$15
Number 72 2022
www.ccj-online.com

CCJ COMBINED CYCLE Journal

User Group Conference Schedule, First Quarter 2023

501F Users Group — Annual Meeting and Vendor Fair
February 19 – 23, Reno, Nev
Contact: jacki@somp.co

501G Users Group — Annual Meeting and Vendor Fair
February 19 – 23, Reno, Nev
Contact: jacki@somp.co

WTUI — 33rd Anniversary Conference
March 12 – 15, San Diego, Calif
Contact: wkawamoto@wtui.com

AOG — Alstom Owners Group Sixth Annual Meeting
March 20 – 24, Charlotte, NC
Contact: ashley@aogusers.com

User Group Reports

Alstom Owners Group 24
Highlights of AOG's virtual fifth annual meeting, conducted early February 2022, included a keynote presentation on technology implementation and organizational transformation plus discussions on the first day. User and vendor presentations on topics selected by the steering committee dominated the remaining four days. Two training workshops—one on gas-turbine component repair, the other featuring tutorials on generator stators and rotors—were conducted the second week

HRSG Forum 42
Modifications to permit higher backpressure and boost combined-cycle output, experience with pressure-wave cleaning, and avoiding explosion risk in condensers were all part of the program for the user group's 10th virtual meeting

V Users Group 53
Update on commercialization of Siemens Energy's 9000HL, said to be the world's largest GT, was incorporated into a robust agenda focused on the SGT6-4000F and SGT6-2000E engines. Topics included wet compression, rotor-casing inspection and evaluation, the OEM's Advanced Stability Margin Controller, experience with M77 ceramic heat-shield material, and the company's Brownfield Engine Exchange

501F Users Group 84
Preview of the upcoming 2023 meeting in Reno, Nev, and highlights of the 2022 in-person conference in New Orleans

Best Practices Awards

The Best of the Best

2022 Best Practices Award — BEST OF THE BEST — CCJ COMBINED CYCLE Journal

CPV Towantic Energy Center 6
How ZLD is maintained with oil/water separator out of service, implementing insurers' recommendations reduces site risks, saves on premiums

St. Charles Energy Center 16
Active, wireless monitoring of high-energy piping improves safety, reliability

Empire Generating LLC 20
Plant upgrades zero-in on solutions for fall prevention

Fairview Energy Center 45
Successes attest to the value of remote M&D, DCS screens enhanced to improve starting reliability

Genelba Thermal Power Plant 63
Combustion-chamber issue identified, corrected using methodology created by plant personel

McIntosh Power Plant (Unit 5) 79
HRSG mod allows increase in backpressure to boost power output, mitigation efforts protect through bolts on W501G turbine rotor

Features

Industry calendar 3
Identifies dates, locations, contacts for 2023 user group conferences

Who ya gonna call the day after a 'bump in the night'? 41
Stresses the importance of having an emergency-trip recovery process in place for your GT

Webinar roundup 66
Rotor life extension, main-steam valve solutions, high-speed balancing, L-0 blade repairs

Film-Forming Substances Fifth Annual Conference 71
Wide range of FFS products, mixtures, makes research, common solutions difficult. Includes sections on cycling and layup protection, ACC case history, industrial hot water and nuclear experience, field switching of FFS, instruments for FFS characterization

Steam-turbine warming, insulation systems 88
Warming-system familiarization, how the Arnold system works, integrating ST warming into plant operations, how much does it cost, case history

Generators: A brief history 92
Electrical insulation systems and support systems for both stator and rotor windings, generator cooling methods, forging for rotor bodies and retaining rings

INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

2023 meetings focusing on user information

February 19–23, 501F Users Group, Annual Meeting, Reno, Nev, Peppermill Resort & Spa. Details/registration at www.501fusers.org as they become available. Chairman: Ivan Kush, Cogentrix Energy Power Management. Contact: Jacki Bennis, jacki@somp.co.

February 19-23, 501G Users Group, Annual Meeting, Reno, Nev, Peppermill Resort & Spa. Meeting is co-located with the 501F Users Group conference. Details/registration at www.501fusers.org as they become available. Chairman: Steve Bates, Vistra Corp. Contact: Jacki Bennis, jacki@somp.co.

March 12-15, Western Turbine Users Inc, 33rd Anniversary Conference and Expo, San Diego, Calif, San Diego Convention Center. Details/registration at www.wtui.com first week of January. President: Ed Jackson, Missouri River Energy Services. Contacts: Charlene Raaker, conference registration coordinator, craaker@wtui.com; Wayne Kawamoto, conference executive director, wkawamoto@wtui.com.

March 20-24, AOG (Alstom Owners Group) Users Conference, Sixth Annual Meeting, Charlotte, NC, EPRI Campus. Details/registration at https://aogusers.com. Contact: Ashley Potts, ashley@aogusers.com.

March 21-23, Film Forming Substances, Sixth International Conference, Prato, Italy (about 20 minutes by car or train from Florence), Monash University. Details/registration at https://FilmFormingSubstances.com. Chairman: Barry Dooley, Structural Integrity Associates (UK). Contact: Rachel Washington, rachel@meccaconcepts.com.au.

April 23-27, CTOTF, Spring Conference and Trade Show, Greenville, SC, Hyatt Regency Greenville. Details/registration at www.ctotf.org. Chairman: Dave Tummonds, LG&E/KU. Contact: Tom Pasha, executive vice chair for operations, tompasha@ctotf.org.

May 15-19, 7F Users Group, 2023 Conference and Vendor Fair, Atlanta, Ga, Renaissance Atlanta Waverly Hotel & Convention Center. Details/registration at https://www.powerusers.org as they become available. Contact: Sheila Vashi, sheila.vashi@sv-events.net.

May 16-18, European HRSG Forum, Ninth International Conference, Prato, Italy (about 20 minutes by car or train from Florence), Monash University. Details/registration at https://europeanHRSGforum.com. Chairman: Barry Dooley, Structural Integrity Associates (UK). Contact: Rachel Washington, rachel@meccaconcepts.com.au.

June (dates TBA), ACC Users Group, Annual Conference, Richmond, Va. Details/registration at https://acc-usersgroup.org as they become available. Chairman: Andy Howell, EPRI. Contact: Sheila Vashi, sheila.vashi@sv-events.net.

June 5-8, Siemens Energy Large Gas Turbine Conference (formerly the Siemens Energy F, G & H Conference, now including 251B10-12 and 501D5-D5A users), Orlando, Fla, Renaissance Orlando at SeaWorld. Details/registration information expected in mid-February. Contact: Dawn McCarter, dawn.mccarter@siemens-energy.com.

June 12-15, HRSG Forum, 2023 Conference and Vendor Fair, Atlanta, Ga, Renaissance Atlanta Waverly Hotel & Convention center. Details/registration at https://www.powerusers.org as they become available. Chairman: Bob Anderson, Competitive Power Resources. Contact: Sheila Vashi, sheila.vashi@sv-events.net.

July 17-20, Legacy Turbine Users Group, Second Annual Conference and Vendor Fair, Chandler, Ariz, Sheraton Grand at Wild Horse Pass. The Frame 5, 6B, and 7EA Users Groups comprise LTUG and meet independently; some joint functions, including meals and vendor fair. Details/registration at https://www.powerusers.org as they become available. Contact: Sheila Vashi, sheila.vashi@sv-events.net.

July 23-27, Ovation Users' Group, Annual Meeting, Pittsburgh, Pa, The Westin. Details/registration at www.ovationusers.com as they become available. Contact: Anne Turkowski, anne.turkowski@emerson.com.

August 28-31, Combined Cycle Users Group, 2023 Conference and Vendor Fair, Atlanta, Ga, Omni Atlanta Hotel at CNN Center. Meeting is co-located with the Steam Turbine, Generator, and Power Plant Controls Users Groups, and the Low Carbon Peer Group; some joint functions, including meals and vendor fair. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi, sheila.vashi@sv-events.net.

August 28-31, Steam Turbine Users Group, 2023 Conference and Vendor Fair, Atlanta, Ga, Omni Atlanta Hotel at CNN Center. Meeting is co-located with the Combined Cycle, Generator, and Power Plant Controls Users Groups, and the Low Carbon Peer Group; some joint functions, including meals and vendor fair. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi, sheila.vashi@sv-events.net.

August 28-31, Generator Users Group, 2023 Conference and Vendor Fair, Atlanta, Ga, Omni Atlanta Hotel at CNN Center. Meeting is co-located with the Steam Turbine, Combined Cycle, and Power Plant Controls Users Groups, and the Low Carbon Peer Group; some joint functions, including meals and vendor fair. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi, sheila.vashi@sv-events.net.

August 28-31, Power Plant Controls Users Group, 2023 Conference and Vendor Fair, Atlanta, Ga, Omni Atlanta Hotel at CNN Center. Meeting is co-located with the Steam Turbine, Generator, and Combined Cycle Users Groups, and the Low Carbon Peer Group; some joint functions, including meals and vendor fair. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi, sheila.vashi@sv-events.net.

September 24-28, CTOTF, Fall Conference and Trade Show, Prior Lake, Minn, Mystic Lake Casino Hotel. Details/registration at www.ctotf.org. Chairman: Dave Tummonds, LG&E/KU. Contact Tom Pasha, executive vice chair for operations, tompasha@ctotf.org.

COMBINED CYCLE Journal

Editorial Staff

Scott G Schwieger
General Manager
Print and Electronic Products
702-612-9406, scott@ccj-online.com

Kiyo Komoda
Creative Director

Steven C Stultz
Consulting Editor

Clark G Schwieger
Special Projects Manager

Robert G Schwieger Sr
Editor Emeritus
702-869-4739, bob@ccj-online.com

COMBINED CYCLE Journal is published by PSI Media Inc, a Pearl Street company. Editorial offices are at 7628 Belmondo Lane, Las Vegas, Nev 89128. Office manager: Robert G Schwieger Jr.

To cancel or change your subscription, write scott@ccj-online.com

MITSUBISHI POWER'S T-POINT 2: THE JOURNEY CONTINUES FOR THE WORLD'S SMARTEST POWER PLANT

Mitsubishi Power's T-Point 2, the world's first operational smart power plant, has been generating power commercially since July 1, 2020. By October 31, 2022, T-Point 2 had more than two years of real-world grid-dispatched operating hours and hundreds of successful start/stop cycles. In addition to generating power, T-Point 2 is generating knowledge and experience to make new and existing power plants more competitive and flexible to support decarbonization goals. Many existing elements of Mitsubishi Power's TOMONI® suite of intelligent solutions were integrated into T-Point 2, and many new solutions are now being validated on T-Point 2 and have made it the smartest power plant in the world.

Since its inception, T-Point 2 has been a proving ground for TOMONI, and a wide range of technology has been applied. In fact, its predecessor plant, T-Point 1, hosted many earlier TOMONI solutions in past years. Much of that validated technology is now deployed on operating power plants, more is being refined currently at T-Point 2 and new technologies are being identified for future application.

T-Point 2 has a total plant data platform for intensive data acquisition and integration. It is the first advanced-class GTCC plant with full Netmation 4S DCS and equipment control systems. And it has a full connection to the Mitsubishi Power Takasago TOMONI HUB, including remote operation of the plant from the TOMONI HUB.

Proving Ground for the Latest Technology

New TOMONI solutions at T-Point 2 are currently focusing on several key areas, including AI-enabled subsystems for automated operation of critical subsystems. The plant is also a proving ground for reliability improvements based on advanced analytics and controls, as well as total plant monitoring and diagnostics.

Thirty-four TOMONI solutions have been installed so far at T-Point 2, including:

- 13 TOMONI solutions that had previously been validated on T-Point 1 and are being used to support operation of T-Point 2; and
- 21 new TOMONI solutions operated for the first time on T-Point 2.

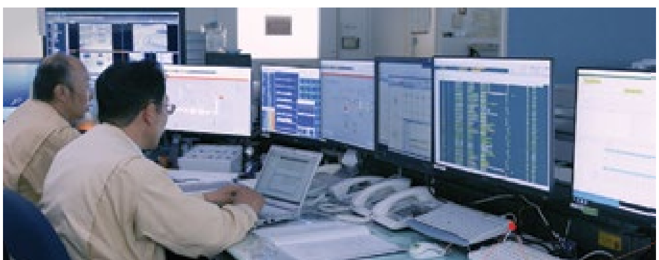
As a result, 14 new TOMONI solutions are being released for fleet applications in 2022 based on the validation to date in T-Point 2.

Autonomous AI-Enabled Subsystems

A good example is an autonomous subsystem that manages gas turbine combustion dynamics while maximizing GTCC output and minimizing emissions. Mitsubishi Power introduced the use of early forms of machine learning in its advanced combustion pressure fluctuation monitor (A-CPFM), first applied in 2003. The logic and algorithms in A-CPFM have been steadily upgraded over the years; the latest version, AI-CPFM, which uses advanced Gaussian process regression (GPR) analysis, was validated in T-Point 2 in 2020–2021 and is now in commercial service on advanced-class gas turbines.

Another TOMONI digital solution installed on T-Point 2 for training and validation, GT Cooling Air AI-Optimization, uses machine learning to actively optimize turbine cooling airflow. This solution automatically adapts to equipment degradation as well as outside factors, such as air temperature, by modulating in real time the amount of cooling airflow based on the minimum amount of air needed to safely cool the turbine. This improves plant efficiency, especially during partial-load operation, and eliminates manual cooling airflow adjustments and potential unplanned downtime.

These are both good examples of the growing family of smart, autonomous controllers that are being steadily deployed in new and existing power plants to create the smarter power plants of the future.



TOMONI HUB Control Center

Reliability Assurance Diagnostics

Advanced controls and diagnostics, combined with prescriptive analytics, can support automated assessments to avoid common sources of unplanned downtime.

- Analysis of 10 years of trip events collected by the TOMONI HUB Analytics & Performance Centers identified the most common sources of startup trips on the monitored fleet of gas turbines and their associated auxiliary systems.
- A family of analytic and diagnostic applications was developed to provide early warning and recommended maintenance actions to avoid such trips and was installed in T-Point 2 for training of the analytics and feedback from plant operators to refine the applications prior to commercial deployment.
- Since T-Point 2 is subjected to the same conditions and operational inputs as a commercial power plant, including DSS operation at times, it is the ideal pilot plant, enabling Mitsubishi Power to offer practical, operator-oriented, intelligent solutions whose reliability is further boosted through daily fine-tuning. This Trip Prevention Package is also now being applied to operating GTCC plants.

Mitsubishi Power works with power plant owners to identify real-world needs. We create intelligent digital solutions that are making new and existing power plants more competitive and flexible to support decarbonization. Additional solutions for validation in T-Point 2 have already been identified for installation and validation. The digital ecosystem of the smart power plant of the future has enhanced flexibility and security, with an improved level of reliability, lower O&M costs and reduced CO^2 emissions. Mitsubishi Power is moving the world forward, and T-Point 2, already the world's smartest power plant, is steadily becoming even smarter. For more information about TOMONI® intelligent solutions, visit www.changeinpower.com/tomoni/smarter.

TOMONI®

The combination of T-Point 2 and TOMONI is achieving all its objectives, and the journey for the world's smartest power plant continues.

Towantic

How zero liquid discharge is maintained with oil/water separator out of service

CPV Towantic Energy Center

Owned by Competitive Power Ventures

Operated by NAES Corp

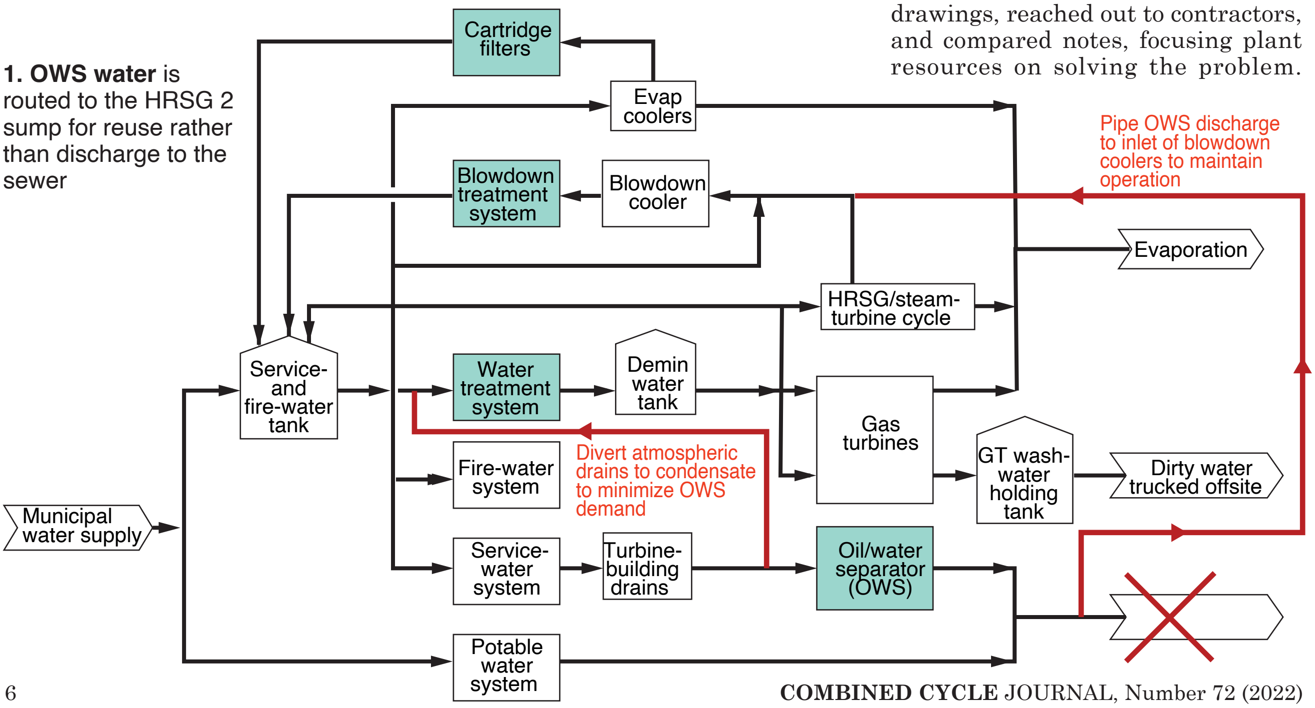
805 MW, gas-fired 2 × 1 7HA.01-powered combined cycle equipped with DLN2.6+ AFS combustion systems, located in Oxford, Conn

Plant manager: Larry Hawk

Challenge. Shortly after commissioning, CPV Towantic noticed its oil/water separator (OWS) effluent flowmeter was inaccurate, requiring the outlet valve to remain closed until the instrument could be repaired or replaced and certified.

