and a few others to launch the 501F Users Group. Tegen was elected the group's first chairman and served in that capacity for about 10 years. He was required to resign when Cogentrix sold its 501F plants, then returned as vice chairman a few years later when his employer bought other 501F assets.

Tegen also was the de facto floor leader at V Users Group meetings in the mid-2000s when Cogentrix owned a pair of V machines in the Caribbean. That user meeting was, and still is, organized by Siemens. The 2018 conference was being conducted in Denver, September 10-13, when this issue of CCJ went to press.

Tegen joined Northern States Power Co in 1976, after graduating from the Milwaukee School of Engineering with a degree in electrical engineering. First job was as a results engineer. Siemens Power Corp (the Siemens entity serving the US market before the company bought Westinghouse) was his next stop where he specialized in controls work. Then it was back to NSP for a year or so before joining LS Power in the mid-1990s as project manager for the 501FC-powered LSP Whitewater Cogen LP. He was then appointed plant manager.


Schneider

Joe Schneider was manager of gas-turbine maintenance in NRG's engineering and technical services group. He had an interesting career and, in his words, "Went out on top." Schneider shared his expertise with the industry as a member of the steering committees for both CTOTF (Siemens roundtable and program chair) and the Combustion Turbine and Combined Cycle Users Organization (CTC^2).

Reflecting, Schneider said mentoring industry newcomers was the part of his job he enjoyed most. He tipped his hat in admiration to plant personnel—especially those responsible for units in their twilight years. There's nothing harder to do, in his opinion, than to keep those engines running in a manner that meets management expectations with little tangible support.

After a few years in the aircraft industry, Schneider migrated to Alaska in the early 1980s to work as a consulting engineer for AVEC, the Alaska Village Electric Co-op, which has more than

53 member villages—most fairly remote and dependent on diesel power. He was involved in the design and installation of village electrification projects. Next gig was with Coffman Engineers doing engineering, installation, and commissioning of village cogeneration projects involving electric power, fresh water production, and sewage treatment.

Demcko

From 1986 to 1999, Schneider was at Chugach Electric Assn Inc where he gained experience in hydro-turbine and Frame 5 maintenance and overhauls before moving to the Beluga plant as a maintenance supervisor for work on 11Ds and 7B to E conversions. During his last six years at Chugach, he was involved in outage planning and maintenance of all the utility's generating units, plus their integration with the so-called railbelt utilities.

Moving to Houston in 1999, Schneider's career snaked through the deregulation era with assets changing ownership frequently over the years—Houston Lighting & Power to Reliant to RRI to GenOn (which merged with Mirant) to NRG. He had engineering positions at a couple of plants and in central engineering offices before being appointed NRG's manager of gas-turbine maintenance.

John Demcko, PE, was a senior consulting engineer for Arizona Public Service Co. He has been a member of the Generator Users Group steering committee since the organization's founding. Demcko has 45 years of professional experience with GE, New York Power Pool (now NYISO), and APS. He plans to migrate into active consulting in 2019 (visit www.eumacinc.com).

APS responsibilities included the implementation of digital-fault-recorder (DFR) technology for monitoring all of the company's major generating units; development of techniques and instrumentation to enhance the utility's ability to perform predictive maintenance; troubleshooting and upgrading of excitation systems; and the introduction of new test and measurement technologies to alert and inform on power-quality problems.

Demcko has authored more than 70 technical publications on generator monitoring, control and protection, and power-system instrumentation and measurements. He received his BS and MS degrees in electrical engineering from Clarkson University.

Conval's advanced manufacturing center focuses on HRSG user needs

HP superheater and reheater drain-system designs and operating practices that do not remove all condensate prior to initiation of steam flow during cold, warm, and hot startups are unable to protect tube-to-header connections, header bores, and nozzle-to-header connections from severe thermal fatigue damage. Such damage has resulted in many premature tube failures and can be expected to cause header bore cracking and/or nozzle-to-header weld failure.

