CCJ

COMBINED CYCLE Journal

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Number 61 2019

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Reports from user group meetings

Feature articles

Register now for these user-group meetings

7EA Users Group

2019 Conference and Vendor Fair
November 3 – 7
Galt House Hotel
Louisville, Ky
Contact: Hostmaster@ge7ea.users-groups.com

AOG

Third Annual Conference
January 27 – 31, 2020
Magnolia Hotel, Houston, Tex
Attendance by invitation
Contact: Jeff Chapin, jchapin@aogusers.com

501F Users Group

2020 Conference and Vendor Fair
February 9 – 13
Hilton West Palm Beach
West Palm Beach, Fla
Contact: Tammy Faust, tammy@somp.co
www.501fusers.org

W.T.U.I. 1990 2020 Long Beach 2020

30th Annual Conference and Expo
March 29 – April 1, 2020
Long Beach (Calif) Convention Center
Contact: Charlene Raaker, craaker@wtui.com
www.wtui.com

Meetings focusing on user information needs

Fourth quarter 2019

October 21-24, ACC Users Group, 11th Annual Conference, Queretaro, Mexico, Grand Fiesta Americana. Details at www.acc-usersgroup.org. Chairman: Dr Andrew Howell, ahowell@epri.com. Contact: Sheila Vashi, sheila.vashi@sv-events.net.

October 30-November 1, Australasian Boiler and HRSG Users Group, 2019 Annual Conference, Brisbane, Queensland, Australia, Brisbane Conference & Exhibition Centre. Details/registration at www.ahug.co.nz. Chairman: Dr R Barry Dooley, bdooley@structint.com. Contact: rachel@meccaconcepts.com.au.

November 3-7, 7EA Users Group, Annual Conference and Exhibition, Louisville, Ky, Galt House Hotel. Details/registration at http://ge7ea.users-groups.com.

First three quarters of 2020

January 27-31, AOG (Alstom Owners Group) Users Conference, Third Annual Conference and Vendor Fair, Houston, Tex, Magnolia Hotel. Details/registration at https://aogusers.com as they become available. Contact: Jeff Chapin, jchapin@aogusers.com.

February 9-13, 501F Users Group, Annual Meeting, West Palm Beach, Fla, Hilton West Palm Beach. Details/registration at www.501fusers.org as they become available. Chairman: Russ Snyder, russ.snyder@cleco.com. Contact: Tammy Faust, meeting coordinator, tammy@somp.co.

March 10-12, Fourth International Conference on Film Forming Substances (FFS 2020), Strasbourg, France, Hilton Strasbourg. Details/registration at www.ppchem.com/event/ffs2020 as they become available. Chairman: Barry Dooley, bdooley@structint.com. Contact: Tapio Werder, tapio.werder@ppchem.com.

March 29-April 1, Western Turbine Users Inc, 30th Anniversary Conference and Expo, Long Beach, Calif, Long Beach Convention Center. Details/registration at www.wtui.com as they become available. Contacts: Charlene Raaker, conference registration coordinator, craaker@wtui.com; Wayne Kawamoto, conference executive director, wkawamoto@wtui.com.

March 29-April 2, CTOTF 45th Spring Conference & Trade Show, Louisville, Ky, Galt House Hotel. Chairman: Jack Borsch, john.borsch@ihipower.com. Details/registration at www.ctotf.org as they become available. Contact: Ivy Suter, ivysuter@gmail.com.

May 18-22, 7F Users Group, 2020 Conference & Vendor Fair, Dallas, Tex, Fairmont Dallas Hotel. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

May 26-28, European HRSG Forum, Seventh Annual Meeting, Strasbourg, France, Hilton Strasbourg. Details/registration at www.ppchem.com/event/ehf2020 as they become available. Chairman: Barry Dooley, bdooley@structint.com. Contact: Tapio Werder, tapio.werder@ppchem.com.

June 2-4, 501D5-D5A Users, 23rd Annual Meeting, St. Louis, Mo, Ritz-Carlton St. Louis. Details/registration at www.501d5-d5ausers.org as they become available. Chairman: Gabe Fleck, gfleck@aeci.org.

June 8-11, Frame 6 Users Group, Annual Conference & Vendor Fair, San Antonio, Tex, La Cantera Resort & Spa. Details/registration at www.Frame6UsersGroup.org as they become available. Co-chairs: Jeff Gillis, william.j.gillis@exxonmobil.com, and Sam Moots, smoots@coloradoenergy.com. Contact: Greg Boland, Creative Ventures Holding, conference manager, greg.boland@ceidmc.com.

Week of June 15, T3K Annual Conference, Orlando, Fla, Renaissance Orlando at SeaWorld. Meeting is co-located with the Siemens Customer Conference for F, G & H Technology. Chairman: Bob Lake, bob.lake@fpl.com. Contact: Elizabeth Moore, elizabeth.moore@siemens.com.

Week of June 15, Siemens Customer Conference for F, G & H Technology, Orlando, Fla, Renaissance Orlando at SeaWorld. Meeting is co-located with the T3K Annual Conference. Contact: Dawn McCarter, dawn.mccarter@siemens.com.

July 20-23, HRSG Forum with Bob Anderson, Fourth Annual Meeting, Orlando, Fla, Rosen Shingle Creek. Details/registration at www.hrsgforum.com as they become available. Chairman: Bob Anderson, anderson@hrsgforum.com. Contact: Alan Morris, commercial manager, amorris@morrismarketinginc.com.

July 26-30, Ovation Users' Group, 33rd Annual Conference, Pittsburgh, Westin Convention Center Hotel. Register for membership (end users of Ovation and WDPF systems only) at www.ovationusers.com and follow website for details. Contact: Kathleen Garvey, kathleen.garvey@emerson.com.

August 31-September 3, Combined Cycle Users Group (CCUG), 2020 Conference and Discussion Forum, San Antonio, Tex, San Antonio Marriott Rivercenter. Meeting is co-located with the Steam Turbine, Generator, and Power Plant Controls Users Groups; some joint functions, including meals and vendor fair. Details/registration at www.ccusers.org as they become available. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

August 31-September 3, Steam Turbine Users Group (STUG), 2020 Conference and Vendor Fair, San Antonio, Tex, San Antonio Marriott Rivercenter. Meeting is co-located with the Combined Cycle, Generator, and Power Plant Controls Users Groups; some joint functions, including meals and vendor fair. Details/registration at www.stusers.org as they become available. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

August 31-September 3, Generator Users Group (GUG), 2020 Conference and Vendor Fair, San Antonio, Tex, San Antonio Marriott Rivercenter. Meeting is co-located with the Combined Cycle, Steam Turbine, and Power Plant Controls Users Groups; some joint functions, including meals and vendor fair. Details/registration at www.genusers.org as they become available. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

31-September 3, Power Plant Controls Users Group (CUG), 2020 Conference and Vendor Fair, San Antonio, Tex, San Antonio Marriott Rivercenter. Meeting is co-located with the Combined Cycle, Steam Turbine, and Generators Users Groups; some joint functions, including meals and vendor fair. Chairman: Peter So, pso@calpine.com. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

Week of September 14, V Users Group, 2020 Annual Conference, Niagara Falls, NY, Hilton Niagara Fallsview. Contact: Dawn McCarter, conference coordinator, dawn.mccarter@siemens.com.

September 20-24, CTOTF Fall Conference & Trade Show, Reno, Nev, Peppermill Resort. Chairman: Jack Borsch, john.borsch@ihipower.com. Details/registration at www.ctotf.org as they become available. Contact: Ivy Suter, ivysuter@gmail.com.

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7F USERS GROUP

The world's largest meeting of frame gas-turbine owner/operators, hosted annually by the 7F Users Group, convenes at the Fairmont Dallas Hotel May 18, 2020 and runs through the 22nd. Preparations are well underway for the organization's 29th annual conference and vendor fair, expected to attract about 250 users and more than that number of commercial attendees representing the nearly 150 companies participating in the exhibit hall.

There are some personnel and program changes to report since the meeting last May in Schaumburg (Ill) as the user group evolves to better serve all participants.

First, several members of the steering committee (photo) have resigned, most because of reassignments by the companies they represent—including Eugene Szpynda and Past Chairs Ed Fuselier and Clift Pompee. Planned retirement caused Dave Such to give up his chair. Finally, Peter So left the 7F steering committee to devote more time to his multiple responsibilities at Power Users (the umbrella organization serving the 7F, Combined Cycle, Generator, Steam Turbine, and Power Plant Controls Users Groups) and as the chairman of the controls group.

Joining the 7F committee since the 2019 meeting are Timothy Null of Eastman Chemical and John Rogers of SRP. Matt Dineen of Duke Energy was elected chairman of the group for 2020, Christa Warren of Tenaska Inc is vice chair.

Second, the vendor fairs on Tuesday and Wednesday move to the afternoon (noon to 2:30 pm) from the traditional evening hours. Buffet lunches will be in the exhibit hall. On Tuesday evening, a *private* networking reception will be held for users and their significant others, and exhibitors. Wednesday evening is open—that is, no formal group events. Keep up with program details by periodically visiting www.PowerUsers.org.

The Monday agenda is simple: GE is at the front of the meeting room from 2 pm to 6, followed immediately by a welcome dinner/reception for users and platinum sponsors. On Tuesday and Wednesday, user sessions are scheduled before and after the vendor fair (8 am to noon; 2:30 to 5), with special vendor breakout sessions featuring three simultaneous presentations from 5:15 to 6.

Thursday is GE Day with general sessions from 8 am to 10 and from 4 pm to 5:30 and five 50-min breakout sessions between them. Lunch is noon to 1 pm. The OEM will host an evening event from 6 to 9. Three more breakout sessions are scheduled for Friday morning, with meeting adjournment at 10:45.

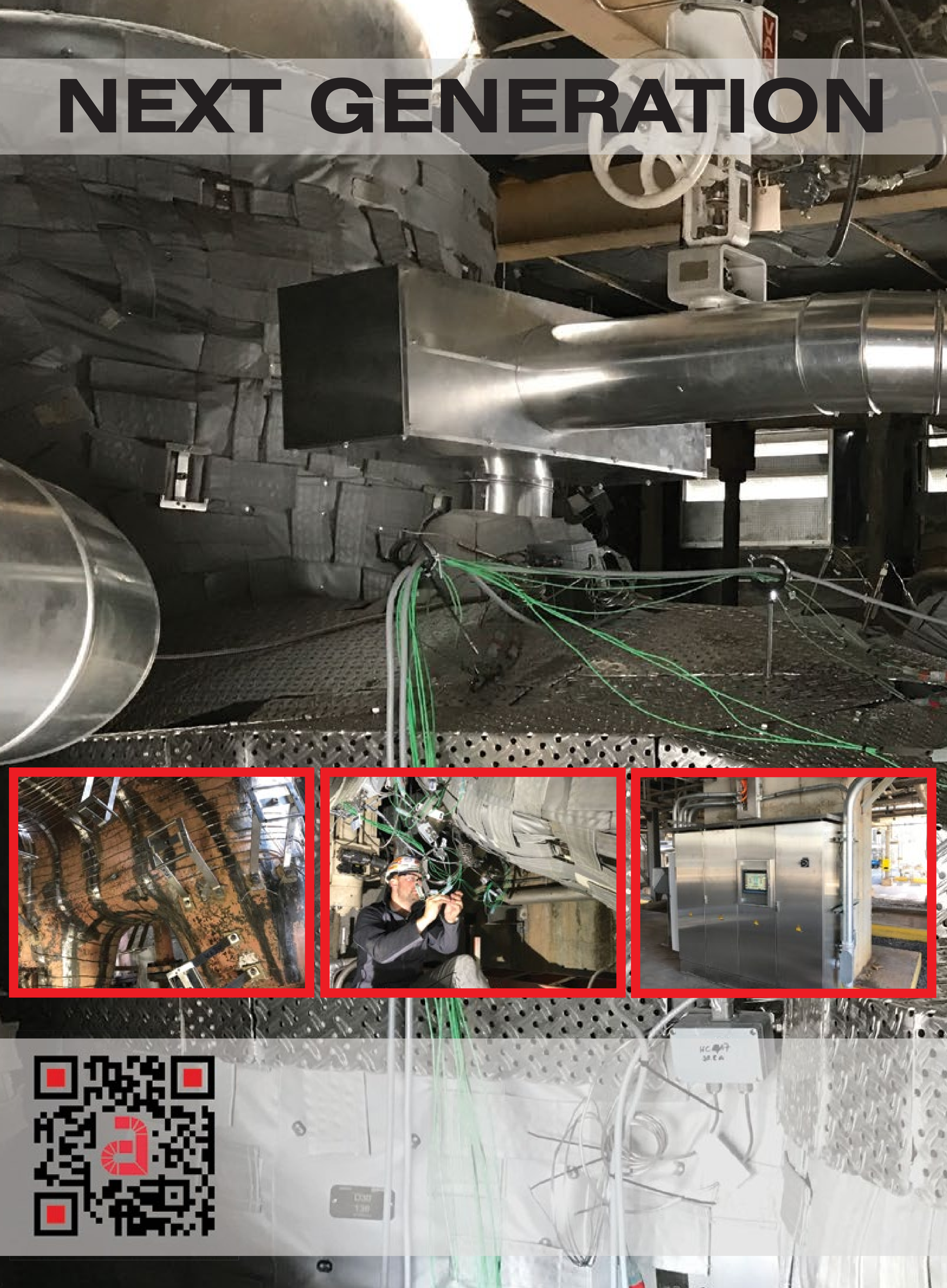
SV Events, headed by Sheila Vashi, manages the business side of all Power Users events (photo). Forward any questions you can't find answers to on the organization's website to sheila.vashi@sv-events.com.

CCJ's coverage of the 2019 meeting begins on p 8 with details of best practices announced at the conference as Best of the Best. The 7F fleet received five such awards this year—a record. Coverage continues in the next issue with summaries of user and vendor presentations and more best practices from the fleet.

7F steering committee at the 2019 conference. Front: Christa Warren (elected 2016), Tenaska Inc; Tricia Keegan (2017), Veolia North America. Second row: Peter Margliotti (2014), Armstrong Power; Kaitlyn Honey (2017), Xcel Energy; Ed Maggio (2013), Tampa Electric Co; Dave Such (2009), Xcel Energy. Third row: Chuck Spanos (2018), Dominion Energy; K K Venkataraman (2019), NextEra Energy Inc; Jeff Gillis (2007), ExxonMobil; Justin McDonald (2013), Southern Company; Peter So (1999), Calpine Corp. Back: Matt Dineen (2016), Duke Energy; Robert LaRoche (2013), SRP; Bryan Graham (2014), Entergy Corp; Luis Barrera (2014), Calpine Corp; Eugene Szpynda (2008), NYPA (all rows l to r)

The muscle behind the steering committee, the SV Events onsite team. Front: Elena Thornton, Riya Vashi, and Mikayla Moreau. Back: Sheila Vashi, Cat Casdia, and Kirsten Schutt (both rows l to r)

NEXT GENERATION



7F owner/operators share their best practices

The 7F Users Group and CCJ are working together to expand the sharing of best practices and lessons learned among owner/operators of large frame engines. One of the organization's objectives is to help members better operate and maintain their plants, and a proactive best practices program supports this goal.

The editors presented a summary of the best practices submitted by 7F users in 2019 during the organization's annual meeting at the Renaissance Schaumburg, May 20-24. Details of the entries judged as the Best of the Best are profiled below. They were submitted by the plants identified in color in the adjacent chart. Best practices from the remaining facilities will be shared in the next issue.

Recall that CCJ launched the industry-wide Best Practices Awards program in late 2004. Its primary objective, says General Manager Scott Schwieger, is recognition of the valuable contributions made by owner/operator personnel to improve the safety and performance of generating facilities powered by gas turbines.

Industry focus today on safety and performance improvement—including starting reliability, fast starts, thermal performance, emissions reduction, and forced-outage reduction—is reflected in the lineup of proven solutions submitted this year.

7F USERS GROUP
Best Practices Awards

Armstrong Power
Barney Davis Energy Center
Calhoun Power
Effingham County Power
Elwood Energy
Green Country Energy
Lawrenceburg Power
MEAG Wansley Unit 9
Nueces Bay Energy Center
Plant Rowan
St. Charles Energy Center
Woodbridge Energy Center

Presented by the COMBINED CYCLE Journal and 7F Users Group

2019

Lawrenceburg leads the Class of 2019 7F Best of the Best award recipients

Lawrenceburg Power LLC

Owned by Lightstone Generation
Operated by CAMS

1186-MW, two 2 × 1 7FA-powered, gas-fired combined cycles located in Lawrenceburg, Ind

Plant manager: Mark Johnson

Lawrenceburg Power LLC, Lawrenceburg, Ind, has had three owners since it began commercial operation in 2004—not surprising given the structural changes to the industry over the last two decades. The nominal 1186-MW gas-fired facility, equipped with two 2 × 1 power blocks powered by GE 7F gas turbines, was owned by PSEG Fossil LLC until AEP Generating Co purchased it in May 2007.

AEP Generating sold the facility to Lightstone Generation LLC and Lawrenceburg Power LLC Jan 4, 2017. Lightstone Generation is a joint venture between Blackstone Group LP and ArcLight Capital Partners LLC; Lawrenceburg Power is a wholly owned subsidiary of Lightstone Generation.

Kindle Energy LLC has primary responsibility for managing the plant; Consolidated Asset Management Services (CAMS) provides O&M services.

Lawrenceburg Power's leadership team, with Plant Manager Mark Johnson at the helm, has made many improvements to the plant since its purchase from AEP. These are reflected in the eight best practices shared on the following pages which have provided meaningful operational benefits.

Performance, flexibility upgrades boost profitability in dynamic market

Challenge. Lawrenceburg Power operates in the PJM Interconnection. Plant owner Lightstone Generation wanted a reliable, cost-effective upgrade to simultaneously maximize capacity payments and align combustion and hot-gas-path (HGP) inspections at a 32,000-hr maintenance interval.

The plant operates in a shale-gas region and can receive fuel from multiple sources that may contain high levels of ethane. Inconsistent fuel properties were identified as the expected root cause for some fuel-nozzle tip burnouts that caused forced outages on multiple units at the site.

A challenge that Lawrenceburg faced was identifying upgrade solutions with predictable impacts on heat-recovery steam generators (HRSGs), the steam turbine/generator (STG), and balance-of-plant (BOP), as well as on startups and shutdowns of the power blocks.

Solution. Lawrenceburg Power entered into a long-term service agreement (LTSA) with PSM in fall 2017. In March 2018, Power Block 1 was shut down to implement the first two PSM FlameTop upgrades for addressing the plant's operational challenges. FlameTop combines PSM's FlameSheet™ combustion system (sidebar) and GTOP3.1 (Gas Turbine Optimization Package).

Converting the block's gas turbines from DLN2.6 to FlameSheet combustion systems increased the allowable variation in the fuel's Modified Wobbe Index (MWI) from 10% to 30%.

The GTOP3.1 package, which includes upgraded hardware to increase compressor flow and reduce combustor pressure drop as well as the amount of turbine cooling and leakage air required, was installed on each GT to improve performance.

FlameTop mode switching logic and AutoTune also were incorporated so the plant could both maximize peak-fire capability and achieve the desired 32,000-hr maintenance interval. PSM AutoTune provides real-time tuning of the gas turbine fuel splits to maintain stable combustion dynamics while managing gas turbine NO_x production throughout the plant's dynamic Ohio River Valley weather patterns.

Lawrenceburg Power engaged an engineering firm to review the new conditions that the upgrade might present to the HRSGs, STG, and BOP equipment. In addition, a steam-turbine contractor was used to perform a pre-outage performance test and to make recommendations on opening the diaphragm clearances to allow the expected increase in flow through the machine—a benefit of GTOP3.1.

The engineering firm also performed a review of HRSG purge times, eventually settling on a 6-min decrease to maintain required volume of air changeout. The 6-min reduction in purge time, together with the FlameSheet combustors not requiring a reduction of speed to flame and warmup but rather flame and warmup at purge speed, provides a significant reduction in start time.

A study was conducted using the site's high-fidelity simulator to ensure changes in startup and shutdown procedures would not introduce a safety issue or cause equipment damage. Numerous simulated startups and shutdowns were performed by site personnel and PSM engineers to refine logic changes and minimize stresses on BOP equipment and the STG. New startup and shutdown procedures were developed prior to the first fire of the upgraded gas turbines.

FlameSheet™ attributes

- Turndown to as low as 30% load on standard firing curve.
  - Extended turndown also is realized on reduced low-load firing curve to protect the unit HRSG.
- Extended fuel flexibility.
  - 30% Modified Wobbe Index variation.
  - Hydrogen up to 40%.
  - C_2 up to 40%.
  - Dual-fuel capable.
- Maintain emissions compliance across the entire load range—including turndown and +50 deg F turbine inlet temperature.
  - NO_x below 9 ppm.
  - CO below 9 ppm.
  - No diluents.
- Inspection intervals: 32,000 hours/1250 starts.

Source: PSM

Results. By incorporating FlameTop, the plant gained nearly 11% in output in Peak 3 firing mode. Each GT upgrade was commissioned with six operating modes—including extended maintenance (40k hr), maintenance (32k), performance (24k), peak 1 (10 deg F over peak firing temperature), peak 2 (20 deg F), and peak 3 (30 deg F).

Steam-turbine diaphragms were modified to accommodate the increase steam flow thereby increasing power-block output. Staff is managing operation in each mode to ensure that the HGP will occur at 32k actual hours of operation.

The site has realized significant ammonia savings (approximately 50%) because of the reduction in turbine NO_x emissions attributed to FlameTop. The units also turn down an additional 10 to 15 MW as compared to pre-outage conditions and on a reduced isotherm which helps to maintain BOP equipment health while operating at minimum load.

Commissioning of the upgrade confirmed simulated startup logic, startup procedures, optimized mode transfers, and refined fuel splits for stability. End result was a combined-cycle startup optimization that reduced start times by 30 minutes (hot) to 45 minutes (cold) without additional stress to the BOP. No hardware issues attributed to shale-gas fuel property swings have been noted since the FlameSheet installs.

Project participants:
Nathan Bailey
Jason Callahan

Switch to self-contained hydraulic valve operators improves turbine-bypass performance

Challenge. Top performance from steam-turbine bypass systems during startups, shutdowns, and trips at combined-cycle plants is critical for achieving the operating-flexibility and availability goals critical to the plant's financial success.

Lawrenceburg uses a triple-pressure cascading bypass system which helps in managing thermal imbalances between the gas turbines and heat-recovery steam generators in cycling scenarios. It includes high-pressure (HP), hot-reheat (HRH), and low-pressure (LP) bypass valves.

In this control scheme, the HP bypass valve maintains HP pressure to minimize thermal stresses on the drum. The HRH bypass, downstream of the reheater, maintains HRH header pressure, and reduces steam pressure/temperature to the condenser. Finally, the LP bypass valve maintains LP drum pressure and protects the condenser by reducing LP steam pressure/temperature to an acceptable exhaust condition.

The pneumatic actuators supplied with the turbine bypass valves were problematic, sometimes even failing to operate on a trip. Plant personnel noted that some of the actuators had multiple volume boosters and the oscillations were "ridiculous." Before the unit was able to settle out, the control system was already calling for the valves to move to a new position. Think of the valves as being in perpetual motion.

Reheat pressure oscillations caused by pneumatic-actuator stiction, overshoot, or dead time cause significant fluctuations in HRH header pressure. Because of the sluggish performance with the TBS blending the lead and lag units it regularly took 3.5 hours for a warm startup.

Solution. After reviewing alternative actuators, staff decided to move away from pneumatic actuation in favor of REXA self-contained hydraulic operators. Personnel originally were skeptical about moving to a hydraulic medium because of issues experienced with oil cleanliness in the past, but they liked the compact/sealed design of the REXA product and were sold by the fact that there were no filters and no requirements for oil maintenance. The new actuators were installed on the existing valves as a drop-in-place solution. Performance improvement was noticed within minutes after the first startup.

Results. Lawrenceburg Power effectively reduced its blending time by 80 minutes for a warm start. The blending scenario occurs between five and 50 days annually (or greater depending on the market), reducing fuel consumption and increasing operating time. Better control of steam pressures and temperatures also promote longer life for the HRSGs.

Trip events associated with the turbine bypass system, common with the original pneumatic actuators, have been eliminated completely. The new actuators operate with zero overshoot or hysteresis, and their response is virtually instantaneous after initiation of the command signal. An added benefit is extended trim life in all turbine bypass valves because the actuator is now driving the plug to the correct seated position.

REXA electronics package is at left, an actuator on a 10-in. steam conditioning valve is at right

Project participant:
Ron Cash, senior technician

Dryers improve performance of hydrogen-cooled generators

Challenge. Most manufacturers of hydrogen-cooled generators recommend having dryers to remove moisture from the gas. When wet, hydrogen loses its beneficial properties for generator cooling, becoming more dense and increasing windage losses. These losses take the form of additional heat production during generator operation and increased fuel requirements to generate the same output.

Moisture also reduces the ability of the generator gas to remove heat from the system, the specific heat of water vapor being lower than that of hydrogen. Recall, too, that some generator failures have been tied directly to moisture in the unit. Perhaps most notable were the failures attributed to stress corrosion cracking in the retaining rings. However, there are other failure modes either caused by, or enhanced by, excessive moisture in the generator.

Lawrenceburg's six hydrogen-cooled generators were supplied without dryers. An in-situ robotic inspection of one gas-turbine generator in one of the two 2 × 1 power blocks revealed red dust on one side of the core iron while the robotic trolley was moving axially down the length of the bore (photo). The dust was found in what appeared to be concentric bands spaced at certain locations down the bore.

In 7FH2 generators like those at Lawrenceburg, such bands of red dust typically are indicative of belly-band looseness.

Solution. Hydrogen coolers were removed from the generator to inspect the back-iron condition and get a better assessment of how loose the core iron was. The inspection was not confined to where the heaviest concentrations

of red dust were identified during the in-situ inspection, but rather to assess the overall condition of accessible core laminations.

The inspection photos revealed red rust in different slots and in different positions of the robotic trolley as it took pictures. These slots all reveal red dust at approximately the same location and position, indicating rings (most likely where the belly bands are located).

Results. After removing the hydrogen coolers on one of the two gas turbines being inspected, the belly bands were checked for tightness. None was found out of spec. With no looseness observed with the knife check, staff concluded that the rust indications were likely from moisture collecting in those areas over the history of the plant.

The plant leadership team decided to forego further testing on the second

Backgrounder on hydrogen dryers

For many years, the only dryers used on hydrogen-cooled generators were of the single-tower type of manually reactivated desiccant dryers (Fig A). While they can be effective, single-tower dryers have several limitations, as described below:

First, with only one tower, it is a batch-type operation. Specifically, it is online drying the gas for a period of time, then taken out of service for reactivation.

Second, reactivation is a manual process. The dryer must be valved out of service and the captive volume of hydrogen bled off, then purged with an inert gas. Next, the dryer is reactivated with air, both heated and cooled. Then that air must be removed. Finally, the dryer is filled with hydrogen and valved back into service.

This is a labor-intensive process, often resulting in the dryer not being used. Keep in mind that during reactivation, the generator is not being dried.

The third limitation is that the single-tower dryer relies solely on generator fan differential pressure to provide the gas flow from the generator to the dryer. If the generator is on turning gear, there is no flow.

In the early 1980s, the dual-tower hydrogen dryer was developed (Fig B). With two towers, one always is online drying the generator while the other is offline being reactivated. Switching of the towers and the reactivation are automatic; no labor is required.

The dual-tower dryer has more desiccant and operates with the generator in service or while on turning gear. It also reactivates with hydrogen at generator pressure so there is no bleeding of hydrogen or inert-gas purging required.

Globally, many hydrogen-cooled generators operate without a dryer—that is, they either don't have one, they have a single-tower manual dryer that they don't use as described above, or their dual-tower dryer is not operational. Plant personnel offer many reasons for this, including the following:

- *The OEM didn't supply a dryer.*

A. Single-tower manually reactivated hydrogen dryer (above)

B. Dual-tower fully automatic hydrogen dryer (right)

Most OEMs offer a dryer as an option. They do recommend keeping the generator dry, but only supply the dryer if the customer specifies it. There are many generators in simple- and combined-cycle plants with a single-tower manually reactivated dryer, or no dryer at all.

- *Manual reactivations are too labor intensive.* In some instances, the OEMs still provide the single-tower dryer, even though the dual-tower dryer is a proven, much better option.
- *This is sort of "out of sight, out of mind."* If a plant doesn't have a dryer or moisture analyzers, personnel just don't think about moisture problems.
- *Don't think there is anywhere for the hydrogen to pick up moisture because their generator is driven by a gas turbine.* This point has been made for years, but actually, most of the moisture comes through the seal oil system. Moisture migrates from the ambient air, into the seal oil and then into the hydrogen. Plants in the middle of a desert might say it's dry in the desert so there's no moisture issue. However, data from analyzers sampling hydrogen on several gas-turbine generators in the Southwest recorded dew points of plus 55F and higher.
- *Don't think moisture matters* because it doesn't feel humid or puddles of water are not in evidence.
- *Hydrogen purity is good so everything must be fine.* Not necessarily so. Most thermal conductivity purity meters have a desiccant filter in front of them, removing the moisture before the sample is analyzed. There is a colored desiccant sight glass at the outlet of the filter that tells when the media becomes saturated and must be replaced. If there were no moisture, there would not be a need for the desiccant filter, and the desiccant would never change colors, indicating saturation.
- *They employ bleed-and-feed or scavenging solutions to deal with purity/moisture issues.* This method has been proven ineffective for maintaining low hydrogen dewpoints. In addition, most hydrogen supply samples tested in a recent study had dewpoints of between plus 15F and plus 30F—not the "bone dry" as most assume. Also, these solutions increase hydrogen consumption considerably. One plant reported a 43% decrease in hydrogen consumption after installing effective dryers.

Red dust in this and other slots was found during an in-situ robotic inspection

gas-turbine generator and worked with supplier Lectrodryer to install hydrogen dryers on the power block's three generators during the outage.

Since installation of the dryers, the plant has been able to maintain a hydrogen dewpoint of minus 20F to minus 50F on all three generators. EMI testing on the generators recently confirmed improvement over testing in prior years, with the only modification being the addition of the dryers. Lawrenceburg was scheduled to install the same dryers on the three generators in the second power block during spring 2019.

Project participants:
Mark Johnson, plant manager
L D Jones, operations superintendent
James Ketchem, maintenance superintendent
Ron Cash, senior technician
Ted Warren
Brent Murray

Training, automation, standardization streamline calibration processes, cut cost

Challenge. Instrument calibration at Lawrenceburg Power was a labor-intensive process involving paper-based procedures resident in a Microsoft® Access® database. Based on a manual review and assessment of the calibrations required, a tool set could be assembled from the vast inventory of test equipment the plant maintained—including gauges, meters, decade boxes, etc.

Execution of a calibration required the technician to manage the multiple pieces of equipment while referring to the printed calibration procedures, determining pass/fail status, and recording the results on the hard-copy document. The documents served as the permanent record and were eventually stored in a physical filing cabinet.

Although this system worked, staff identified several problems with it, including the following:

- User controls were non-existent, questioning data integrity.
- A lack of standardization caused inconsistent calibration results.
- Clerical errors were associated with hand-written records and the paper-based workflow.
- Calibration was time-consuming, introducing the opportunity for process uncertainties.

Solution. Maintenance technicians at Lawrenceburg are all multi-craft and responsible for a wide range of daily tasks. Instrument calibration is just one of those assignments. For this reason, and the sheer amount of instrumentation the technicians manage—about 3600 components, 300 of which require critical calibrations during outages—they needed a data management system that was easy to implement and use.

Also, the responsible personnel wanted to standardize tools and reduce the considerable amount of equipment required and had to be maintained. Ensuring NIST (National Institute of Standards and Technology) traceability was an absolute requirement and had to be easily enforced.

To improve data integrity, the

Metrology training boosts staff confidence in performing calibrations

Prior to implementation of Lawrenceburg's new calibration process described in the text, plant personnel had no formal metrology training. This was conducive to inconsistent calibration results and made employees tasked with instrument calibration uncomfortable.

The plant had a large inventory of calibration equipment that required annual recertification and once recertified would sit in a drawer for up to a year. Technicians wasted a large amount of time looking for the correct equipment, hoses, and fittings to perform calibrations.

Solution to the issue of inconsistent calibration results was to develop a training program so all technicians would gain a better understanding of metrology and perform calibrations in the same manner.

Another goal was to standardize tools and reduce the considerable amount of equipment required to be used and maintained, as well as to reduce the time it took to locate the proper equipment to perform the calibrations.

The second goal was achieved by arranging field calibration equipment in sets (two sets were made) and organizing them in the instrumentation shop for easy accessibility. Senior Technician Ron Cash designed and built a calibration test bench (photo) with all the necessary equipment to train technicians on calibration procedures.

One of the things he did was to convert all the field devices and calibration equipment to Ralston quick-test type fittings and then assemble two fitting and hose sets that will work for any calibration being performed.

Today, with technicians more comfortable performing their calibration duties, the accuracy and repeatability of results have improved markedly.

Calibration test bench includes all the equipment necessary to train technicians

LAWRENCEBURG POWER LLC

Calibration Certificate

Certificate Number: LBP\266/CAL

Position ID: 0LT0040

Printed: 1/16/2019 1:59:39 PM
Printed by: Ron Cash
CMX Version: 2.10.124.0 (2.10)

Position

Name	AUX BOILER DEAERATOR LEVEL
Plant	BOP/AUX BOILER/

Device

Device ID	0LT0040
Serial Number	1848039
Manufacturer	ROSEMOUNT 3051C

Function

Name	DP Level Transmitter (DPLT)	
Transfer Function	Linear	
Range	-60 ... 0 inH2O (G)	4 ... 20 mA

Calibration Event

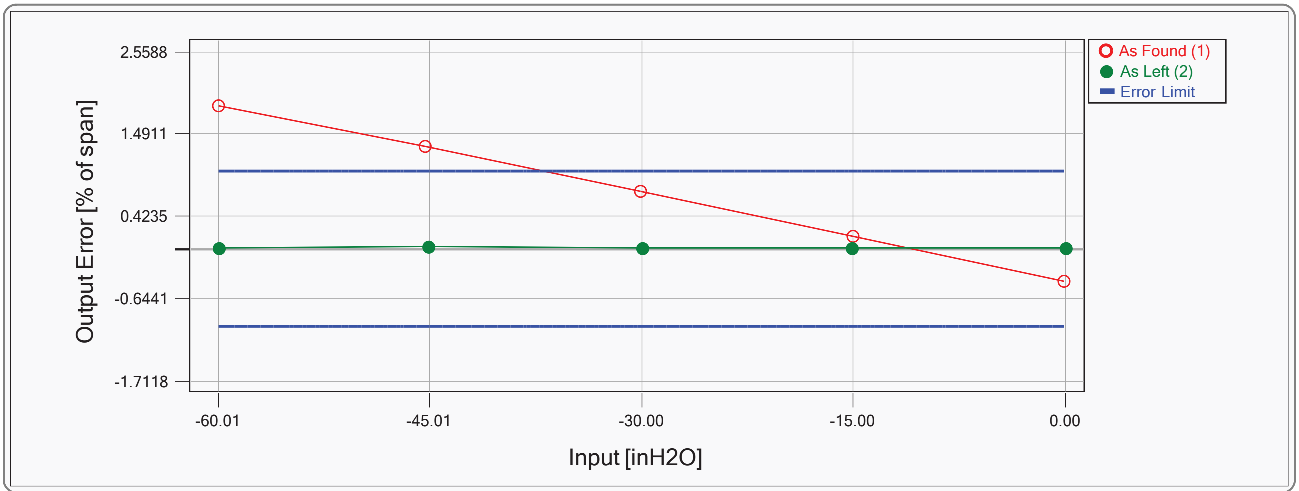
Calibration time	9/26/2018 11:40:50 AM
Next Calibration	9/26/2019

Calibration Procedure

Due Date		Interval	12 months
Reject If Error >	1 % of span		
Adjust To Error <	% of Reject If Error	Classification	
Calibration Strategy			

Calibrators

Input Calibrator	MC6 : 605585	Due Date: 12/2/2018
Input Module	P400mC : 68009	Due Date: 12/4/2018
Output Calibrator	MC6 : 605585	Due Date: 12/2/2018
Output Module	IN : 25110	Due Date: 12/2/2018



1. As Found — FAILED

Maximum Error: 1.847 % of span

Nominal Input [inH2O]	Actual Input [inH2O]	Nominal Output [mA]	Actual Output [mA]	Found Error [% of span]
-60.00	-59.954	4.00	4.3078	1.847
-45.00	-45.270	8.00	8.1398	1.324
-30.00	-30.081	12.00	12.0978	0.746
-15.00	-15.026	16.00	16.0199	0.168
0.000	-0.001	20.000	19.9335	-0.414

2. As Left — PASSED

Maximum Error: 0.025 % of span

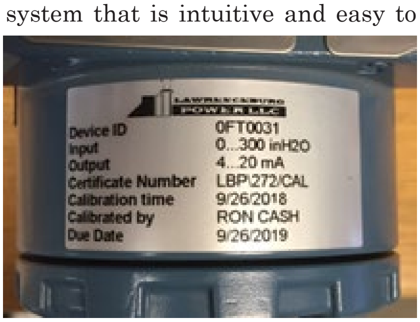
Nominal Input [inH2O]	Actual Input [inH2O]	Nominal Output [mA]	Actual Output [mA]	Found Error [% of span]
-60.00	-60.009	4.00	3.9994	0.011
-45.00	-45.109	8.00	7.9749	0.025
-30.00	-29.967	12.00	12.0119	0.019
-15.00	-15.128	16.00	15.9661	0.001
0.000	0.000	20.000	20.0001	0.001

technicians aimed to minimize the opportunities to "cheat the system" or "pencil whip." They also sought a solution that would provide a professional calibration certificate, audit trail, and provide analytics of the results—such as data trending and hysteresis errors.