Primary concern was that the OWS is responsible for removing oil from the wastewater stream prior to its discharge (Fig 1). To keep the plant in service and remain in compliance as a zero-liquid-discharge (ZLD) facility, staff had to figure out what to do with that water. Team Towantic thought outside the box to find a way to be an operating ZLD facility without the availability of the installed infrastructure.

Solution. All departments reviewed drawings, reached out to contractors, and compared notes, focusing plant resources on solving the problem.



1. OWS water is routed to the HRSG 2 sump for reuse rather than discharge to the sewer

Management coordinated efforts and tracked progress.

From the onset, the team was committed to selecting the simplest solution with the lowest risk. The outcome that met all requirements was to install a sump pump in the OWS and run a hose from the pump discharge to the blowdown sump for the closest HRSG. It turned out to be the perfect idea, considering that the water from the OWS and the blowdown system are similar in composition and temperature.

A key benefit of this solution was about a 15,000-gal/day reduction in the amount of municipal water required by CPV Towantic. Reason: Blowdown sump water now is pumped to the service- and fire-water tank, which retains 375,000 gallons for fire protection and supplies water to the trailer-mounted demineralizers.

Result. Plant operators and mechanics had the sump pump installed, and the discharge hose safely routed to the blowdown sump, within 24 hours. The new installation worked flawlessly. All other plant parameters, such as chemistry, were unaffected. The facility has been able to run in this mode since commissioning without issue, while meeting all of its power-supply and environmental obligations.

Project participants:
The entire plant team

Towantic gets SPCC certification, reduces oil-spill risk, increases safety—all at once

Challenge 1. While CPV Towantic was in the process of its Spill Prevention, Control, and Countermeasure (SPCC) recertification (from the preconstruction initial submission) and was seeking PE certification for EPA submission, the certifying professional engineer expressed concern with the (1) so-called shed roof around the 1.5-million-gal diesel-oil tank's secondary containment, and (2) lack of secondary containment around the outdoor fuel-gas condensate collection tanks.

The site's diesel-fuel tank height is 48 ft with its overflow at approximately 46.5 ft. The secondary containment is designed to hold over 110% of the capacity of the fuel tank, but being of larger circumference is only 41 ft high.

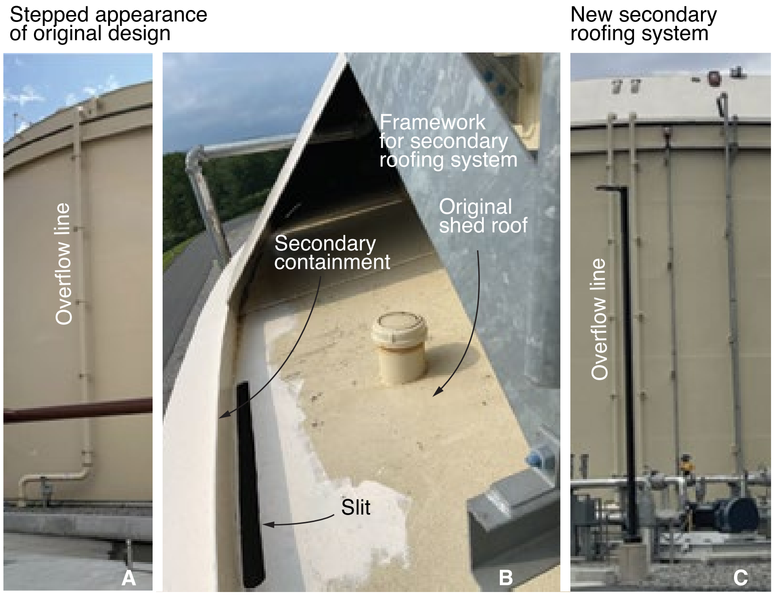
A rain "shed roof" was installed on the skin of the oil tank at elevation 41.7 ft, covering the top of the secondary containment to prevent snow/rain buildup. This created a stepped appearance overall of the tank and secondary system, as seen in Fig 2A.

The PE was concerned that if the tank leaked above the shed roof, diesel oil could possibly travel across the top of the secondary-containment roof and run down the side of the secondary containment onto the ground. The engineer's company wanted the site to drain and inert the tank (which already held over 1-million gal of diesel oil) and physically lower the overfill line to below the level of the secondary containment.

Since administrative controls to solve this were not an acceptable solution to EPA, the site proposed a secondary roofing system. It would span from the top of the tank to the top of the secondary containment (Fig 2B), including alterations in the original shed roof—thereby eliminating the concern. The PE's company had come across this issue previously and viewed their proposed solution as a more proven choice. The consultancy wanted a cost and risk/benefit analysis performed before signing off on the site's solution.

Solution 1. Working with the site owners and NAES Compliance (and NAES Safety during design and construction), CPV Towantic was able to provide the required analysis demonstrating that a secondary roofing system was a better option, and the PE agreed to support it. Although this cost nearly $250k to install and commission, the alternative had (1) a much higher spill risk and cost because of the need to relocate the oil, (2) the challenges associated with inerting the tank, and (3) confined-space consideration to allow hot work inside the oil tank (to physically lower the top of the overflow). The overall saving was about three to four times the cost of the secondary roofing system.

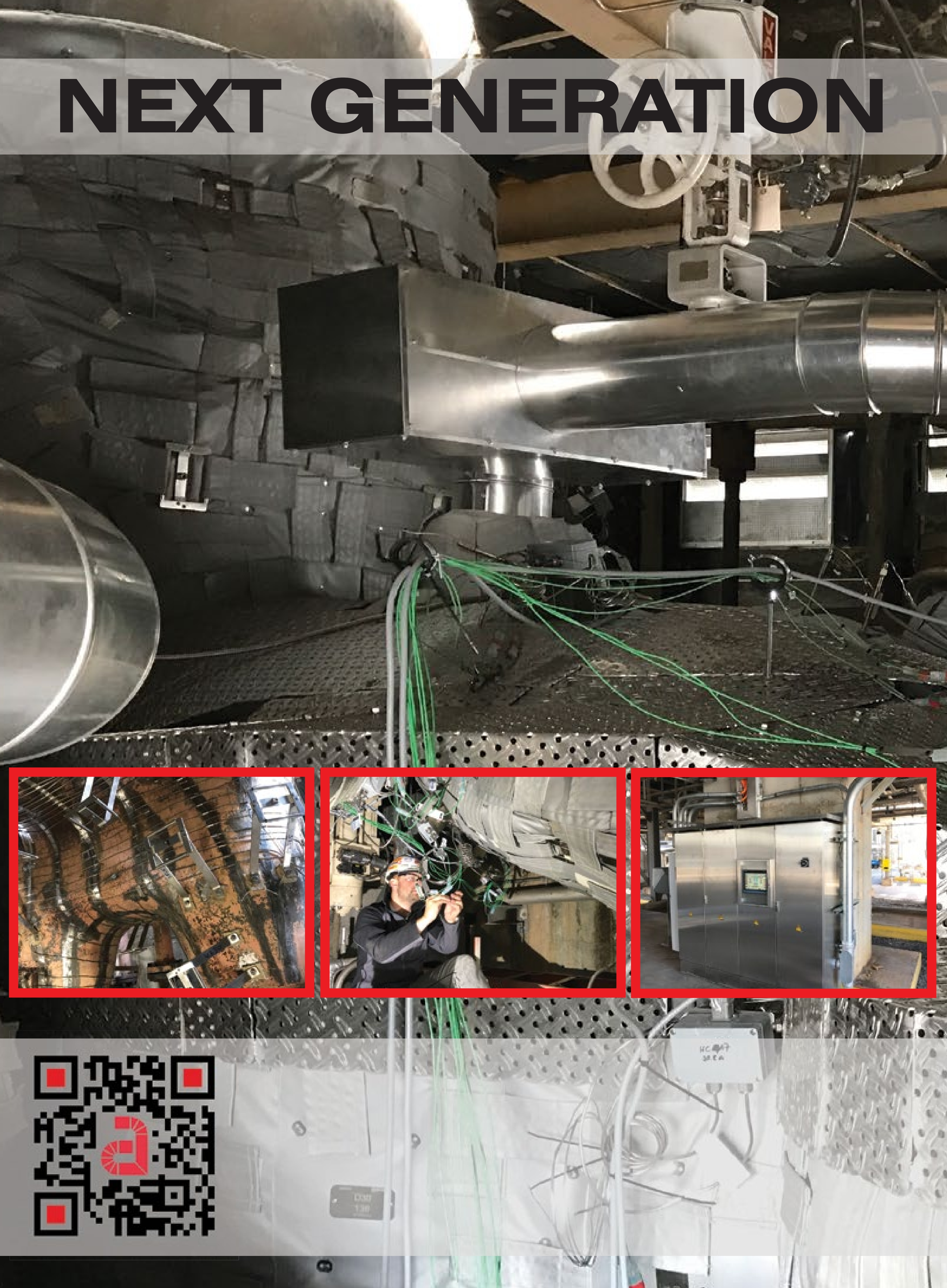
In the end, the PE advised on some



2. Diesel oil tank, as designed, concerned engineers responsible for its EPA certification (A). Design mods (B), to prevent oil from running down the tank wall to ground in the unlikely event of a leak, included the addition of a secondary roofing system and the cutting of slits in the original shed roof. Final approved design is shown in C

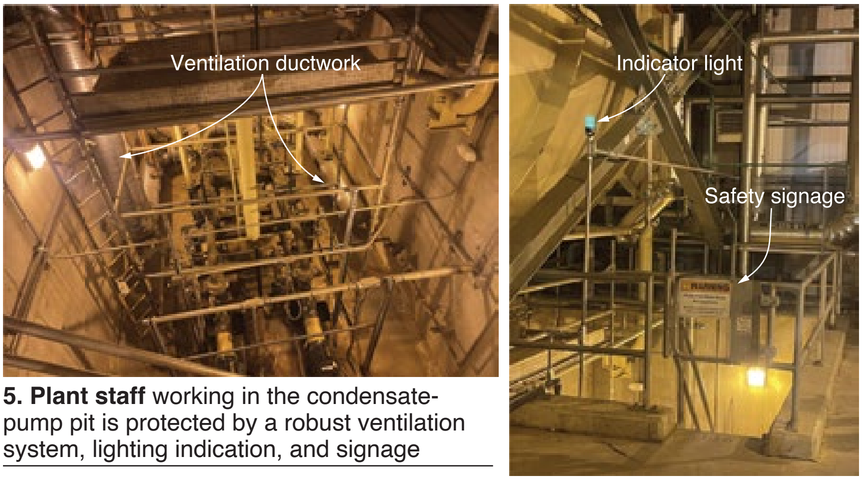
3. Secondary containments of concrete, 1 ft high, were installed around the site's natural-gas condensate collection tanks to protect against unexpected leakage

NEXT GENERATION



TURBINE WARMING
Operational Advantages
• Eliminate Cold Starts
• Maintain Hot-Start Conditions
• Faster Starts
• Mitigate Case Distortion
• Advanced, Customizable Control
Maintenance Advantages
• Easy Access to Critical Areas
• Quick & Easy Removal / Reinstall
• Enhanced Operator Safety Features
Economic Advantages
• Gain Competitive Market Advantage
• Seamless Turnkey Solution
• Reduced Fuel Consumption
• Increase Profitability
Contact: Pierre Ansmann
pierre.ansmann@arnoldgroup.com
unit overview
ON / OFF
ARNOLD GROUP
ARNOLD GROUP

4. Effectiveness of drains to mitigate spillage of diesel oil/NO_x control water (left) during the transition from natural-gas firing to liquid fuel was improved with bolt-on extensions (right)



5. Plant staff working in the condensate-pump pit is protected by a robust ventilation system, lighting indication, and signage

design elements and was impressed with the completed project, signing-off on the SPCC for EPA submission without further hesitation (Fig 2C). Important: To alleviate safety concerns, the site used bolted construction near the top of the tank in lieu of hot work near the skin of the oil tank.

Finally, the site used a local concrete company to install secondary containments (1 ft high with valved and capped drains, and at least 125% tank capacity) around the natural-gas condensate collection tanks (Fig 3).

Challenge 2. The original design of gas-turbine drains allowed for spillage of diesel fuel/NO_x control water during transitions from natural-gas firing to fuel-oil firing.

Solution 2. Plant personnel fabricated bolt-on funnel extensions to prevent the fuel/water mixture from overwhelming the drain system and causing a state-reportable spill (Fig 4). Note that Connecticut does not currently have language for negligible spills, even onto solid surface, so any transition event has a high probability of being a reportable spill caused by back-up of the fuel/water mixture within the relatively small funnel—depending on the length of the transition stage.

Challenge 3. The condensate-pump pit, located inside the steam-turbine building, is below grade and equipped with a standard staircase (not a ladder) to access the equipment. The pit is not considered a confined space because of the staircase.

However, CPV Towantic management recognizes the below-grade area could potentially collect a hazardous atmosphere, possibly compromising the safety of personnel attempting to operate or maintain equipment there. Since the facility normally operates with only two staff operators, this equipment normally would not be inspected with a third person and atmospheric metering to ensure safety.

Solution 3. To ensure proper O&M of equipment installed in the pit while ensuring personnel safety, CPV Towantic installed a robust ventilation system with reed-switch lighted indication (Fig 5). This indicator confirms the ventilation system is functioning. The ventilation system is designed for 50 air exchanges hourly and signage is posted to remind employees to check the status light to ensure the ventilation system is working as designed at time of entry.

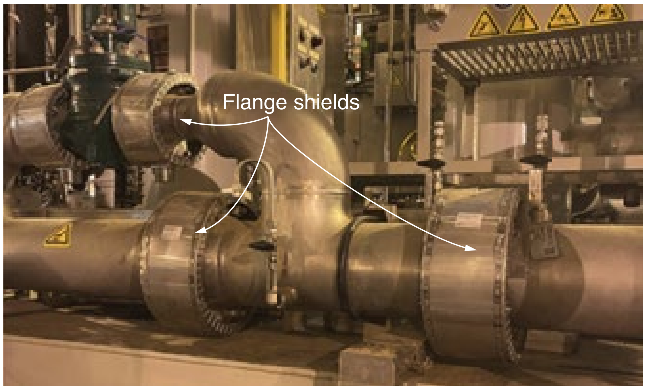
Results 1, 2, 3. The three initiatives described enable the plant to comply with EPA and state regulations, minimize the impact of cost and unnecessary deviation reporting, increase the safety of accessing equipment, and maintain as-designed fuel-storage capacity while assuring operation on oil when required.

Project participants:
The entire plant team

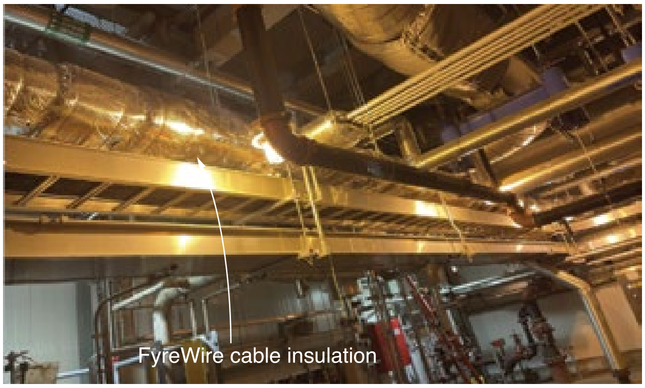
Implementing insurers' recommendations reduces site risks, saves on premiums

Challenge. The annual cost of providing casualty and property insurance to protect facility owners from significant financial hardship in case of a loss event can reach into the millions of dollars. Annual insurance inspections help "rheostat" this cost in either direction. The more areas of concern the insurance engineers and the inspectors have, the more the annual cost to maintain coverage. Being a relatively new facility, CPV Towantic had a typical initial list of recommendations and data requests open from these insurance site visits and inspections.

Solution. The site team set out to complete as many of the open hazard/loss-prevention that it could. While prior-year efforts focused primarily on non-financial, mainly administrative improvements, the site moved to budget the more cost-intensive recommended efforts this year. CPV Towan-



6. Flange shields protect against oil leakage on lines operating at or over 50 psig



7. FyreWire® cable insulation protects power lines in the unlikely event of a fire

8. Fire barrier of 18-gauge steel installed under PDC enclosures protects power lines while enabling safe access to them

9. Concrete-type fire barrier protects structural members

tic worked closely with the owner to establish a proper budget to achieve these goals.

Specifically, these efforts included the following:

- Installation of insurance-company-approved flange shields in pressurized oil systems (lube oil, for example) serving the two gas turbines and the steam turbine (Fig 6). The site procured, and staff installed, over 200 Ramco flange shields targeting any oil-containing equipment operating at, or over, 50 psig.
- Protection of power cables to the steam-turbine lube- and seal-oil pumps (Fig 7). Personnel worked with insurance-company-approved vendors and products (in this case, Unifax FyreWrap®) to install a fire barrier around the dc pumps to prevent loss of operation in the event of a fire in the area.
- Installation of an insurance-company-approved, and CPV Towantic designed and installed, 18-gauge-steel thermal barrier under the PDC enclosures serving both gas turbines (Fig 8). This to satisfy the insurance company's concern that the exposed foam-type insulation could catch fire from an arc caused by the incoming electrical lines.
- Installation of protection for structural-steel columns within the steam-turbine lube-oil containment area. The plant worked with insurance-company-approved vendors to install a 1.125-in.-thick Carobine Pyrocrete fire barrier (Fig 9) around structural steel located inside the steam-turbine's lube-oil-skid secondary containment to minimize the risk of a fire in this space, possibly weakening the steel and causing a building collapse.
- Improve the existing hot-work permit system or implement the insurance carrier's hot-work permit system. CPV Towantic improved its hot-work permit to incorporate the updated OSHA protocol on post-activity fire watch. Note that the site, operations company, and insurance carrier worked together to isolate the areas of the OSHA matrix that applied and simplified the process for better adherence out in the field.
- Initiate annual operational testing of the water-mist fire protection systems for the gas turbines. Plant personnel worked with the system vendor to create a preventive-maintenance program which the supplier would use to perform annual system checks. Plus, staff worked with the insurance carrier to allow an air-only system check—one not involving the release of the water mist. The system supplier was tasked with providing documentation for future records review and insurance inspections.