Damage mitigation demands reliable, leak-tight operation of both tube-panel drain valves and attemperator block valves (to help prevent water entry into tube panels). Conval Inc (www.conval.com), which recently dedicated a 72,000-ft^2 advanced manufacturing center (photo right) in Enfield, Ct, 13 miles down I-91 from Bradley International Airport, has been an industry leader in the supply of US-made forged severe-service valves for half a century.

The company previously made its globe, gate, and ball valves for high-temperature/high-pressure service at a three-building campus in Somers, Ct.

Conval VP Mike Hendrick, who participated in the *HRSG Forum with Bob Anderson* (www.hrsgforum.com) last March (2018), told the editors he prefers ball valves for meeting the on/off (never throttling) demanding service needs of isolation, vent, and drain valves.

For the temperatures and pressures experienced in today's advanced combined cycles, Conval offers ball valves up to 4 in. This size range satisfies most HRSG applications, including attemperator block valves. Note that final superheater harp in a typical F-class HRSG requires the equivalent of three 2-in.-diam drain lines to effectively remove the condensate collected.

Hendrick urged users to select their drain and block valves carefully, making sure metal seats are available when service temperatures are 400F and above, stems are blowout-proof, seat leakage meets the tightest specs after installation, coatings assure long life, and internals can be accessed in-line for inspection and maintenance.

Periodic review of best practices and lessons learned concerning drain and attemperation systems is particularly important today, *HRSG Forum* Chairman Bob Anderson told the editors, especially given the recent and pending retirements of the industry's most knowledgeable boiler personnel (see previous article). The steering committee is considering a presentation or discussion session on this topic at the 2019 meeting. Learn more at www.hrsgforum.com.

Industry news

Allied Power Group acquires Eta Technologies LLC; its principals, Richard Curtis and John Kearney, join Allied in leadership positions. APG President David Theis said "Eta's V-Series expertise fits seamlessly with APG's strategy of providing full-service solutions to the power generation industry—including turbine component repair, rotor repair, new parts manufacturing, and field service. . . ."

Mitsubishi Hitachi Power Systems announces the successful first fire of its three M501J gas turbines at Dominion Energy's 1558-MW Greensville County Power Station. MHPS claims global leadership in the development and delivery of 60-Hz advanced gas turbines rated above 250 MW with 158 units ordered since their first delivery in 2001.

In related announcements, the manufacturer signs an agreement with Gaz Energie to develop a 515-MW gas-fired project that will have the lowest cost of electricity and the lowest emissions of any generating station in Peru when it goes into service in 2021.

MHPS also announces the integration of its Pratt & Whitney Power Systems industrial gas turbine business into Mechanical Dynamics & Analysis. The unified team at MD&A offers a full suite of services, parts, repairs, and upgrades for the 7EA, 7FA, and V94.3AX gas turbines in simple- and combined-cycle configurations.

FIRST/TBS announces Level I Basic and Level II Advanced machine-shop training. The three-day programs consist of a one-day classroom component and two days of hands-on training on lathes, milling machines, etc. In hands-on training, every student manufactures a finished product using drawings and step-by-step instruction.

Indeck Power promotes Ken Altman to service manager. He brings over 30 years of boiler experience to his new role, 17 with Indeck, which stocks boilers rated up to 250,000-lb/hr for immediate shipment on a lease/rental or sale basis.

Vistra Energy Corp, the parent of TXU Energy and Luminant, completes its previously announced merger with Dynegy Inc. Vistra Energy now employs about 6000 people across 12 states and owns about 40,000 MW of generating capacity—more than 60% powered by natural gas and all but 16% located with the Ercot, PJM, and ISO New England markets.

Doble Engineering Co creates new division dedicated to NERC compliance initiatives and hires James Holler, well known in this sector of the industry, as its director of regulatory compliance.

Babcock Power Environmental Inc purchases substantially all the assets of Geo-Synthetics LLC, which offers a full range of erosion and sediment controls and fabricates geotextile tubes for dewatering and materials handling solutions.

Babcock Power Inc appoints Christopher Turner president/CEO of Vogt Power International Inc; he was VP engineering. Before joining Vogt, Turner worked at GE and AAF International.