The MC6 multifunction documenting calibrator from Beamex Oy Ab was the solution implemented. No matter who uses the system, the work is performed and results are recorded similarly, improving system reliability and confidence in the data (see calibration certificate).

Additionally, the software allows printing of custom-designed calibration labels (photo right), eliminating the time-consuming process of hand writing in all the information on a peel-and-stick label.

Results. Thus far, the results have included the retirement of 80 measurement standards which saves about $18,000 annually in recertification costs, implementation of a paperless system that is intuitive and easy to learn, improved data integrity and reliability, exposure of shortfalls in calibration of mission-critical instrumentation, and time saving of up to 50% on calibration work.



Plus, technicians were able to integrate some of the plant's existing standards with the Beamex technology. Example: A HART Scientific temperature dry-block used with the MC6 to automate temperature calibrations. By using a more accurate system, technicians learned that many of Lawrenceburg's switches and drum levels were out of tolerance, which could have caused an emergency outage and cost the plant dearly if not resolved quickly.

Project participant:
Ron Cash, senior technician

Geodesic domes over clarifiers minimize contaminant ingress, evaporation losses

Challenge. Chemicals was one of the biggest expenses for Lawrenceburg's water treatment plant, with purchase and delivery costs running into the hundreds of thousands of dollars annually.

Another big expense was related to the failure of bearings for the plant's clarifier rakes, which occurred several times. When a bearing failed, Lawrenceburg would curtail power production, thus reducing revenue. Plus, bearing replacement, which could take several days, was expensive considering the man-hours involved, cost of the new bearing, the time to drain the clarifier and remove the sediment, the cost of renting a crane, etc.

Disassembly of one of the failed rake bearings, a 47-in. slewing bearing, revealed that the failure was caused by water and contaminant ingress, not over- or under-greasing as might be expected. The clarifier design allowed rainwater to collect in the bearing area with no means of escape. A historical review of other equipment in the immediate area revealed that there has been repeated repairs in the past because of environmental factors.

In their review of the water treatment plant, staff discovered there was a huge loss of sodium hypochlorite (NaClO) from the clarifiers because of evaporation.

Solution. Installing geodesic domes over the clarifiers was a promising way considered by staff to reduce evaporation caused by the sun and wind. Plant personnel worked closely with manufacturer Ultraflote LLC's engineers and agreed on a dome design suitable for Lawrenceburg (photo).

Results. The domes have reduced the annual consumption of sodium hypochlorite by 40%, saving about $60,000. The domes also have eliminated the loss of generation caused by premature failures of the rake bearings and surrounding equipment.

Project participant:
Ron Cash, senior technician

Geodesic domes over Lawrenceburg's clarifiers reduced chemical losses

Fire-protection upgrades make Lawrenceburg a safer place to work

Challenge. Lawrenceburg Power's fire alarm system consisted of several alarm panels from different manufacturers, all integrated into a main panel in the control room. When an alarm was received it was time-consuming and difficult to distinguish what device triggered the alarm because of all the integration.

Solution. Staff decided to replace the entire fire alarm system with Notifier NFS2- 3030 panels, Onyx work station, new signaling devices, and speaker/strobes to have a fire/mass notification system that would meet NFPA 72: National Fire Alarm and Signaling Code®.

The advantage of a mass notification system is that it immediately informs end users of a situation and how to proceed. Notifying occupants via the mass notification system is done by email, loud speaker/intercom, and graphics-board messaging using a message board from Light Engineered Displays Inc.

Lawrenceburg's mass notification system is used for any emergency application—including fire, weather, natural-gas leaks, chemical spills, medical emergency, intruder, terrorist situations, generation alerts, start/lunch/stop times, etc (Fig 1)—and has been programmed to display the time at the top of each hour.

When an alarm comes in today, the operator's screen automatically changes to the screen where the device is located, the device flashes and changes color based on the event, and the message is displayed and played over the system. The message tells you the type and location of the situation and informs everyone except the responders what to do and where to report to. The operator can just look at the screen and know which area and device that he/she needs to direct the responders to.

The system is set to alarm a minimum of five times; it alarms on a fire and gas leak until reset by the operator allowing offsite responders the ability to see the location and type of event on a display board as they enter

1. Notification system addresses all types of emergencies

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the property. Lawrenceburg's fire detection/mass notification system monitors the control room, electrical rooms, transformers, black-start generators, gas turbines, etc (Fig 2). The detection systems used are heat, smoke, and combustible gas; the plant controls FM-200, CO_2, dry pipe, deluge and pre-action fire suppression systems, and monitoring of wet-pipe systems.

The second part of the project was to replace the gas-turbine Chemetron Fire Systems Micro 1 EV control panels. Chemetron had discontinued repairing the Micro 1 EV control boards in April 2008 and obsoleted the product shortly thereafter. The plant had four of these panels and previously had experienced a CO_2 dump because of a failed control board.

With few spare parts available, Lawrenceburg received some spares from its fire service vendor which had been taken out of service at other locations. The plant had experienced many false alarms from these systems. They had limited memory and when not properly cleared out and fully reset would sound the alarms.

An issue with many GE 7EA gas turbines installed in the 1990s and early 2000s is that the 45FTX fire protection shutdown relays are wired in parallel. These seven (or nine) 120-Vdc relays located in the PEECC (packaged electrical and electronics control compartment) fire-protection relay cabinet, activate from the each of the Chemetron fire-system control-panel Aux 1 relays and from the Chemetron discharge pressure switches.

A problem occurred in some locations where repeat actuation of this circuit during a routine CO_2 inspection damaged the Aux 1 relay base because of the momentary excessive current draw of these seven (or nine) relays. The Aux 1 base, soldered to the main Micro 1 integrated-circuit board, cannot be replaced in the field, thereby requiring a complete Chemetron Micro 1 control panel replacement, which is no longer available.

Staff was concerned this could be a possibility on Lawrenceburg's 7FAs as well, and the plant replaced them with the same Notifier NFS2- 3030 panels used in the fire alarm system described earlier. New wiring and some conduit also was installed because of the extreme heat this equipment is exposed to. This was integrated into the main fire control panel and it also populates on the Onyx work station.

The final part of the upgrade was to install pre-discharge pneumatic time-delay systems on each of the gas-turbine CO_2 systems in accordance with NFPA 12. The 2005 edition of this standard requires the implementation of pneumatic time delays and pneumatic pre-discharge alarms into both new and existing CO_2 extinguishing systems where the agent is introduced into normally occupied or occupiable spaces.

2. Lawrenceburg Power upgraded its fire-alarm system, CO_2 fire-alarm panels, and CO_2 system

The pre-discharge pneumatic time-delay retrofit cabinet, when installed in an existing system, creates a pneumatic pre-discharge delay immediately following system actuation during which time a pneumatic siren is sounded. Inhaling large concentrations of CO_2 causes rapid circulatory insufficiency leading to coma and death; asphyxiation is likely to occur before the effects of CO_2 overexposure.

Chronic, harmful effects are not known from repeated inhalation of low concentrations. However, low concentrations of CO_2 are known to cause increased respiration and headache.

When the system is in standby, pilot pressure (300 psig) enters the pneumatic electric pilot cabinet and is stopped at the constant pressure port of the pneumatic pilot valve and the actuation solenoid.

For an automatic discharge, the fire suppression control panel sends an actuation signal to the solenoid valve causing it open. The actuation pressure actuates the pneumatic pilot valve which allows pilot pressure to pass through the three-way valve to the pneumatic time-delay cabinet. When necessary, the pilot valve is capable of manual actuation by use of the associated lever mounted in the pneumatic electric pilot cabinet.

For a manual discharge, the manual discharge lever in the pneumatic electric pilot cabinet is moved to the "open" position allowing the pressure to pass through the pneumatic pilot valve to the pneumatic time-delay cabinet.

Once the system is either automatically or manually actuated, pilot pressure (300 psig) enters the pneumatic time-delay cabinet and is reduced to 100 psig. Pilot pressure also enters the inlets of the initial and extended pneumatic pilot valves for each associated discharge zone. After pilot pressure passes through the 100-psig regulator, it enters the pneumatic timer (set at 30 seconds) and initiates the pre-discharge time delay.

The 100-psig pressure also actuates a ball valve (pneumatically actuated siren valve) which allows pressure directly from the tank vapor outlet, reduced to 100 psig, to sound the pneumatic sirens. Upon completion of the pre-discharge time delay, the pressure passes through the pneumatic timer to the actuation ports of the initial and extended pneumatic pilot valves. Once actuated, the pneumatic pilot valves allow pilot pressure to pass through and actuate the initial and extended discharge valves.

Results. The upgraded protection systems have worked well. To recap, increased personnel protection was achieved through enhanced detection, suppression, improved communication, and notification of personnel onsite as to what potential hazard occurred. Employees are notified what to do, when to do it, and where to report. making Lawrenceburg a safer place to work.

Project participant:
Jeff Darling, ES&H

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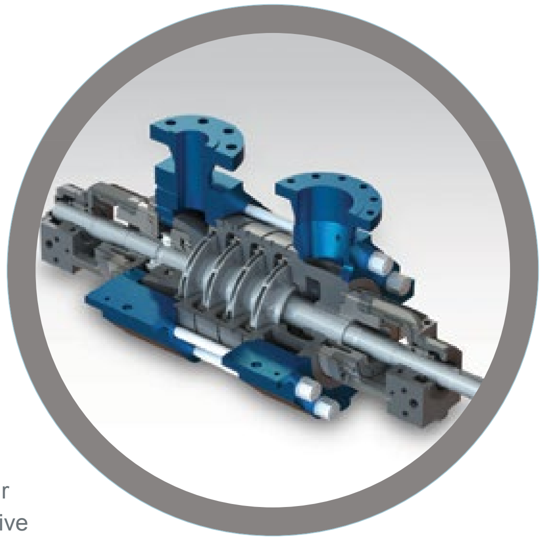

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Burner management system upgrade improves reliability, facilitates troubleshooting

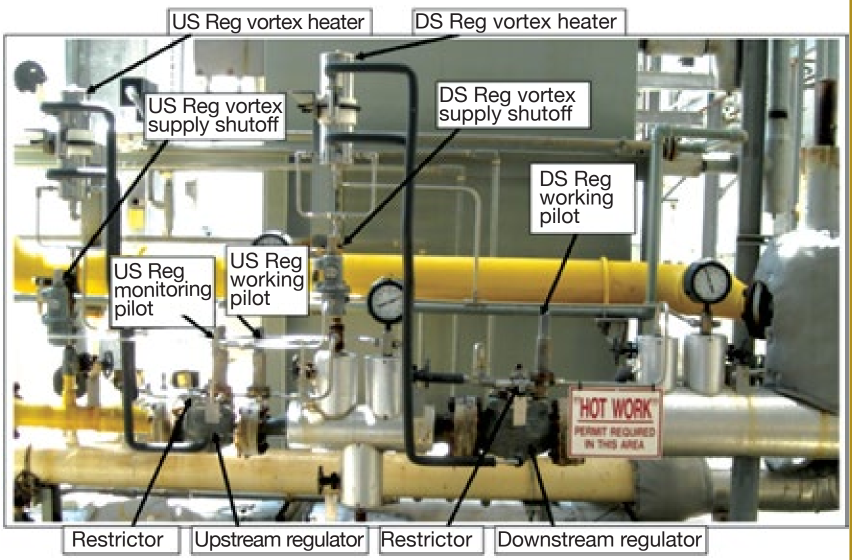
New pressure-reducing station is configured as a "wide-open monitor"

Backgrounder on BMS as supplied

The burner management system (BMS) skids supplied by Coen Co in 2001 for Lawrenceburg Power's Aalborg heat-recovery steam generators featured the following components (figure):

- Two Fisher 399A pressure-reducing regulators.
- Three Fisher 161 pilot regulators.
- Two Fisher 112 restrictor orifices.
- Two Universal Vortex single-path vortex pilot-gas heaters.
- Two Fisher 627 regulators (for the vortex heaters).

The pressure-reducing stations were set up in a "working monitor" configuration. The upstream regulator (US Reg in the diagram) requires two pilots and reduces the inlet pressure from 480 to 140 psig (intermediate pressure) and the downstream regulator (DS Reg in the diagram) reduces the pressure to the final working pressure of 40 psig. In this way, both units always are operating to reduce pressure.



Pressure reducing stations for Lawrenceburg's burner management systems originally were arranged in a "working monitor" configuration

Challenge. Design of the burner management systems (BMS) supplied with Lawrenceburg's HRSGs (sidebar) were difficult to troubleshoot when a component failed, causing longer-than-expected downtimes and added repair cost. Compounding the difficulty, the original Fisher 399A regulators were obsolete.

The system safety design incorporated two "slam-shut" stop valves and a vent valve (double block and bleed) on the pressure reducing station. If the BMS became unstable and a trip initiated, the slam-shut valves would close and the vent would open. This would stop the gas flow instantly, causing system backpressure to spike. By design, the regulator diaphragm is in the flow path and when subjected to high backpressure it was the most likely component to fail.

Solution. Cornerstone Controls Inc, an Emerson partner, was contacted to review the BMS failures. Working together, Lawrenceburg and Cornerstone personnel determined that the Fisher 399A regulators should be replaced based on how the BMS station operates. The solution selected was two Fisher EZH pressure-reducing regulators. In addition, the system required one Universal Vortex dual-path pilot-gas heater and one Fisher 627 regulator.

The new pressure-reducing station (photo) is configured as a "wide-open monitor." In this arrangement, the upstream working regulator controls system outlet pressure. The downstream monitor regulator senses a pressure lower than its set point and tries to increase outlet pressure by going wide open.

If the working regulator fails, the monitoring regulator takes control and holds the outlet pressure to the outlet-pressure setting. The EZH regulators have metal trim and are not affected by system trips. The piping system also was redesigned to allow for easier troubleshooting.

Results. Since the BMS was upgraded, gas pressure is more stable and the plant has had no failures associated with the burner management system.

Project participant:
Ron Cash, senior technician

Rowan

Plant personnel identify, eliminate causes of compressor bleed valve failures

Challenge. Plant Rowan's 7F compressor bleed valve (CBV) design—consisting of a vented-to-atmosphere, air-to-close/spring-to-open air-actuated butterfly—lends itself to unpredictable failures at the worst possible times. Following numerous failures and subsequent replacements plant personnel pursued an affordable and effective solution.

Solution. Plant Rowan's gas-turbine system owners took it upon themselves to tear down and perform a "workbench RCA" on a failed CBV following what was a very frustrating winter morning.

The conclusions were simple: Moisture was the leading contributor to

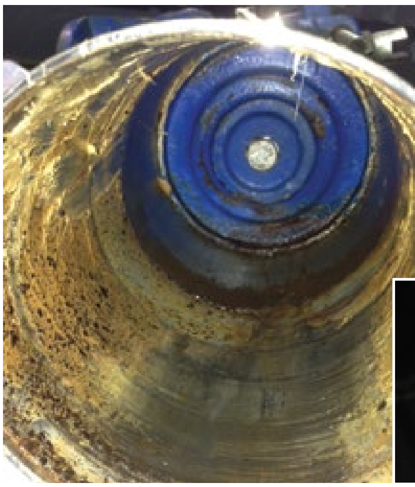
Plant Rowan

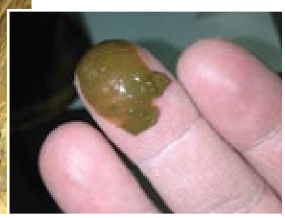
Owned by Southern Company

Operated by Southern Power

985-MW, gas-fired, 2 × 1 combined cycle plus three simple-cycle units, located in Salisbury, NC

Plant manager: Chris Lane





1, 2. Moisture was the leading cause of compressor bleed valve failures at Rowan

3. Removal insulation pad, placed over CPV pairs, protects against rain

4, 5. Heating pads were installed on each air-cylinder body to prevent freeze-up failures (Figs 1 and 2), but on multiple fronts. It wasn't simply a corrosion issue, nor only a freezing issue during winter operations. Rather, any moisture drawn through the air cylinder vent plug would linger causing possible issues year-round.

Trapped moisture accounted for nearly 90% of the failures experienced at various times throughout the year. The remaining issues were simple wiring gremlins. Those were resolved easily by refreshing flexible conduit runs and fittings as well as instituting annual wire-terminal checks.

Moisture issues were resolved on the two fronts identified earlier. First, plant had a removable insulation pad "hut" fabricated and placed over the CBV pairs (Fig 3). This would keep rain away from the valves/actuators and limit pack assemblies.

Second, and most critical, 6 × 12-in. heating pads were installed on each air-cylinder body (Figs 4 and 5). This eliminated potential freezing and helped prevent condensation formation inside the cylinder as it takes in ambient air each cycle (dewpoint control). Personnel made sure they could control heater output with a small SCR drive if they found the system getting too warm. This proved unnecessary in practice (Fig 6).

A thermostat was installed in case the heaters would be used only in wintertime. As it turned out, the systems have been in service year-round for more than six years with no CBV failures attributed to a "failure to actuate" when demanded.

Results. There have been zero failed starts attributed to bleed valves "failing to actuate" in over six years. It took almost no time to realize a return on investment with this small project.

Project participants:
Shaun R Lynch, operations technician III
Steven T Nisbet, instrumentation technician
Dan Leone, maintenance team leader
Jason Sims, I&C team leader

6. Heater controls maintain temperature at desired level

Elwood

Elwood Energy
Owned by J-Power USA
Operated by NAES Corp
1350-MW, gas-fired, nine-unit peaking facility located in Elwood, Ill
Plant manager: Joseph Wood

Developing the next generation of multi-skill employees

Challenge. Elwood Energy, home to nine simple-cycle 7FAs, started commercial operation in 1999. In 2012, prior to the plant's first ownership change and exit from a PPA environment, the leadership team realized it would have to *develop* its next generation of employees. Few job candidates with suitable experience demonstrated sufficient promise to thrive in a multi-skill position.

Retirement and attrition left Elwood with only four of its 13 OMTs (operating/maintenance technicians). Opting for potential over experience, based on early success with a developmental program, the nine candidates hired had either a two- or four-year degree, but minimal relevant experience. Now five years into this program, the average age of the group is 27, with relevant experience averaging four years.

Elwood Energy operates in the PJM capacity performance market where performance is rewarded and failure to perform can be very costly. One hour of unplanned outage for one unit can vary from \$35,000 in lost capacity payments to \$600,000 in penalties during a capacity performance event. For a PJM peaking facility typically operating a unit 400 hours annually, every hour troubleshooting a failure to start can be very costly.

An employee who can work through an issue in two hours can be much more valuable than a less capable employee requiring six hours. Developing a dedicated competent multi-skill staff of OMTs is essential to maintain equipment reliability as well as to promptly resolve equipment malfunction.

Solution. Critical to success were the following actions, among others:

1. When candidates with demonstrated

progressive and relevant work experience are not available, seek out and recruit those with a demonstrated potential to learn. Recruit candidates with two- to four-year degrees who have a demonstrated good work ethic and high aptitude for electrical, I/C, and mechanical maintenance. Offer part time work to promising candidates still in college.

2. Put emphasis on retaining experienced employees. Leverage their experience across your developing employees at every opportunity. Success in developing your future generation of employees requires experienced working supervisors who enjoy developing others.
3. Ensure your highly experienced employees can delegate and control increasingly complex skills as employees' capabilities increase. The highly experienced employees may need growth assignments as well.
4. Develop a qualification program that captures the operational and maintenance skills and knowledge expected of OMTs.
5. Provide well-considered annual performance appraisals.
6. Foster a competitive environment where the more capable and driven employees can develop a strong culture.
7. Know what developing job skills are worth to competitors and be sure to match compensation increases with increasing skills. Slow recognition of increased value may end up in a lost developmental candidate.
8. Have an incentive plan that is aligned with the goals of the owners regarding EFORD, starting reliability, unit trips, compliance with regulations, and plant net income.

Results. Hiring for capability and leveraging of Elwood's existing capabilities has been essential to the plant's success. Elwood has experienced numerous transitions in four ownership changes—switching from PPAs to PJM and then to the PJM capacity performance environment requiring rotating shift coverage.

During this period of change, staff has maintained a safe work environment and strong operational performance—with low EFORD, high starting reliability, and low unit trip performance demonstrated yearly. The O&M team missed very few market opportunities that lost energy margin or capacity payments.

While recent college graduates can approach work with great enthusiasm and capability, they don't know what they don't know. They also are less likely to bring with them undesirable expectations and behaviors than many experienced candidates. One of the changes we managed was moving from working directly for the ownership to one of working for service provider NAES Corp.

NAES has provided support in a few key areas that some of the ownership structures did not. Safe work performance, a key measure of operational excellence, is communicated by NAES and embraced by the Elwood staff. Programs, guidance, and support to develop safety, environmental, and NERC programs greatly enhanced the development of Elwood personnel.

The leadership team has effectively managed the change from a summer peaking facility working under a PPA with the facility unmanned at night and weekends, to a significantly riskier environment where capacity payments can be lost any hour of the year.

The foregoing strategy has been a key factor in achieving challenging business goals year after year despite the significant changes experienced. The new team forged has achieved years of consistent employee performance development conducive to supporting Elwood Energy's business objectives well into the future.

Project participants:
The Elwood leadership team

Effingham runs its string of industry-leading Best of the Best awards to seven

Effingham County Power

Owned by The Carlyle Group

Operated by Cogentrix Energy Power Management

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

General manager: Bob Kulbacki

The Best Practices Awards program for owners and operators of generating facilities powered by gas turbines, sponsored by the COMBINED CYCLE Journal and CCJ ONsite, and their user-group partners, celebrates its 15th anniversary in 2019.

Over the years, more than 700 Best Practices entries have been received from 200-plus individual plants and fleets; the accomplishments of more than 100 have been recognized with awards.

There are two levels of awards to acknowledge the achievements at individual plants: Best Practices and The Best of the Best, as voted by experienced judges who evaluate the submittals with weighted consideration of the following characteristics:

- Business value.
- Degree of complexity.
- Staff involvement.
- Duration of value.

Effingham County Power was awarded one of the eight Best of the Best awards presented in 2019, bringing its total to seven since 2010. No other plant has received more than five. What's particularly noteworthy about Effingham's run is that it has spanned three owners, four plant managers, and several teams of judges. The only common denominators are ties to its former operator, CAMS—Consolidated Asset Management Services, and an empowered staff that embraces a process of continuous improvement.

Effingham's owner back in 2010 was Progress Energy Ventures, then came ArcLight Capital Partners (with minority partners GE Energy Financial and the Government of Singapore), and now The Carlyle Group.

Plant managers over the last 10 years: Eric Garrett, today Senior VP Operations for CAMS; Ken Earl, now VP Operations for eastern plants in the CAMS portfolio; Nick Bohl, currently the CAMS plant manager for Competitive Power Ventures' (CPV) St. Charles Energy Center, a 2 × 1 combined cycle powered by 7F.05 engines; and the incumbent, Bob Kulbacki. All except for Earl were cited for the plant's first Best of the Best, "Retraining and modified operating procedures greatly reduce tolling penalties."

Effingham's 2019 best practices are shared below.

Reduce imbalance and variance charges with consistent plant operation

Challenge. During commissioning of Effingham County Power, procedures were developed for hot, warm, and cold starts based on steam-turbine first-stage metal temperature. Suggested generation tags were provided to the plant along with the startup procedures.

Over the years, staff learned the generation tags didn't apply to the entire temperature range of the three types of starts. For example, the temperature range for warm starts extends from 450F to 750F. The amount of time to start up is affected by temperature and if an improper generation tag has been approved, the plant could incur imbalance and variance charges.

Because warm and cold starts are not performed frequently at Effingham, personnel wanted to develop a template for conducting these startups—one that would ensure repeatability and contribute to lower costs. Reducing startup costs is a priority at merchant plants like Effingham. This can be done by reducing startup time, thereby saving gas and the amount of ramp energy sold to off-takers.

Having several established ramp profiles for the starts performed allow for the operators to submit accurate daily status information to the trading floor. The ramp profiles also can be provided to off-takers when developing power contracts so they are aware of the plant's different startup scenarios.

Another issue encountered was how various conditions affected hot starts, which Effingham performs about 95% of the time. These conditions included executing a hot start with a depressurized HRSG, a cold HRSG following maintenance, and an extended amount of time between hot starts. Staff found that using the same ramps for these different conditions could lead to imbalance and variance costs or improper warming of a cold HRSG.

Solution. Since warm and cold starts are performed infrequently, staff knew it would be a long process to develop accurate ramps for various temperatures. A log sheet was developed which listed the type of start, amount of time in shutdown, and the steam-turbine first-stage metal temperature. Along with these data, the operators were tasked with listing the time they performed crucial steps of the startup.

Ramps used for the startup were recorded along with recommended ramps for the next start. The operators also listed any lesson learned during their startup so that the issue could be avoided during the next time.

All the data sheets were reviewed and saved on the shared drive for each operator to review prior to performing a non-routine start. After several startups with similar start conditions had been performed, staff developed a guide with times for all operators to use and fine-tune. The leadership team continued to review the non-routine starts and once the goal of reducing startup time and imbalance charges was achieved, these ramps were published on a spreadsheet and provided to the applicable groups associated with generating and selling power for the plant.

In documenting starts versus start temperatures, staff was able to develop several warm ramps that were applicable to a wide temperature range. With this information, the Effingham team developed lower-, middle-, and upper-range ramps which were useful for the complete warm-start range. Ramps also were developed for hot starts with a cold HRSG, since the starts differed when a cold HRSG was involved.

Results. This project spanned several years and is re-evaluated each time a non-routine start is performed. The ramps developed have benefitted management and operators involved in providing plant-specific data to outside organizations. Effingham is responsible for submitting a daily status to traders, which includes ambient temperatures, maximum generation, and the startup ramps.

Most of the plants starts are hot and the ramps don't vary with the short shutdown time. As the amount of time the plant is offline increases, the steam-turbine first-stage metal temperature decreases more. This requires adjustment of start ramps to assure the plant is warmed up within established thermal limits.

Having the required data available in a convenient spreadsheet allows for Effingham to provide requested ramps quickly when called by the traders or corporate engineering. An additional benefit of this project has been more consistent plant operation because of the guidelines provided operators for non-routine starts.

The bottom line: Imbalance and variance charges have decreased while performing plant starts in accordance with procedures developed in-house.

Project participant:
Bob Kulbacki, general manager

Logic change increases gas-turbine reliability

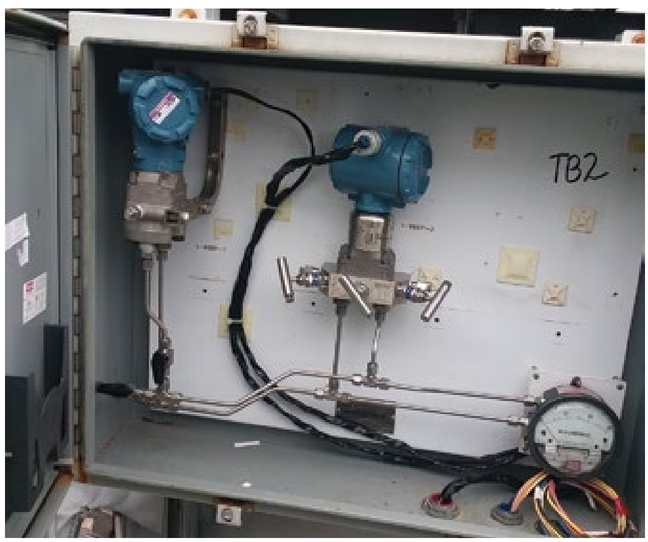
Challenge. Effingham County Power's two gas turbines were supplied with a single duct-pressure transmitter for information only; exhaust-duct pressure was protected by three hardwired switches. One switch was arranged to alarm on the control-system HMI when its set point was exceeded. Set points for the other two switches were set to provide a trip signal to the control system. If two out of three set points were exceeded, the unit would trip.

Since the trips typically occur when the unit is fully loaded, possible mechanical damage can occur. Also, there can be significant monetary cost to the plant because of the loss of generation from this event.

Staff discovered the pressure-switch set points would drift because of gas-turbine vibration and changes in ambient conditions. In 2016, the plant experienced several GT trips because of high pressure in the exhaust duct. After each trip and prior to restart, the switch set points were checked; in all cases they required adjustment to the correct value.

Solution. The plant's short-term solution was to change the tubing to all three switches to allow checking of the set points with the unit online or offline. The increase in frequency of checking the set points helped to increase the unit's reliability.

There was little time for the opera-



Logic change to improve reliability required swapping out exhaust-duct pressure switches (above) with transmitters (right) tor to take action when the set point was exceeded until the trip signal was received. This was observed several times when there were storms in the area causing changes in ambient pressure. Based on this observation, controls engineers were asked to add feedback logic to the system that would allow the GT to reduce exhaust-duct pressure by reducing load automatically without initiating a unit trip.

Staff discussed the Effingham plan with the GT and HRSG OEMs and determined the maximum allowable exhaust-duct pressure to prevent component damage. Once this value was determined, runback and alarm set point values were selected.

A third-party controls engineer was engaged to review the plan and design the necessary logic. The only way this change could work was to swap out the pressure switches with transmitters. Since one transmitter already was installed, an additional transmitter was purchased for each unit.

During the fall maintenance outage, plant personnel removed all pressure switches and tubing and installed one new transmitter with the necessary tubing (photos). In conjunction with mechanical changes to the turbine roof, the controls engineer modified the logic to provide a high-select output from two transmitters. A deviation alarm is provided if transmitter outputs drift apart. These set points are 1-in. apart so the protection system can react during a transient condition as well as protect the GTs and HRSGs.

Results. Once the control-system logic change was made and tested, the units were dispatched; no issues were encountered. Transmitter outputs are displayed on the HMI control screens for operators to monitor when the units are online.

There have been several instances this past year in which the plant has been operating at the alarm set point with the units not in baseload service. In an attempt to maximize output, the load was increased. This increased exhaust-duct pressure, with the runback set point and the control system reacting as designed and reducing the unit load below the set point.

Effingham is charged \$150/MW for lost generation. Typically the unit trips when fully loaded which results in a financial penalty of approximately \$15,000 per occurrence. Total cost of replacing the switches with transmitters and the logic change was \$13,500. In 2016 the plant tripped three times on high exhaust-duct pressure. Since the logic change was implemented, it has not tripped on high exhaust pressure.

Project participants:
Mike Sears
Don Johnson

Fans extend the lives of HRSG lower penetration seals

Challenge. Effingham County Power was replacing failed penetration seals in the floors of its heat-recovery steam generators (HRSGs) about annually. The plant's two HRSGs are arranged with two headers, each serving four seals. Replacement of the plant's 16 seals costs about \$100,000 in materials and labor.

During each overhaul, cracks were discovered adjacent to these seals. No one could determine if the cracks were caused by the failed seals or if the cracks caused the seals to fail. Certified welders were brought to repair the HRSG casings before replacing the seals—at an additional cost of \$50,000 to \$75,000 depending on how extensive the cracks were.

After the 2018 spring outage, new penetration seals were installed and the HRSG casings were repaired. The seals replaced had failed after only about 500 hours of service—cause unknown. Supplier of the penetration seals sent technicians to inspect and replace the damaged components. They determined that the premature seal failures were caused by casing cracks blowing hot flue gas onto the seals.

Investigation revealed casing insulation had deteriorated, exposing the metal to gas-turbine exhaust gas. This caused the HRSG floor to buckle, warp, and crack, allowing the gas to escape and damage the lower seals and the casing. The temperature around the seals was roughly 850F; the maximum design temperature for the external side of the seals was only 700F.

Solution. In April 2018, Effingham installed three external blowers and associated ductwork on each HRSG to provide cooling air to the seal area (photos). The cost of the three blowers and ducting to the seals was $1600 per HRSG. The blowers are driven by 120-Vac motors that are plugged into a plant receptacle. The auxiliary operator verifies the blowers are in service prior to the plant startup. He also checks that the blowers are running during rounds; the fans are de-energized when steam is no longer in the HRSGs.

The plant established a PM to check temperatures in the area of the seals weekly. A spreadsheet was developed to track the temperature scans, which are reviewed to verify the integrity of the seals.

After the installation of the blowers and ducting, the area under the HRSG is cooler allowing personnel access to the blowers and seals. The seals are easy to inspect and to determine if they are starting to fail by observing any color changes in the seals' outer material.

Blowers (left) and associated ductwork (right) cooled the HRSG lower penetration seals, extending their service lives

Results. There was a forced-maintenance outage to repair the HRSG casing and replace the damaged seals. Several engineers inspected the area and determined excessive heat had damaged the HRSG casing and that it had to be replaced. Several vendors were contacted to bid on the replacement.

The blowers and ductwork reduced the temperature in the seal area by 250 to 300 deg F. While the blowers have been in service for only a year, they have extended the lives of the lower seals. This allowed plant dispatch through the critical summer run season, increasing Effingham's bottom line.

Casing replacement and new lower penetration seals are scheduled. After all work is complete the blowers and ducting will be reinstalled and operated to extend casing life.

Project participants:
Sean O'Neill
Berry Hardwick
Kris Brackbill
Russ Howell

Don’t forget to verify the ability of HRSG feet to slide

Challenge. There was a very audible popping sound emanating from Effingham’s HRSGs during unit startup. The cause: Binding of the units’ grease-starved sliding feet during casing expansion. The sliding feet are 40 × 18 in. and they had only two grease zerk fittings—one per side of the webbing in the center of the foot.

The absence of machined passageways to transfer the grease to the outermost areas of the bearing pad was the root cause of the issue. After years of cycling and the extreme pressure exerted on the bearing pads, the grease had formed its path of least resistance: It remains in the center of the sliding feet, forcing about 90% of the bearing-pad surface to be metal-on-metal. Thus, the feet are not able to slide freely while the HRSG expands and contracts.

Once the HRSG begins to grow thermally, pressure is exerted on the sliding feet causing them to bind. When the pressure is high enough to cause the sliding feet to move, a loud noise results and HRSG components are subjected to mechanical shock.

Solution. The first corrective action: Remove any trapped grease from under the feet. The thought was that if there was old hardened grease in this area, it could be blocking the addition of fresh grease to the feet. The plant used a pressure washer to remove the grease which was collected and disposed of properly. However, after adding fresh grease, the noise was still present after startup.

Staff contacted the HRSG OEM to obtain drawings of the sliding feet to verify if the undersides of the feet were channeled or flat. After discussions with the vendor, it was determined that adding more zerc fittings to the feet was the best solution for the problem. The feet located between the stationary support and the turbine were the first to be modified because this section had the highest growth rate of all the HRSG sections.

Original design of sliding feet (left) was changed to accommodate new zerc fittings (right). Also, be sure to check nuts are not so tight as to restrict movement of the sliding feet

Two holes were drilled and tapped into the HRSG feet and zerc fittings were installed (photos). The new holes are located in the far corners of the feet, off-center of the existing zerc fittings. This new configuration has a zerc fitting on all four sides of the sliding feet. With four zerc fittings, the grease is distributed throughout the bearing pads allowing proper lubrication.

Results. The benefit of this practice is that the sliding feet are operating properly. Since the new zerc fittings have been installed, and grease is being distributed to the entire bearing surface, the popping sound following startup has not been heard. By decreasing the stress on the HRSG and letting it grow as designed, Effingham will save a substantial amount of money in weld repairs—and likely extend the lives of the boilers.

Project participants:
Sean O’Neill
Berry Hardwick
Kris Brackbill
Russ Howell

Land application: A practical solution for disposing of cooling-tower blowdown

Challenge. Effingham’s evaporative cooling tower blows down its high-conductivity water into a 2-million-gal holding pond. This water then is sprayed on land in the area of the plant in accordance with Georgia Dept of Natural Resources operating guidelines. The system has five control valves, each serving a different irrigation zone. Valve operation is controlled by programmed logic to ensure the system operates within permit limits.

The valves have recurring issues related to the clogging of sensing and control lines with algae and sediment. Adding to the challenge, the control valves are located in underground vaults usually filled with at least 5 ft of water because of the wet environment (photo, left). The control valve’s diaphragm and sensing and control lines plug with sediment and algae, which doesn’t allow them to operate correctly.

By design, the Bermad 720-55 style valve receives system pressure at the top of its diaphragm, which fully closes the valve. The fouling problem arises because the line that closes the valve dead heads at the top of the diaphragm and over time and mud and algae accumulate in low flow areas conducive to plugging.

When an operator finds a zone is not operating correctly, he/she has to isolate the zone and flush the lines manually from an available above-

Bermad 720-55 control valve is located in an underground vault (left). Red circle shows the location of new flushing line. Monthly flushing is accomplished by simply opening the ball valve (arrow) ground source. This ultimately does not completely flush out the system because of its location and design.

Solution. Each vault was pumped down, and all the lines were detached and freed of blockages. A new line was installed on the top of the valve, above the diaphragm, and run up and out of the control-valve vault. A ball valve was added for manual flushing (photo, right).

The total cost of the project was $800 and the installation was performed by plant personnel. Manual flushing of control valves was added to the existing monthly preventive maintenance tasks for the land application system.

Results. The operators reported increased system pressure after completion of the modification, indicating the zones not in service were fully closed. Operators also walk down the system during operation to confirm all zones are working correctly. This means individual zone discharge limits can't be exceeded because of malfunctioning control valves.