Results. Through the efforts described above, the insurance company acknowledged the facility's diligence in completing numerous open-action items, stating the following:

"As you can see, there is a large number of recommendations that have been completed. . . .I think this is one of the largest single-year lists of completed recommendations that I have seen during my 20-year career. . . . The recommendations were not only completed, but completed well. I really like the job that was done on the thermal protection on the dc pump power supplies and the sheet metal that was installed under the PDCs."

Although insurance premiums recently have been increasing for electric generating facilities, CPV Towantic's owners acknowledge that they have seen less of an increase because of the collective efforts of the operations team and owners to undertake the insurance company's recommendations. More importantly, the insurance carrier's recommendation initiatives serve to continue to reduce risks at the facility.

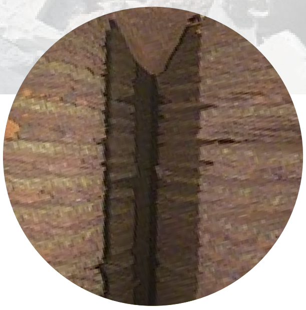
Project participants:
The entire plant team

WHEN IS 10 TONS OF DEBRIS A GOOD THING?

Recently Precision Iceblast Corporation was contracted to clean a standard HRSG located in the United States after explosion cleaning methods were utilized. The client initially experienced somewhat positive results from the explosion cleaning efforts. However, within a short time frame the client's back pressure increased near gas turbine tripping points.

Precision Iceblast Corporation removed an additional 10 tons of debris after explosion cleaning efforts. Client experienced an additional 3.5" reduction in back pressure. Client has been able to maintain the reduced back pressure after the PIC HRSG Deep CleaningTM process.

It was determined that explosion cleaning efforts were only able to clean to the fourth/fifth row of tubes leaving a large amount of the heating surface untouched.



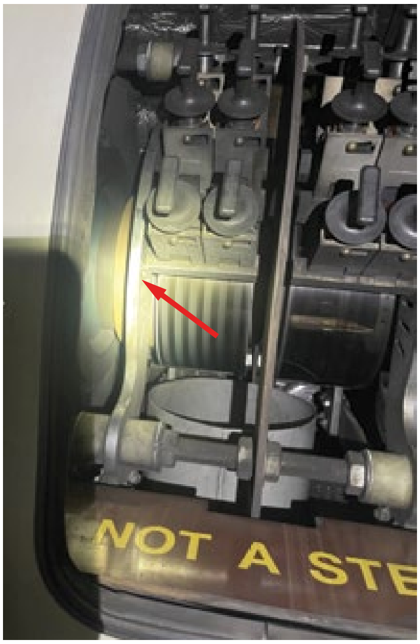
AFTER EXPLOSION CLEANING
(4TH & 5TH ROWS OF TUBES)

AFTER PIC HRSG DEEP CLEANING
(4TH & 5TH ROWS OF TUBES)

PIC HRSG Deep Cleaning

- ✓ No federal permitting required
- ✓ Dramatic reduction in heat rates
- ✓ Dramatic increase in Gas Turbine output
- ✓ Closest return to design back pressure possible
- ✓ No requirement to remove other contractors from the HRSG unit
- ✓ Scaffold required ensuring complete cleanliness allowing for borescope inspection of each level of the HRSG

www.precision-iceblast.com info@precision-iceblast.com +1 906-864-2421



10. Collector with evidence of moisture ingress/rusting (arrow)

11. Tenting around the steam-turbine generator proved ineffective against moisture ingress (left). Permanent fix was the collector building at right

12. Protection of the GT generator in stormy weather with plastic wrap and tarps (left) was ineffective, as it was for the steam-turbine generator at this outdoor plant. Permanent enclosure at right was the solution

Custom weather protection for collector-house assembly reduces trips, water damage

Challenge. CPV Towantic is an outdoor facility. The OEM-provided generator collector-house assemblies allowed moisture to collect around brushes and rigging during heavy rain events (Fig 10). Generator field resistance to ground was alarming, and in one case tripped the generator. Initial thought was moisture was coming in around the brush inspection door. After much investigation it appeared water was running across the concrete foundation onto the collector end of the generator and under the collector-house metal foundation (Figs 11-13).

Solution. Custom-designed prefabricated metal lean-to-style structures were added to the end of each steam- and gas-turbine generator. This successfully blocked water from flowing between the concrete foundation and the collector-house assembly. As an added precaution, drip shields were installed over the air intakes of the collector cooling fans (Fig 14). It appeared that some water was leaking down across the collector end shield and reaching the fan intake, which pulls from the void under the generator.

Result. The plant has seen a significant reduction in adverse heavy-rain impacts on collector ground readings, improving operational reliability during foul weather, as well as increasing the health of the collector equipment by preventing excessive water intrusion.

Project participants:
The entire plant team

13. Rain water infiltrated the GT collector area (left) and was not to be stopped despite a rigorous sealing effort using foam board (right)

14. Solution to the water issue included a rain wall under the generator and an air-intake hood for the collector (above)

St. Charles Energy Center

Owned by Competitive Power Ventures

Operated by Consolidated Asset Management Services

745 MW, gas-fired 2 × 1 7FA.05-powered combined cycle located in Waldorf, Md

Plant manager: Nick Bohl

Active, wireless monitoring of high-energy piping improves safety, reliability

Background. St. Charles Energy Center (SCEC) was commissioned in February 2017. Near the end of 2019 the plant experienced a through-wall leak at a girth weld on a hot-reheat (HRH) bypass line to the condenser, resulting in forced-outage time and the loss of generation revenue. But most concerning was that this was a significant safety concern which could resulted in a catastrophic failure.

Plant management reached out to Structural Integrity Associates Inc to aid in the analysis of the weld failure. A ring section containing the failed girth weld was removed and submitted to SI's materials lab for review. Thermal fatigue was determined to be the most likely cause of the failure.

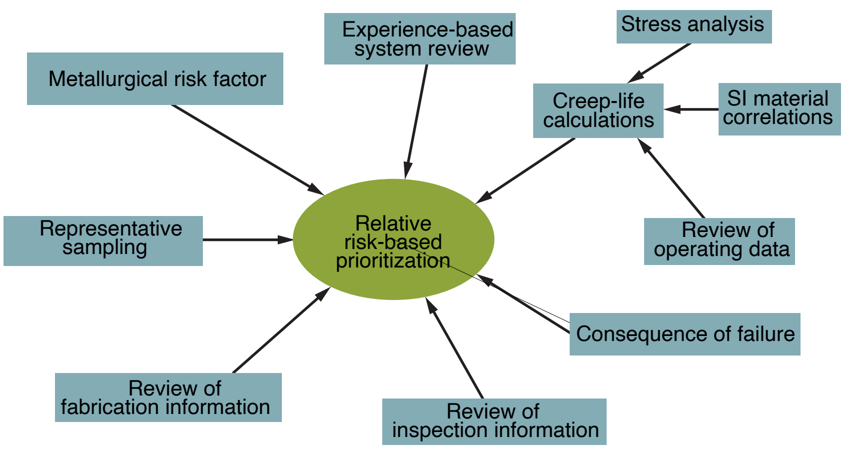
Staff worked with Structural Integrity to install local thermocouples (t/cs) around the failed area of the HRH bypass to assess the magnitude of thermal transients experienced during load-change events and normal operation. In sum, four t/cs were installed on the top, bottom, and sides of the pipe along with a local data logger. Over 30 days that the data logger was in place, temperature variations of up to 700 deg F were observed around the pipe circumference during load-change events.

The live data collected by the t/cs and data logger were analyzed by SI and sent to the manufacturer of the bypass valve. The supplier used these data to redesign the HRH bypass-attemperator spray-nozzle assembly while plant staff modified the attemperator's logic to reduce the large temperature swings and the piping thermal stress they created.

Challenge. Failure of the HRH piping weld worried staff because the facility had been operating for only two years. Staff was concerned there may be other unknown HEP issues in the plant that could lead to a failure prior to the regularly scheduled inspection.

Solution. These concerns were expressed to Structural Integrity, which proposed a wireless sensor network and t/cs to remotely read data in near-real-time and incorporate the t/c readings into St. Charles' PlantTrack online database.

SI's first step in making a timely transition from the facility's traditional HEP asset-management roadmap to "smart data" monitoring was a risk assessment. The methodology used is known as Vindex™ (for vulnerability index). It considers factors such as creep life, Grade 91 risk factors, failure consequences, etc (Fig 1).



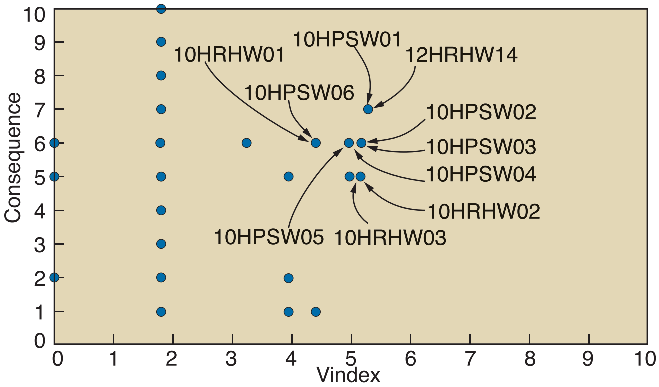
1. First step in transitioning from St. Charles' traditional HEP asset-management roadmap to a "smart data" online monitoring paradigm was a risk assessment

This approach incorporates inspection history and key component characteristics using structured and consistent methodologies that can be used across several piping systems. Each weld, or location of interest, was assessed according to component damage potential and consequence of failure.

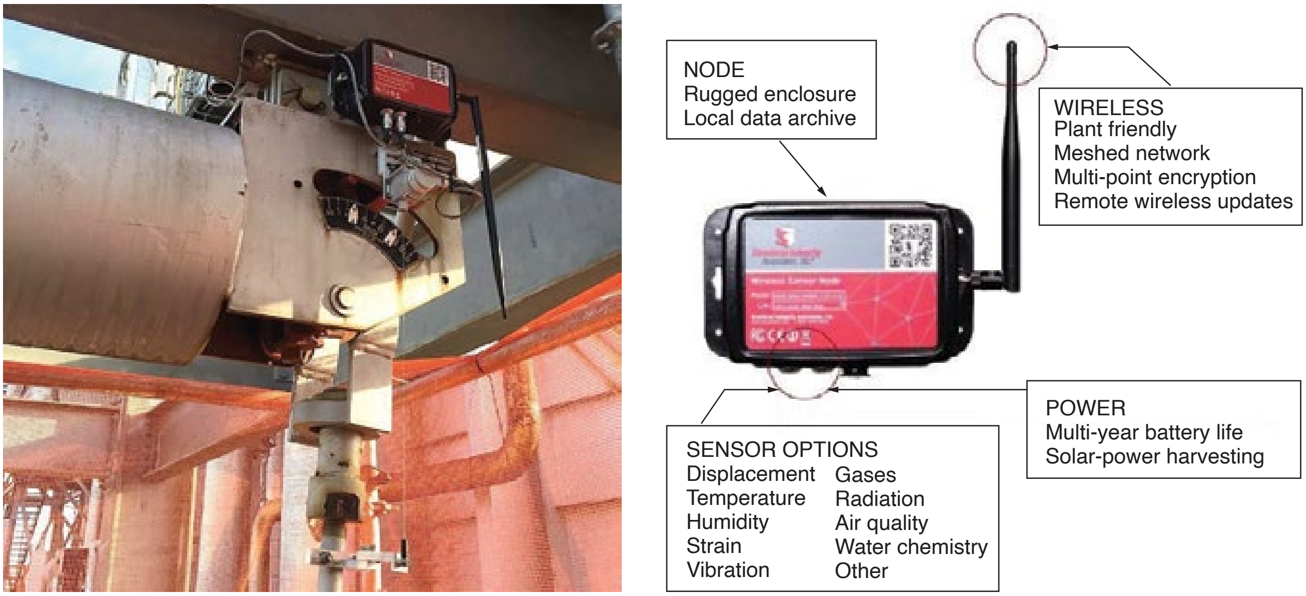
The Vindex provided risk scores for each weld and for each pertinent system/plant within SCEC's PlantTrack database. The risk scores determined the HEP locations that would benefit from active online monitoring. The engineering study concluded that the plant should install t/cs at 10 locations throughout the HEP systems (Fig 2) and active online pipe-hanger position monitors at nine locations. The latter provide real-time hanger-position data to the PlantTrack system to better understand and predict high-stress locations within the piping system.

The wireless sensor network consists of two primary components: (1) sensor nodes that collect local sensor data and transmit it wirelessly to (2) a gateway that transfers the data to the PlantTrack database. Fig 3 illustrates SI's data collection node, highlighting several of its features. Each node has multiple sensor channels and is capable of collecting data from a variety of sensor types. The single node can accommodate up to nine t/cs.

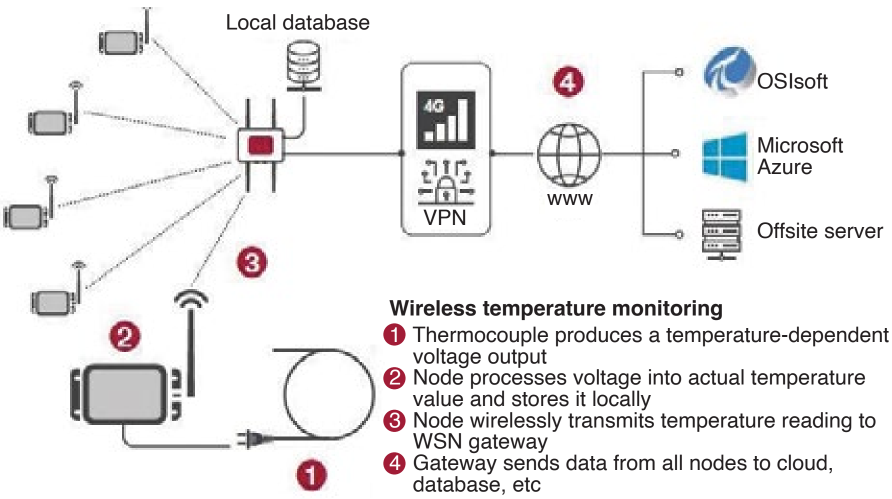
The wireless data-acquisition node is installed in close proximity to the monitored component, and all thermocouples are hardwired to the node. Data from all nodes are transmitted via a 900-MHz wireless protocol to a locally installed Wi-Fi-enabled gateway, which stores the data in a local data-



2. Risk assessment methodology used at St. Charles, Vindex™, considers factors such as creep life, Grade 91 risk factors, consequences of failures, etc. A typical risk matrix is shown



3. Data collection node as installed is at left, in detail at right. It has multiple sensor channels and is capable of collecting data from a variety of sensor types



4. The wireless sensor network infrastructure implemented at St. Charles is described in the drawing above

base until they are transmitted successfully to the PlantTrack cloud database. Once transmitted offsite, data can be accessed through SI's PlantTrack web interface. Fig 4 summarizes the general wireless sensor network infrastructure implemented at SCEC.

Result. This project has resulted in a highly valuable tool for targeting inspections and planning outage scopes more efficiently. The active tracking of temperature differentials with strategically place t/cs provides a means to quantify the number and accumulation of thermal-transient events within individual sections of the HEP network.

Inspections are planned and performed based on live data and detected damage rather than calendar time. This amounts to a huge cost saving for the facility. Without this system in place, an event like the HRH failure in 2019 would have required annual piping inspections to ensure a problem is not developing again, but with the active t/c data staff is able to monitor piping in real time to determine if and when an inspection is necessary.

In addition to gathering real-time data, the monitoring system has been configured to send email alerts when events of certain magnitude occur or based on trends-in-temperature events. SCEC personnel are notified immediately when temperatures climb above set limits and when impingements occur. Quarterly calls are held with subject matter experts from Structural Integrity to review the data and discuss any areas of concern or further operational improvement. PlantTrack Online is also connected to the site data historian, which uses additional sensor data to aid in diagnosing and trending attemperator damage.

In sum, by implementing the wireless HEP monitoring system, SCEC has proactively improved plant safety and reliability, while reducing O&M costs and the potential for losing generation revenue. By routing the data to an online database with integrated analytical algorithms that transform data into operational intelligence, St. Charles is able to make timely and informed decisions about plant operation that will maximize the life of critical components and ensure personnel safety.

Project participants:
Jonathan Bennett, Jacob Boyd, and Nick Bohl

Plant upgrades zero-in on solutions for fall prevention

Empire Generating LLC

Owned by Empire Acquisitions LLC
Operated by NAES Corp

635 MW, gas-fired 2 × 1 7FA.03-powered combined cycle located in Rensselaer, NY

Plant manager: Chet Szymanski

Challenge. Falls are among the most common causes of serious work-related injuries and deaths. OSHA general industry standards require fall protection for persons working at heights of 4 ft or greater above a lower level (6 ft for construction. In 2021, falls remained the top OSHA citation for the 11th consecutive year.

Fall protection systems include employee equipment for fall arrest, such as harnesses and lanyards; special job-related equipment, such as travel restraints, D-bolts to attach to, anchor straps, etc; and fixed systems, such as ladders, guardrails, and gates.

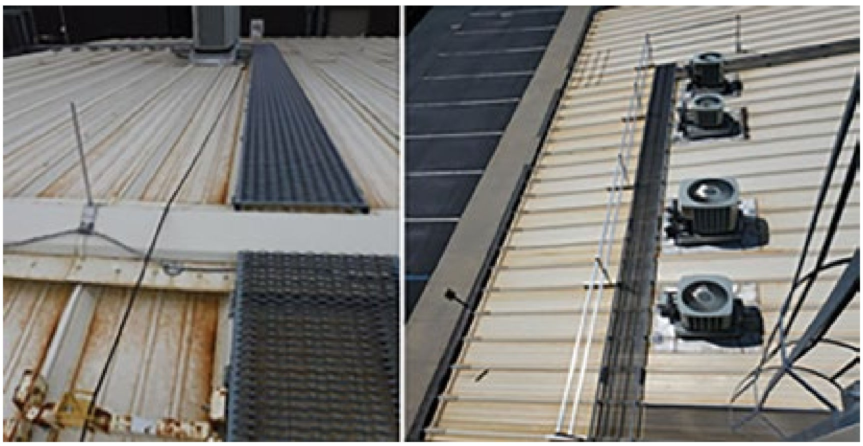
At Empire Generating Co, individually assigned fall-arrest equipment was reaching its end of life. Plus, fixed fall-protection systems were from original construction in 2009 and some were deteriorating, difficult to use, or outdated. A thorough review was needed to identify (1) equipment which required replacement, (2) potential issues or deficiencies, and (3) better solutions to ensure employee safety and regulatory compliance.