Ansaldo Energia appoints Giuseppe Zampini managing director, replacing Filippo Abba, who resigned.

Emerson and AspenTech form an alliance to deliver digital technologies. Initial focus will be on engineering software, supply chain software, and asset performance management. In related news, Emerson acquired Pro-Sys Inc, a global supplier of software and services that increase production and safety at companies in the chemical, oil and gas, pulp and paper, and refining industries.

Swift Filters Inc announces a new line of desiccant breathers for industrial equipment. The Swift-Dri™ breathers block moisture and particulates contained in ambient air from entering hydraulic-system reservoirs, gearboxes, diesel fuel-oil storage tanks, and pumps.

Siemens announces the following:

- SGT-800 upgrade is designed to provide owner/operators significant fuel savings and CO_2 emissions reduction. For 2 × 1 combined-cycle applications, the enhancement could boost output by more than 20 MW while improving heat rate by 3.5%. Upgrade includes improved compressor-blade design for better aerodynamic performance, optimized gas-path mass flow, and component cooling in the turbine section.

- UAE orders three SGT5-4000F gas turbines for the Al Aweer powerplant complex located about 25 miles from downtown Dubai. The additional 815 MW produced by the new equipment will raise Al Aweer's output to 2800 MW.
- Panama orders six SGT-800 gas turbine/generators for a new plant to be located by the seaport of Colon on the Caribbean coast. Siemens also is providing the steam turbine/generator for the 6 × 1 combined cycle. Fuel is LNG, first generation is expected in fall 2020.
- Inter Pipeline Ltd orders two SGT-800s for the company's Heartland Petrochemical Complex under construction near Fort Saskatchewan in Canada's Alberta province.
- Huadian Fuxin Energy Corp Ltd, one of China's five state-owned power producers, orders the country's first H-class gas turbines from Siemens for a combined cooling, heat, and power project in the Zengcheng District of Guangzhou City. Siemens is helping the district replace small coal-fired boilers with clean natural-gas-fired systems. The OEM also plans to digitally upgrade and network gas, steam, and wind turbines and PV for optimal dispatch.

  Output of the 50-Hz units is more than 670 MW at ISO conditions; net generating efficiency reportedly is greater than 62%. Siemens had sold 88 H-class gas turbines worldwide as of April 2018; 65 units were in operation.
- Five compressor trains, each consisting of an SGT-400 gas turbine and a single-shaft pipeline compressor, were supplied to Fermaca Enterprises for two pipeline stations in Mexico.
- Siemens has rebranded and renamed its full subsidiary NEM Energy into Siemens Heat Transfer Technology BV.
- ASME recognizes Siemens with its Emerging Technology Award for the company's first successfully 3D-printed and fully tested gas-turbine blades.
- Siemens and Chromalloy are recognized by Florida Governor Rick Scott for selecting Hillsborough County as the headquarters location for their new joint venture, Advanced Airfoil Components. The company will be located in a 210,000-ft^2 facility in the Tampa Regional Industrial Park; scheduled opening is late 2018.
- Siemens is now offering its SGT-800 industrial gas turbine with a power output of 57 MW and an electrical efficiency of more than 40% in a simple-cycle configuration. When this engine is incorporated into a 2 × 1 combined cycle, output is 163 MW and net efficiency 58.5%. The turbine, originally known under the product name GTX100, was launched in 1997.

Generator Users Group recognizes Consultant Jane Hutt with its 2018 Maughan Award, named in honor of Clyde V Maughan (see page 3), during the organization's annual meeting in Louisville at the end of August. GUG Chairman Ryan Harrison of ATCO Power read the following inscription to the assembled group: "For her outstanding leadership in the pursuit of open communication between generator users and the design/maintenance community. Through her direction and dedication, the International Generator Technical Community (IGTC) online forum has grown to 4200+ present members worldwide."

Combined Cycle Users Group recognizes Dr Robert Mayfield, plant

manager of Tenaska Westmoreland Generating Station, and Robert Krowech, PE, founder of HRST Inc, today perhaps the nation's leading independent HRSG aftermarket products and services firm, with the organization's 2018 Individual Achievement Award.