The zones have not required flushing outside the normal monthly PM schedule since implementing the best practice. This has contributed to more-reliable operation of the land-application spray system and eliminated the labor required for periodic manual flushing of the five zones.

Project participants:
Michael Sears
Robert Lancaster
Kris Brackbill
Russ Howell
Berry Hardwick

Chemical unloading checklists help avoid accidents

Challenge. Almost every type of plant that receives, stores, and uses chemicals has procedures for checking in and transferring the products to onsite storage. The reality is the procedures often are on a shelf or a shared drive. Typically they are lengthy documents that don't get printed or carried into the field when operators are multi-tasking.

There have been several incidents in which the delivery truck was connected to the incorrect storage tank or improperly lined-up for the unloading process. If the wrong combination of chemicals is mixed together the result can be fatal to personnel at the plant and the nearby community.

Since deliveries to the plant can happen at any time, the auxiliary operator is the individual generally assigned to monitor the unloading process. Once the tanker truck arrives onsite (photo, left), there is a limited amount of time to unload the chemical before incurring additional costs. Therefore, it's important that the operator report to the unloading area, brief the driver, and verify the chemical and the line-up are correct.

To ensure the unloading evolution is performed safely and correctly, an approved checklist should be used as guidance. The checklists are saved on the company's shared drive for easy access. It takes time to retrieve the checklist and report to the unloading area. Drivers are prevented from starting the process, possibly leading to additional costs.

Solution. Both plant management and operations recognized a need for a better and safer process. The solution was to preprint chemical unloading checklists and keep them at the chemical offloading areas in a weather-proof container (photo, right).

With this improvement, the correct checklist is available at the point of delivery. It includes both verification of product and destination; also, pre-transfer equipment checks for both transfer equipment and safety equipment—such as wheel chocks and safety showers.

Once all the checks are complete, the auxiliary operator and truck driver sign the checklist to acknowledge all checks have been performed and it is safe to commence the chemical transfer. Once the transfer is completed and the truck has departed the site, the checklist is attached to the all the paperwork associated with that chemical. If there is an issue with the evolution, the names of all involved with the transfer are available to conduct an investigation.

Results. The preprinted checklists have been popular and successful. The plant operators don't have to scramble to find the paperwork. The checklists include all pre-delivery checks and notifications necessary to meet the procedural requirements and assure safe chemical transfer.

By having the driver and auxiliary operator sign the checklists, there is an added insurance that they are performing the evolution correctly. Since having these checklists at the unloading areas, the amount of time that the delivery trucks are onsite has been reduced. Implementing these checklists and storing them at the unloading areas has resulted in no safety observations being discovered during transfers.

Project participants:
Bob Kulbacki, plant manager
Jobie Seward

Unloading area is prepped and ready to accept delivery of chemicals (left); chemical unloading checklists are retained in a protective container in the unloading area (right)

Woodbridge

Woodbridge Energy Center

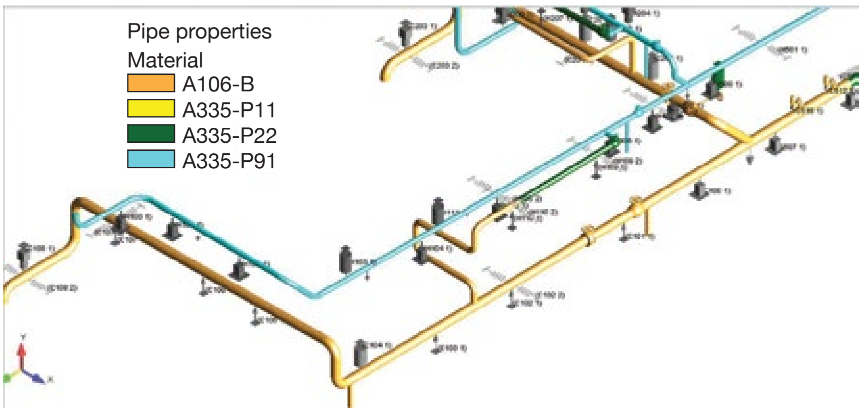
Owned by Competitive Power Ventures

Operated by CAMS

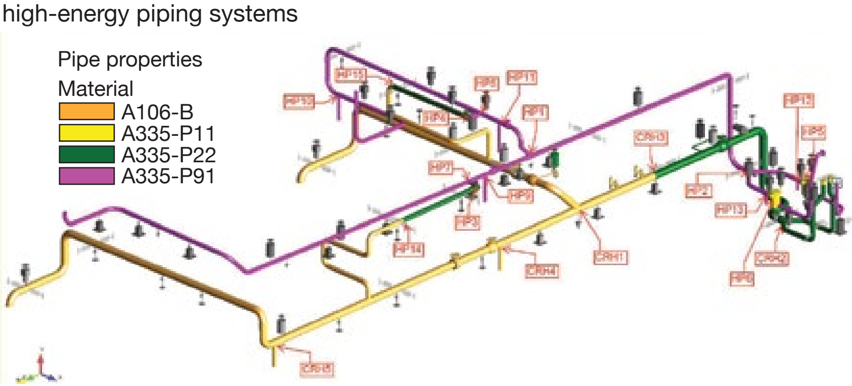
725-MW, 2 × 1 combined cycle powered by 7FA.05 gas turbines, located in Keasbey, NJ

Plant manager: Chip Bergeron

High-energy-piping program simplifies inspection, recordkeeping



1. Hangers are identified on this general arrangement drawing of Woodbridge's high-energy piping systems



2. Welds are shown on this general arrangement drawing of Woodbridge's high-energy piping systems

Challenge. Like any new facility, all of the programs and procedures needed to operate and maintain Woodbridge Energy Center had to be created from scratch. One, the High Energy Piping Program (HEPP), immediately stood out to the plant team as an area that could benefit greatly through customization and simplification. The challenge was how to make a relatively complicated and lengthy program efficient and easy to understand by operations personnel while creating a sense of ownership through participation

Solution. HEPPs have two main goals: Safe operation of the site and long-term reliability of the plant's piping systems. To achieve these goals at Woodbridge, its 22,000 ft of piping was broken down into 495 data points (425 pipe supports and 70 welds). Those data points were then condensed into a form making inspections easy to perform, understand, and track over the life of the site. Typically this area is where most HEPPs fall short because of the massive amount of data needed for inspection and formatting of the results.

Team Woodbridge decided the first area to go after was the actual inspection form itself. With the goal being a form that was visually easy to follow and understand, Plant Engineer Michael Armstrong took the general arrangement drawings for the differ-

										Date		
Point	Pipe Size Nominal in	Support ID	Support Type	Symbol	Direction	Rate/Stiff. lbf/in	Cold load lbf	Size	Figure	Hot Reading	Cold Reading	Comments
H100	16	H100 1	V-Stop	Shoe								
H101	16	H101 1	V-Stop	Shoe								
H102	16	H102 1	V-Stop	Shoe								
H103	16	H103 1	Spring	Hanger		1142	9909	2173	T20-29 R3			
H104	16	H104 1	V-Stop	Shoe								
H105	16	H105 1	V-Stop	Shoe								
H105	16	H105 2	Incline		Global X	Rigid						
H106	16	H106 1	V-Stop	Shoe								
H107	16	H107 1	V-Stop	Shoe								
H107	16	H107 2	Incline		Global X	Rigid						
H108	16	H108 1	V-Stop	Shoe								
H500	18	H500 1	V-Stop	Shoe								
H501	18	H501 1	Incline		Global X	Rigid						
H502	18	H502 1	Spring	Hanger		3806	18947.92	2182	T20-29 R2			
H503	18	H503 1	Incline		Global Z	Rigid						
H504	18	H504 1	V-Stop	Rod Hanger								
H505	18	H505 1	Damper		Global X	Rigid						
H506	18	H506 1	Incline		Global Z	Rigid						
H507	16	H507 1	Spring	Hanger		381	3385.245	2153	T20-29 R3			
H508	16	H508 1	Spring	Hanger		761	3410.189	2163	T20-29 R3			
H200	16	H200 1	Constant	Hanger			8018.448					
H201	16	H201 1	Constant	Hanger			5477.468					
H202	16	H202 1	V-Stop	Bi-Direction								
H202	16	H202 2	Incline		Global Z	Rigid						
H203	16	H203 1	Constant	Hanger			8875.361					
H204	16	H204 1	Constant	Hanger			9804.953					
H109	18	H109 1	V-Stop	Bi-Direction								

3. Spreadsheet developed by Woodbridge personnel provides a clear and concise presentation of inspection results

ent piping systems and added indexed markings showing the location of the hangers (Fig 1) and welds (Fig 2) included in the program.

The last hurdle was the clear and concise presentation of the inspection results. A spreadsheet was developed (Fig 3) that listed the index numbers from the referenced drawings along with related design information (pipe size, pipe support ID, growth direction, plus support type, symbol, and stiffness) for each pipe support/hanger. It also included a section for hot readings, cold readings, and comments.

This enabled the individual performing the inspection to take the annotated piping system drawings with the inspection forms and walk down each support/hanger easily and efficiently.

Regarding weld inspections, a similar sheet was developed; however, the site team is not trained to perform the vast array of necessary inspections (wet fluorescent magnetic-particle testing, ultrasonic thickness testing, metallurgical replication, positive material identification, metal shaving analysis, hardness testing, laser surface profilometry, and linear phased array ultrasonic testing) so the drawings and inspection forms are provided to the third-party contractor prior to starting work.

Results. An otherwise complex program was developed into an efficient and easy-to-understand process that (weld inspections excluded) the team can self-perform. The ability to self-perform the hanger inspections already has proven valuable when issues were discovered by plant staff that likely would have gone unnoticed by contractors not familiar with the site. Being able to catch these problems in-house greatly increased the team's confidence in its own ability to quickly identify issues without having to comb through multiple levels of contractor-provided documentation.

Project participant:
Michael Armstrong, plant engineer

Qualification Card University underpins in-house training program

Challenge. As Woodbridge Energy Center began its third year of commercial operation with a very low turnover rate, it was faced with an unexpected problem in terms of continuing education for staff. After initial training, employees have access to the CAMS Workforce Development Program, which offers a combination of online and hands-on training programs in craft skill areas—such as mechanical, electrical, I&C, and auxiliary operations.

Though most personnel had completed a majority of the training programs, very few had completed all of the training necessary for their Qualification Card. Since Woodbridge is operating at a high capacity factor (nearly baseload), it does not provide sufficient time for learning opportunities that do not interrupt the workflow and routine. Therefore, team members were not able to easily re-engage with training material nor provide additional opportunities for training new hires because of the time constraints.

Solution. To address the problems of staff engagement, new-hire training, and the lack of down time, a new training program was introduced: Qualification Card University (QCU). This training program is led by a "professor" (Production Manager Justin Hughes), uses a set class schedule, and provides a group learning atmosphere.

Initially, the class was held for two hours every Friday afternoon with the weekly topic being chosen off of the Auxiliary Operator Qualification Card. The topic was rotated frequently a means to provide fresh and ever-changing content to the team members who already completed their qualifications, or nearly so. It also provided a means of covering a broad range of content areas for recent employees just starting out in the qualification program.

Results. By the end of the first month of QCU classes there was a dramatic increase in class participation, especially during the 20-min open discussion period at the end of the main lesson. This led to a few classes going well beyond the two-hour mark, and it also kick-started the Workforce Development Program to the point that there was a waiting list for employees to perform their final checkout exams for the various craft skill areas.

While both of those results were fantastic and beyond expectation, the real measure of overall program success came at the end of the year. An extended fall outage forced classes to be put on hold for a few months until the team was surveyed at the year-end safety meeting. Personnel were asked to respond to this question: "What can the management team provide employees to make their careers and overall time at the site better going into 2019?" The overwhelming response to this question: Bring back Qualification Card University.

The program was restarted the second week of January 2019 and has already been expanded (at the plant team's request) to include topics outside of the written portion of the QCU program—such as hands-on training, "field trips" around the site to various pieces of equipment, and "guest speakers" from the plant team. By blocking out and dedicating two hours each week while also creating a group learning environment for the entire staff, QCU doubled the craft skill area completion rates and reignited the team's enthusiasm for continued learning.

Project participants:
Justin Hughes, production manager
Timothy Murphy, senior technician

Mods to haz-gas-analyzer blowback system eliminate alarms, runbacks

Challenge. The 7FA.05 gas turbines at Woodbridge Energy Center were constructed with a new style of hazardous-gas detection system. It uses instrument air and an aspirator to pull air samples from two different compartments on the unit through dedicated LEL (lower explosive limit) sensors (Fig 4).

The LEL sensors have the capability of shutting down the turbine should two sensors in either compartment go into a state of alarm, which is defined as high LEL readings and/or a loss of sample flow through the LEL detector itself. The latter had caused numerous runbacks and required daily attention in order to stop loss-of-flow alarms from coming in constantly.

Initially, one, or both, of the filters installed in each of the sample lines was the suspected cause of the problem. After going through every combination of filter design and mesh, plus a short stint without filters, the issue persisted. Eventually, the opportunity arose to take the entire system offline, allowing the site team enough time to blow high-pressure instrument air back through the sample lines to clear them of any debris left over from construction.

Much to everyone's surprise, this stopped the alarms from coming in for several months before they slowly started becoming a part of the daily routine once again. At this point, it appeared as though the solution was as simple as a finer mesh sock filter on the end of the sample probe. Unfortunately, that filter was/is not available from the OEM and any attempt by the site team to create its own filter ended with loss-of-flow alarms caused by the inability of the aspirator to create a sufficient amount of vacuum on the system.

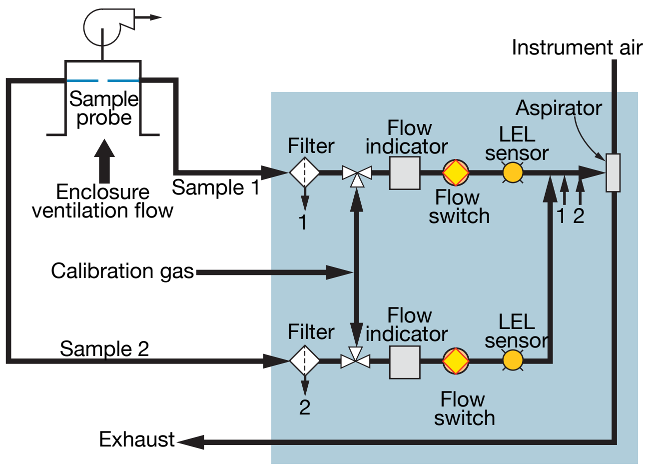
Until a better aspirator and/or filter design became available, the solution to the loss-of-flow alarm issue was to blow back the sample lines quarterly. This process is neither quick nor easy given the location of the analyzers and their OEM's tubing configuration. The analyzers also must be taken out of service for an extended period during this process—not ideal because the unit primarily operates at baseload.

Solution. To expedite the process of clearing the sample lines, the plumbing had to be reconfigured. The first step was to bring a permanent source of instrument air to the area just upstream of the particulate filter mounting block (Fig 5). This eliminated the need to run temporary air hoses for the blowback process over extended distances.

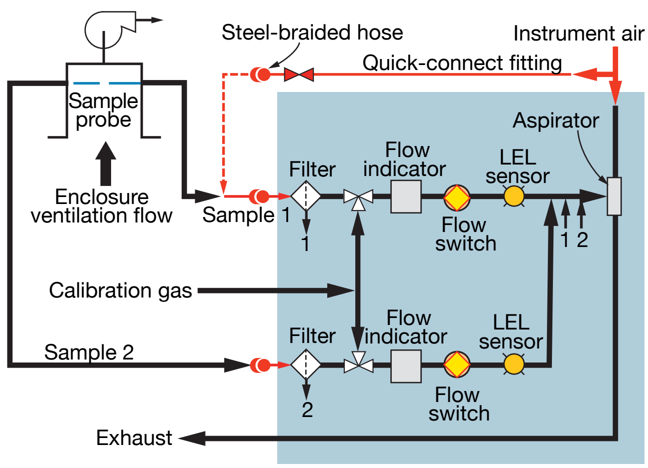
Once this air supply was sourced and brought into the area, the OEM installed compression fittings were removed in favor of a quick-connect style (Fig 6). This allows the technicians to quickly move the lines from their normal line up into the blowback configuration. A ball valve was also installed as a means to block and control the air flow during the blowback process.

Results. After implementing the changes, the blowback process was reduced from a several-hours-long task for each gas turbine to one that takes no more than a few minutes. This reduction in analyzer downtime has allowed the site to perform this work while the plant is in operation with minimal risk of an inadvertent runback.

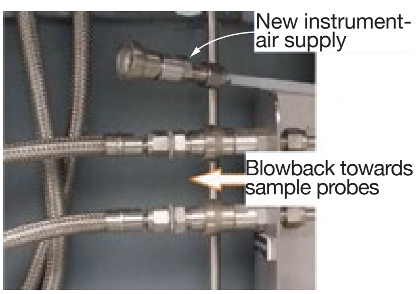
Lastly, now that the process is quick and easy, it is being performed monthly and has completely eliminated the loss-of-flow alarms that had plagued the site for over two years.



4. Hazardous gas analyzer as-built



5. Hazardous gas analyzer lined up for a blowback of Sample 1



6. Filter-block quick-connect fittings installed by plant personnel

Project participants:
Justin Hughes, production manager
Jesse Sincoskie, maintenance team lead

Portable fire-extinguisher improvements make for a safer workplace

Challenge. Combined-cycle facilities require a portable fire-extinguisher program to meet NFPA 10 requirements. Production Team Leader Ray Melcer reviewed the existing portable fire-extinguisher program at Woodbridge Energy Center and identified areas needing improvement.

The review found fire extinguishers without adequate signage and not in the normal path of travel, which created inefficiencies during the monthly inspection process. Furthermore, many extinguishers and inspection tags were exposed to environmental conditions, resulting in degradation over time.

Solution. The first issue tackled was meeting the locational requirements and ensuring the extinguishers were in the normal path of travel with the appropriate signage. The team ended up relocating 15 of the 68 portable fire extinguishers in the field to meet NFPA 10 requirements. This action ensured fire extinguishers were not obstructed or obscured from view.

The team also placed 47 new signs above fire extinguishers to raise awareness of each extinguisher's location. The monthly inspection checklist also was amended to capture the proper order in which fire extinguishers were inspected throughout the facility.

To address the environmental issues and to promote equipment longevity, team members installed covers on each outdoor portable fire extinguisher (Fig 7). These covers go on over top of the extinguisher, protecting it from weather, cooling-tower plume, etc. The covers are relatively inexpensive ($15 each) and are easily installed and removed via a Velcro® strap. The easy removal of each cover allows for quick fire-extinguisher use during times of need. The covers are a bright red color and increase visibility of where each extinguisher is located.

The team also purchased aluminum inspection tags to replace the standard paper inspection tags (Fig 8). Only slightly more expensive than the paper, these tags hold up against wear and tear and help demonstrate compliance during annual fire-protection audits by local authorities.

Results. The team successfully implemented portable fire-extinguisher best practices that strengthened NFPA 10 compliance and improved safety. By rearranging where the fire extinguishers are located in the facility and raising awareness through signage, the team enhanced the visibility of a critical safety resource. This also shortened the time to complete the monthly checklist by one or more man-hours.

Moreover, the team's effort improves longevity by installing individual covers and changing out inspection tags to something more durable. This project cost less than $1000; payback was projected at six to eight months through equipment resilience and saved man-hours.

Project participants:
Ray Melcer, production team leader
Ryan Bullock

7. High-visibility covers both protect fire extinguishers and make it easier to find them

8. Aluminum inspection tags last longer than the standard paper tags

TURBINE TIPS, No. 4 in a series

How to determine if your Oilgear fuel pump is fit for service

By Dave Lucier, PAL Turbine Services LLC
www.pondlucier.com

Turbine Tip No. 4 from the PAL O&M solutions library applies to General Electric Frame 5 models K, L, and LA gas turbines. Focus is on fuel pumps that are retained when the control system is upgraded.

The fuel pump of choice on GE gas turbines following the Great Blackout of November 1965 was Oilgear model PVAZKM-054 (Figs 1-3). When users consider upgrading the control system on these 50-year-old gas turbines, prospective contractors often tell them that they can retain the existing fuel pump. This often is done one of two ways:

- The Oilgear fuel pump can be modified to "fully stroke" it, such that a bypass valve can be installed to control fuel flow to the combustors. Since the existing flow divider from Roper Pump Co does not have speed pickups to measure fuel flow, that device must be replaced as well, so there is not much cost saving.
- Remove the existing Young & Franklin fuel regulator, but retain the constant control oil (CCO) pump to maintain the 300-psig source working pressure. Then install a modern signal actuator with a control range of 4- to 20-milliamps input for 40- to 200-psig control signal output. In this case, the Oilgear fuel pump would continue to work as it had for the previous five decades with the same flow divider.

Note that throughout this article, the control signal is called VCO—for variable control oil pressure (Fig 4).

Fig 5 shows an indicator protruding from the bottom of the fuel pump (red arrow). It displays the pump stroke. From the GE control specifications in Fig 6, read the pump stroke for an unmodified unit: VCO = 40 to 200 psig results in total stroke of 0 to 0.320 in. The first 40 psig is referred to as the zero effective stroke.

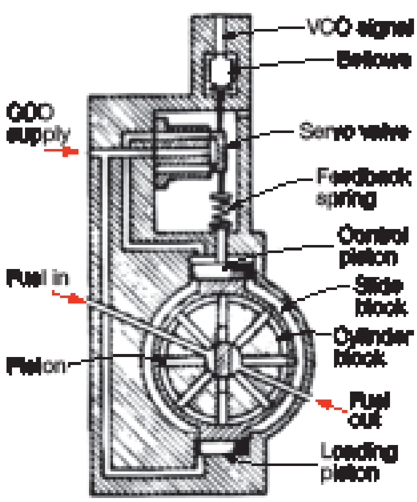
To measure the pump stroke at turbine "cranking" speed (1000 rpm), a precision machinist's rule is recommended, because a dial indicator often vibrates excessively. The confusing part of checking the pump stroke with a ruler is that the stroke indicator "disappears" upward into the pump, as the VCO pressure goes from 0 to 200 psig. Thus, you must take an initial reading of the exposed indicator and then again when selecting the MAX VCO on selector switch **43FS** inside the turbine control panel.

PAL recently visited a plant to do a GEMAC replacement for a customer with an MS5001L engine. The team asked if they could first "crank" the gas turbine to take some readings regarding the fuel regulator, including maximum VCO. This is a typical test done to establish some primary adjustments and observe the fuel-pump stroke.

The owner/operator was told that PAL could measure fuel-pump stroke with a precision ruler that read in 1/32-in. increments. While cranking the turbine, it was observed that the pump-stroke indicator did *not* move upward into the pump body, as shown in Fig 5. The test switch **43FS** used at cranking speed is in Fig. 7.

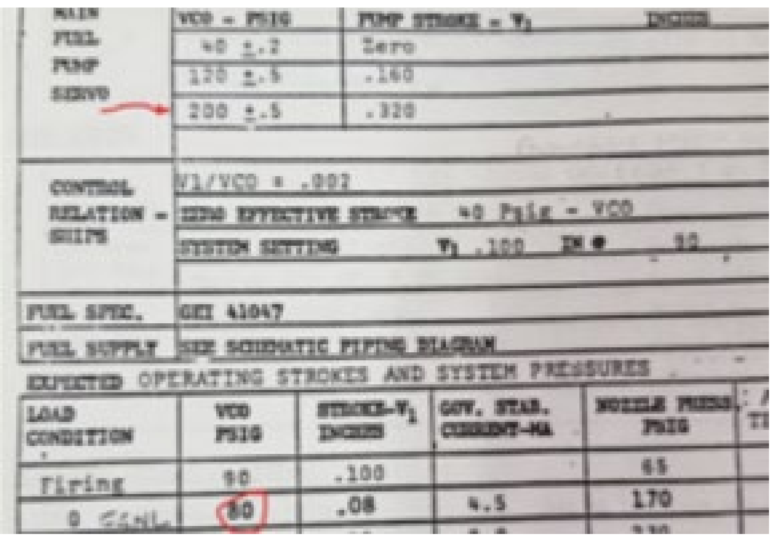
1. Typical Oilgear fuel pump installed on a Frame 5

2, 3. ID tags for Oilgear pump model PVAZKM-054



4. Variable-displacement fuel pump schematic identifies principal components of the model described in the text

5. Stroke indicator is at the bottom of the Oilgear pump (arrow)



	VCO – PSIG	PUMP STROKE – V_1 INCHES
MAIN FUEL PUMP SERVO	40 ±.2	Zero
	120 ±.5	.160
	200 ±.5	.320

CONTROL RELATIONSHIPS – V1/VCO = .002; ZERO EFFECTIVE STROKE 40 Psig – VCO

FUEL SPEC. GEI 41047

FUEL SUPPLY SEE SCHEMATIC PIPING DIAGRAM

EXPECTED OPERATING STROKES AND SYSTEM PRESSURES

LOAD CONDITION	VCO PSIG	STROKE-V_1 INCHES	GOV. STAB. CURRENT-MA	NOZZLE PRESS. PSIG
Firing	90	.100		65
@ FSNL	80	.08	4.5	170

6. GE control specs are for an unmodified unit where VCO = 40 to 200 psig and total stroke ranges from 0 to 0.32 in. (left)

7. Test switch 43FS used at cranking speed is identified by arrow (above)

The PAL team ran the turbine up to 100% speed (FSNL), expecting a VCO pressure of about 80 to 85 psig, as indicated on the last line of the spec sheet in Fig 6. But it was 111 psig, much too high. Recall that fuel flow is a function of both pump speed and stroke. At constant speed (100% FSNL), therefore, an increase in VCO results in an increase in fuel flow (linear to VCO value).

To fully understand pump design, you must subtract 40 psig from pressure readings on the VCO gage. Thus, the expected reading was 80 – 40 = 40 effective VCO. In this case, 40 was subtracted from 111 to get 71 psig. Thus, it was taking far more pump stroke to run the turbine at rated speed than expected from the data in the GE control specifications. PAL's conclusion: The pump was *failing*.

The team suggested that some of the pump's 26 internal pistons likely were stuck in position and not pumping fuel. Disassembly and inspection revealed eight stuck pistons. The owner/operator agreed with PAL that the pump should be replaced with a rebuilt one.

The bottom line: A test is worth 1000 "expert" opinions. Test the Oilgear fuel pump at crank speed before you consider reusing the variable-displacement fuel pump following a control-system upgrade. Don't assume it is operating correctly after 50 years of service. CCJ

SPECIAL REPORT

HRSG FORUM WITH BOB ANDERSON

Trends in HRSG reliability, a 10-year review

Editor's note. This report summarizes information on cycle chemistry and thermal transients at combined-cycle/HRSG plants shared at the industry's leading technical forums worldwide over the last several years—such as the US-based *HRSG Forum with Bob Anderson*. The foundation for many presentations and discussion sessions on these subjects comes from assessments undertaken in the last decade at scores of plants by Barry Dooley, Structural Integrity Associates Inc, and Bob Anderson, Competitive Power Resources Corp (CPR).

Their work has been compiled in an extensive report, "Trends in HRSG Reliability—a 10-Year Review," completed only a couple of months ago. Consulting Editor Steve Stultz has greatly condensed its contents to whet your appetite for the extensive guidance offered on HRSG operation and maintenance. This seminal effort tells us that the potential equipment damage mechanisms from improper chemistry and operation are critical and global, regardless of OEM design or plant location. The problems are fundamental, universal, and should not be ignored. You can download the complete report from the CPR website at no cost. [QR 1]

The overview that follows has two sections: cycle chemistry and thermal transients. Details, hands-on experience, insights, and assessment methods are accessible in a heartbeat by scanning the Quick Response codes provided with your smartphone or tablet. Have questions? Post them on the online HRSG Users Discussion Forum, chaired by Anderson, at www.powerusers.org (users only, registration required, no cost).

Credentials

Dooley serves as executive secretary of the International Association for the Properties of Water and Steam (IAPWS). It was formed in 1929 and today is an international knowledge base concerned with the thermophysical properties of water and steam, powerplant cycle-chemistry guidelines, and other aspects of high-temperature aqueous mixtures relevant to thermal power cycles. These are the folks who developed any steam tables you have used. Selected IAPWS Technical Guidance Documents (TGD) referenced in this report can be downloaded at no cost from the organization's website. [QR 2]

Dooley specializes in identifying and resolving damage and failure mechanisms in powerplants, and has global expertise in HRSG tube failure reduction/cycle-chemistry improvement, and FAC programs (see sidebar of acronyms).

Anderson, as principal of CPR, is focused on HRSGs and their related steam-plant auxiliaries in the combined cycle/cogeneration sector of the electric-power industry. Of particular note is his experience in identifying avoidable and damaging thermal transients in HRSGs and their cause/effect with operating procedures. His relationship with Dooley incorporates decades of powerplant analysis, design, and hands-on experience in both system mechanics and chemistry globally.

IAPWS and related organizations (EPRI, ASME, and several others) keep up with changes in powerplant applications. But all would be first to state that their work is based on the fundamentals and working experience of water chemistry, thermodynamics, fluid dynamics, heat transfer, two-phase flow and circulation, metallurgy, structural analysis, and design.

So when these experts offer insights on trends we should listen, discuss, and learn.

1. Cycle chemistry

If you are fortunate enough to attend one of their conference presentations or discussions, you might sense a bit of frustration on the part of the speakers. "We know how to fix this!" they often state. "And we've known for quite some time."

A decade ago, CCJ issued a report by Dooley and Anderson assessing trends in HRSG cycle-chemistry and thermal-transient performance, compiling information gathered from a variety of plants and locations. Their review noted that the frequency of damage and failures in the subject plants had remained almost the same for 20 years. The latest and much more comprehensive study should leave no doubt about the previous results.

The authors remind us that materials of construction and their long-

QR 1 QR 2 QR 3 QR 4 QR 5 QR 6

QR 7 QR 8 QR 9 QR 10 QR 11 QR 12

QR 13 QR 14 QR 15 QR 16

term reliability depend on internal surface protective oxides. As one primary example (feedwater sections up to about 570F), iron oxide is a passivating protective layer on a metal surface that acts against further corrosion.

Formation of these critical oxides relates directly to the cycle-chemistry treatments used in the condensate, feedwater, boiler/HRSG evaporator water, and steam.

The cycle-chemistry damage and failure mechanisms are all influenced by operating with less than optimum treatments, and doing so results in protective oxide breakdown.

Thus, in a powerplant setting, establishing the appropriate chemistry for the materials involved then exercising vigilance to detect any signs of chemistry upset are required.

The chemistry of the condensate and feedwater is critical to the overall reliability of HRSG plants. Good cycle chemistry is designed to prevent and/or reduce corrosion and deposits in the water/steam circuit, usually initiated and managed through a combination of techniques.

All-volatile treatment (AVT), applied to condensate and feedwater, represents the simplest form of chemical conditioning. The four standard variations are:

- AVT(R), all-volatile treatment (reducing).
- AVT(O), all-volatile treatment (oxidizing).
- OT, oxygenated treatment.
- FFS, film-forming substances.

Over time, AVT(O) has emerged as the preferred treatment for HRSGs in combined-cycle plants. For some units, adding solid alkalizing agents to drum/evaporator water might be needed to improve tolerance to impurities and reduce corrosion risks. Common agent methods are phosphate treatment (PT) and caustic treatment (CT).

Some rules of thumb

IAPWS and the authors of the "10-Year Review" tell us that there are now some proven *Rules of Thumb,* tested by time, location, and operating experience. These are valid for plants where steam and water contact only ferrous materials.

1. An oxidizing treatment—AVT(O) or OT—should be used to prevent single-phase FAC. AVT(R) should *NOT* be used.

And here emerges one of the frustration points. "The global situation is improving, but AVT(R) is still used in more than 30% of units worldwide, reduced from about 70% in the early 1990s," the report states. This, we are told, is a major reason single-phase FAC is still occurring.

2. An elevated pH with ammonia or an alkalizing amine is needed to control two-phase FAC. A pH of up to 9.8 is recommended.

3. Total iron corrosion products should be carefully monitored to target <2 ppb in the feedwater and <5 ppb in the drums. These levels are achievable if the optimum chemistry is used. [QR 4]

FAC detection is critical

Corrosion products like to move. FAC, the authors and others have determined, can occur in the preheaters, economizers, and evaporators of HRSGs. Benign corrosion products released by FAC then move to the HP evaporator and deposit on the heat-transfer surfaces. These deposits, when thick enough, can then "act in the evaporators as initiating centers for some of the tube failure mechanisms." If dangerously thick HP evaporator tube deposits are permitted to accumulate, they must be removed by expensive chemical cleaning to avoid tube failure mechanisms. [QR 5]

Cycle-chemistry adjustments are key to reducing or eliminating both

Table 1: Primary locations of single- and two-phase FAC*

Single-phase FAC
- LP economizer tubes at inlet headers
- LP, IP, and HP evaporator inlet headers
- Piping around boiler feed pump (includes desuperheater supply piping)

Two-phase FAC
- LP evaporator tubes in horizontal-gas-path HRSGs
- Horizontal LP evaporator tubes in vertical HRSGs
- Economizer/preheater tube bends where steaming occurs
- LP/IP economizer outlet tubes
- HP economizer tube bends where steaming occurs
- IP outlet link pipes and evaporator risers
- LP evaporator link pipes and risers
- LP drum internals
- Reducers at control valves
- Turbine exhaust diffusers
- ACC tube entries in upper ducts (streets)

*Full details—including materials, temperatures, and specific conditions—are included in "Trends in HRSG Reliability—a 10-Year Review" [QR 6]

Table 2: Analysis of repeat cycle chemistry situations in combined-cycle/HRSG plants

RCCS categories	Combined cycle/ HRSG plants, %*
Corrosion products	93↑
Fossil waterwall/HRSG evaporator deposition	63↑
Chemical cleaning	<10
Contaminant ingress	<10
Drum carryover	90↑
Air in-leakage	<10
Shutdown protection	61↓ (92**)
On-line alarmed instrumentation	95↑
Not challenging the status quo	83↑

*Percentage of the 90 plants in this sample where the particular RCCS was identified; arrows indicate the trend over the last five years **Percentage of the 90 plants NOT injecting dehumidified air into the steam turbine during shutdown

single- and two-phase FAC, causes of significant and costly equipment failures. The "10-Year Review" [QR 6] stresses, "It is most important to identify the type of FAC correctly because the cycle-chemistry solution to arrest single-phase (use of oxidizing treatments) is quite different to that for two-phase (use of elevated pH up to 9.8)."

According to the report, most plants address single- and two-phase FAC at the same time from a chemistry application, which is incorrect.

The first step is to recognize the primary FAC locations (Table 1). The second step is to find the evidence and distinguish between single- and two-phase FAC. "If these surface features are linked with the location of the FAC, then it should always be possible to identify the correct type of FAC occurring in the HRSG," the report states.

RCCS

By looking at a large HRSG population over a substantial time period and diverse locations, the report's authors can clearly determine repeat cycle-chemistry situations (RCCS) that should alert owner/operators to impending damage. In total, there are 10 RCCS associated with combined-cycle plants, and the most common are outlined below (but all should be studied in the published study): [QR 7]

Corrosion products. The authors tell us that correct monitoring of total iron (Fe) within the system should be a priority for any powerplant. [QR 4] Such analysis is key to optimizing a plant's cycle chemistry, and for lowering the risks of FAC and under-deposit corrosion (UDC). Comprehensive assessments in the latest study uncovered findings such as:

- Corrosion product levels were not known. Even if monitored, there were often too few monitoring locations and/or inadequate sampling techniques. And, if samples were taken, analysis was often limited to the soluble part of total iron. Samples should be digested to determine total iron.
- If proper levels were known, they were too high.

HP evaporators. Corrosion products found on the inside surfaces of HP evaporator tubing should alert owner/operators to corrosion and FAC in the sections of the cycle at lower pressure. Assessments revealed the following:

- Owner/operators had no knowledge of deposit levels, even in plants with severe FAC.
- If known, deposit levels were not linked with chemistry in the lower-pressure circuits or to the levels of transported total iron.
- HP evaporator samples from specific locations had not been taken for proper, accurate, and complete analysis.
- Some evaporators had been sampled and needed cleaning, but management had delayed or cancelled the activity.
- If accurate, deposit levels were known, they were too high. [QR 5]

Online instrumentation. IAPWS offers a detailed guidance document on instrumentation for both monitoring and controlling cycle chemistry in combined-cycle plants. [QR 8] However, site reviews found the following:

- Instrumentation as a percentage of IAPWS guidance, installed and operating, ranged from 0 to only 60%.
- Many plants used grab samples only.
- Instruments were improperly maintained or calibrated, or were simply out of service.
- Alarms for operators in control rooms were lacking or non-existent.

Air in-leakage. The common problem of air in-leakage (AIL) reduces both plant capacity and efficiency and makes cycle chemistry much more difficult to control. According to IAPWS, "AIL often contributes to subcooling of the condensate and to increased concentrations of dissolved oxygen and other contaminants in the condensate." [QR 9]

Common sources of in-leakage are condensers, pumps and valves, and instrumentation penetrations, among many others. Detection and maintenance are critical. But detection program reviews showed a high level of site indifference.

Some owner/operators showed little awareness of potential impacts:

- At some locations, there were no detection teams or programs in place.
- AIL measurement methods were faulty, no vacuum test had been performed, or inert tracer (for example, helium) was not used.
- If air in-leakage was detected, correction was too often given low priority.