Solution. A multi-year project began with a review to identify work tasks at heights, fall hazards, and the current systems in place. This was done by a third party, Safety Compliance Services, which produced a Fall Hazard Survey report.

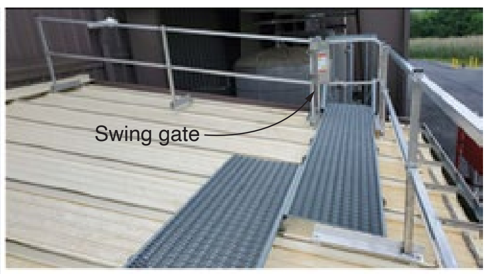
It assessed all existing fall-protection equipment and systems, and fixed ladders, identifying deficiencies and equipment which should be replaced or removed, while making recommendations for upgrades. Each location or task requiring fall protection was ranked for exposure risk to assist in prioritizing projects. In addition, a plan for each location was made with recommended fall-hazard mitigation.

For individually assigned fall-arrest systems and associated equipment, a review was done based on fall hazards identified in the Fall Hazard Survey. Updated equipment was recommended—such as replacing the existing conventional lanyards with self-retracting ones (SRL), travel-restraint equipment, and the addition of other equipment. New harnesses and SRLs then were purchased and assigned to individuals.

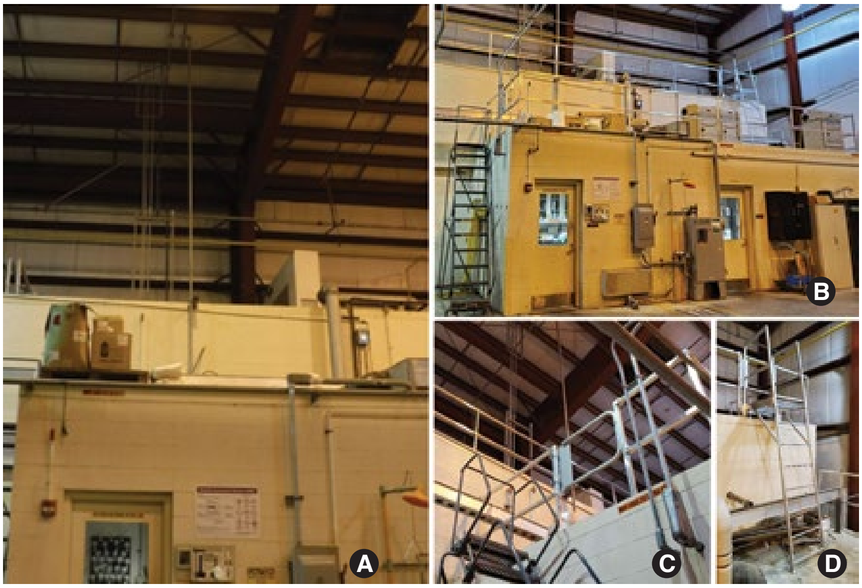
Other equipment was set up in the turbine hall in a labeled cabinet for use as needed. All employees were fitted to their new assigned equipment and training was given by Safety



Deterioration of the horizontal lifelines on the roof of the administration building compromised the safety of employees requiring access to HVAC systems (left). They were replaced with a removable guard-rail system (complete with swing gates) to keep personnel 15 ft from the roof's edge (right)



Roof of the chemical-injection room, which also provides access to HVAC units, had deteriorated lifelines and anchors (left). They were replaced with a removable guard-rail system (with swing gate) to keep personnel 15 ft from the roof's edge (right). A new LadSaf™ was installed to replace the existing ladder system



Storage area over the water-treatment lab and office lacked fall protection (A). A roof guardrail (B), swing gate (C), and a fixed ladder (D) were added to ensure a safer work environment

Guardrail at the loading edge of the steam-turbine-hall mezzanine required two people to remove (A), with each wearing a harness and tying off to an inconvenient anchor point. Safety gate installed (B) can be operated by one person and protects the edge when the guard rail is removed (C)

Access to valves at the top of the CO_2 tank for lockout/tagout and maintenance required a step ladder and awkward body positioning (left). Replacement system under construction when this best practice was submitted includes a fixed ladder, working platform, guardrails, and swing gate (right)

Compliance Services on all of the new equipment.

Some of the items identified in the Fall Hazard Survey were done in-house such as eliminating storage areas over several areas that would require fall-protection systems, installing several swing gates at the lube-oil and chemical bulk storage unloading area, and installing removable guardrails (see photos).

L G White Safety Corp was brought in to review the plant's fixed ladders and the other fall-protection system recommendations in the Fall Hazard Survey. A detailed proposal with photographs and recommendations was developed for ladder safety systems, rooftop equipment access, areas where rails had to be removed to bring up equipment or parts leaving edges unguarded, and where work was being done more than 15 ft from an edge.

In 2021, fall-protection systems installed by L G White included these:

- Replacing six existing ladders on tanks and the stack ladders with 3M's DBI-SALA® Lad-Saf™ systems that have a center tie off for fall protection and tie off points at the top and swing gates.
- Removing existing deteriorated horizontal lifelines and installing grated paths, guardrails, and self-closing swing gates for access to the roofs of the administration and water-treatment buildings.
- Installing a removable guardrail system for a turbine roof deck.
- Installing roof guardrails, swing gate, and a fixed ladder for an inside storage area over an office area (after ensuring load ratings were appropriate).
- Installation of a mezzanine safety gate in the turbine hall.
- A guardrail system to access rooftop vents that are more than 15 ft from a roof edge in several locations.
- Installation of a fixed ladder, swing gate, and working platform with rails to ensure safe access to valves on the top of carbon dioxide tanks.

Additional updates to the initial fall survey plans and procedures and training on the new systems is planned for 2022 now that all the new systems and equipment are in place. Annual inspections also were updated.

Results. Based on the review of work tasks and areas with potential fall hazards, new equipment was purchased and fall protection systems were replaced, upgraded, or removed as shown in the photos. These actions, along with training and inspections will help to ensure compliance and a reduced risk of injury to Empire's employees.

Project participants:

Chester Szymanski, plant manager
Janis Fallon, EHS manager
Jason Glassbrenner, safety committee chair and water-treatment technician
Eric Palmer, maintenance technician
Jim Smith, maintenance technician
Don Bessette, Safety Compliance Services
Mat White, L G White Safety Corp

Alstom Owners Group Sixth Annual Meeting

March 20 – 24, 2023

The AOG, born of necessity to help owner/operators of Alstom gas and steam turbine/generators navigate the O&M challenges arising from GE's purchase of that company in November 2015, looks ahead to its sixth annual meeting, March 20-24, at EPRI's corporate offices and training facility in Charlotte, NC. This will be the organization's first in-person conference since 2020.

AOG has grown dramatically since its founding in 2018. There were 41 members representing eight countries the first year. By the 2022 meeting, those numbers had increased to 193 members in 33 countries. Arnold Group, Pioneer Motor Bearing, Hughes Technical Services (HTS), and Liburdi Turbine Services have supported the organization since its beginning, sponsoring each of the first five meetings.

The 2023 conference agenda, in development as CCJ goes to press, will be posted by year-end at www.aogusers.com, where you'll also find registration, lodging, and other pertinent information. Contact ashley@aogusers.com with any questions.

AOG is a private user organization that enables owner/operators of Alstom equipment to communicate directly with each other, and with third-party services providers, in a secure setting. Membership is limited to individuals directly involved in the construction, operation, and/or maintenance of Alstom gas and steam turbines and who are employed by companies with ownership and/or operational interest in those turbines.

Content for, and conduct of, AOG conferences is organized by a steering committee, with the following members for 2023:

- Brian Vokal, VP operations and engineering for Midland Cogeneration Venture.
- Pierre Ansmann, global head of marketing for Arnold Group.
- Robert Bell, plant manager of Tenaska Berkshire Power.
- Jeff Chapin, AOG founder, Liburdi Turbine Services.
- Ross Goessl, PE, senior engineer for We Energies.

AOG 2022, Day One

The fifth annual (2022) meeting, conducted virtually, was presented over five nominal four-hour days, February 7-11. Training sessions were conducted on two days the following week. Recordings and/or slide decks of all presentations made available to the steering committee can be accessed through the group's website by registered users.

The conference opened with a keynote presentation, "Leading Change and Innovation at your Powerplant," by Wade Younger, CEO, The Value Wave. The motivational speaker/author's professional activities focus on technology implementation and organizational transformation.

User discussion

A structured user-only, two-hour user discussion session followed Younger's keynote. It was divided into the following sections: inlet and filtration, compressor, combustor, rotor and casing, hot-gas section, exhaust systems, generator and electrical, controls/BOP/auxiliaries, and safety/compliance/outages. The steering committee's Bell moderated the discussion session.

One of the combustor topics brought to the floor by users concerned unit pulsation, as well as high NO_x during the shoulder months and winter. Tuning interval was discussed as well. Conclusion: Pulsation monitoring is important. One user disconnected his instrumentation with casing cracking the result. Another said he had no problem with the silo combustor. A GT26 user reported tuning after a major, adding that it took about 30k EOH to go out of tune.

During the combustor discussion the group was asked, "How often do you validate TIT formulas?" A GT11 owner recommended adjusting the C constant after a major inspection and also having a discussion with GE about this. The need for an energy balance around the GT was mentioned as was the need for top-grade instrumentation. HTS was recommended for an independent verification check.

Experience with the fuel water drain valve was next. Question: Have any users simplified or replaced this three-position valve (wash mode, drain, run)? Air leakage through the valve was mentioned as a potential issue. Suggestion by an attendee: Replace the valve with a simpler one.

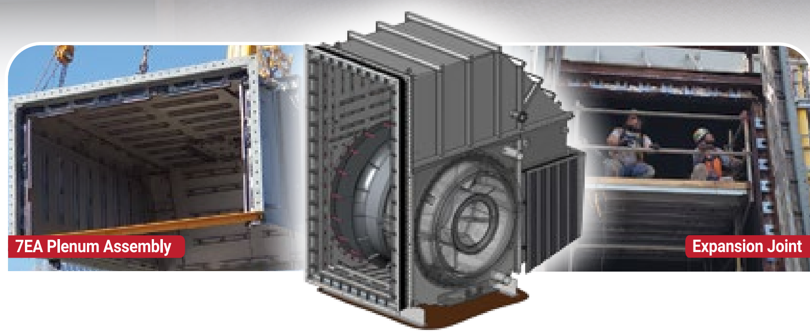
Rotor and casing. The first question concerned the 5000-start inspection recommended in TIL-2040 Rev2. If you have done this, did you do it with the OEM or with a third party,

GasPath SOLUTIONS

Plenum Assemblies and **Diffuser Replacement & Repairs**

Over 75 years industry experience to guide your repair or rebuild project

- Design
- Procurement
- Fabrication
- Project Management
- Installation



Inlet Systems

- *Fabric Inlet Expansion Joints*
- *Acoustical Liner Repairs and Replacement*
- *Inlet Dampers*
- *Inlet Silencer Panels & Ducts*
- *Inlet Bleed Heaters*
- *Inlet Dehumidification Skids*

Air Filtration Systems

- *Full or Partial Filter Grid Replacement and Repair*
- *Replacement Weather Hoods*
- *Filter House Replacement*
- *HEPA Filter Grid Upgrades*

after how many starts? Were there any findings? The message regarding inspection interval: You want to keep the rotor operating as long as possible, but safety should be your primary goal.

One user said his plant did the 5000-start inspection with the OEM plus two third parties—M&M Engineering and Doosan Turbomachinery Services. Recommendation: Use operating data to help decide what to look for—for example, creep.

Question to the group: Has any user encountered combustion casing cracks? If so, what remedial/temporary action is suggested for keeping the asset in operation? Stop/drill and/or weld repairs may be solutions—depending on the specific issue. Coatings and pulsation management also might help in at least some cases. One participant said cracking went away after pulsation was controlled.

Hot-gas section. Have users experienced feather-seal wear on stator heat shields (SHS) severe enough to result in fallout after one cycle? Recall that feather seals are located in grooves between stator heat shield. The user soliciting help said his plant had almost a full set of SHS classified as fallout because of wall loss attributed to seals.

The problem was found during a C-inspection but it was not immediately obvious why feather seals would rub against SHS. The condition was said to be "uncommon." In the opinion of the user, the OEM didn't provide information of value as to why the wear occurred.

Other. An attendee mentioned that he had two units in an outage showing bent pedestal rods. He thought the plant should be able to straighten the rods but he wanted colleagues to share any knowledge they might have on the topic believing two instances as "suspicious." One thought was to check the spring cans under the stilts for freeze-up. Another reported a similar finding of bending and decided to take no immediate action to avoid the possibility of creating another issue.

A question on remote operation of GT11Ns received some good discussion. No one said they were operating remotely but the question transitioned to "What would you have to do to replace the operator who was walking down the unit to enable remote operation?" Example: Plume. Would you have a camera watching the stack? What other instruments would you need for detecting noise, leaks, wherever and whenever they occur? What risks do you have without having a person onsite with the senses one associates with finding a problem: sight, hearing, feel, smell?

There was a concern brought to the group regarding the hardwired pressure switch for starting the emergency dc lube-oil pump. According to the OEM and a third party, operators are able to valve open this switch using the black knob, thereby allowing oil to drain through the manifold. This is supposed to create sufficient pressure drop to activate the pump. But it doesn't.

The user said plant's goal is to check this function weekly or monthly but not possible as configured; an additional orifice or isolation valve would be required, he said. Someone offered that you still would not be fooling the pressure switch with the mod proposed. A question from another attendee: How often do you have to run the test?

Nothing was resolved; perhaps the same question might be posed at an in-person meeting where concerned parties could meet after the session.

What follows are abstracts of the three user presentations made at the meeting, what the OEM had to share on GE Day, and thumbnails of presentations by vendors important to the fleet.

User presentations

Challenges and surprises from recent GT11NM C-inspections

This presentation on Day Three is of particular value to owner/operators of GT11N gas turbines with the M upgrade because it shares the findings of C-inspections on eight peaking units—six in the last couple of years. Coverage includes the following:

Compressor diffuser bolt failure. Turbine rotor axial position and bearing vibration alarms of concern on one of the units were first received in mid-2018. That fall, numerous rotor-seal-air low-DP alarms were received, causing runbacks. By year-end, the plant had revised its alarms based on guidance from the OEM. This scenario was repeated in 2019, 2020, and 2021—reaching the point where the unit could not run reliably because of the runbacks. A forced outage was taken.

Broken vertical split-line and radial bolts were found in the lower casing during the ensuing inspection. The bolting loss had allowed the casing to move about $3/8$ in., resulting in significant casing-to-rotor rubs, Labby seal wear to below that allowed by the spec, and the loss of axial lock tabs on a rotor heat shield.

The bolts, which failed where their shafts and heads meet, have been redesigned to reduce stress in that critical area. The speaker suggested that his colleagues with engines equipped with the original bolts replace them during their next C-inspection, adding that the part numbers of the bolts have not

ARNOLD Group: Single-layer insulation system installed on GT24/26

Doosan Turbomachinery Services: Rotor technicians install locking hardware on a 11NM rotor (left). At right, another 11NM rotor made in the company's La Porte manufacturing complex undergoes a progressive balance run

changed.

Row 5 turbine-blade Z-notch fretting was found on six of the eight N1 units upgraded to NM that had completed their first C-inspections. The speaker stressed the need for a good Z-notch fit to mitigate vibration capable of damaging the base material. He characterized the wear as consistently inconsistent—the wear at all notches not being the same. As to cause, an RCA (root cause analysis) had not been completed prior to the 2022 conference.

Blowoff-valve internal corrosion. A significant amount of rust has been found on the control-air side of these valves. When the valves were opened for inspection, standing water was in evidence. The culprit: Plugging of the small drains in the water traps with gunk and other debris. Action taken: Close, regular inspection to ensure the drain holes remain open.

Fuel-oil block-valve leak through. Fuel-oil nozzle coking was the resulting issue. Plus, there was the odor of gas from a leak in the centrifugal extractor. When the valve was opened, significant pitting was in evidence along with accumulated corrosion products and gunk. Re-machining of valve seat was necessary. The valve has worked well since taking the corrective action and the odor of gas essentially has disappeared.

A valve rebuild kit (FSI 223271) is available and that task is now incorporated into C-inspection activities.

QA/QC issues with OEM parts. Complaints always are a hot topic at user-group meetings. One of the problems raised was the varying degree of Teflon thickness on new seals for blowoff valves. The tolerance is only 1 mm, so this is a significant concern. A fuel-nozzle machining issue also was identified.

Finally, the attendees were made aware of water intrusion into the blowoff-valve silencer and of chattering wear on the pulsation probe assembly.

EV burner front-segment issues

Thursday's (Day Four) user presentation on two incidents of EV front-segment displacements was based on 11 years of experience at an electric-power and desalination plant in the Middle East with five GT26B gas turbines. Arrangement: Two 2 × 1 combined cycles and one backpressure cogeneration unit.

Three machines each had completed three C-inspections prior to the conference, the others, two C-inspections. The second inspections on all machines and the third on three were conducted by Ansaldo Energia—as required by a European Union directive put in place when GE purchased Alstom.

Equivalent operating hours (EOH) of the five gas turbines range from 81,000 to 98,000. The interval between C-inspections conducted by Ansaldo is 32k EOH, up from 28k with Alstom/GE.

The first incident in mid-2016 occurred when the EV pulsation-probe fixation front segment was found displaced during a borescope inspection following multiple trips on high pulsations. A broken "J" hook had allowed the front segment to move. An Alstom specialist with special tools replaced the defective hook without opening the machine.