Mayfield, a former naval officer, spent 27 years on active duty, achieving the rank of submarine commander. Career highlights include service on four nuclear submarines and as academics director of the Naval Nuclear Power School.

After retiring from the Navy, he spent 15 years as plant manager of the 3 × 1, 7FA-powered Tenaska Virginia combined cycle where Mayfield and his team gained recognition as one of the nation's model OSHA VPP Star sites. Plus, they received the Virginia Governor Volunteer and Community Service Award for their hands-on work in promoting science, technology, engineering, and math at elementary and higher schools in the area.

In his spare time, Mayfield has served as an adjunct professor at the graduate-school level and has written two books and numerous publications. He is a tireless advocate for STEM and CTE (Career and Technical Education).

COMBINED CYCLE Journal 2Q/2018

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Products and services from over 100 companies support new unit construction, retrofit and maintenance activities at existing facilities, and plant operations. Solutions span gas and steam turbines, HRSGs, pumps, valves, piping, cooling towers, condensers, etc

Advanced Filtration Concepts

Offers new and innovative filtration products for the GT/CC power industry. Invest to save with inlet air filters that are high efficiency, low back-pressure, and long lasting. As the largest stocking distributor of industrial air filters in the West, AFC is equipped to meet your most urgent GT inlet filtration needs. Turnkey installation available.

Advanced Indoor Air Quality Care

Specializes in cleaning heavy-duty equipment, power generation facilities, and electric utility plants. Options of cleaning include dry-ice blasting, soda blasting, and media blasting depending upon the project.

Advanced Turbine Support

Has delivered unbiased fleet experience and superior customer service for more than a decade. Company provides users high-resolution borescope inspections, cutting edge ultrasonic and eddy-current inspections, and magnetic-particle and liquid dye-penetrant inspections in accordance with OEM Technical Information Letters and Service Bulletins.

AECOM

Power Business Unit specializes in single-point management for grassroots, retrofit, and expansion projects for power industry clients, having engineered and/or constructed more than 280,000 MW of electricity worldwide.

Aeroderivative Gas Turbine Support

AGTSI offers a full range of aeroderivative gas-turbine, off-engine, and package parts from the most basic to the most critical. An expansive inventory of spares and replacement parts is maintained at our warehouse for all models of GE LM2500, LM5000, LM6000, and LMS100, as well as P&W GG4/FT4.

AGTServices

Over 200 years of combined, proven OEM engineering, design, and hands-on experience; known in the industry for its schedule-conscious, cost-effective solutions with respect to generator testing and repairs.

American Chemical Technologies

Provides state-of-the-art synthetic lubricants to the power generation industry. Founded more than 30 years ago in the US, ACT has grown to become an international supplier of value-added lubricants that provide superior benefits to equipment, the environment, and are worker-friendly.

ARNOLD Group

With more than 550 installed insulation systems on heavy-duty gas and steam turbines, company is the global leader in designing, manufacturing, and installing the most efficient and reliable single-layer turbine insulation systems.

Associated Fire Protection

Specializes in the design, installation, commissioning, and 24/7/365 service and aftermarket support of all types of fire protection and life safety systems for the power generation and petrochemical industry. ISO 9001:2015 certified company.

BBM-CPG Technology

Leader in industrial noise control with a proven engineering team and high-quality manufacturing, specializing in design and manufacturing of enclosures, exhaust plenums and ducts, shrouds, flue-gas and steam silencers, and air filtration systems.

Bearings Plus Inc

Provider of repairs and custom technology upgrades for turbomachinery. Designs and manufactures an integrated solution to meet specific requirements for every operating environment, applying the latest fluid film bearing and high-performing seal technology to legacy equipment to optimize performance.

Bremco

Full-service industrial maintenance contractor since 1976. Company experience in combined-cycle projects includes header, tube, and

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complete panel/harp replacements. We also have significant experience in liner repairs/upgrades, duct-burner repairs, penetration seals, and stack-damper installations.