HP drum carryover. This repeat situation is of primary importance to protect the phase transition zone (PTZ) of the steam turbine if contaminants are allowed to enter the cycle. Also, "any condenser leakage will immediately elevate the HP drum and HP superheater chloride levels."

Categories identified in the survey

Acronyms

ACC	Air-cooled condenser
ASME	American Society of Mechanical Engineers
AVT(O)	All-volatile treatment (oxidizing)
AVT(R)	All-volatile treatment (reducing)
CPR	Competitive Power Resources Corp
CT	Caustic treatment
DCS	Distributed control system
DHA	Dehumidified air
EPRI	Electric Power Research Institute
FAC	Flow-accelerated corrosion
FSS	Film-forming substances
GT	Gas turbine
HP	High pressure
HPSH	High-pressure superheater
HRSG	Heat-recovery steam generator
IAPWS	International Association for the Properties of Water and Steam
IP	Intermediate pressure
LP	Low pressure
OEM	Original equipment manufacturer
OT	Oxygenated treatment
PCV	Pressure control valve
PT	Phosphate treatment
PTZ	Phase transition zone (in steam turbines)
RCCS	Repeat cycle chemistry situations
RH	Reheater
SH	Superheater
TGD	Technical guidance document
UDC	Under-deposit corrosion

included:

- No carryover testing had been completed since commissioning.
- Plants were not aware of the simple process involved. [QR 10]
- Saturated-steam sampling equipment was non-existent or not operating.

Shutdown/layup protection. Lack of proper protection has led to serious pitting damage in HRSG drums and in steam turbines. Findings included the following:

- No equipment had been used for nitrogen blanketing and/or dehumidified air (DHA).
- Layup equipment was installed, but had not been maintained or operated properly.
- Owner/operators did not recognize potential risk to the phase transition zone in the low-pressure steam turbine.
- There was no awareness of potential benefits (or dangers) of using film-forming substances. [QR 11]

Challenging the status quo. The authors list this category as "perhaps the most important RCCS for damage prevention (arresting FAC and preventing UDC in power cycles)." Some examples:

- Reducing agents still being used.
- Unchanged system chemistry since commissioning.
- Guidelines incorrect or out of date.
- System pH low.
- Chemical addition points incorrect.
- Widespread failure to question the use of proprietary chemical additions (phosphate blends, amines, film-forming substances) or know the exact composition of the chemicals being added.

One interesting note from the report: "Equal results have been found by Dooley in assessments of over 120 conventional fossil plants."

Things that can be addressed

Here is a telling summary statement from the authors: "For plant operators and chemists who want to be on the path to world-class performance, Table 2 provides the most important cycle-chemistry aspects which need to be addressed to ensure they avoid future cycle-chemistry-influenced damage or failure."

The numbers in the table represent the percentage of plants examined by Dooley and Anderson where the particular RCCS was identified. Arrows indicate RCCS trends industry-wide over the last five years: improvement, no discernable change (no arrow), a step backwards.

The results tabulated illustrate why three major damage/failure concerns (FAC, UDC, and steam-turbine PTZ) continue to occur worldwide despite the excellent understanding of the mechanisms, the well-documented system locations, and the availability of comprehensive guidance available from IAPWS and others.

New and existing plants

For new plant development, the best way to ensure proper chemistry is to incorporate the suite of IAPWS Technical Guidance Documents into the specification phase, proper chemistry thus becoming part of the plant's status-quo policies and procedures. This also will help ensure alignment with the three guiding principles of oxidizing treatment, proper pH, and the achievable values of <2 and <5 ppm iron (feedwater and drums, respectively). [QR 4]

Once in operation, owner/operators should focus their attention to the repeat cycle chemistry situations, addressing each with a clear and complete action plan. Such attention should eliminate situations known to cause damage and failure.

Perhaps most important, each facility should maintain a comprehensive Plant Chemistry Manual that includes the latest cycle-chemistry targets. A suggested table of contents is offered by Dooley and Anderson in their published 2019 study (Table 3).

Table 3: Content of a basic plant-chemistry manual

- HRSG reliability: Failure and damage mechanisms
- Changing perspectives on HRSG failure and damage
- Cycle chemistry importance and major failure mechanisms
- Thermal transients, root-cause analysis, and tube failure programs
- Key aspects for assessments (cycle chemistry)
- Identifying and arresting flow-accelerated corrosion
- Key aspects for assessments (thermal transients)
- How to identify thermal-transient damage
- How to address cycle chemistry in new and operating plants
- How to address thermal transients in new and operating plants
- Conducting an assessment survey
- Conclusions and references

2. Thermal transients

The first part of this report offered selected highlights on the damage and failure mechanisms resulting from improper attention to system water chemistry. Part 2, here, continues with a focus on damaging thermal transients. A thorough review of "Trends in HRSG Reliability—a 10-Year Review" will go deep into details, hands-on experience, insights, and assessment methodology.

Thermal transient damage

In brief form, thermal-transient-influenced damage and failure categories and details are:

HRSG tube failures

- Thermal creep-fatigue in HP superheaters and reheaters at tube-to-header welds.
- Thermal fatigue in economizers at tube-to-header welds.
- Tube distortion in economizers, HP superheaters, and reheaters.
- Accelerated thermal aging (overheating) of HP superheater and reheater tubes downstream of duct burners.
- Water/acid-influenced corrosion in LP economizers (feedwater inlet temperature).

Steam piping failures

- Thermal creep-fatigue in HP superheater and reheater attemperator pipe girth welds.
- Thermal quench cracking in HP superheater and reheater attemperator pipes, elbows, and tees.
- Transient and permanent thermal distortion (hogging and humping) downstream and upstream of attemperators.
- Thermal fatigue in HP superheater and reheater drain pipes.
- Thermal fatigue in girth welds downstream of HP and IP bypass desuperheaters.
- Ageing of pipe downstream of the HP bypass pressure control valve.

HP steam drum damage

- Corrosion fatigue at shell-to-downcomer and shell-to-nozzle welds.

Valve damage

- Erosion of HP bypass pressure control valve (PCV) seat and plug (from improper operation).

Background

Industry and study backgrounds are presented in Part 1. Regardless of OEM, some level of corrosion (both

Table 4: Analysis of avoidable causes of thermal-transient-induced damage/failures

Thermal-transient category	Combined cycle/HRSG plants, %*
Routine attemperator hardware inspections conducted	18↑
Leaking attemperator spray evident in DCS data	82↑
Attemperator spray master control/martyr block-valve logic used	95↑
HPSH attemperator overspray evident in DCS data	31↑
RH attemperator overspray evident in DCS data	12↑
Inappropriate attemperator operation permitted	39↑
HPSH or RH drain pipes too small	65↓
HPSH/RH drain pipes sloped downward	29↑
Blowdown-tank elevation higher than lower HPSH/RH headers	47↓
Poor HPSH draining evident in DCS data	63↓
Poor RH draining evident in DCS data	68↑
HPSH/RH drains open during purge	58↑
Prudent HP drum ramp rate exceeded during startup	25↑
Exhaust-temperature matching used during cold, warm, or hot starts	16↓

*Percentage of the 54 plants in this sample where the stated thermal-transient category was identified; arrows indicate the trend over the last five years

gas- and steam/water-side) and thermal degradation (creep and fatigue) will occur in HRSG pressure parts.

The report's authors, Barry Dooley of Structural Integrity Associates Inc and Bob Anderson of Competitive Power Corp, tell us that "the key to reliable operation and long service life is limiting the rates of these damage mechanisms to those anticipated by the designer."

When the first F-class HRSGs came into service (1990s), contractors, component manufacturers, and owner/operators did not recognize many of the thermal-fatigue damage issues that would or could surface. As one example, few recognized that condensate would form in the HPSH and RH during startup, and drains were not designed to be open during startup.

As another, the *ASME Boiler and Pressure Vessel Code* did not require performance of fatigue analysis during the design process. Most designers and owner/operators projected ongoing baseload operation.

Beginning in 1998, Anderson (then with Florida Power Corp) and others began studying the temperature impacts on HRSG tubes, pipes, and headers. Many of these findings [QR 12-16] are referenced in the new report and form the basis for today's ongoing analyses and system operation reviews.

By 2009, retrofits had addressed some of the problems, including these:

- Redesigned attemperators, control valves, and control logic.
- Modifications to HPSH/RH modules to decrease rigidity.
- Modifications to HP/IP economizer headers.
- Replacing original drain pipes with larger pipe sizes.
- Bypassing elevated blowdown tanks at low pressures.

Since 2009, the authors have conducted surveys at an additional 45 combined cycle/HRSG plants throughout the world and have incorporated those findings in their 2019 report. [QR 6]

Operations

Thermal transients in HRSG components are unavoidable. Repeated transients, aggravated by both cycling and low-load operation, can lead to "incremental accumulation of invisible, irreversible fatigue damage in these components during each transient," according to Anderson and colleagues. The degrees of damage, the assessments tell us, depend primarily on the following:

- Size of the thermal transient (both heating and cooling).
- Component design details.
- Material properties.

In turn, each component's finite fatigue life "is dependent on the degree of fatigue accumulation during each cycle and the number of cycles experienced." Damage is cumulative.

Thus, most failures "are the result of larger and/or more frequent thermal transients than anticipated by the designer."

Enter today's environment of repeated cycling, low-load operation, and shutdown.

Can we see it coming?

The authors' experience indicates that most failures result from unidentified or unresolved operational issues, leading to these common occurrences (among others):

- Leaking of attemperator/desuperheater spray water.
- Attemperator overspray.
- Insufficient draining of HPSH/RH condensate during startup.
- Inappropriate operation of HP and hot-reheat bypass systems.
- Economizer inlet quench.

New results?

Not really. As the authors state, "Unfortunately, many of the avoidable causes of damaging thermal transients identified in 2009 continue to be common findings in these later surveys." Surveys show persistence of some of the design weaknesses and repetition of non-optimum operating procedures, such as:

- Insufficient straight steam-pipe length downstream of attemperator spray nozzles.
- Lack of or improper protective control logic for attemperators and valves.
- Operating procedures that misuse the interstage attemperators during startup and shutdown.
- Attemperator overspray.
- Permitting operators to manipulate attemperator setpoints or manually control spray valves.
- HPSH and RH drain system operating procedures that fail to completely drain during startup.
- Aggressive increase or decrease in HP drum pressure.

A new phenomenon appeared in the HP steam-turbine bypass circuit: Erosion of the pressure control valve cage, disc, and seat by wet steam and water.

How to identify

The authors go into detail on identifying "the most common underlying causes of failures driven by avoidable thermal transients." Emphasis is on the word "avoidable."

Attemperator spray water leaking past the block and control valve remains common (82% of 54 plants evaluated). The authors note that small to moderate leaks (seen on DCS data plots) may be viewed as insignificant by operators, but "even a small leakage rate into hot steam pipes during periods of zero to low steam flow causes cracking (1) of thermal liners, (2) at the inner surface of steam pipes, and (3) in girth welds." Also, temperature differences between bottom and top of pipes can cause distortions that impact even the pipe support system. Water can become trapped in lower areas.

Many systems, the authors say, use master control/martyr block spray valve logic. With many open/close cycles on the block valve, the seat is damaged and the control valve's seating surface is now exposed to high differential pressure. This arrangement is said to be a major cause of leakage.

Overspray means that not all spray water can be evaporated before the first downstream elbow or tee fitting. Best practice is a minimum 50 deg F superheat at the attemperator outlet.

Design issues include insufficient steam pipe length, inferior quality spray nozzles, and improper HPSH/RH heating surface arrangement. Other factors are inferior control logic and operator intervention.

Inappropriate attemperator operation. When steam flow is low or zero and pipes are hot an immediate tube failure is possible because of ductile overload.

More frequent damage is caused by (1) spray operation too early in startup or too late in shutdown, (2) manual manipulation of set points, and (3) inappropriately using interstage spray to match outlet steam attemperators for startup of the steam turbine. One suggestion for plants equipped with GE gas turbines is exhaust-temperature matching.

Inadequate draining during startup. Condensate must be drained before initiation of steam flow in the HPSH and RH. During all types of startup, water will migrate and quench some of the tubes if not completely drained. During hot starts, cooler water in the HPSH and lower piping will move upward and enter the hot upper headers, manifolds, and steam piping.

Aggressive HP drum pressure ramp rates. Dooley and Anderson say that "repeatedly cycling the drum near or beyond the maximum permissible ramp rate is likely to result in cracking of the protective magnetite layer, followed by corrosion fatigue cracking of the underlying steel."

Note that if weld repair becomes necessary, both welding and post-weld heat treatment are expensive and time consuming.

Forced cooling. Many owner/operators force-cool the GT and HRSG after shutdown to expedite maintenance activities. "If not carefully managed, forced cooling can impose extreme thermal transients on the HP drum, HPSH/RH headers and piping, and main steam/hot reheat piping," the authors warn.

HP bypass-valve erosion. Abnormal seat, plug, and cage erosion in bypass pressure control valves has become common regardless of valve manufacturer, "caused by passing wet steam and/or water through the PCV. As damage progresses, superheated steam can leak through and overheat the downstream carbon steel pipe."

HRSG designers have long suggested that cooling steam flow be initiated in the HPSH/RH "as soon as possible." The surveys show an increase in control logic accomplishing this by immediately opening the PCV at GT light off during startup, or before the main steam pipe upstream of the PCV is properly heated. The authors suggest that "as soon as possible" should not require unacceptable damage to the bypass system. Few plants are equipped with permanent instrumentation to measure steam temperature at the PCV.

Ranking the key causes

The authors' original paper, issued in 2009, [QR 3] ranked 55 potential causes of damaging thermal transients. Many have since been addressed through improvements in equipment design and operating procedures. But serious causes remain, and Table 4 presents the most important by category. As for Table 2, the numbers represent the percentage of plants and the arrows indicate trends.

Avoidance

The authors clearly and comprehensively address strategies for avoiding damage in both new and operating plants. These strategies are summarized below.

Leaking spray water. Dooley and Anderson suggest a reverse logic for valve protection, to a master block/martyr control valve logic and an attemperator system release permissive that results in the block valve opening only during startup just prior to first attemperator use, and closing only prior to GT shutdown.

Overspray and inappropriate operation. Overspray strategies include equipment and maintenance upgrades, properly designed and tuned cascade control systems, prohibiting operators from manually adjusting setpoints or operating spray valves, and ensuring an overspray protection feature on system controls to maintain 50 deg F of superheat at the attemperator outlet.

Failure to adequately drain. Key steps in effective drain modifications include calculating the rate of condensate formation, and determining the minimum drain pipe sizes and arrangements. The section on automatic drain control in the 2019 report [QR 6] lists features that should be included in the modifications, such as slope, blowdown tank location, use of thermocouples, installation of an effective automatic drain valve system, and compliance with personnel safety and/or environmental protection practices. Proper procedure results are noted.

Aggressive drum-pressure ramp rates. Legacy units may not have been provided with suitable ramp rates. The authors note that "it may be necessary to hold GT load at a low value for some period during cold/warm startup to avoid exceeding safe HP-drum ramp rate limits. HP bypass and HP sky vent availability and capacity are key factors in complying with drum ramp rate limits later in the startup."

HP bypass valve erosion. Although not a thermal transient, this common problem is discussed and several suggestions listed including: "delaying opening of the HP bypass PCV until steam temperatures upstream and downstream of the HP bypass branch tee have increased above saturation temperature during startup." CCJ

Soon you'll have to decide which conferences to attend in the first quarter of 2020. The schedule of events for gas-turbine owner/operators is on page 3 of this issue.

If you're involved in the specification, installation, operation, and/or maintenance of 501F gas turbines made by Siemens Energy Inc and/or Mitsubishi Hitachi Power Systems (MHPS), participation in the annual meeting of the 501F Users Group is particularly important. It will be held at the Hilton in West Palm Beach, Fla, February 9 – 13.

The players in the service business are changing and their product/services offerings are evolving—oftentimes faster than you might think. It's virtually impossible to do the job company management expects unless you keep up with what the suppliers are doing—in particular, the OEMs and their third-party competitors.

The all-volunteer 501F steering committee (Sidebar 1), headed by Cleco Power LLC's Russ Snyder is working on the program, which will have most of the same elements as the information-rich 2019 conference, last February, in Scottsdale, Ariz, which are summarized in this report. Follow the committee's progress in program development on the group's new official website at https://forum.501fusers.org (Sidebar 2). Register for access as soon as possible; it only takes a couple of minutes.

Here's an overview of the key features of a 501F Users Group meeting:

- User presentations on issues identified in the fleet and solutions implemented, as well as on experience with upgrades to improve unit performance.
- User-only sessions promoting open discussions and short presentations by owner/operators on safety, compressor, combustion section, hot-gas-path components, exhaust, rotors, auxiliaries, and generators.
- Special closed sessions by the major products/services providers serving this frame. At the 2019 meeting, Ansaldo/PSM and MHPS presided over four-hour sessions, Siemens and GE two-hour sessions.
- Vendorama program, comprising about three-dozen half-hour technical presentations by third-party services providers, brings attendees up to date on offerings of primary interest to the 501F community.
- Vendor fair, following the Vendorama program, gives users the opportunity to peruse the offerings of nearly a hundred manufacturers and services firms.

If you have never attended a 501F Users Group meeting, make the 2020 conference your first. You will learn things vital to your plant's future success likely not available in one place anywhere else.

Important note for shy O&M personnel: This is a collaborative organization and first timers (typically one-third to one-half of the 100+ attendees expected at an annual meeting) are accorded the same respect as veterans.

User discussion, presentations

Compressor discussion session touched on several topics of interest to the group, including the following:

- Complications with the re-installation of outlet guide vanes (OGV) surprised many attendees. The OEM installed the airfoils backwards, something most plant personnel didn't think was possible. A clue that something was amiss: Only 7 MW was gained from work done during the outage, half what the sister unit at this 2 × 1 combined cycle gained the previous year with

1. 2020 Conference and Vendor Fair

Hilton West Palm Beach (Florida) • February 9 – 13

For the latest program information, visit https://forum.501fusers.org after November 1.

Refer questions on the vendor fair, sponsorships, etc, to Tammy Faust, tammy@somp.co, or Jacki Bennis, jacki@somp.co, 843-856-5150.

Refer questions on the technical program to Carey Frost, carey.frost@duke-energy.com.

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essentially the same work scope.

A flashback occurred during tuning, at just under 60 MW, and the unit was shut down. Borescope inspection revealed pieces missing from the OGVs and that the upper half of the OGV ring was installed incorrectly. The OEM was said to be modifying its design so it would not be possible to install the OGVs backwards.

Damage was considerable—including some to the first-stage vanes. Rocket tips in one basket burned up because of the flashback. Some pieces of hardware went downstream and were found ahead of the rotor air cooler. The user sharing this experience supported his impromptu presentation with a series of photos that registered users can access at https://forum.501fusers.org.

- Another user reported liberation of a section of a Row 5 blade, but the root-cause analysis (RCA) was inconclusive.
- Attendees generally agreed that coating the compressor was beneficial.
- Representatives from plants in the South said that with evap cooling and/or wet compression you're going to have problems removing compressor blades, possibly in all rows, and this may be a job for a machine shop. Recommendation was to remove the compressor blades at the second major. A user said the OEM agrees with this approach and would provide refurbished blades for units covered by a long-term service agreement. An additional fee will get you new blades.
- Borescope plugs can be difficult to remove. A Chesterton anti-seize product was recommended by one attendee, to prevent galling of stainless.
- A user representing one of the largest 501F fleets in the country said his company was keeping compressor blades in service for at least three majors, adding that half of its units had run at least 100k hours with no failures reported. It was said there was no way to NDE for fatigue impact.

Hexavalent chromium has been a gas-turbine-outage hot topic for the last two years or so given the focus on personnel safety. Surprising, perhaps, because the welding of chromium-rich piping and boiler components has been ongoing for decades with personnel protection and safety always a top priority. If you want to learn more about hex chrome, contact any of the OEMs that participated in the 2019 meeting. Each has published guidelines and procedures for removal and disposal of the yellow material.

A user described his plant's experience with hex chrome during a recent hot-gas-path (HGP) inspection. The insulation provided by the OEM for the gas turbines was replaced during the outage. Residue (dust) containing

2. Visit the new website at https://forum.501fusers.org

The 501F Users Group moved to a new website March 1, shortly after the conclusion of its 2019 meeting in Scottsdale, Ariz. It is the official business portal, library of presentations, and content host for discussion threads of importance for the 501F Users Group. Construction of the new site was completed in early 2019, with ongoing improvements being implemented to optimize functionality for users.

Users already are benefitting from the technical content gathered at meetings since 2008. You can too, by registering for access. It's easy: Go to https://forum.501fusers.org and click on the "Sign Up" button. Required information includes a corporate email address, user name and password, and answers to a few questions regarding job responsibilities. This shouldn't take you more than two or three minutes. Next step: The board will review your qualifications and typically respond within one business day.

hex chrome was found under the insulation in the exhaust-bearing tunnel on one unit.

An environmental services company was engaged to properly remove and dispose of the residue. Process involved establishing a regulated work area, air monitoring, removal of the dust using wet decontamination techniques and hand tools, and final testing (OSHA ID-215M) to confirm airborne concentrations were below the Permissible Exposure Limit. Results showed less than 0.0017 mg/m^3, well below the so-called Action Level of 0.25.

Row 1 vanes got some air time with a user calling attention to a new design with larger cooling holes less likely to plug and cause burn-up of the critical part. This development may be particularly important to users wanting 32k longevity. The speaker said the new design had been operated for 8000 hours at his plant with a borescope inspection confirming success. He said vanes of both the old and new designs could be integrated in the same row.

Four-way joint leakage is a topic of interest at many user-group meetings. An attendee reported on the use of Deacon putty rope as a possible solution. The product was injected to the joint area via a false bolt hole and then cured as instructed. It helped but did not stop the leak.

Combustible-gas detection upgrades were prompted by a rapid gas expansion incident in the electrical package that damaged the DCS and the exterior wall of the motor control center, among other things. The speaker reminded attendees that the lower and upper explosive limits for hydrogen and methane, respectively, were 4% and 74% for the former and 5% and 15% for the latter. Gas concentrations outside those limits are either too lean or too rich to support combustion. Explosion-proof components are a must in areas where gas can be released or can accumulate.

Exhaust cylinder and manifold replacement on one gas turbine at a 2 × 1 combined cycle was part of an 11-week major inspection that included rotor lifetime inspection, replacement of HGP and CI (combustion inspection) parts with those from a third party, and generator and starting-package inspections. Operational stats in round numbers: 1650 equivalent starts, 93,000 total fired hours, and nearly 22,000 turning-gear hours.

Exhaust system issues prompting the replacement of both cylinder and manifold included cracking of the diffuser (severe), strut shield, aft static seal, and struts. The plant owner elected to switch OEMs for the new exhaust components and their installation. The illustrations and photos incorporated into the presentation would be of value to someone planning a similar project. Go to https://forum.501fusers.org.

Torque tube and air separator were replaced by an alternative OEM when the rotor undergoing a comprehensive inspection was in its shop (see item immediately above). The original air separator was replaced with one of bolted design. More detail is available in the MHPS section later in this report. Access the presentation at https://forum.501fusers.org for project photos.

Important to note is that there was no problem with the existing torque tube and air separator. They were replaced with no schedule impact to mitigate risk while the rotor was in the shop (a requirement for replacement), given the problems experienced with the torque tube and air separator from the original OEM. The owner had experienced a torque-tube failure at another plant.

A third torque-tube failure was revisited by another user, this one on a starts-based Model FD (DLN combustor) with a nominal 1400 equivalent starts and 9500 equivalent baseload hours. Following a long run, plant was informed of a vibration increase (exhaust bearing) by the owner's M&D center. Corporate engineering and the plant agreed the unit had to be shut down for inspection.

All major gas-turbine components were checked—including torsion bars, turbine support structure, and trunnions—but no connection to the vibration increase was identified from that work. The 2× component of vibration showed an increase in magnitude at operating speed as well as shifts in both magnitude and speed during coast-down. These findings were consistent with known rotor structural failure signatures. Experts said an increase in the 2× component would "confirm" a torque-tube crack.

The owner's engineers met with another user who had experienced a torque-tube crack to compare vibration signatures from both incidents. They were similar. Data and vibration signatures were included in the presentation; access at https://forum.501fusers.org.

A test plan was developed by the OEM and owner and a restart was attempted. The unit failed to reach full-speed/no-load and was shut down. The rotor was de-stacked at the OEM's shop and a 22-in.-long crack found; the air separator was fine. Torque tube was replaced in-kind because the OEM did not have a new design available at the time.

Generator stator frame cracking had been an ongoing issue with one of the plant's three generators and the presenter from previous years was back at the podium again in 2019. Continuity of expertise is important in years-long investigations.

Review: In October 2015 dusting on endwindings was identified during a routine inspection. While investigating the cause of the dusting, plant personnel discovered 12 cracks in several frame locations. The OEM requested further inspections the following January and March. Three additional cracks were documented.

During a maintenance outage in July 2016, the lower half of the generator was inspected and areas that had not been examined previously were checked. The result: Five additional undocumented cracks were found in the frame rings, plus one in a baffle ring. A few months later the upper half of the generator was re-inspected and three more indications were found. There was no NDE so the indications could not be confirmed as cracks.

By the end of November 2016 the AeroPac II had accumulated more than 56k baseload hours and nearly 2500 equivalent starts. Seventeen upper-half and 13 lower-half cracks had been recorded. To mitigate the problem, stop-crack holes were drilled. These and other photos are at https://forum.501fusers.org.

The OEM suggested installing 44 accelerometers on the machine to help in finding the root cause of the cracking.

Ahead of the 2019 user-group meeting, the OEM revealed that the crack-stop holes had indeed stopped the cracks. It also recommended performing intermediate partial inspections as outage schedules permitted. Plus, the RCA concluded low-cycle fatigue initiated the cracks and high-cycle fatigue promoted their propagation.

The OEM suggested repair plan earlier this year. Attend the 2020 meeting of the 501F Users Group for a report on the results of that effort.

GE experience. The 501F is unique among user groups in that all of the world's major frame gas-turbine manufacturers participate in meaningful fashion. Perhaps the most important question on the minds of owner/operators coming into the 2019 meeting was this: How would GE perform on the overhaul of an engine with which it had no native experience?

While a sample of one is of little statistical significance, Mexico's GPG Company, familiar to many readers, helped answer at least some questions its colleagues had with an information-rich presentation of more the 50 slides. Access it at https://forum.501fusers.org.

GPG has broad gas-turbine knowledge for a relatively small company (four plants). Here's a rundown:

- Hermosillo, 1 × 1 combined cycle powered by an Alstom GT24 engine.
- Naco Nogales, 1 × 1 combined cycle powered by a Siemens 501G.
- Tuxpan, two 2 × 1 combined cycles powered by Mitsubishi 501F3s.
- Norte-Durango, 2 × 1 combined cycle powered by Siemens 501FD3s.

Its Norte-Durango and Tuxpan units are covered by GE performance LTSAs and include both planned and unplanned maintenance for gas and steam turbines and auxiliaries, generators and auxiliaries, main steam valves and actuators, and control systems.

GE delivered on its performance upgrades at Tuxpan with an increase in combined-cycle generating capability of 8.3% and a heat-rate improvement of 2.6%. Numbers were similar for Norte-Durango.

User-group meeting attendees generally do not get the level of detail provided by GPG's engineers. They spelled out what they believe to be the vendor's strengths and weaknesses and where improvement is needed. One example: New connection rings for the generators did not fit (design error), delaying outage completion by 28 days.

Special closed sessions

Ansaldo/PSM

PSM's four-hour session incorporated presentations on the vendor's product line, combustion options, airfoils and upgrades, plant optimization, and rotor solutions, as well as other topics. The product portfolio was reviewed first. Highlights included the following:

- PSM said it can supply all hot-gas-path (HGP) parts for the 501F. The re-engineered, upgraded components are supported by an independent supply chain. No CIs are required for any of the company's combustion parts, with a 32k CI/HGP interval an option.
- Flexible long-term agreements (LTAs) allow a term warranty using the owner's inventory. A customer portal was launched at the end of 2018 to support all owner/operators with LTAs. Document management and easier access to technical expertise are two benefits.
- Rotor-repair and life-assessment services are offered, along with onsite disposition and machining. A seed rotor is available.
- The company reported having done more than 70 combustion conversions, claiming it is the only aftermarket provider of upgrades for output.

The PSM team next discussed the interchangeability of the company's parts—both standard and upgraded—with original equipment, stating that all of the supplier's hardware is set-wise compatible. A few examples presented were these:

- Compressor. Replacements for all FD components.
- Combustor. Full drop-in system or component replacement, gas only and dual fuel. FlameSheet™ is available for both the W501F and M501F.
- Rotor swap with LTE, replacement disc fabrication, and improved bolting and belly-band design.
- Turbine. All major components for the W501FC-FD2 and M501F3 models, plus the first three stages for the W501FD3 (fourth stage is in development). Also available: An improved static seal and inner support ring.
- Exhaust. W501FC-FD2 drop-in cylinder (includes new manifold front flange); FC-FD2 drop-in manifold (available only with PSM exhaust cylinder).

Drop-in combustion-system experience was summarized in one slide. About 70 sets of pilot nozzles had been sold, the speaker said, with fleet leaders about 60k fired hours and 1500 fired starts. Total fleet experience was 1.9 million EBH.

For transition pieces, the numbers were more than 100 sets sold, fleet leaders at more than 60k fired hours and 1400 fired starts, and fleet experience at more than 2.4 million EBH.

Extended-turndown combustion baskets have been installed in more than 35 engines, with fleet leaders at 35k fired hours and more than 600 fired starts.

The numbers for support housings: More than 25 sets sold with fleet leaders at 33k fired hours and more than 600 fired starts.

Turndown solutions is always a hot topic at user-group meetings. PSM reported that for a nominal DLN equipped 501F, turndown to about 65% of rated output is possible without exceeding CO emissions of 10 ppm. AutoTune, in concert with the company's part-load performance (PLP) option, could enable turndown to about 55%, while adding inlet bleed heat might lower that to 40%+. Retrofitting FlameSheet can get turndown into the 30s, and adding exhaust bleed makes a 20% number possible.

A big benefit of FlameSheet, in addition to extended turndown capability, is greater fuel flexibility compared to traditional OEM offerings. This is particularly beneficial both to plants burning shale gas and LNG, which may have a wide range of varying constituents, and to those with access to off-gases from industrial processes. FlameSheet can maintain emissions compliance while operating on fuels with up to 40% hydrogen and up to 40% C_2.

Results from the first two installs of FlameSheet in 2015 at Eastman Chemical Co, Longview, Tex, were reviewed to confirm stated performance. The data:

- Turndown was confirmed to 40% of rated load with NOx emissions below 5 ppm at 40% and less than 7 ppm at 100%.
- CO was less than 9 ppm at 40% load and about 1 ppm at 100%.
- Part-load efficiency was measured at less than 120% of the full-load number; goal was 130%.
- Startup visual emissions were eliminated, reducing exceedance reporting by 200 reports annually.

Important: FlameSheet enables Eastman to keep its units operating year-round because of their increased turndown. Also, it gives the company the potential to burn waste fuel streams rich in hydrogen.

Recent field experience with the GTOP6 and the expected performance benefits of GTOP7 were reviewed. Recall that the components incorporated into the company's GTOP6 (Gas Turbine Optimization Program) upgrade—roughly the equivalent of a Siemens FD3 upgrade for performance, but executed in a smaller scope—can have a maintenance interval of up to 32k/900 starts.

The GTOP6 fleet leader at the time of the 2019 meeting had operated for 19,500 factored fired hours and had 124 FF starts since the upgrade was completed in 2016, increasing combined-cycle output by about 40 MW. A borescope inspection revealed parts in excellent condition. Planned maintenance interval for the gas turbines serving this unit is 25k hours/900 starts, with a four-interval lifetime for all parts.

Performance of the coming GTOP7 bests that of the GTOP6 by a modest amount. For example, the 25k version of the former is expected to increase the simple-cycle output by 20 MW and reduce heat rate by 3.8% compared to a standard W501FD2 engine, while GTOP6 delivers 15 MW and 3.5% better heat rate.

Extending the maintenance interval to 32k from 25k has a significant negative impact on performance. For GTOP6, opting for 32k hours reduces the output gain to 7 MW and drops the heat-rate benefit to 1.5%. For GTOP7, the loss in output is more severe, down to 8 MW from the 20 MW increase at 25k. The heat-rate benefit decreases from the 3.8% at 25k to 2.1%.

The plant optimization presentation focused on PSM's FlexSuite™ offerings to help customers navigate the paradigm shift to faster starting (FlexStart), faster ramping (FlexRamp), etc. The speaker began by stating some of the challenges facing owners in today's world of power operations.

Only a few years ago, he said, the goal for breaker closure on a simple-cycle unit might have been 27 minutes, today it is less than 10; the time to achieve full output was about 40 minutes for a large legacy frame like the 501FD2 to minimize life consumption of hot parts, now 15 minutes is the expectation.

In the rotor presentation, attendees were told PSM had completed eight F-class lifetime evaluations and had five F-class swaps under its belt. Two of the swaps involved 501Fs. During a 2016 swap PSM took possession of a rotor with a cracked torque tube. Incoming inspections were nominal, but NDE revealed a 2-ft through-wall crack and replacement of the torque tube was required. A root-cause investigation did not identify any structurally relevant pitting or other anomalies.

Another 501F rotor was pulled from service in 2017 because of an air separator issue. Onsite machining was unable to remove material hardened because of a rub and the rotor was sent to the shop. During the lifetime evaluation process, a compressor disc was found to have several discontinuities. The unit's owner opted to install a seed rotor rather than extend the outage.

General Electric

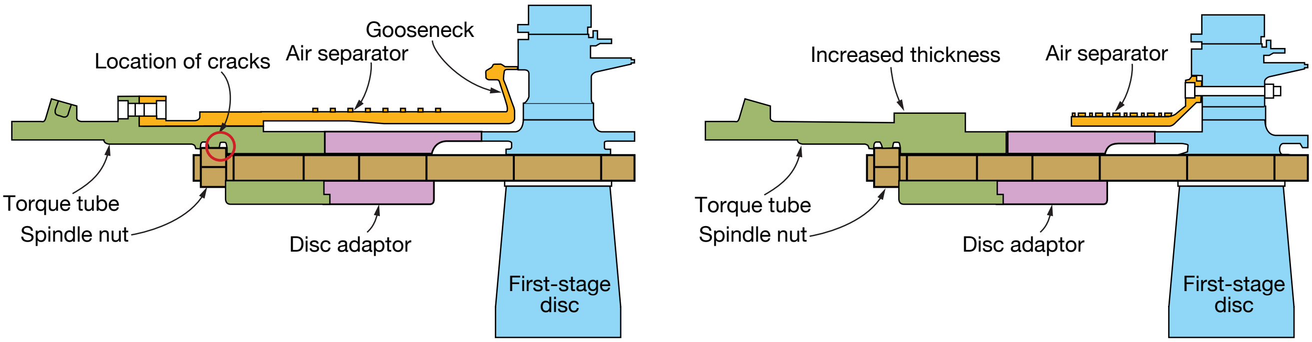
GE's third year of participation in the 501F Users Group's annual Conference and Vendor Fair in 2019 focused on the following three key topics:

- Customer concerns regarding the OEM's business—including its restructuring and creation of GE's Gas Power organization.
- Results from the implementation of upgraded hot-gas-path (HGP) hardware at a combined cycle owned by Naturgy Energy Group SA.
- User-requested topics addressing 501F fleet dynamics and concerns, including these:
  - Cyclic operation, with emphasis on common challenges and solutions—such as implementation of GE's Steam Turbine Agility product at a US combined cycle to reduce startup time, combustion tuning advancements, and controls augmentation.
  - Hexavalent chromium, including additional information on mitigation processes and root-cause/sources based on input from the OEM and its cross-fleet solutions business.
  - Torque-tube cracking, in response to the user group's request to provide a point of view on this emerging fleet concern.
  - Overview of GE Cross-Fleet performance upgrades for 501F hardware.

The OEM's representatives began by reviewing the state of the company and ongoing efforts to make it both less complex and stronger, while improving operations to deliver best value for all stakeholders (customers, employees, and shareholders).

GE Gas Power, the users were told, was formed to create a stronger, more streamlined gas power business that would provide customers better outcomes. It combines the talent and technology of new units and services into one unified team, thereby providing the technology, services, knowledge, and insights need to build, operate, and maintain gas plants well into the future.

The upgrade of combustion and HGP sections on two M501F3 gas



1. Bolted-style air separator and thicker torque tube at right are said to eliminate the cracking experienced with the original W501F gooseneck-style air separator and torque tube shown at the left

turbines installed at the Tuxpan combined-cycle plant in Mexico validated GE's ability to apply its proven F-class technology to the 501F fleet with enviable results: a 9.2% increase in output, 2.9% heat-rate improvement, and maintenance-interval extension to 32,000 hours.

Enhancements included Advanced Gas Path (AGP) and DLN combustors, improvements to the fuel and hazardous-gas detection systems, Netmation controls adaptation, and automated combustion control. Plus, controls improvements increased the plant's operating envelope while improving system safety and assuring grid compliance for additional output.

A case study validated the OEM's ability of its Agility product to reduce the startup time and cost of a non-GE steam turbine—this a Toshiba steamer at a 2 × 1 W501F-powered combined cycle in the MISO region equipped with T3000 controls. Benefits included the following: reduce the average hot-start time by 30 minutes to 1.5 hours and the average cold-start time by 4.5 hours to 2.5 hours.

The advanced combustion control system, which relies on model-based tuning, continually adapts to operating conditions and allows deeper turndown than the original equipment while reducing NO_x emissions. A reduction in combustion dynamics and trip avoidance are two more benefits.