Plant personnel learned EV front-segment displacement had occurred at one other plant at least (see CIB 2012015_GT26) and that Alstom had a new fixation design. The recommendations of the Alstom directive were implemented in all five gas turbines during their second C-inspections.

The fix for the second incident at the Middle Eastern plant was far more complex. In this case, one of the gas turbines was challenged with high CO emissions in some load ranges. Ansaldo borescoped the unit as 2021 drew to a close, finding one EV-combustor front segment leaning because of suspected damage to two of its four "J" hooks.

Concerned that a unit restart at that time might cause the front segment to release and cause significant damage, a forced outage was taken. Rotor removal was required to replace the affected front segment. The outage ran four weeks, costing more than $1 million in parts and repairs, plus business interruption. At the time of the 2022 conference, a third-party consultant had been retained to assist Ansaldo in determining the root cause.

In the editors' minds, this incident certainly warrants discussion at the upcoming meeting—particularly so if the affected front segment had been replaced, as believed, with the new design.

Gas-turbine innovations

A highly experienced gas-turbine engineer/project leader at a UK combined cycle shared, on the last day of the conference, a couple of ideas developed at the facility to reduce outage time. Plant was built in two phases: The first, installed in 1996, is a 3 × 1 unit powered by 13E2 Alstom gas turbines. The second, a 2 × 1 with 13E2 gas turbines as well, went commercial in 1998.

Two of the three Phase I gas turbines were partially (60%) upgraded to Alstom's new (at the time) MXL2 technology during a C-inspection in 2012—the first engines in the fleet so equipped. Full upgrades of the other units followed, including installation of AEV burners on all machines.

The innovations contributing to the plant's "lean" outages are these:

- Bolt beams and access platform. It allows rapid release and tightening of the split line using a high ITH tensioner without need for a crane. Plus, it eliminates the manual handling risks associated with moving the tensioner and heavy bolts during their removal. The process is illustrated in the presentation posted on the AOG website.

Other advantages of the bolt beam: (1) Support a platform (photo provided in presentation) to allow O&M personnel (and rescue team, if necessary) safe entry to and exit from the combustion chamber, (2) eliminates the need for scaffolding, and (3) provides a secure place to attach harnesses when working on casings.

Experience: At the time of the 2022 meeting, the plant had completed two outages—one with the beam, one without. A table compares the times to complete necessary tasks (such as loosening bolts on the split line) under each scenario. Using the new method, approximately 41 hours was saved in setting up and securing from a C-inspection—for each gas turbine. This paid for the bolt beams and access platform with first use.

- Intelligent asset management. The second innovation is a graphical system that tracks gas-turbine components from cradle to grave, providing complete operating data along with all historical documentation (reports and photos)—all while eliminating Excel spreadsheets.

It can be used for multiple different gas turbines—even portfolios—in your fleet. Information available helps you carry out an efficient flow of parts through different GTs or migration to another plant.

Plant personnel developed this system for the 13E2, but it can be adapted for any gas turbine. Versions for the 9E and 9F were under development at the time of the 2022 conference.

The intelligent asset management system is comprised of eight modules—including scheduler, material inspection, plan execution, etc. But you really can't grasp the value of this enhancement without perusing the slides and demo available on the AOG website.

GE Day

If you were unable to sit in on the second day of the 2022 AOG conference and want to hear what the OEM of record (GE) had to say, access the three-hour recording via the links provided in the last paragraph of this section.

Given that three hours is a big bite out of anyone's day, the editors recommend fast forwarding through the first hour and selecting the parts you want to hear using the summary below as a guide. Our guess is that you can listen to everything pertinent to your responsibilities over a typical desk-top lunch.

What's in the first hour? The challenges of the post-Covid world regarding supply-chain issues, stretched-out delivery times for capital parts, the need for better advanced planning, GE's reorganization into three companies, lessons learned, contingency plans, safety initiatives, cross training of personnel to alleviate some training challenges, and on, and on.

Recently released technical information letters pertaining to Alstom steam turbines followed the long intro.

TIL-2052, KA24 ICS steam-turbine IP rotor cracking.

Some significant indications have been found during recent inspections of KA24 steamers. Of the dozen-and-a-half rotors inspected in the time period addressed, half had indications. TIL-2052 was updated to reflect these findings—one a particularly deep crack caused by creep-fatigue interaction. Interestingly, no abnormal vibration behavior was observed by plant personnel when the turbine was operating.

Root cause analysis (RCA) concluded cracking risk depends on the following, among other causes:

- Number of starts and the mixture of hot/warm/cold starts.
- Low steam temperature on hot starts.

This TIL requires rework in the P1, P2, and P3 piston areas at 800 starts, plus operational changes to reduce life consumption.

TILs also have been released recently for units with configurations similar to those of the KA24: 2205 and 2230, equivalent-cycles based, and 2315 and 2316, equivalent-hours based (EOH). These have different equivalent limits and specific inspection and rework requirements based on the lifetimes of limiting features. Attendees were asked to work with their respective GE service reps to assess the current level of equivalent cycles or operating hours, whichever applies. Get the details in Slide 35.

TIL-2010, Radial inlet vane (Radax). Inspections have revealed findings on high- and intermediate-pressure turbines with radial inlet scrolls (Radax)—specifically: bent, partially cracked, and in a few cases, fully cracked/ruptured airfoils.

TIL recommends regular borescope inspections to determine if a problem exists. Particularly important is to borescope about a year before the next major—a/k/a C inspection—to see if there's any cracking (such as at airfoil fillet radaii) that requires new parts so these can be ordered before time becomes an issue, and a casing lift can be incorporated into the outage plan.

This TIL was released in 2017 and since that time findings have been identified in about 20% (round numbers) of the units inspected. A chart presented shows that operating hours and temperature influence component condition.

TIL-2360, Potential for austenitic-blade root cracking. This document is less of concern for combined-cycle units than the TILs mentioned previously. It applies to high-use units with austenitic blade material in the inlet stages. Recent work by the OEM revealed that the underlying root cause of the cracking was creep damage.

Note that "high utilization" is determined by a review of operating history. If it is in evidence, blading should be replaced at the next overhaul with a lower-utilization configuration to help mitigate the risk of premature creep.

TIL-2266, Valve tooling replacements. The OEM learned that tooling being supplied to remove steam-turbine valve internals could yield under appropriate working loads, posing a risk of personnel injury and/or product damage. Recommendation: Replace tooling with improved capability and function prior to your next scheduled outage.

The TIL segment of the program finished with a look at what "damage" can occur to a steam turbine during periods of low load and cycling. This is particularly helpful in operational decision-making. Here are the damage mechanisms to be aware of:

- Inlet valves—throttling and solid-particle erosion.
- HP and IP shells and valve casings—low-cycle fatigue (LCF).
- HP and IP rotors—LCF.
- HP and LP sections—windage heating.
- Casing and last-stage blades—erosion when hood sprays are on.
- Last-stage blades—LCF.

Parts planning is particularly important today, the group was told, given the long lead times associated with replacement capital components. The speaker pointed out that many steam turbines are unique from Day One and some parts must be made—often there are no spares on a warehouse shelf. A review of a given unit's lifetime operational history, a collaborative effort between the OEM and owner/operator, is critical to proper planning.

GE's next-gen steam-turbine valve portfolio was next on the agenda. New valve internal geometries and materials are said to improve component reliability and operability. More specifically: reduced risk of stem leakage and valve sticking, increased throttling range, and ability to accommodate low load and daily starts.

These valves are designed for as little as 25 hours of operation per start, half of what had been recommended previously and more in synch with the operating paradigm forced on many combined cycles today. Another advantage of the durable next-gen valves is that their maintenance can be done on a C-inspection schedule rather than during B inspections.

Options for decarbonizing gas power, a topic at most—if not all—power-industry conferences these days, looked at both pre- and post-combustion solutions. For the former, the following zero- or low-carbon fuels were reviewed: hydrogen (blue, green, pink), synthetic methane, renewable methane, biofuels, and ammonia. Carbon capture by way of liquid solvents or solid sorbents in the exhaust stream, and oxy-fuel cycles, were the post-combustion processes discussed.

Alstom experience burning hydrogen in gas turbines, as reported at the meeting, includes the following: A blend of up to 5% H_2 in natural gas for the EV combustor and 79% H_2 for the GT8's single burner combustor. Also said was that the GT13E2's AEV combustion system has been cleared for burning up to 30% hydrogen in natural gas. Regarding the GT26, analytical work suggests that for mixtures of natural gas with up to 40% by volume of hydrogen, both fuels show the same physics.

The possible impacts of burning hydrogen in existing plants also were covered.

Generators were the subject of a solid presentation that most plant personnel probably would benefit from. The theme was "enhancing reliability to support life extension keeps fleets relevant." The presenter, a highly experienced product manager, began by reminding attendees that the generator is not the turbine most attendees were familiar with. Example given: Its design incorporates organic materials, unlike the turbine.

The cyclic loadings characteristic of today's operating environment are the source of stresses not experienced in baseload service, contributing to increased risk of forced outages (a chart illustrates this point well), and the higher probability of a rewind (15-20 years for a rotor, 25-30 years for a stator).

Typical findings during generator inspections impacting a given unit's lifecycle include the following:

- Rotor—Retaining-ring insulation damage, loose blocking, cuts on winding connections.
- Stator—Loose bolted connections in phase rings, electrical discharges, support cracking.

To reduce the risk and impact of unplanned rewinds, the speaker suggested the following actions:

- Follow GEK103566 Rev M recommendations.
- Consider continuous monitors for the rotor and stator—including shorted turns, partial discharge (PD), shaft voltage, flux, etc.
- Stock long-lead-time parts, such as rotor rewind kit and stator bar set.
- Consider the GE exchange when rotor work is extensive and the unit

is must-run. Bear in mind that the lead time for a new rotor is more than one year.

Review of the following two TILs was suggested:

TIL-2119, Rotor pole-to-pole connector cracking. Applies to generators manufactured between 1996 and 2015.

The cyclic load during start/stop operation causes low-cycle fatigue and can lead to cracking. Several recommendations are made to users with these machines—including replacing pole-to-pole connectors with the upgraded configuration on units with 700 starts or more at the next scheduled inspection.

A pending TIL update regarding the repair of P2P connectors brazed on the rotor coils would allow work with the rotor inside certain models of generators. Get the details from your GE service rep.

TIL-2241, Rotor winding connection inspection and replacement. Applies to WX/Y 21Z and WF 21Z air-cooled machines and WT 21H hydrogen-cooled generators.

Cracks have been found on these units where the two winding connections join the inner-most coils of the rotor winding with the radial stalk. In most cases only one lamella was affected. The good news: No forced outage has been associated with these findings.

Suggested action is a visual inspection of the winding connections. If crack indications are in evidence, a GE rep will work with the affected owner/operator to determine a proper course of action

TIL-2256, Rotor-slot insulation cracking. Applies to 60-Hz, air-cooled units manufactured after 1996—specifically, WX/Y 21Z and WX/Y 23Z machines.

Evidence of rotor insulation damage has been identified during inspections which could lead to a ground fault. However, no such fault had been experienced in the fleet before the meeting. Root causes of the ground fault are explained in the TIL along with the consequences of insulation cracking. Summaries of the findings of thermal and finite-element analyses likely answer most questions users would have. Recommended preventive measures are described as well.

Issues with 21Z generators manufactured before 2008 was a subject of importance to many users. The concern is that some of these GVPI (global vacuum pressure impregnation) machines have suffered stator-core spacer migrations that should be addressed.

However, it is not so easy to rewind a GVPI machine. The simpler route, the speaker said, is to replace the stator with one developed in 2013 and designed to reduce core and endwinding vibration by shifting natural frequencies away from 120 Hz. A slide in the presentation explains how this is accomplished.

Discussion of spare parts closed out the generator presentation. GE recommends that owner/operators maintain an inventory of such strategic parts as wound rotor, spare exciter, stator bar kit, etc. The speaker noted that the lead time for a new generator, new stator, new rotor field, and excitation and controls all are 24 months or longer today. Lead times for various components and types of upgrades are provided.

To dig deeper on all topics discussed by the OEM during the conference, access the presentations on the GE Power Customer Portal (formerly MyDashboard). The new user interface features enhanced navigation to keep users informed on the disposition of TILs, provide the ability to follow your outage from planning to closeout, track parts orders, and retain reports and other documentation of importance—such as O&M manuals—in one location.

To register for access, go to https://

Registration.gepower.com/registration. To log in, go to https://mydashboard.gepower.com/dashboard.

Doosan Turbomachinery Services: Certified repair specialists weld-prep blades prior to re-establishing tip heights. In foreground, multiple dovetail-root simulators enable fitment and rock checks

Vendor presentations

Doosan Turbomachinery Services

GT 11NM rotor lifetime assessment and fleet management

Come up to speed on Doosan's capabilities by accessing this presentation by Christian "Alex" Ford. It begins with a short overview on the parent company's activities in the power industry and beyond. Highlights include drop-in replacements for major steam-turbine sections—such as the HP/IP.

Next is a review of Doosan Turbomachinery Services' capabilities in Houston—including gas- and steam-turbine component repair, rotor inspection and assessment, welding, heavy mechanical work, parts, onsite services, etc.

The meat of the presentation is a review of several rotor-repair case studies with a focus on C-inspections and the advance planning they require. Standard inspections and activities performed in Doosan's Houston rotor shop are reviewed next: visual, bearing journal diameter, seal diametrical inspections, and full NDE evaluation, plus rotor cleaning, rotor runout, rotor balance, and metallurgical evaluation.

The goal of the inspection effort is to find indications in critical areas that, at expected intervals, could adversely impact rotor lifetime. The company's rotor modeling and thermal-mechanical analysis capabilities provide a critical assist in this regard.

In-depth repair capabilities also are reviewed by the presenter. They include L-bore mods, indication removal, re-contouring, and transition radius adjustment

The advantage of having access to a spare rotor was included in a brief section on optimizing the use of fleet assets.

Hughes Technical Services

Alstom gas-turbine services and solutions

HTS is a relatively new company, founded in 2014 by former ABB/Alstom engineers. If you want to know what Hughes can do for you regarding plant commissioning and maintenance, listen to Fernando Velez's presentation.

The company specializes in control-system service, upgrade, and retrofit, and excitation and frequency conversion. Plus, gas- and steam-turbine services, along with balance-of-plant solutions. It also offers tools for monitoring pulsations and blowoff valves, which owner/operators mentioned as being of concern to them (see section with user presentations).

ARNOLD Group

Insulation systems for Alstom gas and steam turbines

Pierre Ansmann opened his presentation on "the most advanced turbine insulation combined with a high-performance heating system to improve startup flexibility," by summarizing its value proposition thusly:

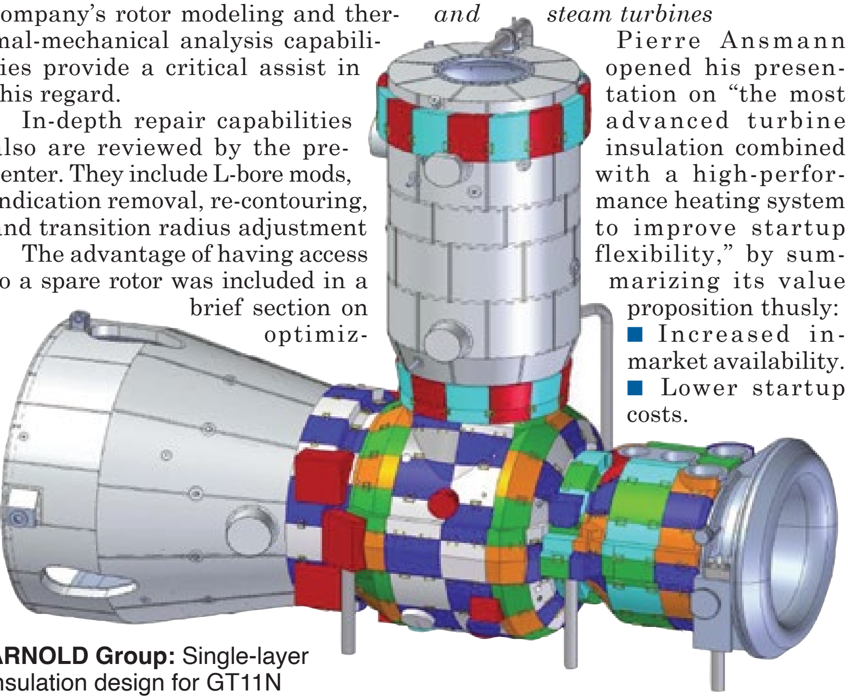
- Increased in-market availability.
- Lower startup costs.
- Reduced thermal fatigue and longer mean time to repair for critical components.
- Increased operating flexibility

The ARNOLD system features interlocking high-performance blankets which conform perfectly to the turbine surface. High-quality materials and manufacturing, and long-term high-temperature resistance, allow the company to guarantee reuse of its insulation system for 15 outages without a decrease in efficiency.

Dozens of thermocouples, strategically located on the turbine, ensure proper heating. Each of the 18 or so heating zones has t/cs installed on the heating wires to double check that the zone is responding correctly and at the specified temperature. Below every heating zone, multiple t/cs are mounted on the casing to confirm even heating of the turbine.

A properly maintained ARNOLD insulation system is said to maintain your turbine in a hot-start condition for at least four or five days after shutdown. No preheating of the unit is required prior to a start within this time period, reducing startup fuel consumption and auxiliary power.

Major portions of the presentation are dedicated to the GT24/26, and GT11N and GT13D. A special focus on ARNOLD's repair solution for inner insulation at the exhaust diffuser was another highlight of the presentation encompassing more than 60 slides.



ARNOLD Group: Single-layer insulation design for GT11N

Liburdi Turbine Services

User-driven reverse engineering of GT components: Practicality of new technologies and strategies

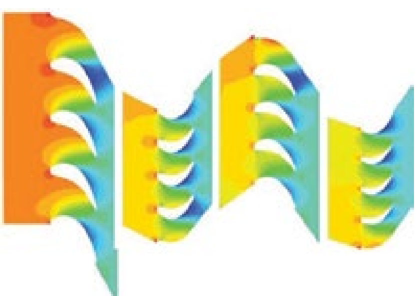
Doug Nagy, manager of gas-turbine component repair, and four colleagues told attendees that successfully reverse engineered gas-turbine components can provide cost savings and/or alleviate supply-chain issues. But it's important for owner/operators to understand the key characteristics of a component, its production processes, and the various costs and lead-times involved.