C C Jensen Oil Maintenance

Manufactures CJC™ kidney-loop fine filters and filter separators for the conditioning of lube oil, hydraulic oil, and control fluids. Our extensive know-how ensures optimal maintenance of oil systems and equipment reliability.

Caldwell Energy

Power augmentation, including inlet fogging and wet compression solutions, boosts the output and efficiency of gas turbines. With more than 400k hours of operating experience in power generation, these systems offer proven performance and are backed by a three-year warranty.

Camfil Farr Power Systems

A world leader in the development, manufacture, and supply of clean air and noise reducing systems for gas turbines. A correctly designed system minimizes engine degradation, leading to lower operating costs, optimum efficiency, and less environmental impact.

Cemtek KVB-Enertec

Leading supplier of custom-engineered extractive, dilution, and mercury CEMS from single units to multiple complex units in cabinets and shelters; and provider of support for compliance and non-compliance applications.

Chanute Manufacturing

Contract fabricator of HRSG products—including finned tubes, pressure-part modules, headers, ducting, casing, and steam drums.

Cormetech

The world's leading developer, manufacturer, and supplier of catalysts for selective catalytic reduction (SCR) systems to control emissions of nitrogen oxides from stationary sources. Cormetech SCR catalysts are highly efficient and cost-effective where systems must be capable of reducing NO_x by more than 90%.

COVERFLEX Manufacturing

Offers superior removable insulation systems for an array of gas and steam turbines. Based on OEM turbine designs and feedback from plant managers, insulation systems are custom-designed to provide comprehensive thermal protection.

Creative Power Solutions

CPS is a group of engineering companies in the power generation and energy utilization sector. Its mission is to provide advanced, efficient, and customized technology solutions to clients ranging from OEMs to plant operators and energy consumers.

Crown Electric Engineering & Manufacturing

Engineers, designs, fabricates, and installs isolated phase bus, large bus duct systems, and outdoor switchgear. Specializes in rapid response needs such as IPB for GSU change-outs, quick-ship fabrication, and emergency on-site service needs.

Cust-O-Fab Specialty Services

Provides the latest technology in exhaust plenums, exhaust ductwork, and exhaust interior liner upgrades that will drastically reduce external heat transfer, making the unit safer and more efficient and easier to operate and maintain.

Cutsforth

Our experience and innovative designs have brought best-in-class brush holders, collector rings, shaft grounding, and onsite field services for generators and exciters to some of the world's largest power companies.

DEKOMTE de Temple

Manufactures fabric and metal expansion joints which compensate for changes in length caused by changes in ductwork temperature. Axial, lateral, or angular movements can be compensated for. Company has gained a global reputation for ingenuity of design and quality of products.

Donaldson Company

Leading worldwide provider of filtration systems that improve people's lives, enhance equipment performance, and protect the environment. Donaldson is committed to satisfying customer needs for filtration solutions through innovative research and development, application expertise, and global presence.

ECT-Engine Cleaning Technologies

Offers R-MC and PowerBack gas turbine and compressor cleaners to eliminate compressor fouling. Additionally, ECT designs specialty nozzle assemblies and custom pump skids for the proper injection of chemicals and water for cleaning, power augmentation, and fogging.

Environex Inc

Engineering and consulting experts in post-combustion NOx and CO control technologies. Primary focus is SCR and oxidation catalyst testing and system maintenance, catalyst management and selection, troubleshooting, and design.

Emerson Automation Solutions

Ovation™ control system offers fully coordinated boiler and turbine control, integrated generator exciter control, automated startup and shutdown sequencing, fault tolerance for failsafe operation, extensive cyber security features, and embedded advanced control applications that can dramatically improve plant reliability and efficiency.

EthosEnergy

This JV between Wood Group and Siemens is a leading independent service provider of rotating equipment services and solutions. Globally, these services include EPC; facility O&M; design, manufacture, and application of engineered components, upgrades, and re-rates; repair, overhaul, and optimization of gas and steam turbines, generators, pumps, compressors, and other high-speed rotating equipment.