GE's presentation on hex-chrome mirrored what others have said on the topic over the last couple of years. It conducted a comprehensive review across the lifecycles of gas-turbine hardware, investigating coatings, surface treatments, and assembly materials in the process. Anti-seize formulations containing calcium and calcium oxide tested positive for Cr(VI)—as others have reported.

The OEM's recommendation is for personnel handling GT parts to stay vigilant for yellow residue and to avoid skin and eye contact using safety glasses, nitrile gloves, and possibly even a Tyvec® suit. Special measures should be taken where yellow residue may become airborne. Proper disposal, including warning labels, also is necessary. To dig deeper, access Product Service Safety Bulletin 20180709A-R2 at https://forum.501fusers.org, or request a copy from your plant's customer service representative.

GE's backgrounder on the torque-tube issue was general in nature. The speaker estimated that fewer than 5% of the units in the fleet were impacted, adding that M501F rotors were less susceptible to cracking than the W501F rotors. Regarding crack location, three characteristics were noted:

- It is in the elevated-stress region of the turbine-end nut groove.
- Location is inaccessible and concealed by the air separator.
- Crack initiates in the inner diameter and propagates outward.

Despite nothing new here for experienced users, Siemens and Mitsubishi having presented similar material for the last several years, the GE team received many questions from users and the user-group leadership which promoted a vibrant discussion.

Final topic on the agenda concerned GE's Flex Pack upgrade for extending parts life and/or increasing performance. GE said its DLN combustors were a drop-in solution for both Siemens and Mitsubishi engines, offering an HGP interval of 32,000 factored fired hours or 1250 factored fired starts. Fuel flexibility cited was ±15% Modified Wobbe Index and up to 25% ethane.

GE's AGP upgrade was said to boost output by up to 10% and reduce heat rate by up to 3.5% while offering a 32k hours/1250 starts HGP interval. Also cited was improved clearance control via abradable ring segments.

MHPS

Mitsubishi Hitachi Power Systems has a great deal of meaningful experience to share at 501F User Group meetings given its long-term involvement with this frame. Recall that MHI (Mitsubishi Heavy Industries), as MHPS was known before Mitsubishi and Hitachi merged their power-generation business units in 2014, and Westinghouse Electric Corp shared a technology agreement and partnered in the development of the original 501F engine. That partnership was dissolved shortly after Siemens' acquisition of Westinghouse in 1997 and the two companies pursued different design paths regarding engine refinements.

MHPS executives and engineers presented for four hours on the third day of the 2019 meeting, focusing on safety, rotor solutions, the turbine section, performance improvement, and inlet/exhaust solutions.

Given space considerations, the editors focus here on the highlights of the following topics of high interest to owner/operators:

- Rotor torque-tube and air-separator cracking, including the root cause of that damage and replacement options.
- Comprehensive rotor inspections (CRI).
- Lifecycle experience with MHPS turbine parts.
- Turbine exhaust-casing replacement.

Owner/operators can dig into the details, and review the OEM's other presentations, by accessing the slides posted on the user group's new website at https://forum.501fusers.org.

Torque-tube cracking was one of Scott Cloyd's presentation topics. The chief engineer of MHPS Americas Gas Turbine Service Engineering Dept is well respected by users for his deep knowledge of the 501F and willingness to go "beyond the script" to address concerns of plant personnel.

If you're unfamiliar with the torque tube, which joins the compressor and turbine sections of the rotor, and the air separator, look at the sketches in Fig 1. Note that cracks have occurred only on torque tubes configured for goose-neck type air separators (left-hand drawing); also that the cracks are concealed by the air separator.

Cloyd told the group that the initial flaw size is very small and something you would not look for in a normal inspection. It takes about 30 to 70 starts for a crack to propagate from a tiny corrosion pit to the size required to initiate a vibration event, growing radially outward and circumferentially from the downstream nut-retention relief groove. The crack proceeds slowly after initiation, he continued, then accelerates through a high-cycle fatigue phase to failure. Cloyd recommended that if a vibration event points to a torque-tube crack, confirm with ultrasound before removing the rotor.

He added that thermal transients heat the air separator faster than the torque tube during startup, increasing the stress at the relief groove. Spindle-bolt torque and gooseneck air-separator compression variations, in combination with a high delta in stiffness near the U-notch, are considered likely contributors to crack formation. The preload on all spindle bolts must be uniform during rotor assembly, Cloyd stressed.

Two engines in the fleet are known to have reported forced outages caused by vibration events traced to through-cracks in their torque tubes. A crack was found on one unit after only 10,000 operating hours (but 90,000 hours on turning gear); it continued for about 45 deg around the circumference of the torque tube and vibration became a concern.

Owners facing a torque-tube issue have several options, according to Cloyd: Replace the rotor (exchange with a new or refurbished rotor), in-kind torque-tube replacement, and an upgrade option. The last includes a replacement torque tube with additional thickness where cracks have occurred and a bolted separator (elimination of the spring-loaded goose-neck design).

Cloyd is bullish on the last option because MHPS has nearly 3-million actual operating hours and 30,000 starts on its bolted separator (right-hand sketch in Fig 1) without a failure. MHI redesigned the torque tube and air separator for engines of its manufacture after a failure about 20 years ago at a plant equipped with the industry's first 501Fs (a joint project with Westinghouse).

The first MHPS torque tube/bolted separator was retrofitted on a W501F in start/stop service more than a year ago and has not experienced any issues. Another retrofit is planned for fall 2019; eight more projects are in the pipeline. Cloyd recommends replacing the torque tubes and air separators on all W501 rotors that come into its shop.

A pre-CRI inspection is recommended at any outage with a cover lift. This includes visual inspections, hardness testing, and a phased-array UT inspection of the spindle bolts to detect the presence of a crack, if one exists, prior to pulling the rotor and entering a CRI inspection. What you'll see when you look under the hood of a W501FD2 is shown in Fig 2.

Owner/operators benefit from having the best data possible in advance to be sure the work scope addresses all the issues of concern and the necessary parts are available when work on the rotor begins. Keep in mind that historian data are important to the accuracy of any rotor assessment. Trending of rotor ageing characteristics improve component life predictions.

A compressor-disc creep and corrosion assessment should be conducted during the turbine inspection (TI) in advance of the CRI. Turbine- and compressor-blade groove wear and corrosion evaluations are recommended as well. There should be no adverse impact on the outage schedule for this work, which is all done onsite.

Users might consider adding to their onsite inspection scope, the cleaning and NDE of all exposed rotor surfaces. The more information, the better.

A CRI in MHPS's rotor facility takes about a month. When complete the rotor will be certified for 100,000 hours or 12 years of operation, whichever comes first. While this work is ongoing, performance and reliability upgrades can be implemented. These can add to the scheduled shop time, especially when the required planning is not done in advance.

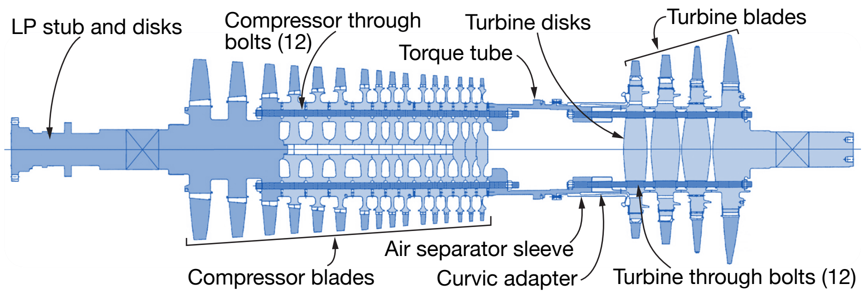
Of course, unplanned schedule impact can be taken out of the equation with a rotor exchange. The replacement rotor would be installed while the one removed is sent to the shop for refurbishment.

Turbine airfoils. Design Section Manager Travis Pigon reviewed with attendees the excellent service histories of the company's turbine vanes and blades. Cloyd and his associates have been bringing hot parts to 501F meeting for years so attendees could see and feel first-hand how well they age in service. You can't get better proof than that. Here, however, the only viable alternative is photos.

MHPS said its parts had not suffered any product issues—such as cracking and coating spallation—because the company had fully addressed failure mechanisms reported in the 501F fleet. Looking at a vane segment removed from a baseload machine for inspection after 40,000 service hours and 290 starts (Fig 3), note that the thermal barrier coating (TBC) is intact, there are no detectable cracks, and no oxidation-caused wall thinning. Same result for the vane segment removed from a cycling machine with 1000 starts (15,000 service hours).

A "light" repair scope was all that was required to prep these airfoils for a return to service. The company's fallout rate for its R1 vanes over the last four years was reported as *zero*. Such positive results were said to validate MHPS's claim of 32k/1200 start intervals.

Inspection results on first-stage blades were the same, except for visible cooling traces on the airfoils (Fig 4). Fallout rate attributed to design



2. Rotor arrangement for a W501FD2 shows location of the torque tube and air separator

3. R1 vanes required only light repairs after 40,000 hours of service (left) and 1000 starts (right)

4. R1 turbine blades had TBC intact and no detectable cracks after 35,000 hours of service (left) and 1000 starts (center and right)

issues was 0%, 13% from FOD, tip rubbing, etc.

Repair scope was light, like that for the R1 vanes.

Results from inspections of second-stage vanes and blades were similar to those recorded for R1 airfoils, except for minor platform cracking on some vanes. No matter, light repair scope with 0% fallout validated inspection intervals of 32k hours/1200 starts.

Photos shared of MHPS hot parts in W501FD2 engines after more than 23,000 operating hours and 700 starts revealed sufficient margin to operate longer intervals.

Matt Marinelli, GT design engineer, presented on MHPS exhaust solutions to address recurring durability issues associated with the legacy W501F exhaust cylinder (such as cracking in the diffuser, dead-air-space strut shield, aft static seal, and struts) and manifold (diffuser and Y-joint cracking).

Marinelli discussed improvements made by MHPS to the original W501F exhaust cylinder—including improved material, floating diffuser system, cooled robust aft static seal, and passive strut cooling system. Improvements to the original W501F exhaust manifold: more durable material, reduced upstream flange thickness, partitioned teardrop, vertically bolted two-piece design, and elimination of circumferential ribs.

Next, he identified some of the technical solutions available to extend the operability of customer exhaust systems until replacement is possible.

MHPS's retrofit offering is based on the company's M501F3 and G-frame designs, said to have had no history of fatigue cracking in millions of hours of operation. It is a drop-in replacement with no auxiliary-piping or foundation changes necessary. A design feature of particular interest to owner/operators is the ability to remove the exhaust bearing through the teardrop rather than removing the tail cone or the upper half of the exhaust cylinder.

Siemens

Given the challenging business conditions facing power generators and their equipment/services suppliers, Siemens opened its two-hour session at the 2019 501F Users Group meeting with a brief discussion of some steps it is taking to support customers during these turbulent times.

The company said it is investing more on the service side, including the upgrade of repair facilities in Winston. Siemens is in the process of moving its Houston repair business to Winston because there's not enough business to sustain the Texas operation. The transition is expected to take about a year. Regarding staff, some new-unit employees are transferring to openings in the service group to both maintain a critical mass of talent and to cope with the falloff in sales of new units.

The Siemens session included updates on gas-turbine technology and the company's field-service operation, as well as an overview of mods and upgrades for increasing output and improving performance (interval extension, advanced DLN and ULN, FD6 thermal performance upgrade, low-load turndown), and a review of the company's expanded-scope solutions (exhaust-gas attemperator, exhaust purge credit, value-added controls).

Focus here is on key points made during the technical update. Registered users can access information communicated during the Siemens program by reading through the presentations at https://forum.501fusers.org or by visiting the OEM's Customer Extranet Portal (CEP).

The technology presentation began with an overview of the torque-tube cracking issue that the steering committee requested be included in presentations by the four OEMs participating in the meeting—Ansaldo (PSM), GE, Mitsubishi Hitachi Power

Siemens' Customer Conference for F, G, and H users

Another venue for sharing experiences with owner/operators of Siemens 501F gas turbines is the OEM's customer conference. It is held about half a year after the 501F Users Group conference and vendor fair. In 2020, the 501F Users Group will meet at the Hilton in West Palm Beach, February 9-13; the Siemens Customer Conference for F, G, and H Technology will be at the Renaissance Orlando at SeaWorld, the week of June 15.

The 2019 Siemens meeting at the Hilton Orlando Bonnet Creek, June 17-20, attracted nearly 200 F, G, and H owner operators from around the world. Vinod Philip, CEO, Service Power Generation, opened the meeting by sharing the Gas and Power spin-off status and how creating a unique energy and power company will bring attractive opportunities. The focus for this conference was to discuss technical issues, findings, resolutions, and recommendations for the F, G, and H frames.

It included various frame-specific technical presentations by the OEM's experts, closed customer sessions, feedback sessions, breakout sessions on steam turbines, generators, and digitalization, networking opportunities, and a Technology and Innovation Showcase which included participation by 20 preferred suppliers invited by Siemens.

There were many opportunities to visit the Showcase during the event where users had the opportunity to see hardware, tools, and technologies and discuss topics one-on-one with subject-matter experts. Three-dozen Siemens booths featured gas-turbine components, digitalization, generator and steam-turbine innovations, plant operations support and training, grid solutions, virtual reality, mods and upgrades, field-service technologies, robotic inspection, environmental health and safety, and much more.

Users who missed this conference can access the presentations on the Customer Extranet Portal at https://siemens.force.com/cep.

Siemens reported receiving a high 90s overall satisfaction rating from attendees, who had particularly high regard for the value of information presented, frame sessions, and the product and technology showcase.

Systems, and Siemens.

MHPS and Siemens, the manufacturers of record for torque tubes supplied with 501F engines, had the most experience to share on this subject. The former said torque tubes of its design had not cracked in service. Siemens reported investigating three cases and was told of two more which it had not evaluated at the time of the meeting. The affected engines had the following operating histories: 9589 equivalent baseload hours/1410 equivalent starts, 13,541 EBH/646 ES, and 133,161 EBH/5655 ES.

Common findings included these:

- A review of manufacturing and repair records did not reveal any findings with a connection to the mode of cracking.
- Materials evaluations indicated no anomalies in chemical composition, mechanical properties, or metallographic structure.
- Fractures initiated on the ID of the first undercut near the aft turbine bolt flange.
- Corrosion present on the initial crack surface suggested slow propagation of the defect.
- Crack initiation was consistent with low-cycle fatigue which transitioned later to high-cycle fatigue from rotational bending, as indicated by rapid crack propagation and an increase in vibration. In one instance the unit tripped on high vibration.
- Siemens has not determined the cause of crack initiation; however, a leading theory is a combination of spindle-nut tensioning sequence and a pit exposed to corrosion over time.

The last four bullet points are in general agreement with findings by MHPS as noted in the preceding section.

Siemens' recommended actions for its torque tubes are similar to those offered by MHPS in the preceding section:

- UT the torque tube after removing the air separator, and after restacking the rotor, to confirm the absence of cracking.
- Replace the torque tube during a shop visit for rotor and casing inspection and evaluation (RCIE)—if warranted based on consideration of accumulated and projected actual starts.
- Polish and paint rotor fillets after disassembly to prevent corrosion and pitting.

Siemens reported that it has updated its guidelines for bolt tensioning/sequence to reduce the probability of torque-tube cracking. Plus, it is considering torque-tube design mods for the fleet's advanced Fs. No such action is being taken on the earlier 501F engines at this time.

Radial rubbing at the interface of the air separator and torque-tube seal housing was described. One significant event fleet-wide was reported; however, five rotors were replaced based on inspection findings. About 100 engines were inspected. Refer to service bulletin SB3-15-0046-GT-EN-01 for details and recommendations.

The rub mechanism described relates to the manufacturing process and certain transient conditions that reduce the clearance between the air separator and torque tube—likely in combination.

Inlet manifold cracking has been reported on some FD3 engines with welded-pipe struts, which were installed to provide axial stiffness. Cracks typically are found in the pipe struts and welds, between the strut and manifold. A switch to bolted pipe struts was identified as a viable solution.

Cracks in the compressor inlet manifolds of 17 F5 engines (30 units inspected) were reported as having been identified. Noise-suppression blankets consisting of an acoustic cover sewn to a thermal insulation layer coated with fiberglass cloth can mitigate cracking. A dozen engines outfitted with the blankets prior to first fire have been inspected to date without evidence of cracking.

Four-way joint leaks continue to be a nuisance. Leaks are generally found at vertical flanges on both the upper and lower halves of the compressor, combustor, and turbine casings near the horizontal joint. Leaking has been attributed to casing distortion, thermal stress, cracks, irregular surfaces, and foreign material between mating joint surfaces.

Leakage mitigation/prevention involves proper bolting, high-temperature sealants, and solutions that divert gas away from the leakage path. Regarding bolting, success has been achieved, the group was told, by alternating the tightening sequence between the vertical and horizontal joints while working away from the four-way joint.

The harmonized exhaust for the F5ee model, and the variable-guide-vane distress observed on the inner diameter of some F5 and F5ee units (Stages 2 and 3), received air time as well. However, given the association of these issues with only the fleet's most advanced engines, most CCJ readers would have only passing interest. Those wanting to know more are referred to the presentation at https://forum.501fusers.org.

Vendorama

The Vendorama program gives attendees access to live presentations by dozens of products/services providers offering O&M solutions. The program matrix for the 2019 meeting allowed each attendee to participate in up to seven presentations, vetted for technical content by the steering committee. There were seven half-hour sessions, each featuring five concurrent presentations.

The participating companies in boldface color type are CCJ business partners. Their support enables you to receive the Journal at no cost. The quick response (QR) codes provided give you one-click access to their websites. Simply scan the QR code with your smartphone or tablet to connect.

The presentations summarized below provide perspective on the quality of information disseminated. Owner/operators registered for website access can retrieve the PowerPoints online at https://forum.501fusers.org.

Advanced Turbine Support LLC, "501F compressor NDE, impact damage, tip liberations, and in-situ blending capabilities" and, together with PSM, "In-situ torque-tube inspection and prediction methodology" (QR1)

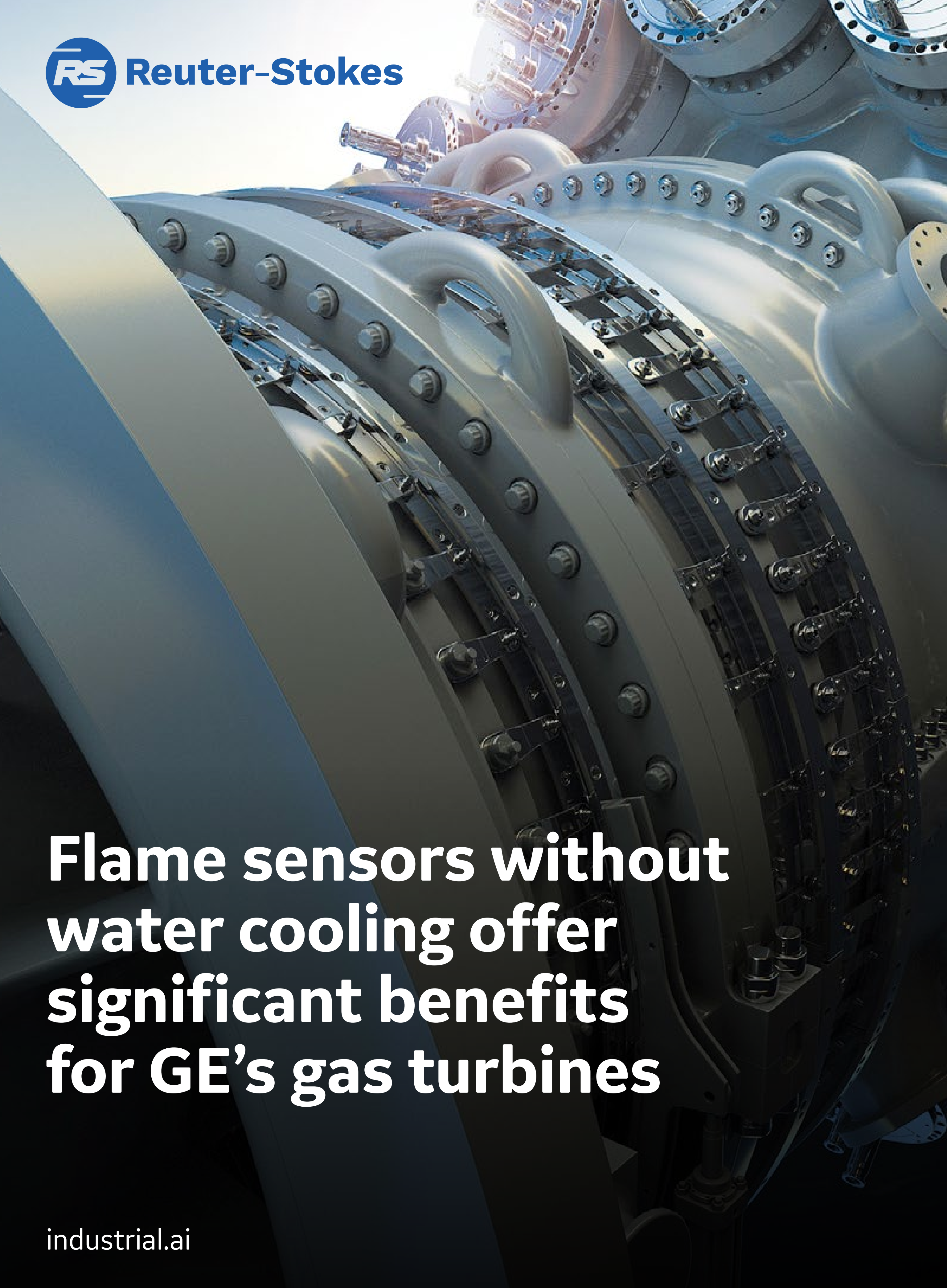
Blending of compressor blades and vanes damaged in service, but repairable, removes stress concentrations or cracks that otherwise might lead to metal liberation with downstream consequences. Significant time and cost savings result when blending can be done in-situ.

A couple of years ago, in-situ blending was considered viable only on the first stage or two of the 501F compressor. Advanced Turbine Support's Mike Hoogsteden, director of field services, told attendees that blending was now possible from the variable inlet guide vanes to Row 7 and showed the results in a series of photos.

AGTServices Inc, "The negative impact of increasing cyclic duty on electric generators" (QR2)

Jamie Clark, a frequent speaker at user-group meetings, strongly recommended to 501F owner/operators that they schedule baseline condition assessments for their generators as soon as possible—this to avoid unplanned repairs resulting from the frequent starts/stops characteristic of powerplant operations today.

Correct any deficiencies identified quickly, he added. Make sure repairs



Reuter-Stokes

Flame sensors without water cooling offer significant benefits for GE's gas turbines

industrial.ai

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Engineers and researchers at Baker Hughes, a GE company (BHGE), strive to keep the OEM's gas turbines worldwide operating as efficiently and effectively as possible. These efforts include examining the impact of individual systems and components on the turbines' overall performance and reporting the results of our studies. Recently we took a look at the flame sensors in use in GE gas turbines, and reached an important conclusion: The elimination of flame-sensor water cooling can significantly enhance gas-turbine reliability and uptime.

Background

GE's gas turbines use one of two flame sensors from Reuter-Stokes—the Flame Tracker or the Flame Tracker Dry 325 (FTD 325). In use for many years, the Flame Tracker employs a water-cooling system to keep the sensor temperature below 150C. Conversely, the FTD 325 uses innovative remote electronics technology to eliminate the need for water cooling on both the hot and cool end of the sensor.

Built on the proven silicon carbide sensing element used in the Flame Tracker, the FTD 325 system takes advantage of a remote electronics configuration that places a sensing element capable of operation at temperatures up to 325C in the hot end of the sensor and moves the temperature-sensitive electronics to a low spot in the turbine compartment where temperatures are below its 150C operational limits. The electrical signal from the hot end is transmitted to the cool end via a 30-ft-long mineral insulated cable.

Water cooling concerns

The use of a water-cooling system introduces risk associated with high impact water leaks as well as the more commonplace damage to Flame Trackers due to overheating caused by cooling system failures.

High-impact water leaks. Located over the compressor casing's combustion chambers, the Flame Tracker's water-cooling lines occasionally develop a leak as a result of loose fittings or vibration-related damage.

When the leaking water sprays over the compressor casing, the casing cools and shrinks causing the compressor rotor blades to rub against the inside of the casing. Eventually the blades are damaged, and in the most severe cases liberated blades cause cascading damage to additional compressor components (known as "corn cobbing").

Even when the leaking water does not lead to compressor blade damage, it can still create a fire hazard. When cooling water mixed with antifreeze—such as ethylene glycol or propylene glycol—contacts the hot turbine casing, residual glycol can combust on the casing as the water boils away.

Overheating failures. While the maximum operating temperature for the Flame Tracker is 150C, the ambient air around the sensor can reach temperatures as high as 280C. This means that when the water-cooling system fails, the Flame Tracker can quickly overheat and incur damage.

A variety of different failure modes—from water lines blocked due to hard water deposits, biological growth, silt, corrosion, and freezing, to the occasional forgetful operator who fails to turn on the cooling-water valves after an outage—can inhibit sufficient water cooling, leading to Flame Tracker malfunction and often permanent damage.

FTD 325 advantages

The FTD 325 achieves greater flame sensor reliability and delivers operational benefits for gas turbines. The FTD 325's elimination of a water-cooling system translates to:

- No high-impact water leaks
- Significantly reduced maintenance due to overheated sensors
- Enhanced availability/reliability
- Simplified outage maintenance

Enhanced availability/reliability. The safety integrity levels of the electronic sensors for both the Flame Tracker and FTD 325 were analyzed using reliability models—the standard approach used to develop safety manuals and establish safety integrity levels (SIL).

Results predicted a mean time to failure (MTTF) of 130,000 hours for the FTD 325, a value four times the required design life of the product. An analysis of Flame Tracker reliability found that 77% of all of its failures were due to overheating resulting from water-cooling system failures. Because the FTD 325 eliminates these failures, its reliability is better than that of the Flame Tracker units.

Simplified outage maintenance. By eliminating water-cooling lines and associated electrical conduits running throughout the turbine, the FTD 325 offers significantly simplified outage maintenance. Its mineral-insulated cables easily can be removed from the strut channel supports and the hot-end half of the sensor can be rolled up and hung out of the way. Reassembly at the end of an outage is similarly less time consuming for the FTD 325 than for the Flame Tracker. Outages are simplified and labor hours are reduced by using the non-water-cooled sensor.

Conclusion

While high-impact water leaks associated with the Flame Tracker are infrequent, they can create a great deal of expense associated with the extensive repairs and potential multiple-week disruption when the turbine is out of service.

Additionally, Flame Tracker sensor overheating can be costly in terms of parts and labor replacement requirements as well as the occasional additional expense of a related turbine trip. These reasons along with the enhanced availability, reliability, and simplified outage maintenance associated with the FTD 325, have led BHGE to recommend the use of the non-water-cooled flame sensor as a cost-effective solution to help achieve overall gas-turbine performance improvement.

Mike Spalding. Application Engineer,
Industrial Sensors Product Line, Reuter-Stokes, BHGE

QR 1 QR 2 QR 3 QR 4 QR 5 QR 6

QR 7 QR 8 QR 9 QR 10 QR 11 QR 12

QR 13 QR 14 QR 15 QR 16 QR 17 QR 18

are done right the first time—even if it means taking a major to do so. Then consider robotic inspections for future inspections in lieu of field removal, he said.

Be mindful of significant changes in operating duty because they likely will require changes to your outage schedule, Clark continued. Cycling units warrant shorter intervals than baseload and seldom-run machines.

AGTServices has found that, compared to outages conducted only a few years ago, today's most involved repairs are related to problems caused by cycling. Clark mentioned the following examples:

- Endwinding loosening and insulation damage.
- Core and belly-band loosening.
- Winding migration, which can block off cooling.

He closed by urging the sharing of generator experiences during open user discussion forums. Some units (OEM, model, etc) suffer common problems, Clark said: It's in your best interest to know what they are. Access this presentation at https://forum.501fusers.org.

Alta Solutions Inc, "Better integration of turbine health monitoring for gas and steam turbines"

ARNOLD Group, "Technical differences between optically similar single-layer insulation systems" (QR3)

Pierre Ansmann told attendees that ARNOLD Group's single-layer insulation system is state-of-the-art technology capable of solving all known insulation-related problems associated with the operation and maintenance of gas and steam turbines. Particularly important given the challenges created by today's demanding operating paradigms is that the company guarantees reuse of its insulation system for 15 outages without a decrease in efficiency.

During operation, ARNOLD insulation enables users to decrease compartment temperatures significantly—by more than 50% in some cases—while decreasing fuel consumption and increasing power production.

During maintenance activities, the single-layer system reduces outage time and related cost because there are fewer blankets to remove, repair, and replace. Plus less local insulation labor and less scaffolding are required for outages.

Ansmann closed his session by describing the company's design innovations in 2017 and 2018 to improve on the insulation of turbine bearing tunnels. As the slides in his PowerPoint (available at https://forum.501fusers.org) explain, the ARNOLD substructure bracket system assures ease of maintenance access while protecting against damage from both engine vibration and from oil that might leak into the tunnel.

BPhase Inc, "Rewind and repair of the Decatur Unit 1 generator (Aeropac I)"

C C Jensen Inc, "Big data in oil conditioning and monitoring" (QR4)

With owner/operators becoming more comfortable using online data collection and analysis for large capital equipment, C C Jensen's Axel Wegner spent his Vendorama session explaining to plant personnel why they should consider doing the same for turbine oil. Storing retrievable lube-oil data in PI or similar system allows users to adopt a "big data" approach for identifying off-normal conditions, monitoring their development, and taking appropriate corrective action in a timely manner.

Online particle counting was one example he gave for identifying component-specific problems before they caused a breakdown or operational emergency.

Wegner's presentation was a good overview of the effects of oil contaminants on machine life, oil sampling, oil analysis, and online condition monitoring, while providing real-life examples. Access this primer at https://forum.501fusers.org.

CECO Peerless, "Importance of ammonia injection grid design to SCR performance" (QR5)

Attendees were told that the company's ammonia injection grid (AIG) is designed and optimized to provide the desired reagent distribution across the duct to assure expected SCR efficiency and performance. The square cross section of CECO Peerless' EDGE™ AIG lances are said to promote better mixing, thereby improving NO_x reduction, reducing ammonia slip, promoting longer catalyst life, and reducing the cost of operation.

A lab comparison of EDGE and an AIG with traditional lances revealed better performance from the former in half the distance from the AIG grid to the catalyst. A 30% reduction in ammonia consumption was reported by a plant after conversion of its AIG to EDGE.

Three brief case studies also

are provided in the presentation at https://forum.501fusers.org.

Doosan Turbomachinery Services, "501F rotor Class III inspection, new torque tube/air separator accomplished in 69 days of shop time" (QR6)

The company's capabilities are explained by way of a Class III inspection of a 501F rotor with 116,000 fired hours and nearly 2000 starts. The project, which took 69 days in the shop, included complete reverse engineering and manufacture of the torque tube, air separator, and four rows of compressor blades, as well as complete disassembly, inspection, and reassembly.

A Class III inspection in the Doosan shop includes the following steps:

- Deblade and unstack compressor and turbine sections.
- Inspect and analyze all rotor components.
- Make engineering recommendations on any life-limiting factors.
- Install new belly bands.
- Reassemble, balance, and ship to site.

Digging into the details of a turbine unstack illustrates the depth of discussion and level of detail presented. The six steps here are these:

- Put rotor in vertical position.
- Measure and record stretch of turbine bolts.
- De-tension 12 bolts.
- Remove turbine disks.
- Photograph and visually inspect curvic couplings.
- Prep parts for cleaning.

A checklist of important items to remember during reassembly of the compressor and turbine, including balancing tips, was a valuable primer for anyone unfamiliar with the guts of the engine or anyone looking ahead to a lifetime evaluation of his/her machine. Attendees were reminded that in-depth planning for a Class III inspection is critical and that both bolting and parts are long-lead-time items.

Testifying to the success of this project was that the rotor required only 271 grams of balance weights on the turbine end with all blades installed. Further, that there was less than 1-mil vibration at full load and no need for a field balance.

EagleBurgmann Expansion Joint Solutions, "Siemens SGT6-5000F expansion joints"

Emerson Automation Solutions, "Benefits of incorporating hardware/software that provides total plant solutions provided by MHPS and Emerson collaboration" (QR7)

Presentation focused on the capabilities and achievements of the Mitsubishi Hitachi Power Systems/Emerson alliance formed in 2008 to provide state-of-the-art turbine (gas and steam) and controls solutions. Successful projects completed since the alliance was formed include logic improvements, tuning, and dual-fuel conversions with full Ovation upgrades. Emerson reported having completed over a hundred upgrades of Siemens TXP systems.

Ovation is much more than a traditional distributed plant control system. In addition to native advanced applications for optimizing plant operations, it now supports integrated machinery health monitoring and generator excitation, as well as embedded simulation and enhanced cybersecurity solutions.

For more on Ovation's capabilities and owner/operator experience with this controls platform, read CCJ's report on the 2019 meeting of the Ovation Users Group elsewhere in this issue.

Environex Inc, "Advancements in CO and NO_x control technology" (QR8)

Andy Toback regularly shares Environex Inc's knowledge of CO and NO_x control technologies with CCJ readers. You can access some of this information with a keyword search of the magazine's archives at www.ccj-online.com. At the 501F Users Group's 2019 Vendorama he focused on four advancements in CO and NO_x control that owner/operators should be aware of. They are:

- Dual-function catalyst, which combines the functions of the SCR and CO catalysts into a single catalyst.
- Sulfur-tolerant CO catalyst, a modified CO catalyst formulation that provides greater resistance to performance loss from sulfur poisoning than conventional CO catalyst.
- Low-pressure-drop catalysts. The increased performance requirements for SCR systems require higher catalyst volumes of traditional designs, which, in turn, causer higher backpressure and efficiency losses.
- Improved reagent mixing made possible by retrofits to improve ammonia-to-NO_x distribution before the SCR catalyst.

Get the details by accessing Toback's presentation at https://forum.501fusers.org.

EnvironmentOne Corp, "Hydrogen auxiliary system upgrades" (QR9)

Chris Breslin's 50-slide Vendorama presentation with the title "Hydrogen auxiliary system upgrades" clearly exceeded expectations. It was more like a short course on the care and handling of hydrogen (read "safety"). Most welcome considering a couple of high-profile explosions in the last decade and the general lack of knowledge about, and respect for, this gas by many of the relatively inexperienced personnel being hired at powerplants today.

You might want to consider downloading Breslin's presentation at https://forum.501fusers.org, giving your employees a copy—it's easy to understand and to the point—and then using it as the basis for a "lunch and learn."

Breslin begins by answering the question of "Why hydrogen?" then explains the properties of the gas, moving quickly into safety best practices. The safety and efficiency reasons for hydrogen purity monitoring are included along with the reasons for upgrading existing equipment: Safety is Number One!

There's a section on generator condition monitoring and another on hydrogen dryers. The benefits of automated purge also are examined.

Frenzelit Inc, "501F exhaust cracking RCA and upgrades"

GE, "Realities of 501F rotor challenges with a focus on torque tubes" and "Time for your checkup: Improve performance with a healthy controls system"

Gulf Coast Filters and Supply Inc, "Field services engineering"

Hilco Div of Hilliard Corp, "Combined cycle oil filtration and conditioning" (QR10)

The Hilco team explained to users how its products bring fluid contamination problems under control, cost-effectively. The company offers full-service fluids management—including sample-taking, fluid analysis, equipment consulting, field techs, startup help, etc.

Conditioning equipment discussed included coalescer/separators for removing moisture and contamination from steam-turbine lube oils, reclaimers for restoring contaminated oil to a like-new condition, gas filters in both simplex and duplex arrangements for gas-turbine fuel systems, and oil-mist eliminators for reclaiming the oil found equipment vent air—coalescer only and coalescer with blower and silencer.

Hy-Pro Filtration, "Turbine oil tests and frequencies; water contamination mitigation and control" (QR11)

A presentation on lubricant maintenance and analysis is particularly helpful during the Vendorama sessions which precede the vendor fair at 501F User Group meetings. There always are several companies in the exhibit hall offering turbine oils and conditioning services and it's tough to remember all the standards and reasons for requesting the various tests you should be conducting. Without a primer like that presented by Scott Howard you might not remember the questions you should be asking on the show floor.

He began by introducing (re-introducing to many attendees) the turbine-oil testing guidelines published in ASTM 4378-13 and then moved quickly to test frequency. Regular analyses (appearance, viscosity—ASTM D445, total acid number—ASTM D664, ISO particle count—ISO 446, MPC—ASTM D7843, moisture—ASTM D6304/D7546, metals—ASTM D5185), he reminded, should be done every one to three months, periodic analyses (Ruler—ASTM D69071, RPVOT—ASTM D2272, rust—ASTM D664 for steam turbines) every three to 12 months. But be sure to run a battery of tests within 24 hours of any lubricant change.

Analyses to conduct as required include the following: FT-IR—ASTM E2412, rust—ASTM D664 for gas turbines, foaming—ASTM D892, air release—ASTM D3427, demulsibility—ASTM D1401, insoluble—ASTM 2273, and flash point—ASTM D92.

Measurement of varnish potential was discussed in two parts: one for mineral oils, one for phosphate esters. Course notes for this portion of the presentation were provided by EPT; learn more at www.cleanoil.com/likeitwasyourown.