The presentation team assured users that the repair industry already possesses many of the skills required to reverse engineer critical parts. They have been developed over the years to better understand the component designs to address their repair needs and implement upgrades as appropriate. The tools and analyses required for successful reverse engineering are detailed in the slide deck.

ST Power Services

GT lifecycle and plant obsolescence management

Presentation begins with a list of general challenges facing owner/operators of powerplants powered by gas turbines—such as rising O&M costs, evolving pricing models, aging technology and workforce—and spends the remainder of the podium time discussing the company's portfolio of solutions and services for Alstom GT8, GT11, GT13, and GT24/26.



Liburdi Turbine Services: CFD modeling of turbine flows at each critical row is a valuable analytical tool

PSG Power Services Group

Recent field-service projects

Mike Lake, VP sales, began his presentation by introducing key company personnel formerly associated with Alstom and summarized PSG's considerable experience in the inspection and repair of Alstom gas turbines (GT8 and GT11) and steam turbines.

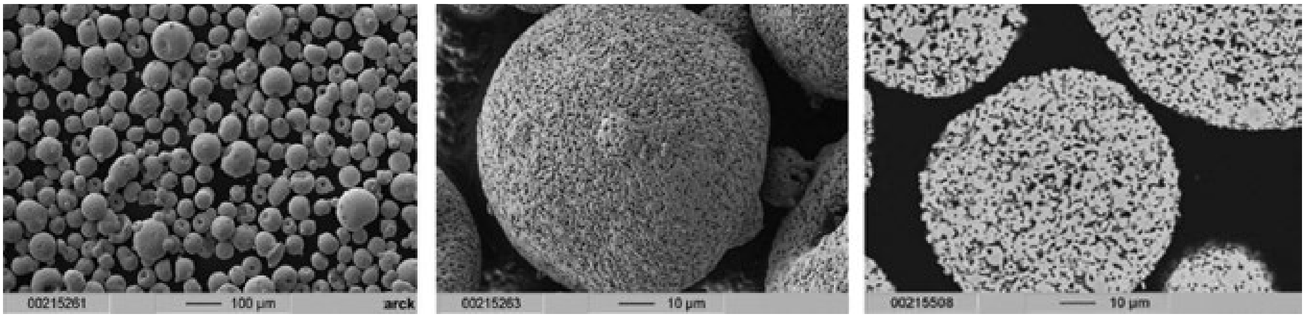
Then he dove into specific recent projects to validate the company's capabilities. They included the following:

- A-inspections on the bearings and HP/IP/LP stop and control valves for a 479-MW STF60 commissioned in 2018, plus LP crawl-through and HP/IP borescope. Photos and notes provided give details.
- B-inspections on the IP stop valves for a 190-MW STF. Planning for C-inspection in 2023 was included in the work scope.
- A/B-inspections on a GT11N1 included work to secure the unit's inner gas ring.
- B-inspections and repairs to key components of a GT11N2 (hot-gas casing upper intake, flow separator).
- Locking-block replacement for a GT11D found missing the center portion of its block during a borescope inspection.

PSG Power Services Group: Locking block replacement was required when the center piece for a GT11D Row 16 three-piece lock was found missing during a borescope exam. The job ran nearly 20 single-shift days given access challenges

Vibro-Consult AG

Vibration analysis and balancing



Hoganas: Company's patented Low Kappa REO-SZ (Amperit® 808.006) blade coating is said to outperform conventional TBCs

Fabio Massaccesi, senior vibration expert, described the capabilities of this small enterprise with extensive knowledge and experience in the area of measurement and vibration technology for rotating power generation equipment and industrial machines. Pertinent to user members of the Alstom Owners Group, Vibro-Consult has helped owner/operators with solutions for the GT8, GT9, GT11, GT13, and GT24/26, plus single- and multi-shaft combined cycles with both air- and hydrogen-cooled generators.

Specific services include the following:

- Root-cause analysis and advanced troubleshooting.
- Vibration investigation and analysis.
- Condition monitoring.
- In-situ balancing of rotor trains during operating periods and after major inspections.
- Vibration training.
- Multi-plane rotor balancing.
- Computer-aided balancing.

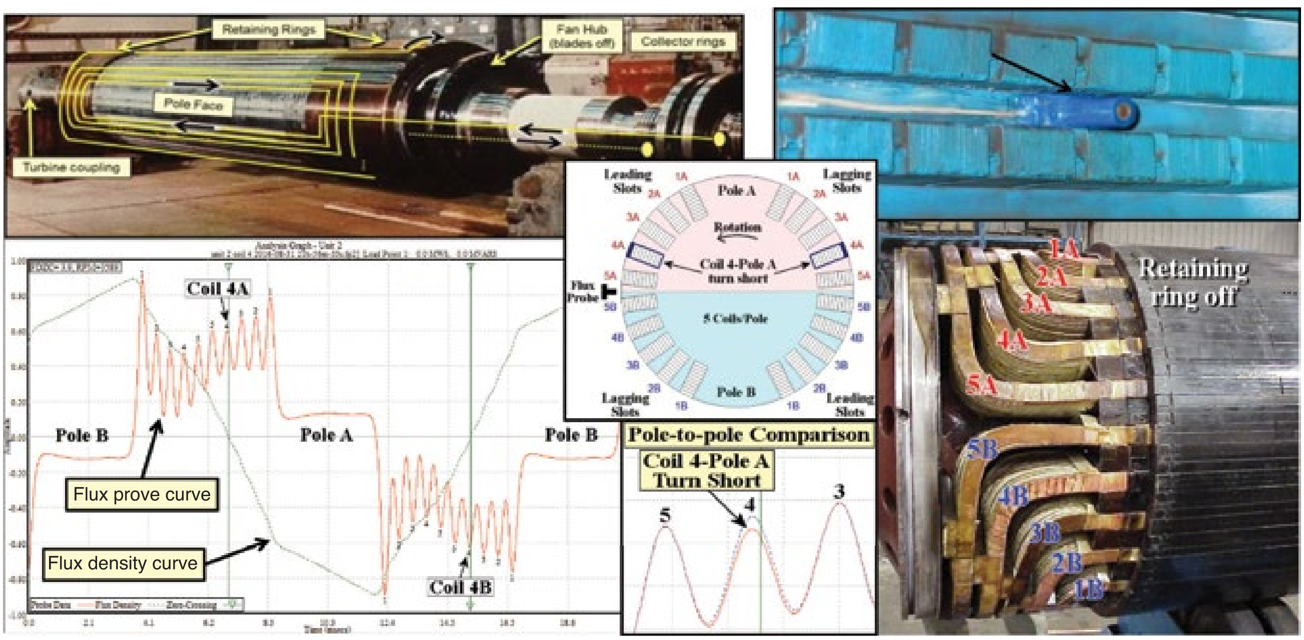
Höganäs AB

Introduction to TBC and Höganäs' REO-SZ low "K" TBC

MD&A: Out-of-round steam-turbine casing was "re-rounded," assembled, and prepped for heat treatment

David Sanson's presentation begins with a crash course on standard thermal barrier coatings (typically 7-8% yttria partially stabilized zirconia, used effectively for more than 50 years) and their morphologies and microstructures. He then reminded attendees that conventional TBCs may be challenged at today's high firing temperatures, pointing to numerous recent patents for advanced coatings.

Sanson then discusses the benefits of his company's low-kappa REO-SZ (Amperit® 808.006), a product users might want to investigate. Data presented include thermal conductivity, thermal-shock-test results, and SEM



Generatortech: Generator rotor winding shorted-turn detection—flux-probe theory and case studies

and phase analysis (EDS and XRD). Höganäs offers a wide range of powders that meet Alstom specs.

Generatortech Inc

Generator rotor winding shorted-turn detection: Flux-probe theory and case studies

David Albright's conclusions suggest what you can expect to learn from his presentation. They are:

- Shorted turns in field windings occur frequently. While not a big issue in many cases, they can be a serious and expensive problem.
- Online testing is critical because offline tests will miss speed- and temperature-dependent turn shorts.
- Testing over a full range of loads is critical to identify all true turn shorts and eliminate all false turn shorts.
- Installing flux probes during outages can save time and money on future generator maintenance decisions.

Albright explains turn-to-turn (and coil-to-coil) shorts with good illustrations and provides photos of typical damage. Beware the vicious cycle of turn short development, he warns, explaining that each turn short creates higher temperatures that increase the likelihood of new turn-short development, possibly leading to rapid insulation degradation. Example given: Rapid degradation of a rotor winding for a 680-MW generator caused an increase in turn shorts from two to 10 in 18 months. Several two-pole rotor case studies enhance the learning experience.

Mechanical Dynamics & Analysis

Alstom steam-turbine casing repairs

Dave Rasmussen, PE, explains MD&A's engineered casing repair methods that apply to Alstom steam-turbine designs and materials. He covers typical casing-related overhaul inspections and dimensional checks, plus the more common repairs to correct wear, mechanical damage, distortion, and steam leakage. Photography facilitates understanding stationary-blade repair and seal-strip replacement and machining as well as the re-rounding of HP turbine casings.

AGT Services Inc

Alstom WX/WY-21 series air-cooled phase cracking

Jamie Clark, well known to users because of his frequent presentations at user-group meetings presented the case history of an Alstom 60WX-21Z-085 machine that was modified by the OEM in 2016 to prevent phase-jumper connector failures. This generator is relatively common, Clark said, and the information presented is applicable to several other models as well.

The subject air-cooled, 18-kV generator is rated 188 MVA with 0.85 power factor and Class F MicaDur (GVPI stator). Clark began by reviewing the root causes of stator braze connection issues: Poorly designed/executed joint, vibration attributed to 1/rev and 2/rev frequency drivers, a poor endwinding support system (one that either permits excessive vibration or provides too much restraint), and increasing thermal stress.

The challenges facing owner/operators responding to the OEM's recommendations in its bulletin on phase lug cracking can be formidable. Recall that there are thousands of brazes in a generator—all done manually and then insulated manually.

Visual inspection is virtually impossible in some cases given joint location. Plus, even if the field is removed and the joints are accessible, you can't see them unless the insulation is removed. Radiography is an alternative, but that has its own challenges, personnel safety among them. UT and use of a thermal-vision camera may be your best option to identify poor braze quality and cracking before a failure occurs. Clark shows how this is accomplished by way of superior illustrations and explanation in the recorded presentation.

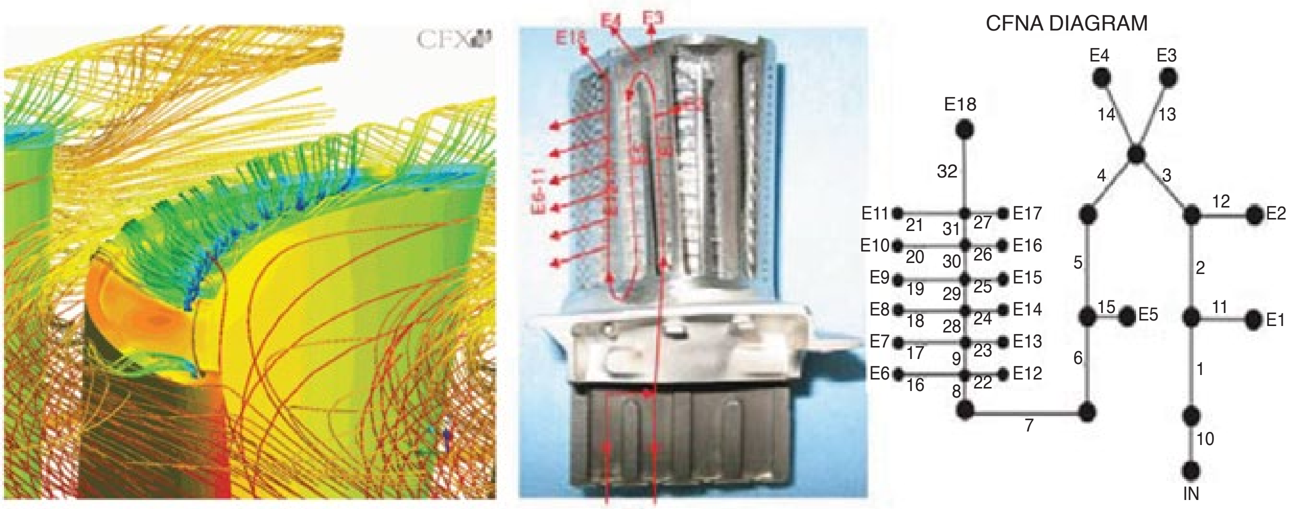
It's important to avoid a failure, especially given the GVPI stator which is very difficult to rewind. Remember, too, a failure typically generates carbon and copper byproducts from the burning that occurs and they are ingested by the fan and distributed throughout the unit. The field is affected, of course. Likely, rings will have to be removed and the rotor rewound.

However, those are not your only concerns. The redesigned joints add mass, changing the resonant frequency of the endwinding support system. Expect that de-tuning also will be required.

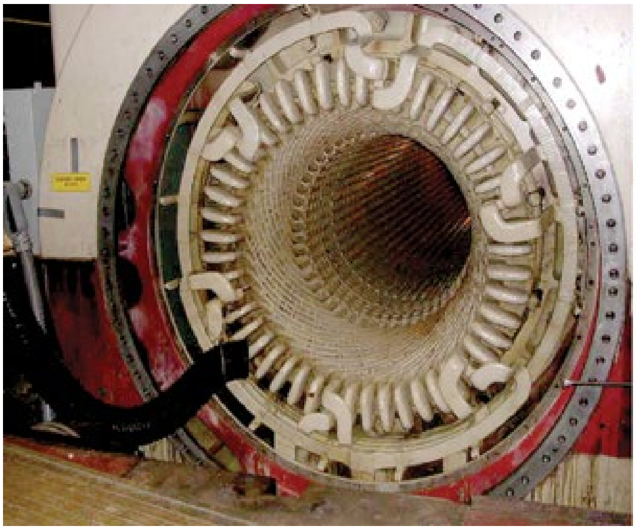
Training workshops

A distinguishing characteristic of annual meetings hosted by the Alstom Owners Group is its training workshops. The 2022 program featured three two-hour training sessions during the second week of the virtual event—one in Spanish language. The two sessions in English were conducted by these well-respected presenters with deep technical experience:

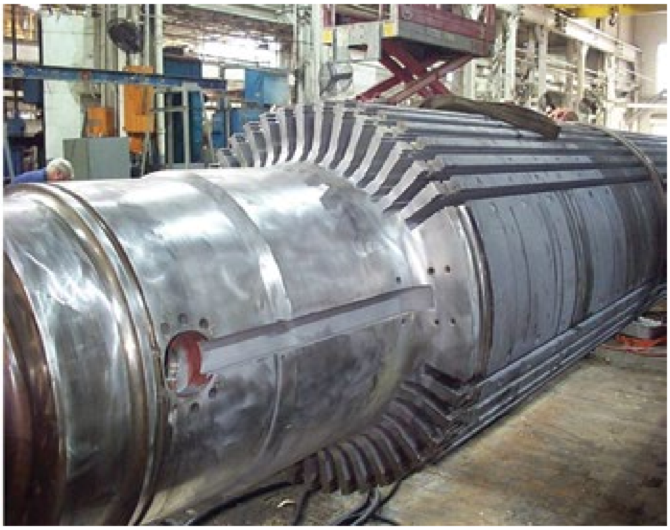
- Doug Nagy, manager of gas-turbine component repair at Liburdi Turbine Services.
- W Howard Moudy, director of



Liburdi Turbine Services: Meaningful failure investigation involves the use of sophisticated tools—such as CFD simulation of turbine-blade cooling-channel exits (left) and a fluid-flow model of cooling-air distribution (right)



National Electric Coil: Stator consists of the frame, core iron, and coils, with the first holding everything together. Core iron provides a magnetic pathway for the flux, the coils carry the current generated by the induced voltage



National Electric Coil. Rotor forging was machined from a single piece of NiCrMoV steel to withstand torsional, lateral bending, vibratory, and rotational stresses

operations, National Electric Coil

Both presentations are worthy of consideration for lunch-and-learns in the plant break room. It's easy to divide both workshops into two one-hour sessions. For example, Nagy's lends well to segments on failure-analysis techniques and causes of gas-turbine failures; Moudy's to a session on stators and another on rotors.

Nagy began by saying failure analysis is a strong learning opportunity and that all failure analyses should lead to one or more corrective actions. Failure analysis, he says, encompasses root-cause determination, investigative frameworks (such as fishbone diagrams), methods, and testing, and mechanical analysis.

First steps include gathering accurate reports and evidence on the affected components, plus conducting mechanical and metallurgical examinations. The importance of visual and dimensional inspections is covered, along with a review of nondestructive testing methods (liquid penetrant, magnetic particle, eddy current, ultrasonic, x-ray, and microhardness). All this is both a good refresher for experienced staff and a primer for newcomers. Slide format is conducive to input from attendees for sharing experiences; it is not textbook style with lots of words.

Causes of gas-turbine failures are explained and well-illustrated in more than half of the slides. The outline of that content below might encourage your review of the presentation:

- Design factors—design basis of components, system design deficiencies, economic and environmental constraints.
- Operational factors—procedural errors, common operational mistakes, and monitoring and data analysis.
- Maintenance factors—maintenance plan and schedule flaws, and design migration.
- Repair factors—design basis for repairs, effect of refurbishment on potential integrity, and inspection during the repair process.

Moudy's stator tutorial resembles a medical text showing all the body parts. The illustrations will benefit greatly O&M personnel who never have seen a generator apart. The stator, Moudy said, consists of the frame, core iron, and coils, the first "holding everything together." The core iron provides a magnetic path for the flux, while the coils carry the current generated by the induced voltage.

Illustrations of proper core clamping and the types of core laminations follow. Spark erosion then is explained and described with photos showing the progression of a failure. Side ripple filler was touted as a cure for SE.

Final topics in this portion of the program included the following: stator slot wedges, stator coil bracing, coil design, endwinding stability, and phase leads and phase rings.