Evapco-BLCT Dry Cooling Inc

Specializes in the design and supply of air-cooled condensers (ACCs) and air-cooled heat exchangers (ACHEs) for the power industry with over 5000 MW of operating references in the USA and considered a premier ACC supplier for the global power market.

EvapTech Inc

Full service provider of new towers and aftermarket services for field erected cooling towers. World leader in evaporative and hybrid cooling technologies specializing in design, component manufacturing, construction services, parts, upgrades, and consultation.

Falcon Crest Aviation

Distributor of ZOK27 and ZOKmx gas-turbine compressor cleaning detergents. ZOK27 is a single cleaner and inhibitor in one that cleans and protects the engine—and also inhibits corrosion. ZOKmx is a power cleaner formulated to replace solvents providing exceptional cleaning without the health and environmental risks associated with solvents.

Federal Steel Supply Inc

Distributor of seamless HRSG high-energy pipe and power piping. Scheduled and heavier than scheduled walls in stock for headers, steam lines, etc. SA106 B/C and SA335 P11/P22/P91. Fittings to complement all pipe. Offering cut-to-length, custom fittings, specialty end preparation, supplemental testing, and emergency same-day shipments.

Frenzelit North America

Specializes in providing long-term expansion-joint solutions for gas-turbine exhaust applications. In addition to manufacturing superior quality expansion joints, Frenzelit also makes HRSG penetration seals, insulating materials, and acoustic pillows for silencers.

Gas Turbine Controls

World's largest stock of GE Speedtronic circuit boards and components for the OEM's gas and steam turbines. GTC stocks thousands of genuine GE-manufactured cards for the MKI, MKII, MKIII, MKIV, MKV, MKVI, and LCI controls, as well as EX2000, Alterrex and Generrex excitation.

Groome Industrial Service Group

Offers a variety of SCR and CO catalyst cleaning and maintenance services nationwide and has formed strategic alliances with industry experts and catalyst manufacturers to ensure that Groome offers the most widely supported, comprehensive, turnkey service available.

GTC Services

Field engineering company offers gas-turbine owners and operators worldwide "Total Speedtronic Support." Engineers have decades of experience servicing and troubleshooting all GE Speedtronic systems.

Haldor Topsoe

Our air pollution technology includes a series of unique catalysts for Selective Catalytic Reduction (SCR) systems for the control of nitrogen oxides (NO_x), and the reduction of carbon monoxide (CO) and volatile organic compounds (VOCs), from stationary and mobile sources.

Hilliard

The HILCO® Division cost-effectively brings fluid-contamination problems under control and engineers a full-range of filters, cartridges, vessels, vent mist eliminators, transfer valves, reclaimers, coolant recyclers and systems, and membrane filtration systems.

HRST

Specializes in technical services and product designs for HRSGs, waste heat boilers, and smaller gas or oil fired power boilers globally. Experience on over 200 boilers annually and able to provide quality inspections, analysis work, design upgrades, professional training, and more.

Hydro

Engineered solutions enable combined-cycle plants to achieve pump reliability and reduced O&M costs. As the largest independent pump rebuilder, Hydro works hand-in-hand with pump users to optimize the performance and reliability of their pumping systems.

Hy-Pro Filtration

Provides innovative products, support, and solutions to solve hydraulic, lubrication, and diesel contamination problems. Company's global distribution and technical-support networks enable customers to get the most out of their diesel, hydraulic, and lube-oil assets. ISO 9001 certified.

JASC

Engineers and manufactures actuators and fluid-control components for power generation, aerospace, defense, and research applications to improve operational capability and performance.

KnechtionRepair Tools

Manufactures tools designed to make thread repairs to both the female and male ends of cross-threaded compression fittings. In most cases, the repair will be accomplished without removing the tube from the system. This saves the O&M tech time and avoids additional downtime.

Kobelco Compressors America

Provides robust, high-efficiency fuel-gas compressors for use with all major types of gas turbines—including GE, Mitsubishi, Alstom, Siemens, Rolls-Royce, and Solar. Over 300 of the company's screw-type compressors have been supplied for gas turbines.