JASC, "The science of liquid-fuel-system reliability in dual-fuel applications" (QR12)

Reliable operation of dual-fuel gas turbines on oil demands that owner/operators protect against coking in fuel-system valves and piping. Active cooling is one solution available to users for assuring both reliable starts on liquid fuel and reliable fuel transfers from gas to oil.

JASC offers several cooling options that are easy to retrofit on turbines at plants concerned about liquid fuel system reliability. One of these, the so-called "thermal clamp," introduced only about two years ago, is rapidly gaining industry attention. Results from the first few commercial installations confirm success in both protecting against coking and eliminating the need for "verification" firing of oil every month to confirm liquid-fuel system operability.

The company's latest system configuration, which involves moving fuel piping off the hot casing and installing thermal clamps, water-cooled fuel valves, and controls, enables owner/operators to extend the intervals between runs on back-up liquid fuel to six months or longer without sacrificing reliability.

To illustrate, a 7F gas turbine operated on liquid fuel during commissioning of its fuel-system upgrade and then burned gas exclusively for the next nine months. After a shutdown, the turbine started and operated on distillate without incident.

A typical F-class unit needing to confirm oil firing capability would have paid approximately $30,000 each month the test was conducted.

Get the details on thermal clamps and other water-cooled liquid-fuel system components at https://forum.501fusersgroup. The schematics and case studies included in the presentation can help you get started on your project today.

Koenig Engineering Inc, "Koenig replacement of a Voith starting system"

Mee Industries Inc,. "Benefits of wet compression" (QR13)

Thomas Mee may be the industry's foremost expert on fogging/wet compression, having decades of analytical and plant-level experience on the technology. He encouraged attendees to consider this cost-effective method of power augmentation for delivering additional megawatts virtually instantly in times of need.

Fogging/wet compression systems are easy to integrate with gas-turbine controls, he said, adding that his company can deliver the necessary equipment in 12 weeks or less and can connect the new system to existing equipment within a favorable outage window—perhaps in only 24 hours.

Responding to a question, the speaker said erosion risk is reduced with small droplet size—a distinguishing characteristic of Mee systems. Droplet size and its impact on equipment received significant air time. Details at https://forum.501fusers.org.

Meggitt Sensing Systems, "Self-diagnostics for accelerometers and dynamic pressure sensors"

Mitsubishi Hitachi Power Systems, "Rotor inspection techniques, observations, and solutions" and "TOMONI—

digital solutions methodology for W501F fleet" (QR14)

See the MHPS segment of the OEM section in this report and connect to the vendor's Vendorama presentations at http://forum.501fusers.org.

National Electric Coil, "An Aeropac user maintenance checklist" (QR15)

National Electric Coil, TOPS Field Services, and Doosan Turbomachinery Services co-presented on the subject of non-OEM outage solutions and the advantages offered by their collaboration. TOPS Toby Wooster took the lead, explaining that OEMs have been marketing an all-under-one-roof outage approach to powerplanrt owner/operators, where the engine manufacturers supply the field service, parts repairs, and engineering as a package.

This consortium's presentation reminded users that the all-under-one-roof solution lacks the ability to deliver consistent quality, turnaround, and, most importantly, partnerships for plants that, for the most part, are unique.

TOPS and its partners have found through discussion with many users across the industry that vendors lack the partnership approach in their proposals: They don't work with owner/operators to help solve their maintenance problems; their goal is to complete the outage at the lowest possible cost and move on to the next job.

The presentation suggested that the solution of greatest value came from working closely with a pure-play vendor that invests in relationships, flexibility, quality, and transparency, and responds quickly to the unique challenges every plant faces.

Wooster next explained how TOPS and its partners can deliver on their outage solution at a competitive price:

- They invest heavily in the personnel who work onsite. The result: team members have been with their respective companies for years and bring that experience to bear on your project.
- They work with the plant well in advance of the outage to identify early risks that can impact cost and schedule—risks not identified in the RFP.
- The development of solutions to improve outage performance, reduce duration, and minimize risks is ongoing in the back office.

Nederman Pneumafil, "Holistic maintenance? A case for maintaining generating facilities"

ORR Protection Systems, "Fire detection and suppression experts for turbines"

Pioneer Motor Bearing Co, "Developing an innovative bearing radial load sensor" (QR 16)

The session opened with a review of how babbitted fluid-film bearings work and the types of sensors available to track their health—including thermocouples and RTDs to monitor temperature, proximity probes and accelerometers to track vibration, and load cells and strain gauges to monitor load. Temperature is important, of course, because the higher it is, the thinner the oil film. Vibration is measured to prevent bearing contact and to detect machine operating anomalies.

Progress is being made in the development of embedded strain gauges to accurately measure the load on the bearing train. The expectation is they will be able to detect wipe events without visual inspection, detect metal-to-metal contact/surface friction faster than a temperature sensor, and assist owner/operators in run/repair decisions.

A roadmap with critical objectives was presented. Access the presentation at https://forum.501fusers.org.

Precision Iceblast Corp, "HRSG deep cleaning"

Schock Manufacturing, "Combustion turbine exhaust liner/silencer upgrade"

SVI Dynamics, "GT exhaust system repair and upgrade considerations" (QR17)

SVI Dynamics is, perhaps, best known for its aftermarket design, engineering, and field services work from the gas-turbine exhaust to the stack exit. Scott Schreeg made a few points in his Vendorama presentation particularly worthwhile considering by plant O&M personnel. They are:

- Most gas-turbine exhausts are fine until there is a hiccup and the project must be expedited, limiting options and flexibility to achieve the optimal repairs and/or upgrades.
- If inspections are an option, typical failure modes can be monitored using thermography, noise surveys, and visual inspections to provide the information and time necessary for proper outage planning.
- Upgrading gas-turbine exhausts using CFD analysis to improve aerodynamics will provide a longer-lasting system by reducing velocities and pressure drop, while using current methods and materials for maximum durability.
- Project specifications can include parameters for acoustical, thermal, and aerodynamic guarantees to ensure the owner/operator has the opportunity to meet its project goals.
- Turnkey contracts—including engineering, material/equipment supply, demolition, and erection—can mitigate risks and streamline project execution.

Tetra Engineering Group Inc, "NFPA 85 HRSG purge credit: Option selection, benefits, and ROI evaluation"

TOPS Field Services, "Non-OEM solutions" (QR18)

TOPS Field Services, National Electric Coil, and Doosan Turbomachinery Services co-presented on the subject of non-OEM outage solutions and the advantages offered by their collaboration. TOPS Toby Wooster took the lead, explaining that OEMs have been marketing an all-under-one-roof outage approach to powerplanrt owner/operators, where the engine manufacturers supply the field service, parts repairs, and engineering as a package.

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- The development of solutions to improve outage performance, reduce duration, and minimize risks is ongoing in the back office.

Dogwood

Checking HRSG drum door gaskets: An open and shut case

Challenge. Dogwood, like many other combined cycles, opens its steam-drum doors on a routine basis to perform internal inspections. While properly aligning and closing the doors at the end of an inspection is a challenge in and of itself, the larger challenges and risks often are associated with making sure the gaskets do not get damaged during installation and that a good seal on the drum door has been established before removing the LOTO and lining up the HRSG for operation.

Depending on when a gasket leak is found, the plant would either have to drain the HRSG, if the leak was identified before starting up the gas turbine, or to bring the affected unit offline, depressurize the drum, and establish a LOTO and confined space to protect personnel performing the work.

Staff then would remove and replace the gasket, and inspect and clean gasket sealing surfaces, potentially requiring work near hot surfaces. If parts of the old gasket material are accidently dropped into the drum when making the repair, the outage might have to be extended to locate and remove that material.

Work complete and the LOTOs released, the plant would start the unit back up and hope for the best. Depending on the success of the repairs, this repair evolution could have taken several hours and caused missed dispatch schedules.

Solution. After several drum-gasket leak events impacting plant dispatch had occurred at Dogwood, operations personnel put their heads together to find a way to better ensure that the drum-door gaskets would seal and hold. They found that after bottling up the HRSG, as when blanketing the unit with nitrogen, they could inject plant air via the nitrogen circuit to pressurize the drums and check for leaks.

Once the pressure reached 30 to 50 psig, staff could walk down the drum doors and listen for leaks.

Dogwood has had great success in filling the HRSGs and restarting the plant when checking the doors with this process.

Caution: Before using a system for purposes outside of its original scope, engineers should evaluate the system to verify that piping design conditions are not exceeded and that there are no compatibility issues. Maintaining system integrity is an important component of safety.

Results. Dogwood has been using this method to check for drum-door gasket leaks for several years. During this time, leaks have been repaired before filling the HRSG, reducing the probability of a forced outage associated with drum-door gasket leakage. This process has produced several benefits, including these:

Dogwood Energy Facility

Owned by Dogwood Energy, City of Independence, Missouri Joint Municipal Electric Utility Commission, Kansas City Board of Public Utilities, and the Kansas Power Pool

Operated by NAES Corp

650-MW, gas-fired, 2 × 1 combined cycle located in Pleasant Hill, Mo

Plant manager: Steve Hilger

- Allows Dogwood to check for leaks while the plant is still in an outage.
- Checks are completed with minimal equipment in service, making it easier for operators to hear leaks.
- If a leak is identified, the gasket usually can be replaced within the scheduled outage, with the main-steam and water LOTOs in place.
- Drum shell temperatures are not an issue as all temps are at ambient conditions instead of discovering a leak during a startup, where metal temperatures may be several hundred degrees.

Project participants:
Mike Curry, Mike Davis, Jeff Hamrick, Karl Schultz, and Shawn Swinney

Eliminating the risk of hot-torqueing steam drum doors

Challenge. After opening drum doors for inspection, replacing manway gaskets typically calls for plant staff to tighten the manway bolts to a given torque to hold the manway cover in place while the drum is below operating pressure. The seal around the manway is formed when the pressure from the steam inside the drum provides enough force to compress the gasket between the sealing surfaces on the door and drum.

Once the drum has been brought up to operating conditions, retorqueing (a/k/a hot torqueing) the bolts is required to ensure that slack in drum door hardware from thermal growth gets taken up and the gasket remains

1. Belleville washers and a different style of gasket eliminated the need for hot-torqueing of HP steam-drum bolts during unit starts

2, 3. Torqueing steam-drum hardware (above); drum ready for HRSG restart at right

compressed when the plant is cycled. Hot torqueing places plant staff directly in harm's way if something were to go amiss during this process.

Solution. Safety concerns, driven by events at other facilities, encouraged Dogwood personnel to investigate possible alternative procedures for tightening the steam-drum manway bolts without putting personnel in a potentially unsafe position.

Dogwood worked with an engineering firm that was in the process of developing a solution using Belleville washers and a different style of gasket to eliminate the need for hot torqueing (Fig 1). Dogwood removed the existing studs and washers and replaced them with longer studs to accommodate the Belleville washers.

In addition, the engineering firm recommended using a graphite ring gasket that does not liberate like the spiral-wound gaskets typically used on drum doors. This design uses the spring pressure of the Belleville washers to hold the gasket sealing surface tight as drums go from atmospheric to normal operating conditions (Figs 2 and 3). Note that the gasket has a spring-wave feature that allows it to accommodate thermal growth.

Dogwood Energy's HP drums have round manways, not the elliptical ones found on most steam drums. Personnel confirmed that the recommended gasket was flexible enough to install through the drum door opening without distorting or damaging it.

Dogwood offered to be the beta test site for the Belleville washer and gasket solution in an effort to validate the engineered solution on its HP drums. The new assembly was installed on one of the HP drums during the fall 2017 outage and followed a test plan to validate the assembly.

Results. Dogwood completed installation of hardware on the Unit 1 HP drum in November 2017 and the following criteria were established to validate the design over a three-month test period:

- Conduct 1000 hours of cycling operations and/or a minimum of 12 unit starts during the test period.
- No additional torqueing of the manway hardware allowed.
- The measure of a successful test would be zero gasket leakage.

During the three-month test window, Dogwood operated for approximately 800 hours with the new gaskets and completed 23 unit starts. While the plant did not achieve 1000 hours of operation, management believed the new design had proven itself.

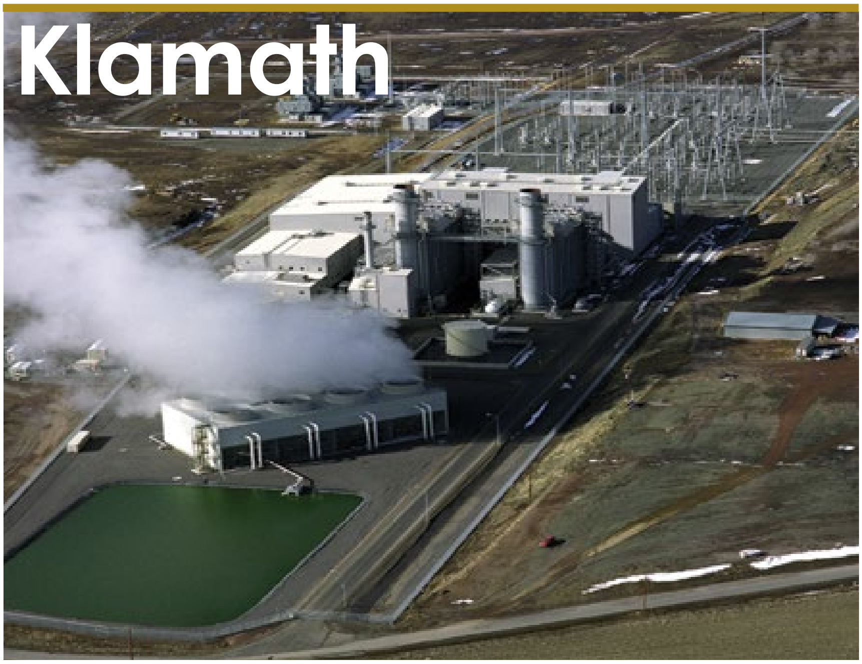
Dogwood did not hot-torque the manway doors and did not experience any gasket leaks during the test period, when HP steam-drum conditions ranged from atmospheric to 2225 psig/645F (average HP drum metal temperature).

At the beginning of 2019, Dogwood had approximately 4400 operating hours and 200 starts on Unit 1 without any gasket leaks on the HP drum. The same system was installed on the Unit 2 HP steam-drum doors in May 2018 without any indication of a leak after approximately 3100 operating hours and 140 starts.

Given the good results, Dogwood plans to install a similar system on the IP and LP steam drums in the future.

Finally, keep in mind that before modifying a drum door or other equipment in the plant, it is best to consult with the OEM or an engineering firm to ensure staff doesn't miss anything in its evaluation of an issue concerning the recommended design change. This step also helps minimize potential issues in the future.

Project participants:
Chuck Berg, engineering manager



Klamath Energy LLC

Avangrid Renewables

536-MW, gas-fired, 2 x 1 combined-cycle cogeneration plant located in Klamath Falls, Ore

Plant manager: Dennis Winn

Rerouting fuel-gas piping above-ground cuts inspection cost dramatically

Challenge. TransCanada, Klamath Cogen's fuel-gas supplier, installed its control, filtering, and metering station at the plant fence. The piping network on plant property, serving the gas turbines, auxiliary boiler, and plant heaters, was buried, and expensive to inspect.

Buried gas lines at Klamath had to be inspected every five years. Cost was $400,000 per inspection—including rental launchers, rental receivers, inspection equipment, labor, restoration, and cleanup. Additionally, a site outage of 10 days was necessary to conduct the required inspection.

Solution. Plant management engaged an Oregon firm to help with the engineering aspects of a project to consider the design, seismic, routing, and structures for moving fuel-gas piping above-ground. With the firm's assistance, plant personnel developed a scope of work with the required bill of materials. Responsibilities for the project were split: Klamath personnel purchased all pressure components and ensured that the pipe and material test reports were correct while the contractor selected provided support structures and their materials.

Metallurgy. Engineering review of the project identified a problem with using standard A106 grade B pipe. There was a risk of brittle fracture because of the material's insufficient manganese-to-carbon ratio for cold-temperature service. The typical fuel-gas temperature at Klamath is less than 40F.

An article in the National Certified Pipe Welding Bureau's May 2016 Technical Bulletin, discussing developments in the steel-making industry over the previous five years, suggested that purchase orders for seamless carbon-steel pipe, fittings, and flanges specify a manganese-to-carbon ratio of 5:1 or greater, and a grain size of 7 or finer, to avoid failures. Klamath elected to adhere to a manganese-to-carbon ratio greater than 5:1 as a requirement for all of its steel pipe, fittings, and flanges.

Above-ground fuel-gas piping. After developing a scope, construction contractors were contacted, and the scope of work was publicized for solicitation. Bids were received and the construction company was awarded.

The road crossing was a main concern given the potential of something striking the overhead piping. A pair of W12×30 beams was installed on both sides of the piping, with the piping set well inside the protective structure (photo). The bottom elevation of the wide-flange beams has a clearance of 19.5 ft.

Additionally, valving was installed on the piping so nitrogen purges could be executed during times when fuel-gas outages dictated such use on the 10-, 4-, and 1.5-in. piping.

Results. The completed piping project eliminated a financial burden that occurred every five years, and scheduling of additional people and equipment to be onsite during the examination process was discontinued. Additionally, the waste stream of products used during the pigging and inspection were eliminated. This was significant because none of the inspections companies was willing to take responsibility for waste disposal.

This project paid for itself by avoiding one underground pipe inspection.

Project participants:
Dennis Winn, plant manager
Greg Dolezal, maintenance manager
Bruce Willard, operations and engineering manager

W12×30 beams, located 19.5 ft above the road, protect fuel gas piping

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Tuxpan II & V

Filter cleaning procedure yields heat-rate improvement

Challenge. Tuxpan is located in a salt air environment containing a great deal of dust from both agricultural and industrial activities in the area. These contaminants present a challenge because plant performance rapidly degrades as the air inlet filters foul.

Solution. Quarterly, use a pressure washer to clean the screen located ahead of the pre-filter to collect airborne dust and salt. This new practice enables plant personnel to achieve the desired pressure drop across the gas-turbine inlet filters and maintain expected performance.

The cleaning process begins by removing the panels that hold the filter mesh inside the filter house (Fig 1). Once outside, they are washed with high-pressure water until clean (Fig 2). Final step is to reinstall the panels in the filter house.

With this procedure, plant can extend the lives of the 450 pre-filters in each gas-turbine inlet, saving approximately $20,000 annually.

Results. Based on data recorded from Jan 12-Jan 15, 2019, before and after high-pressure cleaning of the screens on January 14, washing reduced the pressure drop through the inlet filters by 0.32 in. H_2O, producing a nominal performance gain in each engine of 50 Btu/kWh.

Project participants:
Leonel Rosas Maitret, PE, production director
Jose Alamilla Hernandez, maintenance manager

CCC Tuxpan II & 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

1. Plant personnel begin removing the panels for cleaning

2. High-pressure washing of the screens is done quarterly

Fremont

Inlet fogging pump upgrade reduces O&M cost, increases revenue

AMP Fremont Energy Center

Owned by American Municipal Power

Operated by NAES Corp

703-MW, gas-fired, 2 × 1 combined cycle located in Fremont, Ohio

Plant manager: Steve Greene

Challenge. Costly fogging-pump failures and consequent maintenance repairs had negatively affected Fremont Energy Center's summer peak season performance and its maintenance budget. Plant personnel realized the need to prevent premature pump failures and avert costly fogging-system downtime.

Solution The plant maintenance staff began investigation of multiple issues linked to premature failures of the station's fogging pumps. In the process, personnel learned that the low lubricity of demineralized water was causing pump seals to fail.

They devised a plan to upgrade the fogging system. It included the use of service water to flush pump seals, thereby cooling and lubricating them. This was accomplished by retrofitting all of the fogging pumps with flushed manifold heads. The result was increased seal life plus dramatically lower maintenance cost and fogging-system downtime.

To implement this solution, the maintenance staff and site engineer hot-tapped the service-water headers for flushing liquid, routed the service water through two particulate filters to a manifold near the fogging skid, and branched off those lines to each of the pumps (Fig 1).

Technicians then installed solenoids on the service water supply and tied them into the fogging-pump start logic to begin supplying flushing water before the fogging pumps start (Fig 2). Lastly, they tied drain lines from each pump into one common plant drain (refer back to Fig 1).

Results. This project has saved the site approximately $100,000 per year by reducing fogging-system downtime and increasing power output.

Project participants:
Josh Barker, lead O&M technician
Rick Moyer and Rudy Galindo, mechanics
Josh Lindstrom, Bill Avers, and George Danko, I&C techs
John Maher, engineer

1. Service water is routed through filters mounted on the column to the right of the skid to remove particulate matter before being used to flush the fogging-pump seals. A common drain line runs alongside the skid at the bottom of the photo

2. Solenoid valves in the flush-water supply manifold open to start water flowing prior to pump start

OVATION USERS' GROUP

Automation rises to platform for 'trusted' services

Intel, the venerable computer chip maker, is often lauded by marketing gurus for its "Intel Inside" stickers. The strategy allowed a supplier of invisible "pieces and parts" to be brand-recognized by the end user.

Emerson's Power & Water Solutions business might consider "Ovation at your side." At its annual Ovation Users Group conference, the Emerson leadership, and rank and file, made it clear, without overt reference, that Ovation will be more than control systems, automation, and plant knowledge management; it is evolving into a platform for a variety of enhanced services within a "trust domain" established with the customer (Fig 1).

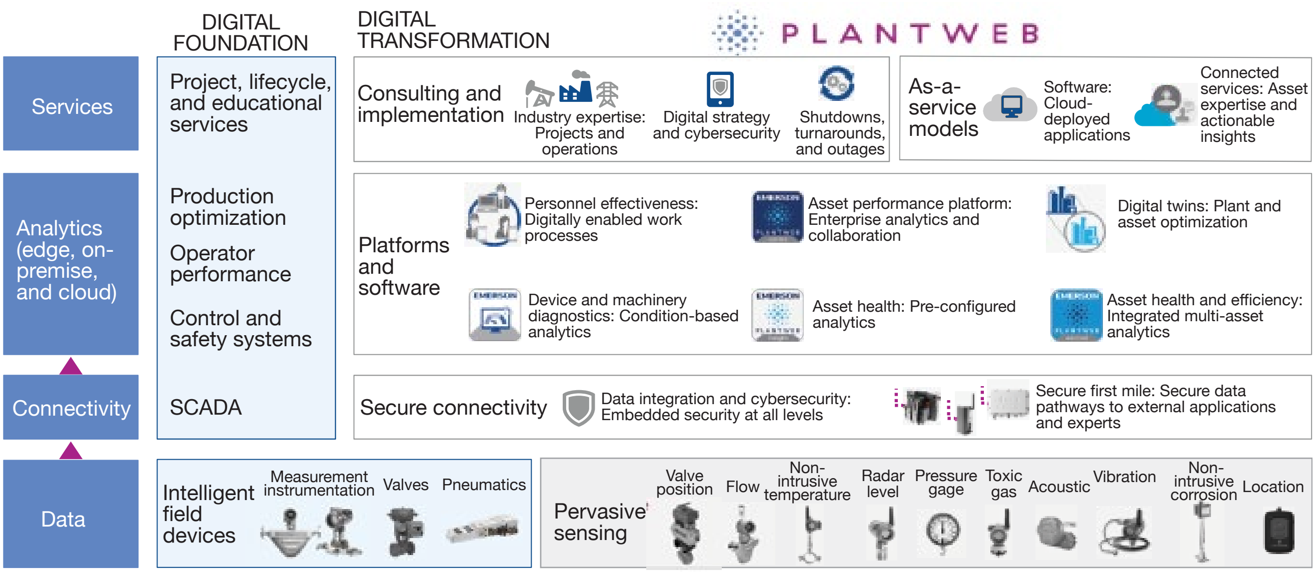
Jim Nyquist, Group President, Emerson's Systems & Solutions organization, opened the meeting by proclaiming this to be the "most challenging environment in history for power and water." He reported that Emerson corporate restructured by selling off one-third of the company over the last three years, even as the firm made key acquisitions, most notably GE Intelligent Platforms.

Nyquist's most insightful comment, though, was that its Power & Water Solutions business is becoming "a trusted advisor to the industries it serves."

Robert Yeager, president of that business, as he does every year, next assumed bragging rights, noting that Ovation is now installed on well over one-third of the electricity generating capacity in the US, and close to one-fifth of the capacity around the world.

The group has its sights on a remote monitoring and digital collaboration center, a "collaborative work environment of the future," said Yeager. When built out, it is expected to anchor enhanced services in cybersecurity, cloud-hosting, remote M&D, troubleshooting by subject matter experts, and real-time control and advisory services to operators and engineers on the customer side.

"The 'live' digital twin (not a "snapshot," Yeager emphasized) means the simulator and plant control system share an integrated database, same DNA, and same engineering tools," he said. This is what allows "trusted advisors" remote, real-time visibility into the facility, to support the plant staff as necessary and desired (Fig 2). Over 125 embedded simulators, the



1. Value-added services are the next leap for digital transformation through the Ovation platform

Ovation Users Group
2020 Conference

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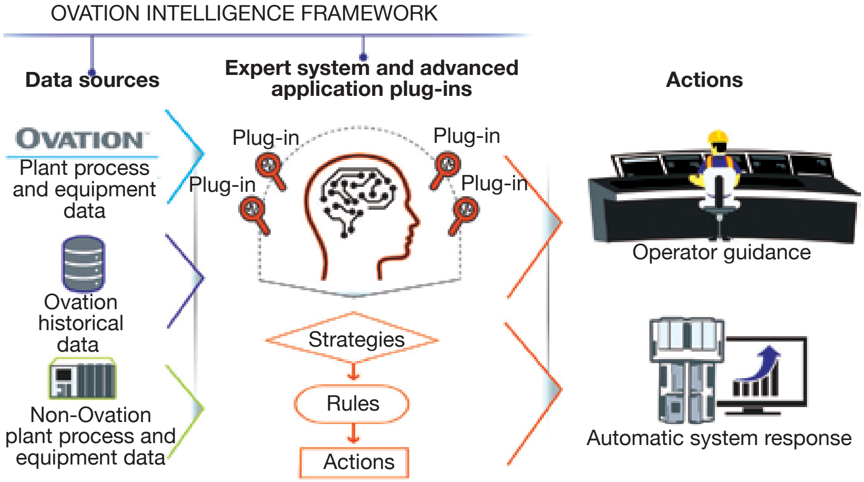


2. The value hierarchy for data culminates in the actions that can be taken by operators and engineers, by the automation system (autonomous control), and/or by remote staff assisting the plant

3. Evolution of this scalable controller is the backbone for Ovation applied to distributed generation, wind farms, grid-scale storage, and other facilities composed of many identical or similar units dispersed across a wide region

core of the "digital-twin" concept, are now installed or proceeding through the factory, Yeager reported.

Luke Williams, Executive Director, NYU Berkeley Innovation Lab, delivered the "out of the box" TED-talk type lecture, noting a transition in economic thought from the scarcity mindset to a "non-rival" goods paradigm. He used a lot of concepts from economics and social science to, essentially, describe the "sharing economy" (think Lyft, AirBnB).

"A chair is a thing, but the idea of a chair can be used by everyone," Williams argued, you can "re-arrange things to satisfy other objectives, to disrupt path dependence and historical continuities." Message between the lines, perhaps: Emerson is re-arranging the "ingredients" of its Ovation platform to deliver value-added services.

Progress with the Ovation backbone technologies was delineated by Steve Schilling, VP, Technology, including the following:

- The scalability of the Ovation controller (OCR) continues with the release of the simplex version of the OCC100 compact controller and progression towards the next-gen OCR and microcontroller (Fig 3).
- Software defined networks for fast fault detection and healing, and improved visibility into network health and security.
- Integration of trusted corporate domains and security groups into the Ovation domain.
- Models constantly being added to the live digital twin.
- Machinery health protection and prediction as well as Ovation plant prognostics.
- Major focus on cybersecurity.

Glenn Heinl, VP Lifecycle Services, Jaime Foose, Director Lifecycle Shared Services, and Mike Brown, Manager Lifecycle Proposals, rounded out the opening session, discussing all the ways their organization will be supporting customers in the months and years ahead, including advanced support programs, performance optimization support, programs to assist sites with replacing PLC-based and skid-mounted controls and integrating them into Ovation; the availability of subject matter experts; remote diagnostics; monthly support webinars; quarterly informational newsletters; and dozens of Ovation engineers who take calls 24/7.

Emerson recently invested in Dragos, a Hanover, Md, cybersecurity firm, and its CEO, Robert Lee, kicked off the second morning's general session. His main theme was that owner/operators have to transition from relying solely on passive defenses against cyberattacks to a more active defense based on intelligence-informed actions.

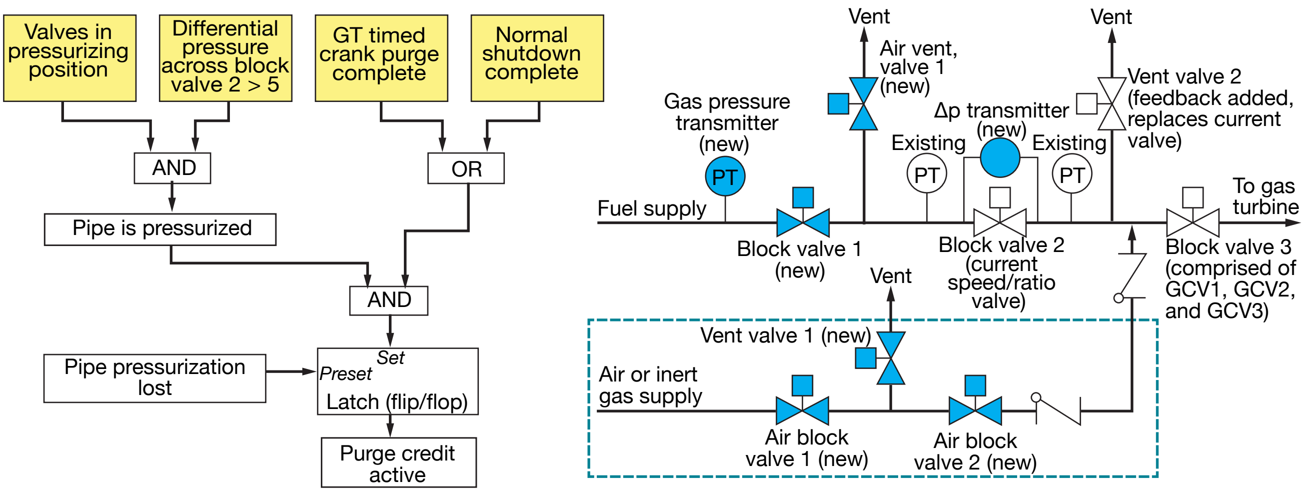
Adversaries, he said, set the stage for attacks months and years before they actually occur. He distinguished between intrusions, like phishing emails, and an incursion in which the adversary steals the information that assists in the later attack.

In one case overseas, Lee said, the adversary was able to install new logic into the safety system controller at a petrochemical complex. In other words, the adversary *pre-staged* malicious software on the DCS three years before the attack occurred in 2017.

In another event, the adversary spent six months "learning" the industrial environment, developed electric transmission capability, installed protocol-capable software, created malicious services, and coordinated action via a timer to de-energize a critical substation. While the entity responsible for the substation claimed it was "back up" within six hours after the attack, what they did not report was that they were operating in manual for six months afterwards.

Yet, despite these events, he noted that defending industrial systems is in a much better place than people realize.

In another general presentation on the second morning, Glen Wagner, VP North American Projects and Sales, noted that Emerson completed 52 gas-turbine retrofit projects in 2018,



4. HRSG purge credit was achieved by leveraging Ovation, replacing original PLCs, and adding requisite vent and block valves and pressure monitors

Second vent valve added to duct burner at top of riser

Third block and second vent valves added to GT gas supply

Duct-burner air skid

mostly to help users achieve flexibility in capturing high-value services in the organized electricity markets. Interestingly, he also noted that hydroelectric facilities are seeking modernization and optimization solutions for similar reasons—to capture market value filling in around must-take renewables.

Consistent with the overall emphasis on services, Wagner stated that Ovation experts can help on the front end as well, such as delivering return-on-investment analyses for contemplated upgrades and retrofits.

Application briefs

Minutes matter. That's true in obvious situations, like when someone is shot, injured, or having a heart attack. It's also true when capturing additional value in the organized electricity markets. One presentation described successful results leveraging Ovation controls in eliminating 20 minutes from the gas turbine start cycle by implementing the HRSG purge credit.

Of the three general options described in National Fire Protection Association NFPA 85 (2015 edition), the one selected (Fig 4) was retrofitted in a week during a 14-day steam turbine/generator retrofit outage, with $170,000 additional revenue expected. The project included replacing six-year-old duct-burner controls, adding an air skid to monitor pressures, adding a third vent valve to the duct burner, and a third vent valve and second block valve to the gas turbine. Programmable logic controllers (PLCs) were replaced with redundant Ovation OCC100 controllers.

According to a representative knowledgeable about the plant, they "never know when the next dispatch will come." The facility experiences 250-300 starts annually, has to hot-start within one hour, and cold-start within three hours, or pay up to $300,000 in penalties. Thus, avoiding penalties is worth more than gaining revenue.

Not as easily calculated is monetizing the reduction in thermal stresses on the HRSG, a design which includes two superheaters, but no reheat section.

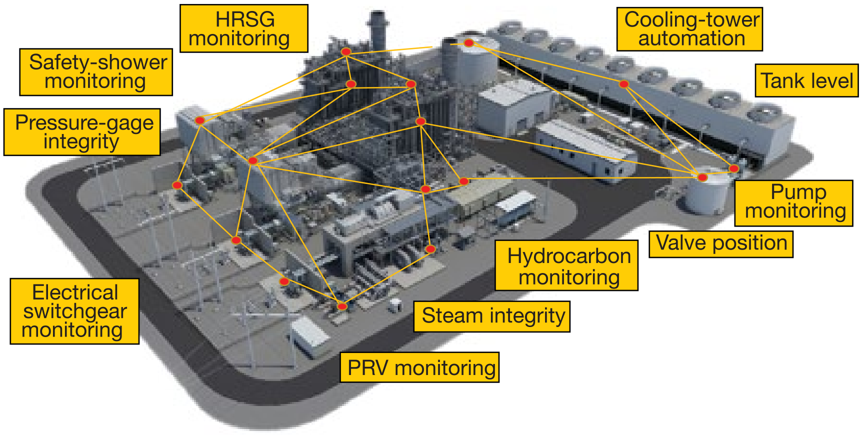
Plant reps estimate a factor of 10 reduction in hot/warm start contribution to superheater fatigue. Importantly, the retrofit moves superheater repairs out of the 10-year PPA window. As well, a three- to five-factor reduction in fatigue damage to the steam drum, downcomers, and outlet nozzles was calculated.

There is also a reduced risk of water hammer and low-cycle fatigue damage now that less condensate is produced. The original condensate removal drains were not sized for the operating modes the facility currently experiences, in other words, not for frequent starts and purge cycles.

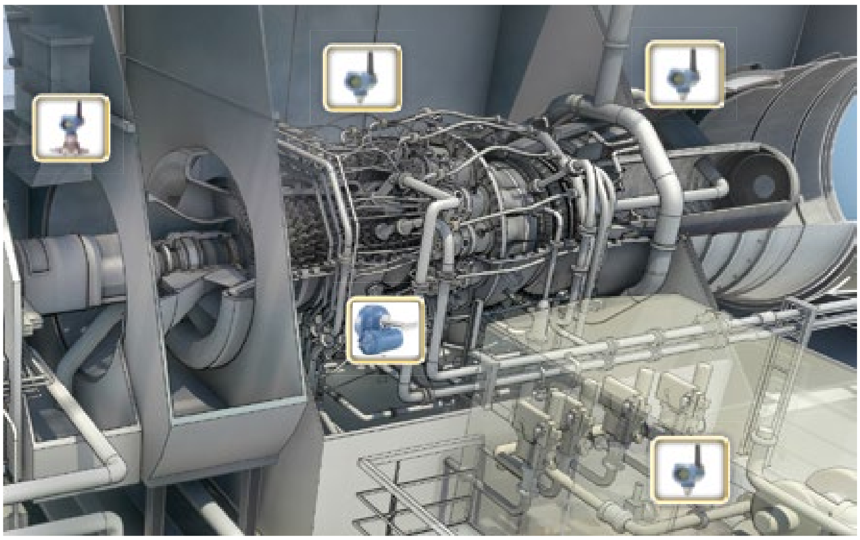
Beyond training. Three users presented on how they have used their Ovation embedded high-fidelity simulator and benefits therein. One of the facilities, a combined cycle, is new, experiencing "first fire" the week of the Ovation confab. Note that none of the three is yet being used as a "live" digital twin.

Uses and benefits include these:

- Assist in engineering and validating operator procedures.
- Detect design flaws in transitional operating states, especially with a "complex auxiliary steam system with multiple operating modes" presented by the EPC.
- Validate "intent of design" by running startup, ramping, baseload, and shutdown scenarios.
- Validate setpoints and alarms.
- Represent interactions between turbine controls and balance of plant.
- Aid engineers in vetting logic and HMI graphics, training operators, and optimizing plant controls.
- Detect superheater spray logic flaws.



5. Intelligent sensing and remote monitoring are key elements for unmanned GT sites



Monitor any temperature, pressure, flow, vibration or sound wirelessly

- Turbine compartment, CDC leaks/fire
- Compartment, Δp/air leaks
- Exhaust compartment, temperature/exhaust leaks
- Inlet filter house, Δp/filter health
- Compressor, Acoustic/blade rubs
- Inlet, Δp/temperature
- Fuel oil, flow/performance
- Bushing box/isophase bus duct, humidity/temperature and leaks/conductor
- Vibration, DC lube-oil pumps and other rotating equipment

- Revise and update operating data and procedures.