In his rotor tutorial, Moudy began at the beginning—with William Sturgeon's finding in 1823 that current running through copper wire wound around a piece of iron produces a magnetic field. He reviewed the basic components of rotors and their purposes. For example, the shaft, retaining rings, and wedges are of forged steel, the winding of copper. Then there's the insulation.

The photo nearby shows the slots machined in the rotor forging to hold the winding's copper turns. Wedge grooves, "fir tree-" or "T-" shaped allow wedges to hold copper turns in place during rotation. He went on to describe the various types/designs of retaining rings and the material preferred for them for holding the windings in place.

Cooling was Moudy's next topic. He covered conventional indirect cooled, inner-cooled conductors, inner-cooled coils and insulation, and GE's diagonal cooled windings. Details on coil-to-coil and pole-to-pole connectors for a variety of machines followed.

Remaining segments of the presentation included end-turn blocking, rotor slot wedges, slip rings/collector rings, radial and axial connections, J-strap leads, rotor journals and bearings, and rotor fans/blowers. CCJ

Who ya gonna call the day after a 'bump in the night'?

What do you do when your gas turbine experiences a forced outage (FO), or as Sulzer's Jim Neurohr and Michael Andrepont put it, a "bump in the night"? Hopefully, your plant already has a plan in place for such emergencies, and they hope you'll call Sulzer and let them put their full-service shop in LaPorte, Tex, to work on your behalf.

The underlying message of the webinar, "A Bump in the Night: GT Forced-Outage Response," hosted by CCJ Online, July 28, 2022, was to dramatize the benefits of responding to the FO by contracting one service firm with a single point of contact between site/owner and the shop, rather than trying to manage multiple service firms.

Neurohr and Andrepont imagined the emergency trip of a 7EA machine operating at baseload in a combined cycle, with significant damage to the compressor's fifth stage, and collateral damage to downstream components, discovered through borescope inspection after the machine cooled down. The two then proceeded to illustrate every major step (sidebar), and many minor ones, between exclamations of "What the hell" in the control room and a gleaming, fully repaired (and perhaps even upgraded) rotor returned to the site weeks later.

The photo journey depicted through the slides includes lifting of the casing top, onsite data and evidence preserving and gathering, lifting and transporting the rotor, in-shop rotor inspection and evaluation (turbine and compressor), rotor unstacking, root-cause failure analysis (RCFA), rotor overhaul plan and commercial proposal, repairs, coatings, replacement parts, rotor rebuild, rotor bolt stretching, cooling flow testing, final balancing, the findings of the extensive metallurgical inspection and analysis and RCFA, install of the refurbished rotor, and testing and tuning prior to the machine's return to commercial service.

As part of a response to an attendee question, the presenters noted that they can assist the owner/operator in working with their insurance carrier to cover a non-OEM refurbished machine.

The viewer is also treated to a veritable tour of the LaPorte service facility, first built in 1973, which now boasts 500 employees and a full complement of state-of-the-art inspection, evaluation, repair, coating, testing, and balancing facilities.

These days, replacement parts can be difficult to procure, especially one-offs. Sulzer stocks many of the replacement parts (photos), is increasing its on-hand inventory, and/or can manufacture them on short notice to keep the project moving forward. Upgraded components "in many cases can run longer than OEM recommended intervals," the pair said.

10 critical steps in Sulzer's inspection/repair process

1. Receive parts, record, and ID
2. Perform incoming visual and dimensional inspections
3. Grit blasting/strip coating
4. NDT components
5. Generate repair quote
6. Pre-weld heat treat, NDT, weld prep
7. Weld repair, NDT, dimensional check
8. Post-weld heat treatment, NDT
9. Final dimensions, customer witness
10. Prep, ship, provide Turbodocs

Most of the questions were practical in nature, but not readily answerable because each FO or turbine wreck is unique. RCFAs are time consuming and involve "heavy analytics," the specialists noted. Not all RCFA findings are "conclusive," but "generally, we've seen whatever failure mode it is before."

In a response to a question about fuel nozzle and combustor damage, the Sulzer duo reported that, year to date, three 7EAs have experienced failures of transition pieces in DLN units, new failure modes are being observed, and nozzles are wearing faster and showing new damage indications. CCJ

Blading (A), disk inserts (B), and rotor bolting (C) are just a few of the replacement parts which may be needed to get a damaged rotor back in service

Fix HRSG backpressure maladies; avoid explosion risk in condenser

The HRSG Forum continued its tradition of offering excellent user-driven content in its 10th virtual meeting, held Oct 13, 2022.

The first presentation, by Harold Snyder, PE, of Lakeland (Fla) Electric's McIntosh Power Plant, addressed a two-decade operating history of high HRSG backpressure (BP) and derates in Unit 5, a 1 × 1 501G-powered combined cycle. The second presentation, by Steve Bates and Steve Harvey, reviewed a catastrophic incident at the 2 × 1 501G-powered Wise County (Tex) Power Plant in which natural gas accumulated in the condenser during an extended outage and exploded when a welder attempted to repair an external pipe.

McIntosh Unit 5 was commissioned in 2001, one of the plants typical of that era designed for baseload operation but soon pressed into cycling service for many years thereafter. Almost from the get-go, the HRSG experienced fouling by ammonia salts from the SCR and rust accumulation, most evident in the last tube sections, resulting in a gas-turbine (GT) derate of 15 MW.

After years of monitoring pressures, trying online cleaning methods (sonic horns, vibrators on lower headers) and offline cleaning (dry ice, air jets, pressure wave), and dehumidifiers on the GT inlet and low-pressure (LP) inlet to the HRSG, McIntosh, beginning in 2008, resorted to adding stiffeners in the HRSG, removed lower baffle plates (Fig 1) in the LP and intermediate-pressure (IP) sections (and trying several different baffle configurations), and adjusted SCR controls and economizer recirculation temperature controls, to increase the allowable BP from 28 to 30 in. H_2O.

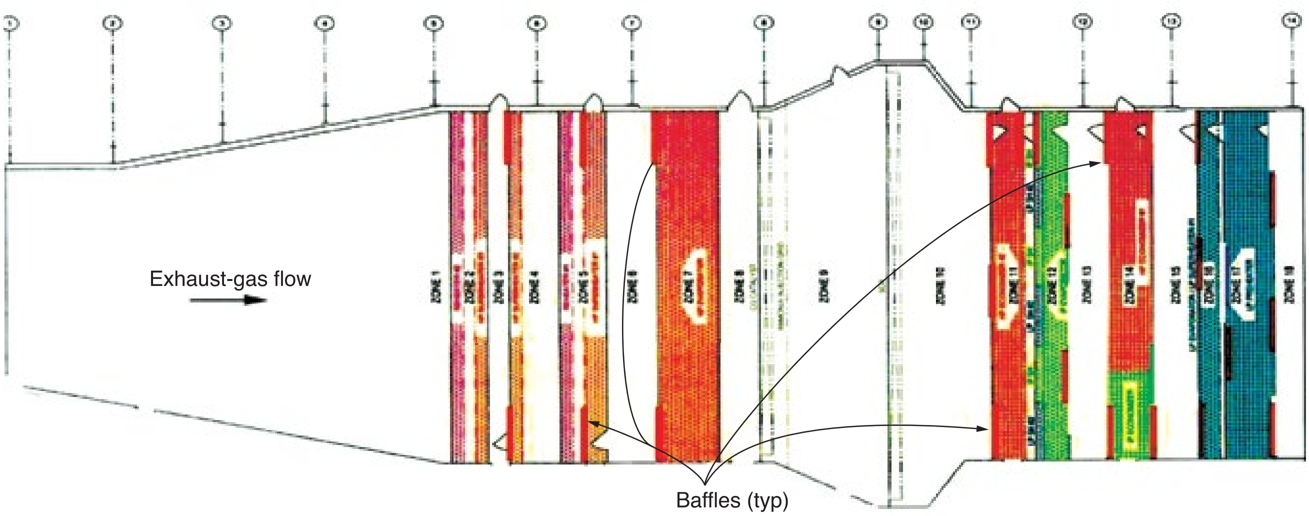
In the face of continued elevated BP in 2016, McIntosh pursued permanent modifications beginning in 2017 (through 2020) to increase allowable backpressure to 45 in. H_2O and address other issues—such as tube leaks. These included doubling the number of stiffening plates in the roof, floor, and walls; replacing the LP economizer, LP superheater No. 1, and LP evaporator tube bundles; and upgrading the expansion joints. Eleven tube rows in the LP economizer were replaced with 15 smaller-diameter tubes, creating a 20 in. cleaning lane between the LP economizer and the LP evaporator/superheater No. 1.

Snyder noted, during the Q&A, that pressure-wave cleaning was by far the most effective, stating that the technique was able to remove about five times as much debris as dry ice. Readers are encouraged to listen to all of the Q&A, available at https://HRSGforum.com, which generated critical discussion and insight into ancillary causes of the BP issues, consequences of different baffling configurations, and other topics. Slides include detailed diagrams of baffle and stiffener configurations and external photos of stiffeners.

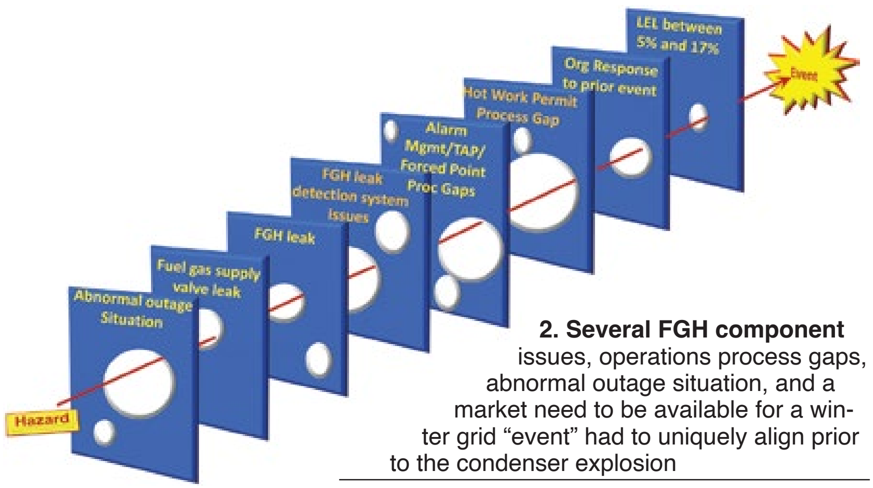
The story may not be over, though. The unit has not been cleaned since 2020 and BP is beginning to rise again, reported Snyder, even though the unit is now operating baseload.

The Wise County Power Plant presentation on the condenser event could very well be one of the most valuable safety briefs you'll receive if you have a combined-cycle plant with a fuel gas heater (FGH). An abridged account follows.

As a result of a failure of a main lead in the steam turbine/generator, the facility was in a steam-turbine outage in January 2022 during which the Wise County GTs remained "available" to the grid (with fuel at pressure up to the FGH stop valves). With the plant experiencing numerous issues



1. Different baffle configurations in the HRSG and other mitigation steps were tried, but backpressure continued to rise. One of the baffle patterns tried in 2015 is illustrated in the diagram



2. Several FGH component issues, operations process gaps, abnormal outage situation, and a market need to be available for a winter grid "event" had to uniquely align prior to the condenser explosion

with the FGH (for example, leaking gas isolation valves) and its leak detection system (prone to false alarms), and other factors, natural gas found its way to the condenser through the IP water-side supply line (the source of heat for the FGH).

The plant was down for 10 days, but with cold weather in the forecast, the gas turbines were started to build up pressure to about 50 psig in the HRSG to prevent freezing. The steam pressure in the HRSG provided the motive force to move the gas that had been accumulating in the IP drum to flow down the steam piping to the condenser.

When a welder arrived to repair a 1-in. pipe connection on the outside of the condenser, the arc ignited the gas and the subsequent explosion blew out six rupture discs on top of the unit, caused bolting threads on the LP steam-turbine cover to fail, and damaged internal structural supports. Rupture-disc parts were found all over the plant site. The explosion was heard and felt throughout the plant.

Mercifully, no one was injured (not even the welder), no condenser tube leaks resulted, and the LP section of the turbine suffered no internal damage.

Plant Manager Steven Bates covered the events (Fig 2) at the plant which had to uniquely align for this incident to even be possible, as well as his company's fleet-wide assessment and recommendations to avoid a similar incident elsewhere, including the following:

- Eddy current test FGH tube bundles and perform leaking testing at least every six years.
- Utilize more robust inserts when plugging tubes.
- Ease plant staff access to vent valving and instrumentation.
- Establish fleet standard critical preventive maintenance guidelines for FGH systems.
- Perform comprehensive FGH system design review.
- Install permanent redundant methane detectors on air ejectors with feedback to control system.

Since the presentation will not be made available online (it has been presented at other industry forums, including the Combined Cycle Users Group conference at the end of August 2022), those interested in learning more should contact Bates directly. CCJ

Fairview

Successes attest to the value of remote M&D

Challenge. Powerplants built over the past several decades are packed with instrumentation, transmitters, and computers. This extensive automation has allowed reduced staffing levels while introducing challenges for effectively analyzing and acting on degrading conditions that may occur long before alarm levels are reached.

Fairview Energy Center

Owned by Competitive Power Ventures, Osaka Gas, and DLE

Operated by NAES Corp

1050 MW, gas-fired 2 × 1 7HA.02-powered combined cycle located in Johnstown, Pa

Plant manager: Bob Burchfield

Regardless of staffing levels, certain machine failure modes are diagnosed by a monitoring service that uses intelligent algorithms designed to provide early warning of adverse conditions, and capable of constantly monitoring thousands of points continuously.

Solution. Many combined cycles use all, or portions of, remote monitoring and diagnostic (M&D) support. Having had remote M&D experience at other plants, the Fairview staff wanted to share some tips gained while operating under the comprehensive M&D program established by owner Competitive Power Ventures.

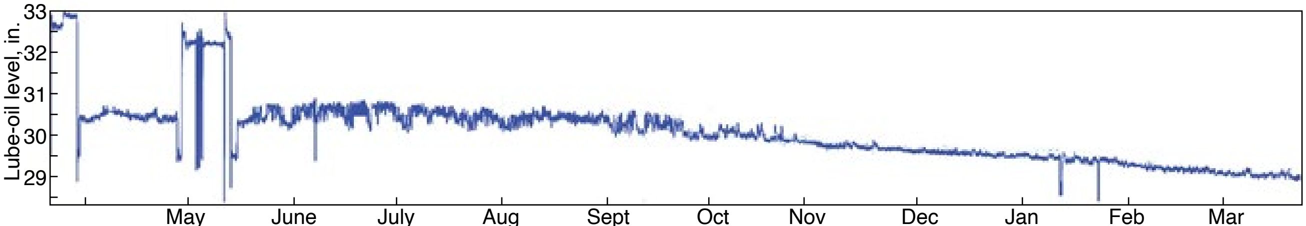
CPV thought it important to contract M&D as a service offering, as opposed to purchasing software to use in-house. Knowing that plant teams are running lean, with each team member already playing a strategic role, the manpower required to learn and maintain new, complicated software wasn't readily available. The M&D services contracted both compliment and augment Fairview's in-house capabilities.

The plant team recognizes the service offering is a dynamic and adaptive process that can be improved as lessons are learned. Communication with the service provider is a "two-way street." Staff doesn't hesitate to ask the provider for help diagnosing symptoms or adding specific logic that might not have been included in the original setup.

Outsourcing M&D as a service has several advantages, including the following:

- More cost effective than staffing a dedicated in-house team to manage M&D around the clock, 365 days a year.
- Remote M&D frees up the limited plant staff to remain focused on other demands of the job.
- When set up correctly, M&D can alert to adverse conditions that might otherwise go undetected. The example trend in Fig 1, flagged by remote M&D software, illustrates a 1-in. drop in lube-oil sump level over about a six-month span. During a subsequent review, plant personnel confirmed they had been collecting oil from a small leak while awaiting an outage to replace an oil deflector.

Fig 2 illustrates the huge amount of data an operator is required to process. Staff welcomes the benefits offered by a remote M&D tool that ultimately



1. Remote M&D flagged a 1-in. drop in lube-oil tank level over a six-month span supports the team in generating power safely and reliably.

Using the major equipment OEM to provide M&D services has the additional advantage of leveraging specific fleet lessons into the software that monitors for known adverse patterns. Plus, it allows for the consolidation of all issues into one platform where they are tracked and discussed on a regular basis. Recommendations that come from the OEM through the platform have the advantage of access to the OEM's bench strength.

In another example of how subtle deviations are picked up by the remote service, the trend plotted in Fig 3 shows process flow versus valve position. The software has identified a subtle variance in which no flow is observed with the valve slightly open. Cases like these are flagged and discussed with the plant team in regularly scheduled meetings.

While some deviations may be minor issues, if the valve in question is inlet bleed heat, for example, it may be robbing output or not protecting against compressor icing if left unchecked. Symptoms like this can be difficult for humans to catch, particularly when they are tasked with overseeing several thousand data points across multiple DCS screens.

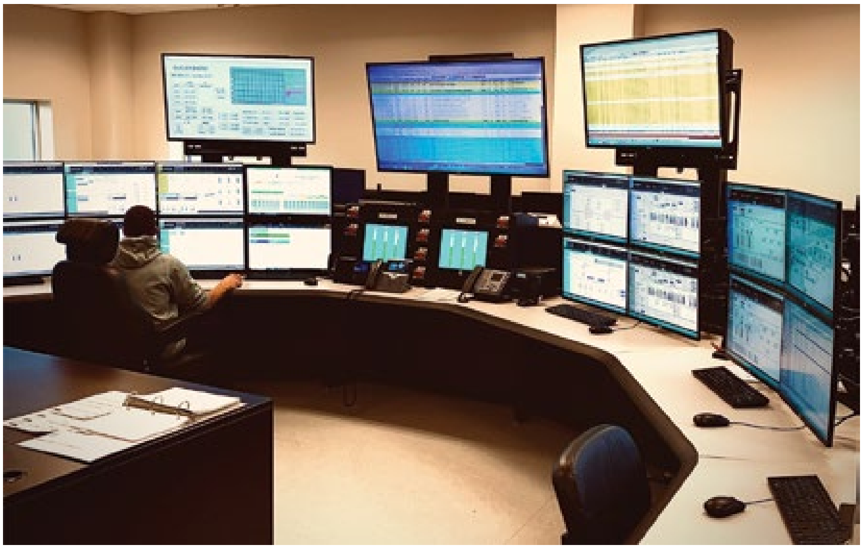
For owners like CPV with multiple assets, remote M&D greatly enhances the ability to stay current on plant issues across their fleets. Plant personnel manage the program, participate in biweekly calls discussing recent anomalies, and provide updates on previous actions taken.