Liburdi Turbine Services

Advanced repairs employ the latest technologies and are proven to extend the life of components for all engine types. Company specializes in high-reliability component repairs and upgrades for blades, vanes, nozzles, shrouds, combustors, and transitions.

M & M Engineering

Provides failure analyses and related services to industrial and insurance-company clients. M&M's expertise includes corrosion in boilers, steam turbines, generators, combustion turbines, deaerators, feedwater heaters, and water and steam piping.

Mechanical Dynamics & Analysis

One of the largest turbine/generator engineering and outage-services companies in the US. MD&A provides complete project management, overhaul, and reconditioning of heavy rotating equipment worldwide.

Membrana, a 3M company

Market-leading producer of microporous membranes and membrane devices used in healthcare and industrial degassing applications. The Industrial & Specialty Filtration Group manufactures Liqui-Flux® ultrafiltration and microfiltration modules as well as Liqui-Cel® membrane contactors.

Mitten Manufacturing

Leading fluid system packager for numerous OEMs, EPC firms, utilities, and plant operators all over the world offering a number of value-added designs, spare parts management, and field services.

Multifab Inc (MFI)

Over 40 years of experience in design and manufacturing of products used for high-temp equipment along with air and flue gas applications. Offers a wide variety of services for all types of expansion joints, dampers, and high-temp products including installation, removal, repair, and splicing.

NAES

One of the world's largest independent providers of operations, construction, and maintenance services, provided through a tightly integrated family of subsidiaries and operating divisions. NAES services include O&M; construction, retrofit, and maintenance under dedicated long-term maintenance or individual project contracts; and customized services designed to improve plant and personnel effectiveness.

National Breaker Services

Industry leader in switchgear life optimization, life extension, and system upgrades. Manufactures new, highly customized low- and medium-voltage switchgear and provides on-site troubleshooting, maintenance, and testing of existing systems.

National Electric Coil

Leading independent manufacturer of high-voltage generator stator windings with expertise in design and manufacturing of stator windings for any size, make, or type of generator. This includes diamond coils, Roebel bars—including direct cooled, inner-gas, and inner-liquid cooled bars—and wave windings.

Parker Balston

Develops and manufactures nitrogen generators for all your power generation needs including boiler layup, gas seals, purging gas lines prior to service, blanketing demin water tanks, and LNG terminals.

Parker Hannifin

Reduce costs and optimize performance with the world's leading diversified OEM of motion, flow, process control, filtration, and sealing technologies, providing precision engineered solutions for the power generation market.

Parker Hannifin Gas Turbine Filtration

With over 50 years of experience delivering innovative solutions for GT inlet filtration and monitoring fleet-wide performance data, our industry and applications experts will select the appropriate filter for your site designed to meet specific operating goals.

FIND A VENDOR, FIX A PLANT

Power Service Consultants

Boutique consulting group focusing on LTSA contract negotiation support for owner/operators of gas turbines, steam turbines, and generators. With over 30 years of experience in power systems service, our focus is to drive down avoidable maintenance costs.

Praxair Surface Technologies

Leading global supplier of surface-enhancing processes and materials, as well as an innovator in thermal spray, composite electroplating, diffusion, and high-performance slurry coatings processes. Company produces and applies metallic and ceramic coatings that protect critical metal components such as in gas turbines.

Precision Iceblast

World leader in HRSG tube cleaning. PIC cleans more HRSGs than any other ice blasting company in the world. It ensures that HRSGs operate efficiently by providing the cleanest boiler tubes possible.

PSM

Full-service provider to gas-turbine equipped generating plants, offering technologically advanced aftermarket turbine components and performance upgrades, parts reconditioning, field services, and flexible Long Term Agreements (LTAs) to the worldwide power generation industry.

PW Power Systems

Provides competitive, efficient, and flexible gas-turbine packages rated from 25 to 120 MW. PWPS offers a full range of maintenance, overhaul, repair and spare parts for other manufacturers' GTs with specific concentration on the high-temperature F-class industrial machines.