No operator, no dog. Even two decades ago, automation specialists joked that in time, only an operator and a dog would be onsite at power stations and the dog's job was to keep the operator's hands off the controls. David Cicconi, Emerson Turbine Business Development Manager, reviewed a variety of technology enhancements now available to completely monitor and operate a multi-unit simple-cycle gas-turbine facility, even ones with HRSGs for cogeneration, remotely, with no personnel dispatched unless issues arise.

Cicconi distinguished a remote *start* from remote *operation,* stating that the former involves, among other things, personnel dispatched to the site for continuing operations and limited intelligence available following a failed start. Many other industries are already running complex energy systems remotely, such as unmanned mine sites, he noted.

Categories of enhancements covered include the following:

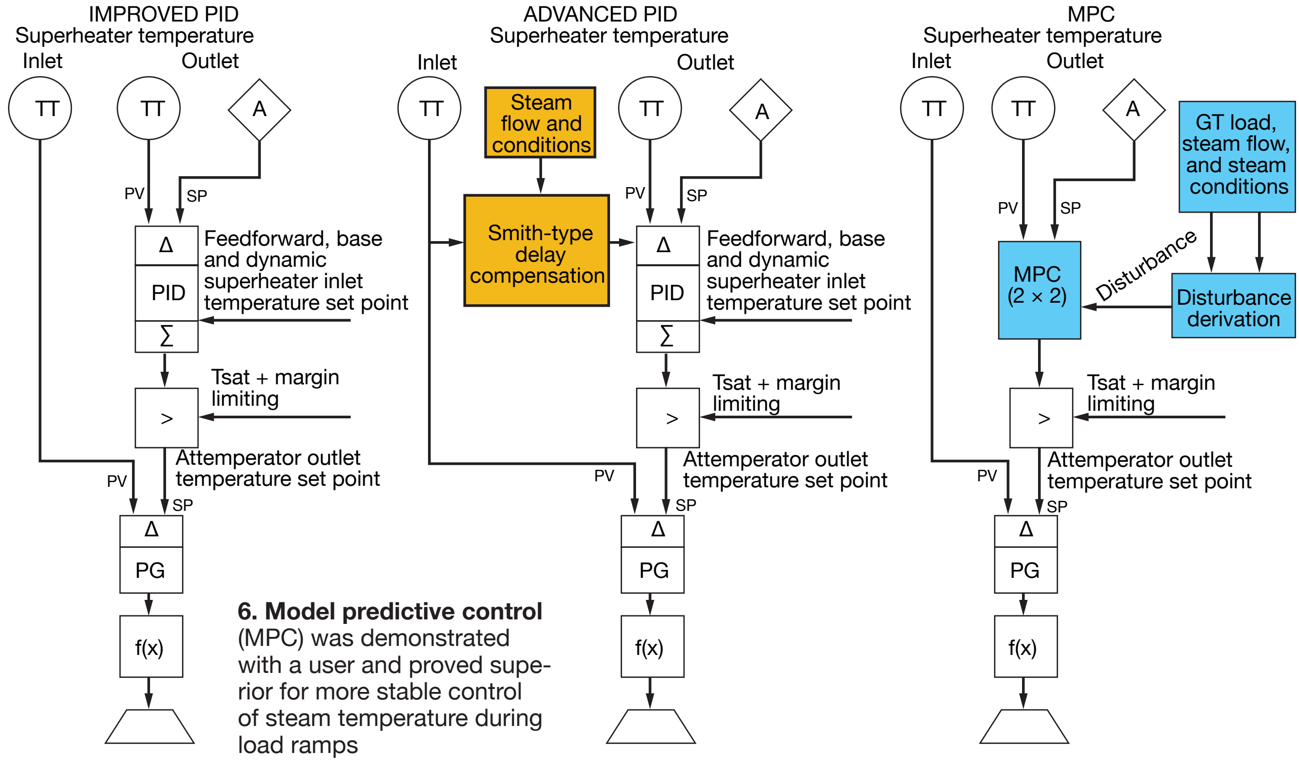
- Expand remote monitoring and control beyond the gas turbine (already completely automated) to BOP systems and skids.
- Add vibration monitoring to BOP pumps and motors.
- Add wireless transmitters to monitor remote equipment.
- Deploy advanced pattern recognition to detect onset of performance deterioration and reliability events (such as cracked GT combustor transition pieces).
- More tightly integrate BOP and auxiliaries.
- Add cameras for site surveillance with thermal monitoring software for critical locations.
- Shift from periodic to continuous monitoring (Fig 5).

Faster, less stressful ramping. Emerson worked with a utility user (2 × 1 combined cycle), EPRI, and a consulting firm to evaluate advanced steam-temperature control for HRSG applications. Ultimate goal is a control mode that allows faster, less stressful ramping, especially for units originally designed for baseload service and now experiencing daily start/stop, more rapid ramping, and/or operations over a wider load range.

Of the three options evaluated (Fig 6), the model predictive control (MPC) scheme proved superior, with 25-50% less standard deviation in superheat and reheat temperatures, 35-60% improvement in integrated error, consistently stable and fast response, and a straightforward tuning process. Two MPCs (controllers) were able to handle the entire HRSG load range.

The benefits are as follows:

- Reduced deviations allow faster ramp rates when steam temperature variations are limiting factors.
- Better stability reduces thermal stresses especially under automatic generation control (AGC), and reduces valve actuator activity.
- Closer operation to setpoint may enable base steam temperature setpoint to be raised without suffering additional creep life cost, and may improve steam-cycle efficiency by



6. Model predictive control (MPC) was demonstrated with a user and proved superior for more stable control of steam temperature during load ramps

up to 0.1% for additional fuel savings worth $20K annually.

Fewer rounds. Emerson's Business Development Manager Juan Panama offered a compendium of technology applications to "build the utility of tomorrow." Perhaps the most eye-opening one is to significantly cut operator rounds and make better use of limited manpower by installing wireless devices at all points where data are now taken manually. One combined-cycle site estimated that it could avoid 58 man-hours per week per power block in applying this approach and keep staff more focused on the important business of repairing what the sensors detect.

Panama also noted that Emerson offers a device that connects to any wired device to convert it into a wireless device, allowing additional HART information to be collected.

Other ideas (those not covered in earlier presentations) include remote monitoring for continuous operation of critical valves, especially around the steam cycle; wireless acoustic listening devices to detect the onset of HRSG tube leaks; wireless corrosion and erosion monitoring in areas prone to oxygen pitting and flow accelerated corrosion; wireless pressure transmitters to give insight into when tube bundles show signs of fouling; and continuous electrical condition monitoring on equipment rated less than 40 kV.

This last could eliminate the need for periodic IR measurements on live equipment with personnel in arc-flash suits, third-party partial discharge testing, and heater and insulation failures in isophase bus ducts.

Panama provided some rough estimates showing that sites in the low end of maintenance costs–ranging from $3.53/MWh in the top third of performers to $8.59 for the bottom third—apply many of these latest technologies discussed.

Your long-lost twin. You may not know it yet but your Ovation system could have a twin, a digital twin, the real-time "live" version of the Ovation embedded simulator when it is pulling data from and synced to the control system database.

Emerson's James Thompson and Shen Zhang provided an update on digital-twin technology, noting that 180 models in eight "suites" (base, electrical, turbine, flue-gas desulfurization, selective catalytic reduction, combined cycle, boiler, and balance of plant) have now been validated and included in the algorithm library.

Without repeating the benefits and tools available from what was mentioned previously, the digital-twin capability is being integrated into the Ovation services model, especially in its Emerson "cloud-hosted" configuration, meaning it is entirely offsite in the Emerson-controlled cloud.

As such, it becomes an engineering simulator with the attendant fidelity and graphical realism, as well as the platform for real-time process and controls optimization (for example, root-cause analysis and upgrades), autonomous control (instead of operator assisted control), and loop testing and validation.

As the presenters stressed, full-scale adoption of the live digital twin will require maintenance beyond just keeping the simulator updated and synchronized with the control system. Consideration will have to be given to cybersecurity, NERC-CIPs regulatory compliance, recalibration of the models to gain higher fidelity, and installing additional sensors in plants that are not properly instrumented or want to generate additional data for higher-level prognostics tools. CCJ

7EA Users Group

If you own and/or operate a GE MS7001A, B, C, E, or EA gas turbine, the technical meeting offering the most "bang for the buck" is the 2019 conference and exhibition conducted by the 7EA Users Group, November 3 – 7, at the Galt House Hotel in Louisville, Ky.

Register today and be among about 100 owner/operators willing to share their experiences—both successes and failures—with colleagues. Presentations and discussion sessions will provide 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.

If you're new to 7EAs, you won't feel out of place at this meeting. Roughly one-third of the attendees in any given year are first-timers. The reason, of course, is that user-group meetings are invaluable training forums.

And your involvement with the people you'll meet in Louisville, and others in the greater community of 7EA users, doesn't end with the last session. The organization's online forum, which is accessed via the website, helps users stay in touch and get answers to their questions between meetings.

This service, provided by Gregory Carvalho, Simplified Technology Co, and the steering committee (sidebar), was implemented in summer 2003. Over the years there have been, in round numbers, 20,000 postings. Registered 7EA users have access to this information resource at http://ge7ea.users-groups.com. You'll find presentations from the last decade there as well.

The 2019 conference agenda, posted on the user group's website, can help you organize your thoughts/questions ahead of the meeting. The program kicks off Monday morning (November 4) with Advanced Turbine Support's annual assessment of fleet findings by the company's inspection team. This is of particular value to first-timers requiring an engine orientation lesson (the photos are invaluable) as well as a primer on what to look for and where during inspections to assure reliable service from generating assets.

The remainder of the first day is dedicated to presentations by the OEM's engineers. By the end of the Monday program, the novice will be able to participate in discussions about the 7EA with confidence. More than a dozen technical presentations by industry experts, and discussion sessions, fill the final two days of the meeting.

Engine inspection. A review of Advanced Turbine Support's presentation last year is a good primer/refresher for every attendee. Several of President Rod Shidler's discussion points will be reiterated in Louisville given the size and average age of engines in the 7B-EA fleet. Better preparation will help you extract maximum value from the meeting.

The goal of every engine inspection, Shidler began, 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.

2019 Conference and Exhibition

November 3 – 7
The Galt House Hotel
Louisville, Ky
Details/registration at http://ge7ea.users-groups.com

Steering committee

Syed Mehdi Ali, *GM operations, K-Electric Ltd (Pakistan)*
Dale Anderson, *GT technician/foreman, East Kentucky Power Co-op Inc*
Tracy Dreymala, *facility manager, San Jacinto Peakers, EthosEnergy Group*
Ronald Eldred, *plant manager, Rosemary Power Station, Dominion Energy*
Guy LeBlanc, *supervisor, Consolidated GT Plants, First Energy Corp*
Tony Ostlund, *combustion turbine technician, Puget Sound Energy*
Doug Reves, *outage coordinator, Arkansas Electric Co-op Corp*
Randall Rieder, *mechanical engineer, ATCO Power (Canada)*
Mike Vonallmen, *maintenance supervisor, Clarksdale Public Utilities*
Lane Watson, *account engineer, FM Global*

Stay connected with colleagues year-round via the user forum at http://ge7ea.users-groups.com

What follows are the highlights of Shidler's presentation at the 2018 meeting, still current today:

- TIL 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.

- TIL 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.

While the TIL recommends visible or fluorescent dye, Advanced Turbine Support favors eddy current for these inspections using previous discoveries to support its opinion. Shidler said that if the stator vanes are coated, visible or fluorescent dye penetrant inspections may not be dependable, nor will they have an acceptable probability of detection. UT results also could be compromised if coating degradation, such as disbonding, occurs.

Shidler explained that if the stator vanes are coated, the company's eddy-current technique—featuring ultra-high sensitivity and very high resolution—has the ability to maintain sizing capabilities through coatings of up to 0.125 in. thick. He added that eddy current also is preferred when looking for crack initiation because it can detect problems sooner than ultrasonics.

- TIL 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.

Shidler cautioned that 1854 does not address first-stage rotor blade tips, does not recommend in-situ inspections, and suggests tip losses are considered low risk. He questioned the OEM's beliefs noting that Advanced Turbine Support has performed more than 1000 in-situ visible dye penetrant inspections, identifying over 64 cracked rotor blades and more than 40 tip liberations in the course of this work.

In this portion of the presentation, the inspection expert took time to "brag" a bit about his company's in-situ blending capabilities for both rotor blades and stator vanes and its ability to reach deep into the compressor to perform this work. Photos illustrated repairs to 11th-stage vanes and 12th-stage rotor blades.

- TIL 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.

- Distress in the 11th stage air-extraction section, including casing cracking and material liberation.

- TIL 1090-2R1 on compressor R17 platform and spacer movement was something else users should be mindful of.

- TIL 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.

Quail Run

Quail Run Energy Center

Owned by Quail Run Energy Partners LP

Operated by NAES Corp

550-MW, gas-fired, two 2 × 1 combined-cycle power blocks located in Odessa, Tex

Plant manager: Steve Reinhart

Investigative process addresses, helps correct generator thermal sensitivity

Challenge. Quail Run Energy Center consists of two 2 × 1 combined-cycle power blocks equipped with 7EA gas turbines, GE steam turbines, and Deltak/Vogt heat-recovery steam generators. The plant began commercial operation of Block 1 in 2007, Block 2 the following year. With a typical net capacity factor of less than 20%, Quail Run must be ready to start up whenever it is dispatched.

Over the years, gas turbine/generator No. 1 developed excessive vibration on the exciter end of the machine, sometimes exceeding alarm limits. Personnel were unable to definitively identify a root cause for the condition and an investigative process was initiated.

To mitigate the potential for trips and forced outages, Quail Run hired contractors to conduct vibration testing of Unit 1 to determine the cause of the vibration. Analysis revealed no correlation between vibration and speed and/or load, indicating the vibration was sensitive to another variable—most likely rotor temperature.

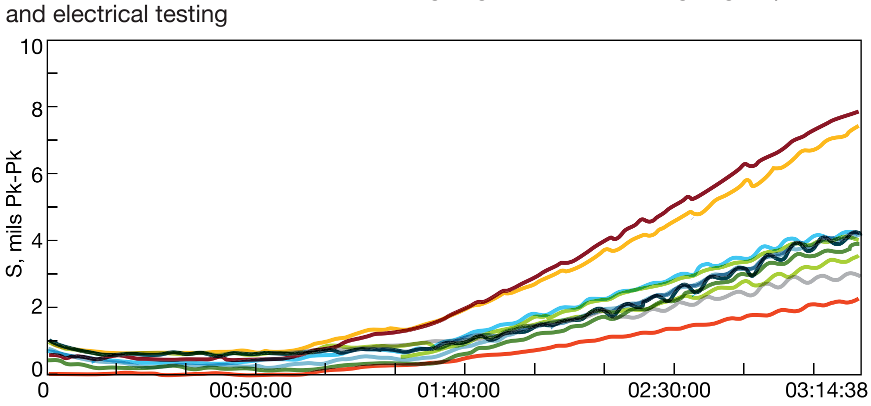
Solution. By following the plant's root cause analysis (RCA) processes, staff was able to eliminate the excessive vibration on the gas turbine/generator without use of balance weights, which may have caused other problems.

To resolve the vibration issue, plant management planned to inspect and repair the generator during the fall 2018 outage. This included removal of the rotor/field from the generator for inspection and repair, removal of the bearings for inspection and repair, and inspection and repair of the stator.

The rotor (a/k/a field) was sent to a repair facility, where the steps below were taken to determine if the rotor was thermally sensitive, then to attempt to find the cause of the thermal sensitivity, and finally to find a solution to the sensitivity issue:

1. Generator field in the shop, retaining rings removed, undergoing inspection and electrical testing

2. Some turn-insulation migration was in evidence



3. Initial testing revealed thermal sensitivity

Step 1. At the shop, a visual inspection and electrical testing of the rotor were conducted, along with NDE of the retaining rings (Fig 1). Once the retaining rings were off the rotor, the shop found some turn-insulation migration (Fig 2). There were about 10 turns where the slot turn insulation had worked its way out. A patch of insulation was added with an air-dry epoxy. This was not believed to have been a major factor in the vibration issue.

Step 2. With no initial finding

for the cause of the vibration, Quail Run management decided to perform a balance and thermal sensitivity test on the rotor in a high-speed balance pit. This included the following:
- Perform dial-indicator runouts and slow-roll TIRs (total indicator runout) of journals, TE coupling, retaining rings, and collectors.
- Perform a rough balance.
- Perform flux probe run.
- Perform overspeed run.
- Perform flux probe after overspeed.
- Balance for thermal run.
- Perform thermal run.
- Perform flux probe after thermal run.

The test results (table) indicated that there was thermal sensitivity with just under 8 mils deflection (Fig 3).

Step 3. With confirmation that the rotor was indeed thermally sensitive, plant leadership decided to rewind the field. This required removing the coils (Fig 4), wedges, blocks, sand blasting the forging, and reassembly.

Step 4. After completion of the rewind (Fig 5) another balance and thermal sensitivity test were performed (Fig 6), finding thermal sensitivity was no longer an issue. Maximum thermal deflection was just over 1.3 mils. Electrical testing of the rotor was performed with no issues noted (Fig 7).

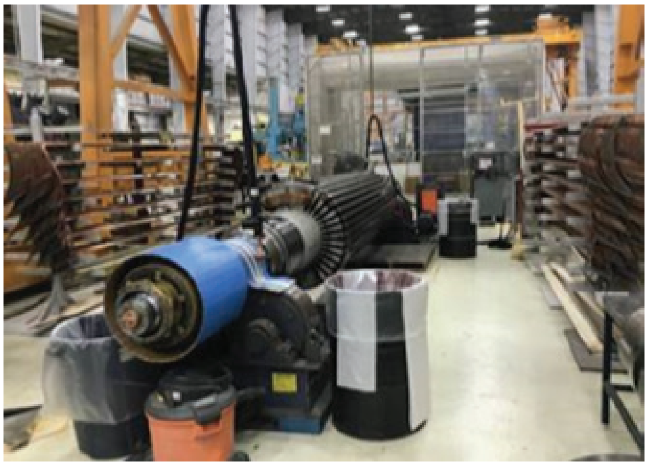
After completion of the inspections, testing, and rewind, the rotor was returned to the plant and installed in the generator (Fig 8). Vibration was monitored on restart to ensure performance had returned to design specifications. This was confirmed.

The generator tilting-pad bearings were inspected and repaired by a local bearing shop to ensure they were not a cause of the vibration. Nothing was found to suggest they were.

Results of vibration testing on the Quail Run Unit 1 generator

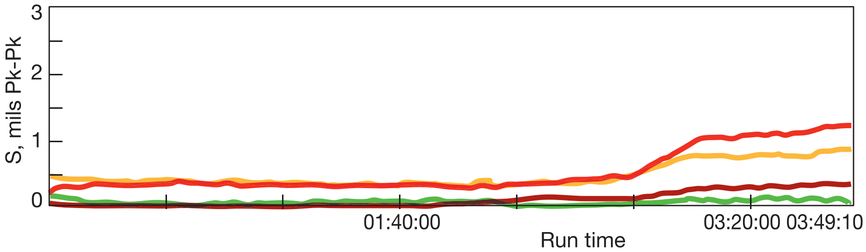
Location		Direction	Overall vibration amplitude*	Maximum vibration component*	Guideline
Generator outboard bearing housing		Axial Vertical Horizontal	0.41 ips Pk 0.56 ips Pk 0.35 ips Pk	0.38 ips Pk at 1× 0.54 ips Pk at 1× 0.31 ips Pk at 1×	Overall 0.3 ips Pk
Generator bearing housing	Inboard No. 4	X Y	N/A N/A		
	Outboard No. 5	X Y	2.86 mils Pk-Pk 1.17 mils Pk-Pk		
Generator shaft probes	Inboard No. 4	X Y	1.16 mils Pk-Pk 1.00 mils Pk-Pk	0.83 mils Pk-Pk at 1× 0.59 mils Pk-Pk at 1×	Overall 2.0 mils Pk-Pk
	Outboard No. 5	X Y	2.35 mils Pk-Pk 2.51 mils Pk-Pk	2.23 mils Pk-Pk at 1× 2.43 mils Pk-Pk at 1x	
Generator shaft (absolute)	Inboard No. 4	X Y	N/A N/A		N/A
	Outboard No. 5	X Y	5.09 mils Pk-Pk 2.95 mils Pk-Pk		
Exciter housing		Axial Vertical Horizontal	2.25 ips Pk 2.30 ips Pk 4.72 ips Pk	2.18 ips Pk 2.20 ips Pk 4.71 ips Pk	Overall 0.3 ips Pk

*Values in red exceed guideline



4. Coil removal is in process

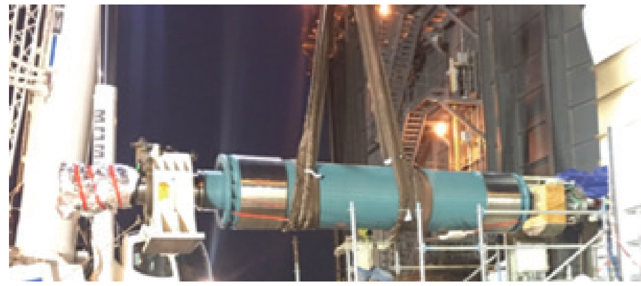
5. Field being reassembled



6. Final thermal-sensitivity test results show much improvement over those in Fig 3

While the rotor was out of the generator, the stator was inspected and tested—including the following:
- Initial electrical tests conducted.
- New wedges installed.
- Wedge map completed.
- Final electrical tests conducted.

Results. By using an investigative process, Quail Run personnel were able



7. Electrical testing complete field is ready for shipment back to the plant (left)

8. Last step: Rotor is reinstalled in the generator (above)

to address the thermal sensitivity of the Unit 1 generator rotor. The steps taken were the following:

- Removed rotor and sent it to a repair shop for inspection and repairs.
- Conducted a balance and sensitivity test to determine if the magnitude of the thermal sensitivity.
- Rewound the rotor.
- Conducted a final balance and thermal sensitivity test to assure the sensitivity issue was addressed.
- Installed the rotor in the generator.
- Completed in-situ testing of the generator with a cold start, hot start, and a test run with hot shutdown.

Bottom line: The generator is now able to operate within its proper design parameters.

Project participants:
Steve Reinhart, Pablo Chaves, and Chris Bailey.

Lightweight manhole covers boost productivity, enhance safety

Mulberry Cogeneration
Owned by Northern Star Generation
Operated by CAMS
115-MW, dual-fuel, 1 × 1 combined-cycle cogeneration facility located in Bartow, Fla
Plant manager: Allen Czerkiewicz

Challenge. Mulberry Cogeneration, a 7EA-powered combined cycle, exports power to the local utility and sells steam to nearby facilities for process use.

Operators were required to open manholes in the water treatment area with covers that were very large and weighed around 250 pounds. This practice raised a safety concern as there was no easy way to maneuver the covers. To open a manhole, it would take several employees and crowbars and there was a risk of injury to hands and backs (Fig 1).

The Mulberry team was tasked with finding a better way to remove the heavy covers safely with one operator and with no risk of injury from the cover itself.

Solution. Plant staff looked at several possible solutions. A manhole cover-lifter was purchased but it did not work for Mulberry, requiring participation by several employees in its operation and the possibility of hand injuries.

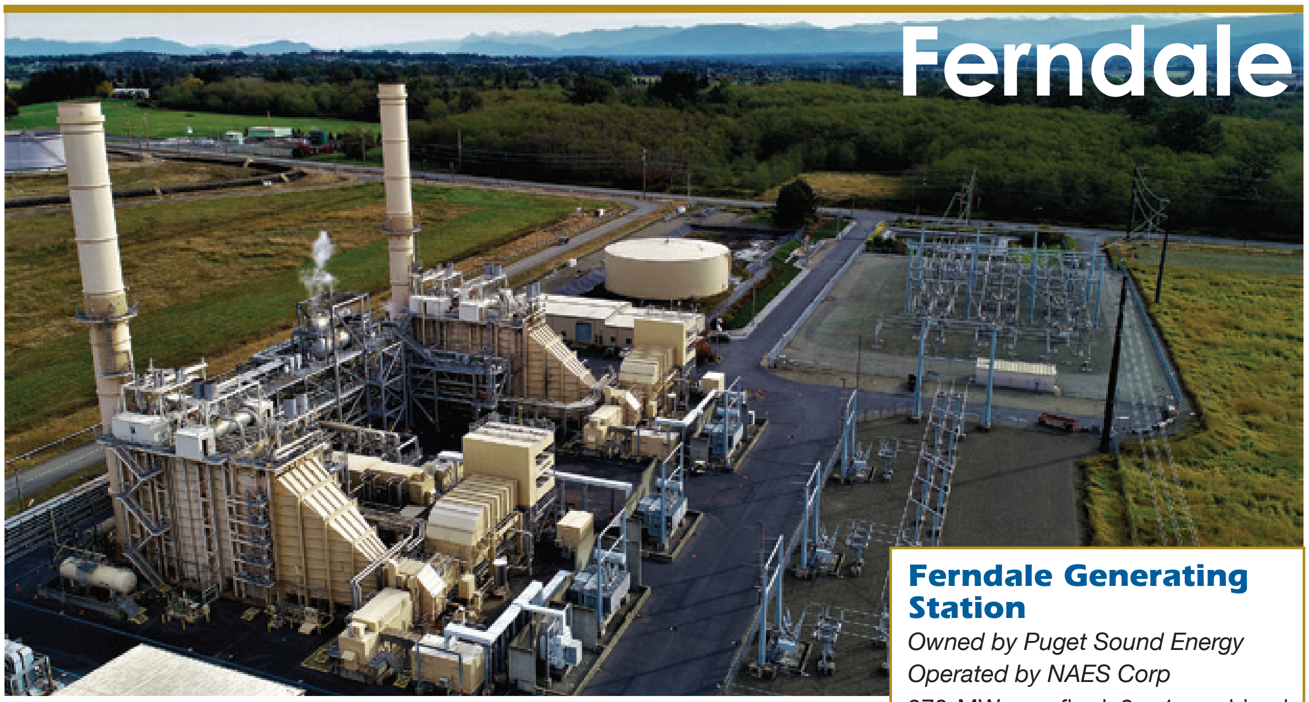
Mulberry settled on the fabrication and installation of aluminum covers, light enough to be handled by one person and rated to support a personnel load (Fig 2). Because they are not yet rated for vehicle loads, covers have not been replaced in areas with vehicular traffic.

Results. The new lightweight aluminum covers are working well. Personnel can now remove them safely with no risk of a hand or back injury from heavy lifting. The secondary benefit from this upgrade is that it greatly reduces the time that personnel spend opening the covers now that they are not heavy and awkward. Covers can now be removed safely by one employee rather than requiring two or three.

Project participants:
Trent Poitevint, operator
Allen Czerkiewicz, plant manager
Kristen Albritton, EHS manager
Jason Wolfe, operations manager

1. Traditional manhole covers required several employees to lift, with a threat of hand and back injury

2. Aluminum covers can be removed by one person safely



Ferndale Generating Station

Owned by Puget Sound Energy
Operated by NAES Corp
270-MW, gas-fired, 2 × 1 combined-cycle cogen plant located in Ferndale, Wash
Plant manager: Tim Miller

Turbine-compartment roof handrails promote safety

Challenge. According to the National Safety Council, slips, trips, and falls are among the most common and costly workplace incidents across all industries. They account for 35% of incidents, 36% of emergency room visits, and 65% of lost workdays. Additionally, and more staggering, OSHA says slips, trips, and falls account for 15% of all accidental deaths, second only to automobile fatalities.

When it comes to falls in the workplace, OSHA's focused efforts help prevent disabilities and deaths. Disabilities often come with many large expenditures. It is estimated that more than $61 billion is spent annually on disability claims in America with $15.57 billion (25.1%) resulting from falls. Interestingly, two-thirds of the falls are to the same level, one-third to a lower level. Also noteworthy, slips and trips without falls cost $2.35 billion (3.8%).

Adding to this cost is that an employee suffering from a slip, trip, or fall incident misses an average of 38 workdays, costing millions of dollars to organizations in lost productivity while also driving up insurance costs.

OSHA and plant safety procedures require a fall arrest system be used when working on something other than a walking/working surface where there is a potential fall hazard of greater than 4 ft.

Ferndale Generating Station's combined cycle, powered by two 7EA gas turbines, is capable of sending process steam to a neighboring refinery. Each gas turbine's compartment roof, approximately 12 ft from ground elevation, is accessed frequently to maintain equipment.

Without handrails in place, fall protection harnesses and lanyards would be required.

Tie-off points for the lanyards are limited, given plant configuration and type of equipment. Plus, once lanyards are attached to appropriate anchorage points, new hazards are introduced—including tripping on the lanyard and limited accessibility.

Handrails and toe boards on the turbine-compartment roof eliminates the need for potentially problematic fall protection harnesses and lanyards

Solution. Plant staff performed a root cause analysis using "Think Reliability's Cause Mapping Tool" in a "What if?" approach to determine potential hazards and possible solutions to eliminate or reduce the identified hazards.

Several corrective actions were recommended, but not selected—including the following: installing an overhead cable as an anchoring point, using a man lift for inspection, and installing railing on top of turbine-compartment vent fans.

The plant safety committee chose to implement the following corrective actions: Restrict the use of self-retracting lanyards to overhead connections only and add handrails on the turbine-compartment roof.

Results. Working with a third-party engineering and fabrication company, a railing system was designed and installed on the roof, eliminating the need for fall protection while working aloft. A system was installed with adequate handrails and toe boards to meet the regulated requirements. The total cost was approximately $8000 per gas turbine. In 2018, several maintenance tasks were completed without incident or need to use fall protection equipment to ensure safety.

Project participants:
Terry Grumbles, maintenance manager/safety director
Jim Stevens, mechanic
Joel Underwood, purchaser
Plant Safety Committee

Alstom Owners Group

Powerplant work can be lonely, particularly when you work at a combined-cycle plant where the total headcount might only be a couple of dozen folks, even for a 2 × 1 advanced-class unit. "Thin" staffing takes on a new meaning these days, especially when only a few employees have a decade or more of relevant gas-turbine experience. Include the staff's level of knowledge on steam turbines, HRSGs, and generators and a plant manager could have nightmares.

When questions arise, whom do you call? If the owner is a relatively small IPP with, say, fewer than a dozen engines, there's probably no support staff. Logically, the OEM should be able to help. But what if you have an Alstom engine? The original manufacturer is gone, along with many of the engineers with deep knowledge of the machine.

This scenario is what led to the formation of the Alstom Owners Group (AOG). It's a self-help organization that brings plant O&M personnel together with third-party service providers to share engine knowledge and develop the solutions necessary to maintain the high levels of reliability and availability required to keep generating plants competitive in today's cutthroat power market.

If your facility has Alstom rotating equipment, consider attending the AOG's third annual meeting, January 27-31, in Houston. This article provides information that can help you make an informed decision. The main text highlights some of the material disseminated by users and vendors at the 2019 meeting last February, the sidebars provide information on the 2020 conference—including venue and steering committee (Sidebar 1), AOG organization (2), training workshops (3), and featured presentations (4).

User presentations

The most important aspect of any user-group meeting is the sharing of information among owner/operators without the presence of suppliers. At the 2019 conference, users convened for the last few hours of Day One to discuss issues, experiences, and concerns pertinent to the Alstom fleet. More than 50 owner/operators participated, about half of whom did not attend the first meeting in 2018.

User viewpoints—an open forum. What follows are some of the frustrations vented, experiences and best practices shared, and user wants and needs.

1. 2020 Conference

January 27 – 31
Magnolia Hotel Houston
1100 Texas Ave
Houston, Tex 77002

Details/registration at https://aogusers.com

Conference organized by
Jeff Chapin, jchapin@aogusers.com

Steering committee

Brian Vokal, *Midland Cogeneration Venture*
Chris Hutson, *Georgia Power*
Robert Bell, *Tenaska Berkshire Power*
Pierre Ansmann, *Arnold Group*
Jeff Chapin, *Liburdi Turbine Services*

2. Alstom turbine owner/operators: Welcome to the AOG

If you're an owner/operator of Alstom-manufactured steam and gas turbine/generators—or a provider of products and/or services for that equipment—and are not familiar with the Alstom Owners Group, please read on.

AOG, as the industry's newest user group is known, will host its third annual conference Jan 27 – 31, 2020 at the Magnolia Hotel in Houston, Tex. The vacuum created by sale of Alstom to GE has left many owner/operators scrambling for parts and service. This is an excellent opportunity for you to gauge the impact of the industry shakeout on your supply chain and share experiences with Alstom turbine owners from all over the world.

Register now for the conference at https://aogusers.com. The fee is a very affordable $300 to glimpse the changes important to your plant's profitability first-hand.

Here are some important things for you to know:

- AOG is managed and supported by owners of Alstom equipment for owners of Alstom equipment.
- User-to-vendor ratio for the first two meetings was better than 3:1.
- Innovative format allows multiple days to discuss your plant problems/solutions with colleagues and to meet with suppliers of interest in a relaxed setting.
- Includes limited participation by the OEM and a select group of highly respected third-party parts and services providers.
- An owners-only open forum, allowing users to discuss confidential topics in private.
- The previous bullet point aside, AOG is a truly transparent event where solutions providers are welcome to attend all presentations and training sessions, and to participate in the conference tour of Doosan Turbomachinery Services shop facilities.
- Multiple training sessions/workshops are included in the conference registration fee (see pages 93 and 95).

The Pioneer Index

1.5 Lowest operating speed in rpms of any thrust bearing designed and manufactured by Pioneer (supporting thrust loads up to 2,000,000 lbs.)

1 Number of companies in North America, holding a license to use ABB and Alstom bearing IP (drawings and specs) to provide service and repairs direct to end-users.

26 Number of years Pioneer has manufactured and serviced ABB and Alstom gas and steam turbine-generator fluid film bearings for ABB, Alstom Power, and end-users.

30 Number of years Pioneer has been the exclusive licensee of bearing IP of Westinghouse and Siemens to provide service and repairs direct to end-users.

99 Number of years Pioneer has manufactured and repaired fluid film bearings.

5 Number of companies that have granted Pioneer exclusive bearing IP licenses (Siemens; GE—for Alstom IP; Michell Bearings; Zollern; and Yamato Metal).

4 Number of generations of the same family that has owned and managed Pioneer since its founding in 1920.

www.pioneer1.com E-Mail: sales@pioneer1.com engineering@pioneer1.com
Engineering, Sales & Manufacturing 129 Battleground Rd., Kings Mountain, NC 28086, USA Tel (704) 937-7000, Fax (704) 937-9429, 1-888-813-9001

The session got rolling with attendees expressing dissatisfaction with the way GE manages drawings and documentation. Examples given included long lead times, quoting delays, notifications not applicable to site, etc.

A major concern noted was that the loss in technical knowledge of Alstom engines has been incredibly deep. So much so that an attendee said his company was going in the direction of "What can we get reverse engineered?" Another user asked, "How is GE managing the supply chain?"

Burners for supplementary-fired HRSGs were introduced into the discussion. Recall that Alstom was one of the major suppliers of heat-recovery steam generators for combined-cycle systems before its demise. The participant said one of his plant's burners revealed a great deal of distortion during a gas-side inspection of the unit. Plant had an extra burner and sent it to Liburdi, which fabricated a new one and had it back to the site in four days. That solution surprised many in the room.

Controls strategy received some interest. "Do you stick with ABB or go with a third-party alternative?" A recommendation made was to pull all PLCs into the control system so if a control-system upgrade is necessary five or six years down the road, it will be easier. One user touted Emerson's success in plants with Alstom equipment. Specifically, he said, Ovation was installed on eight GT11NM engines at his facility.

A question from the podium to the group: "What issues/equipment would you like to understand better?" Most responses were general in nature, including the following: variable inlet guide vanes, exhaust cracking, inner liners, burners, gas detection, generator inspections, fire suppression, retrofitting of solenoids, parts trading. . . . The list certainly gave members of the steering committee ideas for presentations at upcoming meetings.

No matter what user-group meeting you attend, varnish issues likely will be factored into the discussion. At AOG 2019, lint-free rags were suggested for cleaning of lube-oil tanks, recommendations included taking oil samples monthly and stroking valves weekly. Users voiced their opinions on which varnish-removal system they thought most effective.

Other topics introduced and discussed to varying degrees included the following:

- What to do about a CO catalyst at risk of mechanical failure?
- ABB breakers and starters. How do you retrofit a 480-V generator breaker because of obsolescence?

3. Training workshops differentiate AOG from other user-group meetings

There's pent up demand for engine-specific knowledge among Alstom gas-turbine (and steam turbine) owner/operators given the OEM's flagging efforts in customer training as its commercial activities wound down before the sale to GE, and in the months that followed the transfer in ownership. Both users and vendors recognized this and collaborated to develop a conference agenda to meet the unique needs of the AOG community.

Integrated into a fast-moving program of nominal half-hour supplier and user presentations, and closed discussion sessions for owners, are no fewer than five training sessions—each at least four hours in length. There are no special charges for attending the workshops. All, plus a tour of Doosan's La Porte shop to witness repair processes first-hand, are included in the $300 conference fee. Register today at https://aogusers.com.

Here's the lineup of training sessions, current as of October 1. Check for periodic updates on the organization's website.

Introduction to Gas Turbine Controls, Emerson Automation Solutions, *Monday, January 27, 1 to 5 pm.*

Designed for operators, engineers, and managers wanting to learn more about control theory and how it applies to gas turbines. Presentation includes an overview of the universal principles of governor and auxiliary control for GTs with a focus on control components and logic for an Alstom GT11N.

Field Rewind of an Alstom Generator, Mechanical Dynamics & Analysis (MD&A), *Monday, January 27, 1 to 5 pm.*

This case study profiles the field rewind of an Alstom 60WY/WX23Z-109 air-cooled generator. It covers both the cracking of slot armor experienced in many of these units and pole-to-pole connector cracking.

Bearing Fundamentals, Pioneer Motor Bearing Co, *Thursday, January 30, 1 to 5 pm.*

Content is outlined in the sidebar on p 95.

P13/P14 Blueline Training, Hughes Technical Services, *Monday, January 27, 1 to 5 pm and Thursday, January 30, 1 to 5 pm.*

An abstract of the content will be posted at https://aogusers.com when available.

Basic GT Metallurgy, Repair Technology, and Condition Assessment, Liburdi Turbine Services, *Friday, January 31, 8 am to 5 pm*

Content is outlined in the sidebar on p 93.

- LCI issues came next. Lightning damaged P800 and P800-5 parts which are proving difficult to find. Without them, you can't put the unit back in service. Suggestions?
- What are the advantages of upgrading EHC controllers for gas valves?
- Can you rebuild NO_x water pumps?
- How do you avoid issues with your fuel-oil system—fuel transfer, etc?
- What upgrades to you suggest for generator circuit breakers?
- Acoustic monitoring for PD: Is it effective?
- Units tripping on high vibration. What to do?
- What's the group's experience with third-party suppliers?

Best practices for managing employee attrition. Presentation was made by the plant manager of a very large cogeneration project, one with 12 gas turbines and HRSGs and one repowered steam turbine from a retired nuclear project. Staff totals 121 O&M and administrative personnel.

By way of background, the facility experienced very low turnover until 2013 when the average age was 50 and plant tenure averaged 20 years. In 2013 there was 35% attrition. Fast forward to 2019, 40% of the staff has fewer than six years of experience.

Lessons were learned, the speaker said. He suggested the following:

- Identify people who will retire.
- Analyze job responsibilities for all positions.
- Develop a recruiting plan.
- Create a plan for knowledge transfer.
- Develop an in-house training program.
- Manage employee retention.

Optimization of major maintenance through better planning and execution. With oil prices falling, the speaker's company was seeking avenues for cost savings. This user's experience is that major maintenance accounts for half of a plant's O&M expenditures and half of that goes for parts refurbishment. Here's what he suggested to drive down costs:

- Evaluate purchase versus refurbishing of major capital parts, taking into consideration parts-life extension and outage-interval

Liburdi workshop focuses on gas-turbine metallurgy and repair technology

Doug Nagy of Liburdi Turbine Services conducted an eight-hour seminar at the 2019 AOG Users Conference on gas-turbine metallurgy and repair technology for two-dozen attendees—including end users, GT subject-matter experts, and PhD candidates from North Carolina State University. Participants were asked to submit questions in advance regarding specific repair issues faced at their job sites to enhance the value of the session.

This non-commercial training course explained superalloy metallurgy as it applies to gas-turbine components, focusing on component damage experienced from GT service exposure as well as the techniques used to determine the remaining lives of critical hot parts. Protective coatings, advancements in component repair technologies, and repair quality-assurance techniques were included in the syllabus.

Plus, attendees were exposed to several case-study examples and got to participate in an interactive wrap-up session where they developed real-world repair solutions.

This course will be conducted again in 2020. But seating is limited so be sure to register early. You can do that now at https://aogusers.com. The best part is that the seminar is included in the conference registration fee of only $300. Participants will receive an attendance certificate and be eligible to earn eight Professional Development Hours.

Nagy, who has decades of experience in the repair of gas-turbine components, said he designed this course for professionals involved with the technology or business of gas turbines in the oil and gas and power-generation industries—in particular, those with the following responsibilities:

- Plant, engineering, asset, technical, maintenance, and/or operations manager.
- Plant, mechanical, production, and/or reliability engineer.

Course outline for 2020 Liburdi workshop

- Introduction: Why repair and refurbish parts?
- Nomenclature: A review of typical GT components and the respective environments they withstand.
- Materials and metallurgy: GT materials and their properties.
- Coatings typically used in gas turbines—such as anti-corrosion, wear surface, and thermal barrier.
- Degradation characteristics of GT components—including creep, low-cycle fatigue, etc, and their effects on GT components.
- Evaluation of used compoents and how to determine the appropriate repair/refurbishment process.
- Refurbishment and repair processes: Procedures and techniques used to restore components to industry standards.
- Quality assurance: Methods and procedures to verify components meet industry standards.
- Vendor selection and verification.
- Case studies and problem-solving: Case studies presented by the instructors to illustrate the process of component repair and refurbishment. The class then will be divided into teams and given components for which they will determine the best repair/refurbishment process.
- Roundtable discussion regarding the latest repair trends and participant questions.

4. Featured presentations

Vetting by the steering committee of presentations recommended by users and vendors for AOG 2020 is a work in progress and likely will continue into December. Below are abstracts of some presentations already accepted for the conference. Program updates will be posted online at https://aogusers.com.

Tuesday keynote

Jeff Henry, president, ATC-CES Inc, one of the world's leading authorities on advanced alloys for high-temperature/high-pressure steam service, will update the group on Grade 91 experience in nuclear and fossil plants. Henry, who spent more than 30 years with Alstom Power, focuses his professional time today on the behavior of materials at high temperature and failure analysis. He also supports critical manufacturing activities for the production of steam generating equipment.

Wednesday keynote

EPRI's Robert Steele and Leonard Angello, well known to US generation professionals, will present the research organization's GT26 overhaul plan, much of which is applicable to the GT24. It is designed to help owner/operators plan, manage, and document major overhauls, and incorporates custom-built databases with details on the numerous maintenance tasks necessary to complete a gas-turbine major.

Presentations by users

GT11N Maintenance and Inspection, Chris Hutson, Georgia Power.

Presentation will examine maintenance strategies, A, B, and C inspections and parts requirements for each, issues related to both peaking and baseload operation, experience with the OEM on FSI and CIB conversion to TILs, and development of a GT parts list and spreadsheet.

Maintenance Decision-making, Jim Murray, CAMS Orlando Cogen.

It's a new world. Case history describes how this user makes maintenance decisions using a wireless remote condition monitoring system.

Benchmarking, Steering Committee.

The AOG is investigating the launch of a group-wide effort to benchmark Alstom units against their respective fleets. Discussion will focus on a preliminary plan for that activity and get feedback from the user community.

Presentations by first-time vendors

Inspection Best Practices and Findings for Alstom Gas and Steam Turbines, Advanced Turbine Support

Improved Air Inlet System for the GT24, Camfil.

Case study of a retrofit project to improve the performance of the existing inlet system on six GT24s. Goals were to reduce the frequency of compressor washes and improve engine performance. Four years of operating data will be reviewed. The bottom line: Company's mobile laboratory identified a filter design that improved the collection efficiency of sub-micron particles from about 30% to 98%, thereby greatly reducing the number of wash cycles.

Demystifying Varnish, Axel Wegner, C C Jensen Oil Maintenance.

Presentation will provide a comprehensive update on varnish, including: troubleshooting the problem, methods of varnish removal, oil analysis, and improved-performance validation of the benefits of varnish removal.

Combatting High Ammonia Consumption and Slip in GT24s and Other Alstom Units, Groome Industrial Service Group.

A user's guide on how to deal with legacy HRSGs and their ageing catalyst systems. High slip and ammonia consumption are common problems. The benefits of catalyst replacement for ammonia efficiency gains will be discussed.

Tooling and Fixtures for Repair/Replacement of GT11 Stationary HGP Components, Major Tool and Machine.

This is a company capabilities presentation of value to users not having any knowledge of MTM, which has been supplying parts for gas turbines made by Brown Boveri & Cie, ABB, and Alstom since the late 1970s. Experience extends from the GT8 to the GT36.

NEC's Solution to Endwinding Issues in Alstom WX and WY Generators, Howard Moudy, National Electric Coil.

Manufacturing, Repair, and Overhaul Solutions for Alstom Gas and Steam Turbines, Sulzer Rotating Equipment Services.

Other first-time vendors that will be participating in AOG 2020 include Corzan Industrial Services, Ethos Energy Group, Nord-Lock Group, Hughes Technical Services, and MD&A. The last two will be conducting training workshops (refer to Sidebar 3).

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extension. If you don't have a parts tracking database, get one.

- Review and update your repair quality-management process, including repair standards, scope customization, and cost and quality validation.
- Requalify repair facilities—especially regarding experience level and engineering processes. Turnover can adversely impact repair quality as can shortcuts that may have crept into procedures to reduce costs.

Vendor presentations

A dozen companies that participated in AOG 2019 already have signed up for the 2020 meeting—including AGT Services, Ansaldo Energia/PSM, Arnold Group, Doosan Turbomachinery Services, Emerson Automation Solutions, GE, Inpirio International, Liburdi Turbine Services, Pioneer Motor Bearing, Power Services Group, and Stork Turbo Blading.

Vendor first-timers in 2020 are identified in Sidebar 4.

The following presentations made by the vendor community in 2019 were well received by the users and are summarized in the online version of this report available at www.ccj-online.com.

Generator Inspections and Robotic Capabilities, Jamie Clark, AGT Services.

Ansaldo Energia's Service Organization and Product Portfolio, Leone Tessarini, Ansaldo Energia.

Advanced Insulation for all Alstom Gas and Steam Turbines, ARNOLD Group.

11N Rotor Assessment and Overhaul, Alex Ford and Glenn Turner, Doosan Turbomachinery Services.

Emerson Gas Turbine Controls, Emerson Automation Solutions.

Power Services, GE.

Delivering Value Through Proven Cost Savings with Technology-Driven Life Extensions of HGP Parts, Liburdi Turbine Services Inc.

Capabilities and Experience, Power Services Group.

Reverse Engineering of Bolting, Blades, Valve Parts, Pump Casings, Turbine Wheels, Rotors, and Casings, STORK, a Fluor company.

Learn the basics of fluid-film bearings from the experts

Pioneer Motor Bearing Co conducted a four-hour training session at the 2019 AOG Users Conference on fluid-film radial and thrust bearings, these oft-forgotten components being critical to reliable turbine operation. Note that authorized repairs of bearings in Alstom equipment are available from GE for both gas and steam turbines and from Pioneer Motor Bearing for steam turbines. Also, that Pioneer is the exclusive US licensee of Alstom intellectual property for the servicing and repair of steam-turbine bearings.

The workshop opened with a backgrounder on the theory and operation of fluid-film bearings—including important material and lubricant properties. Photos of damaged bearings were an eye-opener for many users in attendance, most of whom had never received formal training on bearings from the now-defunct OEM.

The session, led by Dr Lyle Branagan, Pioneer's engineering manager, got a "two thumbs up" from participants and will be conducted again in 2020. But seating is limited, as it is for the gas-turbine metallurgy and repair workshop described on p 93, so be sure to register early. You can do that now at https://aogusers.com. Participation in the bearing seminar is included in the $300 conference registration fee.

Branagan stressed the importance of a careful visual examination of bearings after their removal from a machine because of the opportunity it affords the owner/operator to identify any of several potential conditions of distress. Because the babbitt (white-metal) lining of a bearing is deliberately a renewable, sacrificial layer, refurbishment often is possible to restore the bearing for long-term operation.

Such refurbishment generally is cost-effective even for simple bearings with bore sizes above about 12 in. Of course, if a spare or new bearing from the OEM is not readily available on a timely basis, repair and refurbishment becomes a necessity no matter what the size.

The international group attending the 2019 presentation asked for specific guidance in order to make better decisions regarding whether to continue to operate a variety of Alstom gas and steam turbine/generator bearings or to have them refurbished. Branagan provided rules-of-thumb and guidelines with photographic examples to help in making these "run/repair" determinations.

Moreover, he walked attendees through the specific steps, illustrated during his talk, of babbitt casting and bearing refurbishment. Several participants expressed interest in attending Pioneer's more detailed course on these topics, available as a three-day, in-house workshop.

A post-training survey revealed that Pioneer's position as the licensee of Alstom, and now of GE, for the repair of Alstom steam-turbine bearings in the US was not widely known.

Pioneer
MOTOR BEARING

ORLANDO COGEN

Condition monitoring system facilitates maintenance decision-making

Challenge. Determine if a wireless condition monitoring system (CMS) could help this 25-year-old plant affordably improve efficiency and/or operational effectiveness through better planning of O&M activities.

Solution. Plant personnel evaluated a few competing systems before deciding on the purchase of four wireless vibration and temperature sensors and a cellular gateway device from ProAxion Inc to vet CMS technology on pumps and motors installed in 1993.

After successfully completing the first phase of the trial to test ease of installation and set-up, Orlando CoGen purchased eight additional sensors for its four-cell wet cooling tower in April 2017. Each cell has a 100-hp motor with an extended shaft connecting to a right-angle gearbox which drives the fan.

The plant's cooling-tower maintenance outage, scheduled for December 2017, included replacement of one motor/gearbox set based on operational hours. But the CMS indicated that the equipment looked in good health based on temperature and vibration data collected.

However, a motor not scheduled for replacement was in an alarm condition before the outage and the CMS indicated it was likely near end-of-life given vibration patterns associated with bearing failure. This information guided staff to replace the motor in alarm instead of the motor/gearbox targeted for replacement.

The result was a double benefit:
- The expense of replacing an otherwise healthy motor and gearbox was avoided.
- The potential threat of an unexpected failure causing a reduced-capacity event was eliminated by removing the motor nearing end-of-life.

After this success, the plant purchased four additional sensors for its steam-turbine vacuum system, bringing the total to 16 vibration and temperature sensors that are monitored 24/365. Importantly, if a sensor goes into alarm, the CMS automatically sends email and text alerts to inform plant staff.

Orlando CoGen management considers its CMS trial an unqualified success. Installation, setup, use, and understanding of the system was straightforward and easy, and the results have provided a positive cost/benefit.

Project participants:
James T Murray, plant manager
Tim Smith

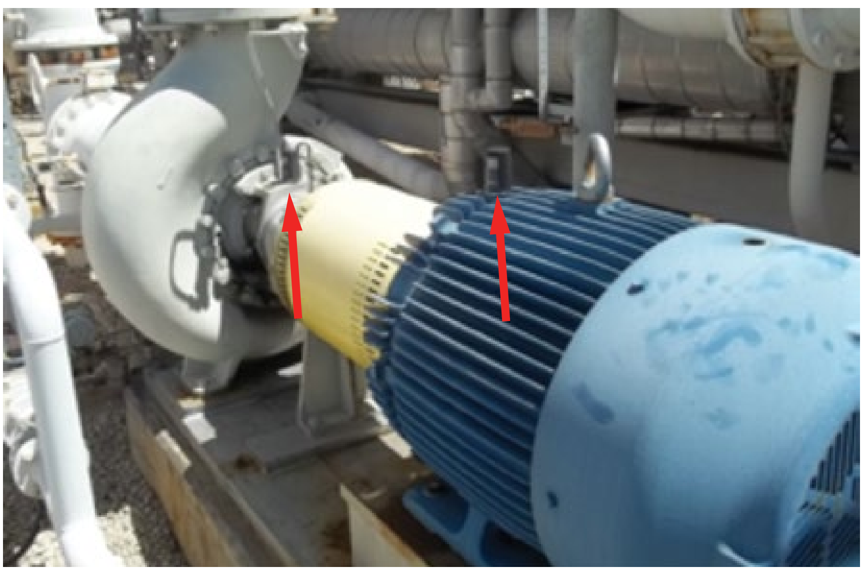
Orlando CoGen Ltd

Owned by Northern Star Generation Services and Atlantic Power

Operated by Consolidated Asset Management Services

119 MW, gas-fired, 1 × 1 combined-cycle cogeneration plant equipped with a GT11NMC Alstom gas turbine and Siemens VAX steam turbine located in Orlando, Fla

Plant manager: James T Murray



Sensors installed on the pump and its motor driver monitor vibration and temperature around the clock

Chihuahua

How to reduce the time to analyze operating data—and do it remotely

Challenge. Monitoring and diagnostic tools typically allow plant personnel to visualize trends and store historical data for future analysis. Most also provide the capability to create notifications by email, alarms, and perform comparative calculations of current versus expected performance.

However, some tools are not conducive to real-time analysis of a variable because of the time it takes to identify the TAG name of the instrument and to extract its data for subsequent graphing, filtering, and analysis. In some cases, such as when several variables are involved, the process of data acquisition and analysis can consume valuable time—time you may not have when a potential trip situation exists.

Solution. With the objective of reducing the analysis times of variables involved in the power generation process, staff used PI ProcessBook to reproduce each of the control-system screens (Fig 1), enabling personnel to access them on demand and view at any time the current value of each variable, plot its trend, and confirm equipment status (on/off).

This allowed Chihuahua team members to monitor the behavior of each system in the plant remotely as if they were in the control room. Plus, during an unexpected event, the origin of the cycle imbalance can be analyzed simultaneously with different scenarios, shortening the detection time of the fault.

Added benefit: This monitoring tool allows new employees to educate themselves on the navigation among the different control-system screens, thereby achieving operational confidence without committing an error that could affect plant operation.

The utility of PI ProcessBook screens was enhanced with additional information—such as the protection matrix and the identification of critical instruments. Additionally, shortcut buttons were included to link information related to equipment—such as manuals, fault reports, data plates, P&IDs, and photos.

Results. Before the enhanced PI ProcessBook screens were available, each time technicians were assigned a maintenance task on a critical piece of equipment they had to go to the control room and ask the operator about the recent behavior of equipment associated with the work order. This could create anxious moments if the operator was unavailable to provide the assistance needed in a timely manner.

Today, with the required information available remotely, well-trained O&M personnel can access it on their own, without delay. Thus, any negative impact on plant operations likely can be avoided. The proof: This Best Practice contributed significantly to plant reliability—including a run of 232 consecutive days without an event affecting generation dispatch and an annual percentage of unavailability of 0.18%.

Project participant:
Juan Diego Delgado Aragón

Energía Chihuahua III

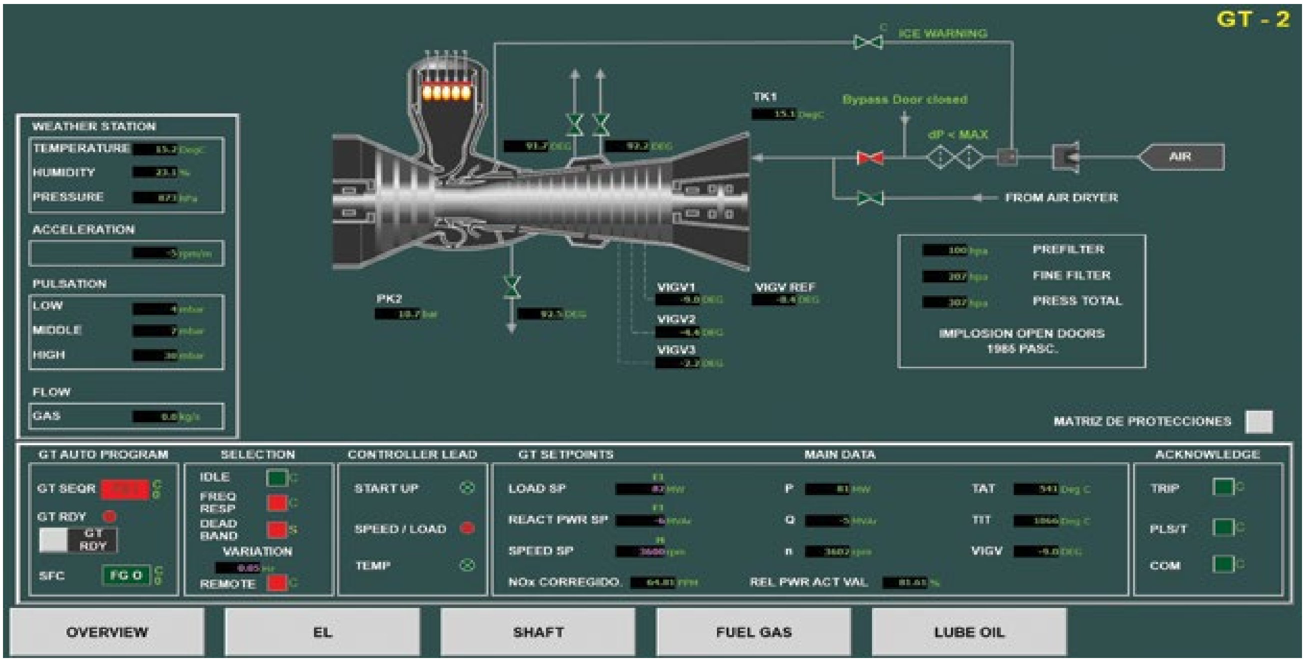
Saavi Energía

278-MW, 2 × 1 combined cycle with Alstom GT11N2 gas turbines, Cerrey HRSGs, and Siemens steam turbine located in Chihuahua, Mexico

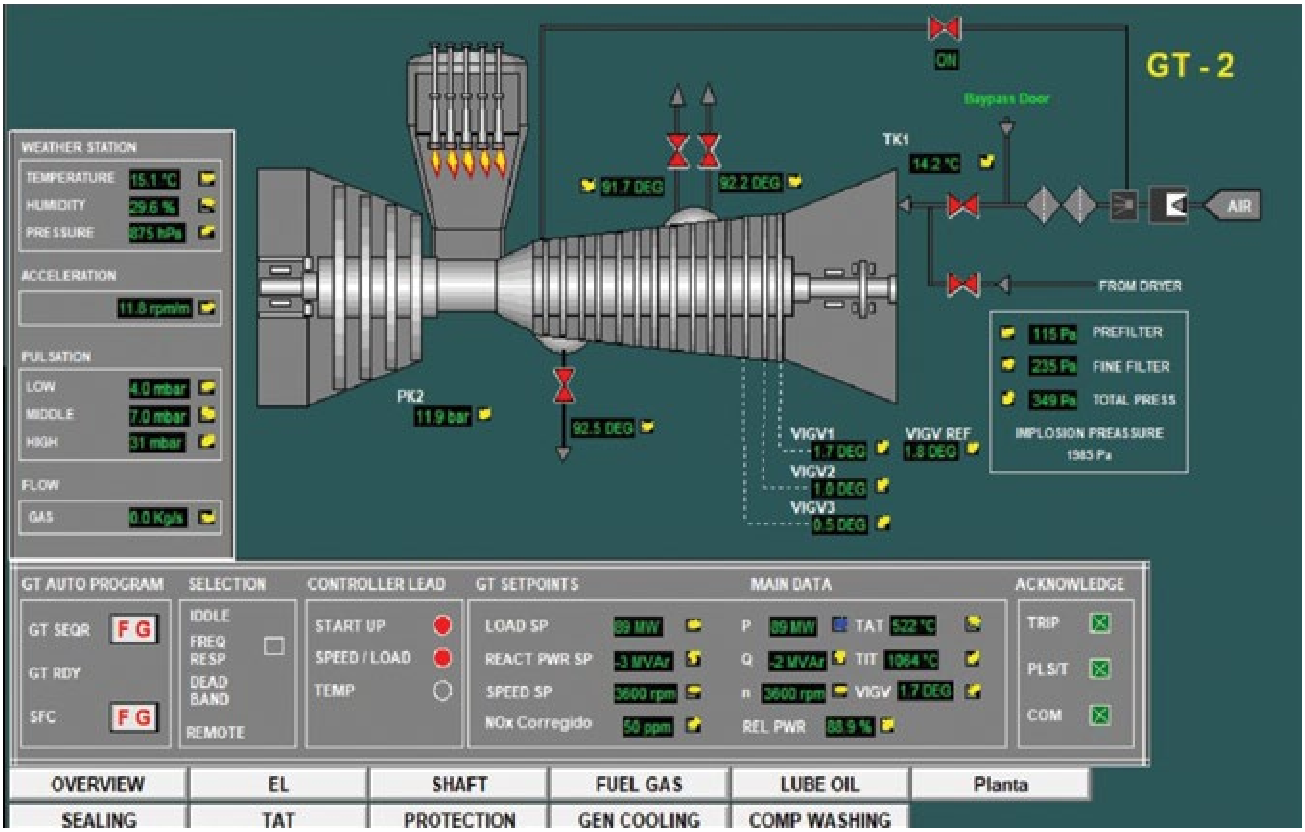
Plant manager: Daniel Cepeda

Timely HRSG inspections, repairs help promote high availability

Challenge. Maintaining high reliability and availability of the Energía Chihuahua III combined cycle demands that close attention be paid to the plant's 15-year-old heat-recovery steam generators (HRSGs)—in particular, the conduct of meaningful and rapid inspections and repairs.



1. Control-room screen (above) is replicated below in PI ProcessBook, which is accessible to technicians requiring current as well as historical information on the deck plates



Solutions:

Inspection windows in headers proved valuable to the plant team for identifying material degradation on the water-side of the HRSGs related to flow-accelerated corrosion (FAC), water-chemistry issues, and other causes.

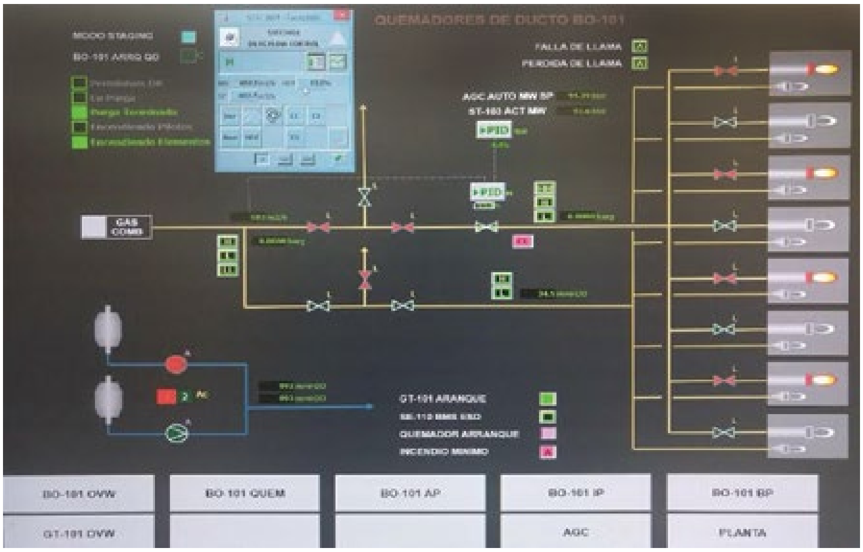
For example, windows cut into the upper headers of the low-pressure evaporators pinpointed damage in the curves of the risers. The information and perspective gained from this investigative effort is being used in the formulation of a plan to replace 68 upper curves in the two boilers.

A clue to the existence of additional damage can be seen in Fig 2, which shows windows were cut into adjacent headers near their respective end caps (the one on the right already welded closed) to assess tube damage. This could indicate that the gap seals in the gas path between these left and right modules are not properly positioned or are in poor condition and permitting increased gas velocity in the gap to cause the end-most tubes to run hotter. A condition such as this can drive the FAC found at the upper bends and also contribute to fatigue damage because of the tube-to-tube temperature differences.

A careful review of the plant's cycle chemistry also was conducted because of the inspection findings. Iron solubility is influenced by pH, pressure,

2. Inspection windows cut into headers allow a meaningful assessment of tube damage on the water side

3. Plugging is used when it is not possible to repair a damaged tube and still meet the plant's dispatch commitment



4. Staging of duct burners provides good control of the steam-generation process with minimal impact on the balance of the cycle

temperature, and the tube material (alloy). Staff fine-tuned Chihuahua's chemistry to mitigate FAC. Specifically, the pH range was increased from 9.2 to 9.8 to 9.6 to 10.0 and dissolved oxygen, which was below 5 ppb, is now maintained between 10 and 20 ppb.

Tube plugging. When a tube wall is breached because of FAC, fatigue, or other reason, it can be challenging to decide between repair and plugging. Some arguments to consider include, time, material, qualified personnel, and budget. So, during an inspection you hope for the best, but must prepare for the worst. Chihuahua is prepared with plugs, welding gear, and other equipment required to open headers and plug the upper and lower ends of a failed tube when this course of action is required (Fig 3).

To identify the exact location of a damaged tube, plant staff uses a laser meter. It is pointed to where the water leak is located and measures the exact distance. The same distance is measured from the top of the HRSG to prevent cutting at a location away from the fractured tube. To access the upper and lower windows, fixed marine stairs are installed to help protect workers from injury, minimize downtime, and reduce the cost of labor and scaffolding.

Staging of duct burners. Eight-element duct burners were incorporated into the design of Chihuahua's two HRSGs (Fig 4). As installed, the burners were unstaged—meaning all eight operated when the supplementary system was called into service, without considering the steam requirements for a specific dispatch. This caused a supply/demand imbalance that could be so great as to require the throttling of steam inlet valves.

Modifications were made to allow staging—the step-by-step operation of the elements through gradual modulation of the gas control valve. This results in better control of steam generation without putting the balance of the cycle at risk.

Results. The practices outlined above contributed to the rapid inspection and repair of Chihuahua's HRSGs, making it unnecessary to extend a 2.5-day minor maintenance outage. This enabled an enviable availability run of 232 days and an annual 99.82% availability.

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PD monitoring helps guide stator-winding maintenance

By G C Stone, Iris Power-Qualitrol

Editor's note: *Progress has been made in making online partial discharge (PD) monitoring technology a viable method for assessing the condition of motor and generator stator-winding insulation. Problems have been identified on many machines and maintenance was possible to slow down or correct the problem before failure occurred.*

To gain this acceptance, earlier skepticism of the usefulness and effectiveness of the technology had to be overcome. Specifically, better noise separation and interpretation methods were developed to reduce the risk of false-negative and false-positive "alarms."

To date, thousands of machines have been equipped for online monitoring and hundreds of studies have been published documenting cases where online PD monitoring has detected problems well before catastrophic failure. Partial-discharge monitoring is a proven, highly valuable motor and generator diagnostic tool.

Partial discharges are small electrical sparks that can occur in the high-voltage electrical insulation of stator windings. PD can occur internal to, or on the surface of, the insulation, and tends to be a slow-acting deterioration mechanism. The occurrence of PD on a stator winding may manifest itself in many forms, as illustrated in the accompanying photographs.

PD is a symptom of certain manufacturing problems and stator-winding deterioration mechanisms. In the late 1940s, Westinghouse Electric Corp's John Johnson was the first to measure PD on operating high-voltage generators. His aim was to find an online method to determine if stator winding coils or bars were vibrating excessively in the stator magnetic core. These vibrating coils in the slot led to abrasion of the high-voltage electrical insulation, and eventual failure.

Johnson was successful in identifying those generators suffering most from this problem, which was caused by an inadequate method of securing the coils in the stator slots. The success of the Johnson online PD measuring system inspired other machine manufacturers, and even a few utilities, to develop their own methods.

Even though online PD testing was introduced 70 years ago, its application was not as widespread as one might have expected. Various issues, both technical and non-technical, intervened. Only in the past 25 years has online PD monitoring been accepted as a legitimate, reliable method to assess stator-winding insulation condition. This article summarizes the present state-of-the-art, as well as some limitations of the test.

Online PD methods

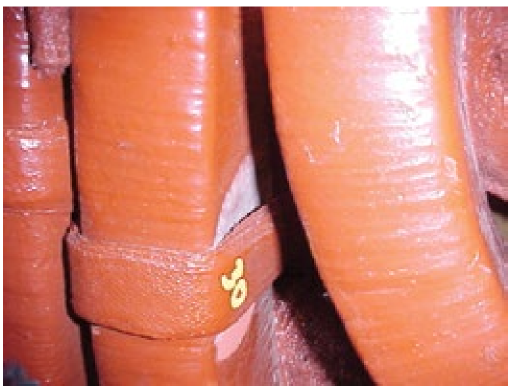
An online PD monitoring system must have the following components:

- A sensor to detect the PD current and convert it to a voltage.
- Instrumentation to characterize the PD signals and help distinguish them from electrical noise.

- Software and/or a human being to convert PD data into information about the condition of the insulation system.

Shortly after Johnson published a paper on PD monitoring in 1951, other similar test methods were introduced. The use of capacitive sensors at each phase terminal of the stator winding became popular. The introduction of high-speed digital electronics in the 1970s and 1980s helped to capture the number and magnitude of pulses more precisely and allowed more accurate interpretation of results.

Today, online PD testing comes in two flavors: low frequency (LF) and very high frequency (VHF). The LF test



requires some expertise to extract the stator-winding PD from noise, while the VHF test using 80-pF couplers on the machine terminals often can be interpreted by plant personnel after receiving a couple of days of training.

Routine online PD testing using the VHF method is conducted on more than 18,000 motors and generators to provide early warning of developing insulation problems. Thus, online PD monitoring has become a mainstream condition-based maintenance tool for stator windings.

Innovations that have led to a higher level of acceptance include better noise-suppression methods, more reliable means for determining the

Categories of failure root causes and insulation systems

	Root cause						Mica insulation system		
Machine type	**Contamination**	**Vibration**	**Design, manufacturing**	**O&M**	**Non-stator**	**Root cause, total**	**Asphalt**	**Polyester**	**Epoxy**
Steam-turbine drive, H_2-cooled	2	6	8	–	–	16	7	1	9
Steam-turbine drive, air-cooled	1	4	14	8	2	29	2	1	26
Hydro-turbine drive	3	28	83	1	–	115	28	32	37
Motor	3	12	20	2	3	40	–	–	39
Totals	**9**	**50**	**125**	**11**	**5**	**200**	**37**	**34**	**111**

severity of the PD, better methods for identifying failure mechanisms, and fewer fantastic claims. The introduction of the IEEE 1434 and IEC 60034-27-2 standards also have educated end users on what methods to use and what the test can do, and not do.

Iris Power's Vicki Warren has defined what constitutes a high level of PD based on data from well over 600,000 online tests, using the same method on many thousands of machines. The so-called "severity tables" developed from this information are valid only for PD measurements in the VHF frequency range.

The high PD levels are most affected by measurement method, voltage class (which affects the surge impedance), and hydrogen pressure (if relevant). Machine power rating, insulation class, or type (motor, hydro, etc) seem much less important. The publishing of PD "alert levels," and taking account of the trend in levels, seem to have reduced the risk of false indications.

Clyde V Maughan of Maughan Generator Consultants published a paper in 2006 summarizing a survey of 200 case studies by end users on problems that have been detected on stator windings in motors and generators. Since then at least an equal number of problems have been found (table).

Credibility of test results

Until the end of the 1970s, online PD monitoring was available from only a few major machine manufacturers and routinely used by only a few utilities—such as TVA, Canada's Ontario Hydro, and the UK's CEGB. There were many reasons for the limited use of online PD assessment. The main issue was that the results often lacked credibility.

More specifically, there was a high risk of false-positive or false-negative indications. The false-indication rate was such that many felt the test was worthless. This viewpoint was widely held by many utility maintenance engineers because of bad experiences with the technique. There were many specific reasons for this lack of credibility, as described below:

Noise rejection has been a difficult problem for all online PD monitoring systems and imperfect rejection has led to many false positives. Advancements in the application of online PD monitoring in recent years have eliminated many of the problems associated with noise false-positive issues, especially when using the VHF method.

Over-claiming. Another cause of poor credibility was the ambitious claims of effectiveness which many vendors made for their monitors. This is an inherent human nature issue that should attenuate with the passage of time and improvement of PD assessment capability. In addition, it is apparent that online PD cannot detect problems such as endwinding vibration, water leaks in direct water-cooled windings, and any problem in the low-voltage portion of the winding.

Unreliable "high-PD" indicators. Most online monitoring systems rely on trends in the PD level over time, or

on tables of what constitutes a high-PD level, or both, to determine the need for stator-winding maintenance. While these criteria are somewhat coarse, experience has shown them to be useful—if accompanied by good judgement.

Sensor reliability. Capacitors are, by a very large margin, the most widely applied PD sensors, and if a defective sensor incorrectly indicates a machine fault, this will certainly lower the credibility of the test.

The sensors most likely to cause a machine failure are capacitive couplers, since they are normally connected to the machine's high-voltage terminals. Vendors have focused on producing sensors very unlikely to fail in service. IEEE 1434 and IEC 60034-27-2 define standardized tests vendors must perform to assure their sensors do not fail.

Remaining life. In the past, some researchers and vendors have claimed that using the measured PD data, the time-to-failure of a winding can be predicted with some accuracy. There is no objective evidence to support this claim. PD itself usually is not a direct cause of failure; it is mainly just a symptom of thermal, contamination, or loose-winding issues.

In addition, experience has shown that when significant insulation deterioration is occurring, PD will increase over time—but it will not necessarily increase until failure occurs. Instead, even though the winding continues to deteriorate, the PD tends to level off, or may even decrease.

Incorrect identification of the failure mechanism. Stator windings have many different failure mechanisms of which PD is a symptom or a cause. Knowing in advance the specific failure mechanism is useful since it helps define the needed repair options, and may also yield an indication of the time required for corrective repairs.

Many methods have been developed to attempt to identify the failure mechanism based on the pattern of the PD. Regretfully, a winding sometimes is correctly assessed by PD level or rate-of-increase as having insulation problems, but the wrong mechanism is identified. As a result, the wrong repairs may be scheduled and the credibility of PD monitoring damaged. CCJ

The bottom line. Over time it has been possible to address these credibility issues to a point that partial discharge monitoring has become a proven, valuable motor and generator monitoring tool. Questions? Contact Greg Stone at gstone@qualitrolcorp.com.

Acknowledgement: Clyde V Maughan contributed to this article.

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