Rentech Boiler Systems

International provider of high-quality, engineered industrial boiler systems. Rentech is a market leader in providing HRSGs for cogeneration and CHP plants. It is in its second decade of designing and manufacturing high-quality custom boilers—including HRSGs, waste-heat boilers, fired packaged boilers, specialty boilers, and emissions control systems.

Sargent & Lundy

Provides complete engineering and design, project services, and energy business consulting for power projects and system-wide planning. The firm has been dedicated exclusively to serving electric power and energy-intensive clients for more than 120 years.

Siemens Energy

A leading global supplier for the generation, transmission, and distribution of power and for the extraction, conversion, and transport of oil and gas. Leadership in the increasingly complex energy business makes it a first-choice supplier for global customers. Known for innovation, excellence and responsibility, company has the answers to the sustainability, flexibility, reliability, and cost challenges facing customers today.

SNC Lavalin

Global engineering, construction, and project management company, and a major player in the ownership of infrastructure. Our passion for solving complex problems has allowed us to excel across many industrial sectors. We are a market leader in thermal power, having designed and constructed more than 50 GW of power capacity in over 200 locations.

SSS Clutch Company

Clutches enable operators to disconnect generators from simple-cycle turbines for synchronous-condenser service. Clutches also find application in CHP plants and in single-shaft combined-cycle facilities where operating flexibility is beneficial.

Strategic Power Systems

Provides products and services focused on capturing powerplant operational and maintenance data to develop reliability metrics and benchmarks for end users—including some of the most recognized organizations in the global energy market.

Sulzer

Provides cutting-edge maintenance and service solutions for rotating equipment dedicated to improving customers' processes and business performances. When pumps, turbines, compressors, generators, and motors are essential to operations, Sulzer offers technically advanced and innovative solutions.

TEC-The Energy Corp

Our skills and experience assist GT owners with front-end engineering, procurement of major equipment, and management of engineering, construction, and commissioning of new facilities. From due diligence to detailed design, TEC covers all phases of complex power projects.

TEi Services

Offers a full range of heat-transfer products and services and fully trained, certified maintenance personnel. Provides world-class emergency repair services, underpinned by a 75-yr history in the design and manufacture of condensers, feedwater heaters, and heat exchangers.

TesTex Inc

World leader in electromagnetic non-destructive testing (NDT). We continually define the state-of-the-art for the testing of ferrous and non-ferrous materials and structures through applied research and development.

Trinity Turbine Technology LP

Provides innovative, cost-effective and reliable gas and steam turbine maintenance solutions to industrial operators worldwide. We provide high quality and reliable turn-key outage support and component repairs with unmatched responsiveness and dependability.

ValvTechnologies

Global leader in the design and manufacturing of zero-leakage metal-seated ball valve solutions for severe service applications. Committed, dependable partner providing the best isolation solutions to ensure customer satisfaction, safety and reliability, and improved process and performance.

Vogt Power International

Supplies custom-designed HRSGs for GTs from 25 to 375 MW and has extensive experience in supplementary-fired units. Scope of supply includes SCR and CO systems, stack dampers, silencers, shrouds, and exhaust bypass systems.

World of Controls

Worldwide, low-cost provider of DCS circuit boards offering an array of ancillary services which include testing/repair of circuit boards, parts, DCS troubleshooting, Dos support, HMI upgrades/backup and field-based mechanical and controls training.

Young & Franklin

Premier fuel control supplier for combustion turbines for both long-term hydraulic solutions and, more recently, innovative all-electric controls solutions. Product scope supports natural gas, liquid, syngas, and alternative fuels as well as providing air controls to provide proper fuel to air mixtures.

Zokman Products

Distributor of ZOK27 and ZOKmx gas-turbine compressor cleaning detergents. ZOK27 is a single cleaner and inhibitor in one that cleans and protects the engine—and also inhibits corrosion. ZOKmx is a power cleaner formulated to replace solvents providing exceptional cleaning without the health and environmental risks associated with solvents.