M&D also serves as a tool to aid to help drive the scope of work for upcoming outages. Program effectiveness can partially be quantified by observing the number of actions items landing on outage planning lists.

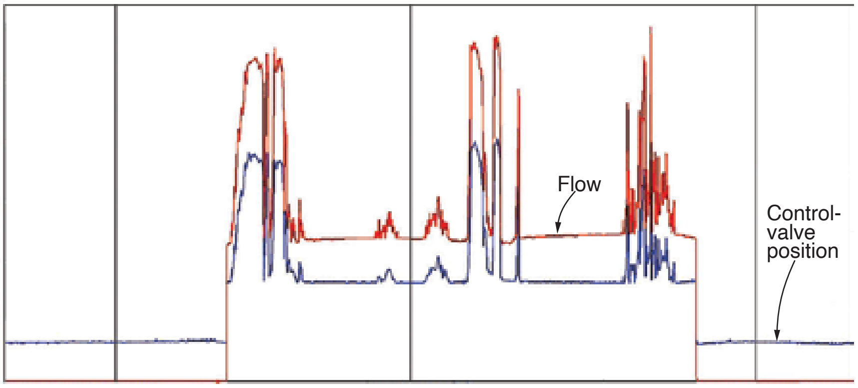
Even though the M&D service is performed by the turbine OEM, the entire BOP is monitored as well for Fairview Energy Center and other CPV plants—including turbine heat rates, machine-specific efficiencies, and full plant performance. This service adds significant value even though performance calculations already are being performed in-house. A comparison of independent thermal models serves as a QA function and helps to confirm causal factors of degradation.

If you currently have a "turbine-only" option for remote M&D monitoring, it's worth reassessing the value of "whole plant" remote monitoring.

Results. Early detection of adverse conditions has reduced forced-outage hours and in at least one instance, prevented additional consequential



2. Staff welcomed the benefits of a remote M&D tool given the large amount of data operators are expected to track



3. A subtle deviation that might go unnoticed by the busy operator but "caught" by the remote R&D tool is illustrated here. Control valve is shown as partially open (blue) on the right and left sides of the chart, yet mass flow is zero

4. A gradual decay in reheat outlet pressure with the control system eventually closing the reheater inlet valves as a protective response, pointed to a frozen pressure-transmitter sensing line (circle at top center of photo) damage to a gas turbine. Discoveries are shared by email in advance of biweekly planning calls to review new issues and track disposition of previous actions. The conference call includes M&D engineers, plant staff, and owner management collectively determining (1) which repairs can be deferred to outages, (2) needed parts, and (3) whether the work can be performed safely without shutting down.

Urgent symptoms are phoned in to the control room from the remotely staffed monitoring center, and in high-priority cases, a notification is sent to the plant manager. Fairfield's Bob Burchfield recalls instances at different facilities in which he was notified with a recommendation to immediately shut down.

In one instance, rotating turbine blades were losing material because of contact with stationary vanes. In another, compressor blades were damaged. In both cases, alarms had not yet activated, the adverse conditions having been caught by M&D software and the 24/7 remote monitoring team. Though there certainly is value in avoiding an imminent failure, the aim is to identify and address issues well ahead of failure, allowing staff to avoid or reduce forced outages by converting them to planned outages. This is what drives Fairview's ROI.

During a recent cold-weather-induced event, plant staff initially struggled with a thrust-related steam-turbine alarm that was void of evidence to confirm an actual thrust condition. The only symptom preceding the alarm was a gradual reduction in turbine reheat outlet pressure. M&D engineers explained the alarm was a calculation based on the difference between inlet and outlet pressures and an assumed thrust.

Subsequent investigation revealed a sensing line had slowly frozen, resulting in a gradual decay of reheat outlet pressure with the control system eventually closing the reheater inlet valves as a protective response. The decision to phone M&D early greatly reduced forced-outage time during a peak market period that could have otherwise resulted in steep financial penalties. The affected sensing line circled in red can been seen in Fig 4.

Relative to notifying M&D for urgent support, Fairview personnel recommend keeping the M&D phone number programmed in your cell phone along with each unit's serial number. Staff can be overwhelmed with alarms. Remote M&D can confirm suspect causes and open emergency engineering cases for review. Having turbine serial numbers visible on your cell is very helpful—particularly when you're at home and initiate a call for help in the middle of the night.

Other benefits of M&D include minimizing the time for identifying and managing thermal-performance degradation and better preparation for planned outages.

Project participants:
CPV: Dominic DiBari, Ali Bibonge, Joe Michienzi, Preston Patterson
NAES: Irv Holes, operations manager; Curtis Speer, lead operator; Rick Marshall, maintenance manager; Jeff Lellock, engineering team

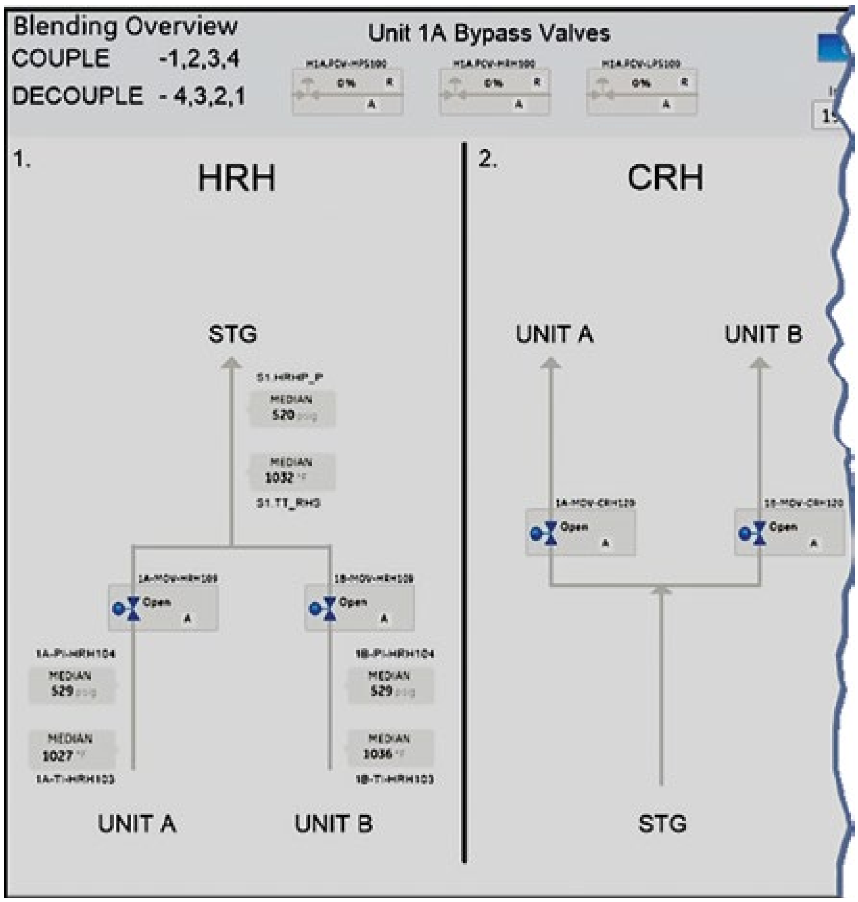
DCS monitoring screens enhanced to improve starting reliability

Challenge. Fairview incurred several plant trips following commissioning because of valves hanging up and/or key parameters being overlooked until it was too late for the Mark VIe control system to keep the unit in service. After a handful of failed starts, staff began to discuss how plant operation could be made more reliable and profitable.

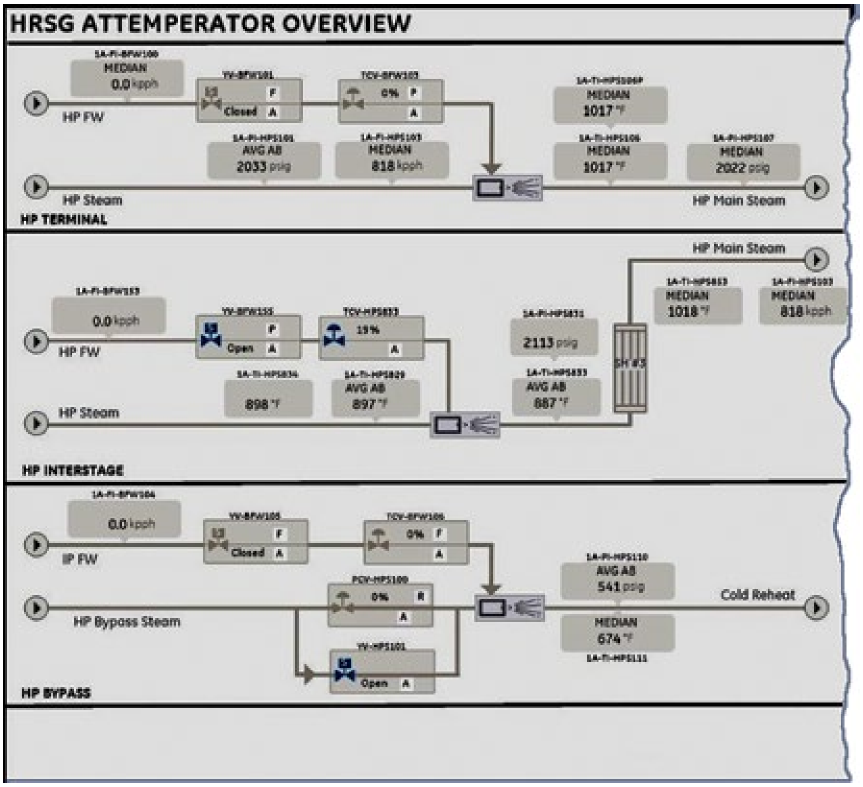
Most of the discussions revolved around issues experienced with key systems, the critical steps that had to be monitored simultaneously across multiple DCS screens, and the time it took to navigate numerous DCS pages.

Specifically, issues were found with attemperating valves not operating properly—typically just after minimum-emissions-compliance load was achieved, when the HRSG and associated piping began warming up and required cooling. Another troublesome area was the unit bypass valves not operating as expected. Or unexpectedly closing to protect piping from overheating because of failed attemperators, and initiating a unit shutdown in the process.

Solution. Working with onsite OEM personnel, staff learned other sites incorporated several parameters, previously spread out over multiple DCS monitoring pages, into a few simple



5. Charts used for blending the outputs of both HRSGs were created for easy viewing and troubleshooting by combining multiple parameters into one easy-to-view page. The left half of that page is shown here; the right half presented the same information for HP and LP steam



6. Attemperator information was aggregated in one screen. The left half of that page is shown here. The right half shows data for the hot-reheat (HRH) terminal, the HRH interstage attemperator, the HRH bypass, and the LP bypass

pages. The specific items monitored—such as troublesome attemperators and their associated block valves, unit isolation valves, and steam-header bypass valves—were shown on individual pages for ease of monitoring during plant starts. However, grouping these separate DCS pages together into a single monitoring page mitigated the delay experienced when browsing page to page.

Results. Individual pages used for blending the outputs of both HRSGs after an initial 1 × 1 startup were created for easy viewing and troubleshooting by combining multiple parameters into one easy-to-view screen (Fig 5). This single unit blending page consolidated what would be been eight separate pages into one.

Additionally, plant-specific, combined attemperator pages were created to monitor each unit's attemperators during the crucial periods of startup to ensure that temperatures remain within design limits during GT starts and that valves move as expected (Fig 6). Attemperator and block-valve graphics from five separate DCS screens were condensed into one for each unit.

Monitoring the new DCS screens increased plant starting reliability, allowing Fairview to come online more consistently without delays, and dispatch sooner.

Project participants:
Curtis Speer, control room operator
Aaron Roberts, I&E technician
Dave Walker, FieldCore engineering team

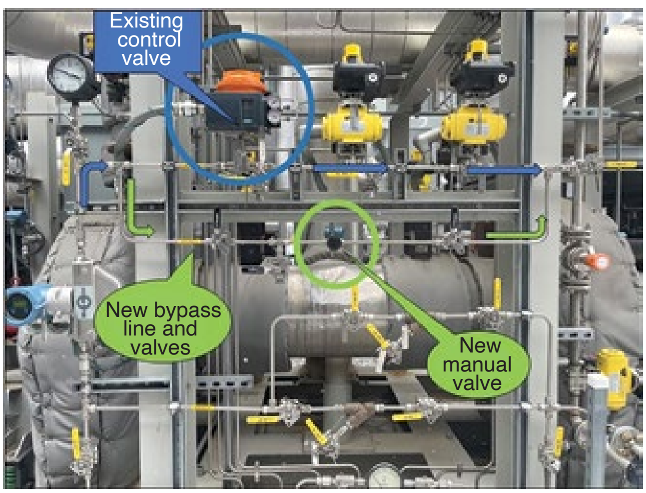
Redundant ammonia injection equipment reduces probability of NO_x exceedance

Challenge. Soon after commissioning, staff discovered that a single point of failure of the ammonia-injection control valve could create an emissions exceedance, limiting the plant's response and output, as dictated by state environmental permitting.

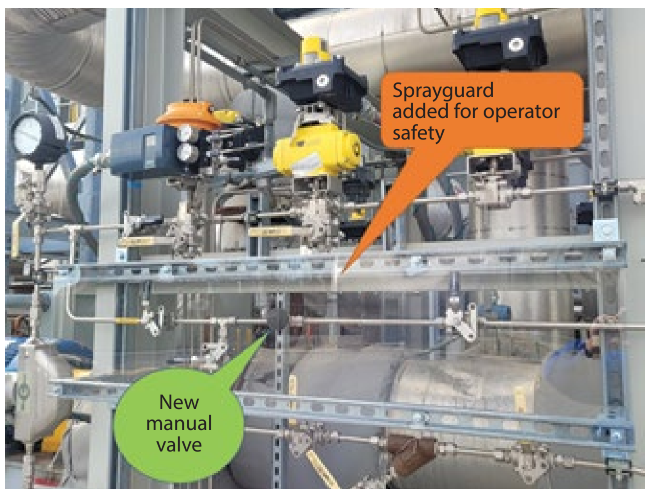
An hourly NO_x exceedance was experienced less than one month after commissioning because of a faulty flowmeter indication. It limited the amount of ammonia injected necessary to meet the NO_x removal rate at the desired load.

An alternative method for injecting ammonia was needed to maintain emissions compliance and remain online and dispatchable while operating with a fault ammonia control valve or associated instrument.

A redundant ammonia injection



7. Manual bypass line and valve allow ammonia injection if instrumentation goes awry or the control valve fails



8. Spray guard provides personnel an added measure of protection when operating the manual bypass line train was not desirable because of the time involved for procuring and installing the additional controls, combined with space challenges (Fig 7). An alternative means of ammonia injection was proposed by one of the plant's operators—a manual bypass valve. It could be installed quickly and, if necessary, be replaced later by a fully automated redundant header with automatic control and block valve.

Solution. It was apparent that a manual bypass valve around the automated control valve would be essential for providing an alternative means of ammonia injection to prevent a NO_x exceedance in cases of faulty instrumentation or failed control valve. By ensuring continuous operation with emissions limits, the plant would be able to stay online and ensure the reliability of the Bulk Electric System.

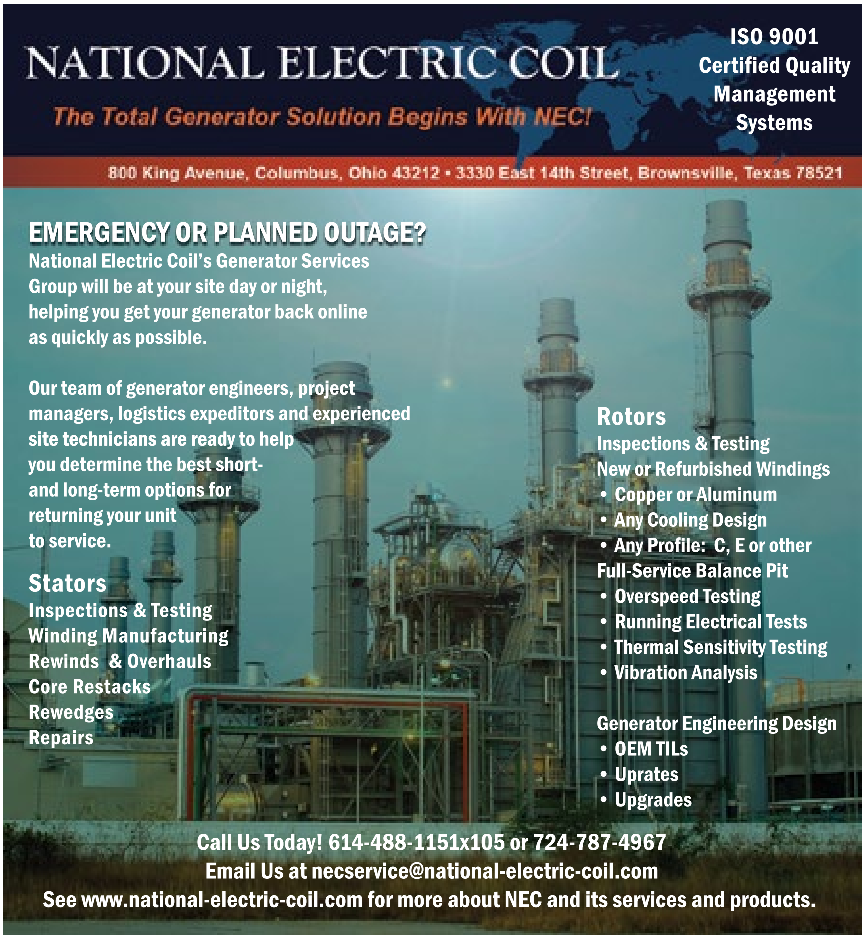
A management-of-change plan was initiated and a new ammonia line was specced out along with the valves necessary to both allow continued ammonia injection and permit safe changeout of the existing ammonia control valve in case it fails.

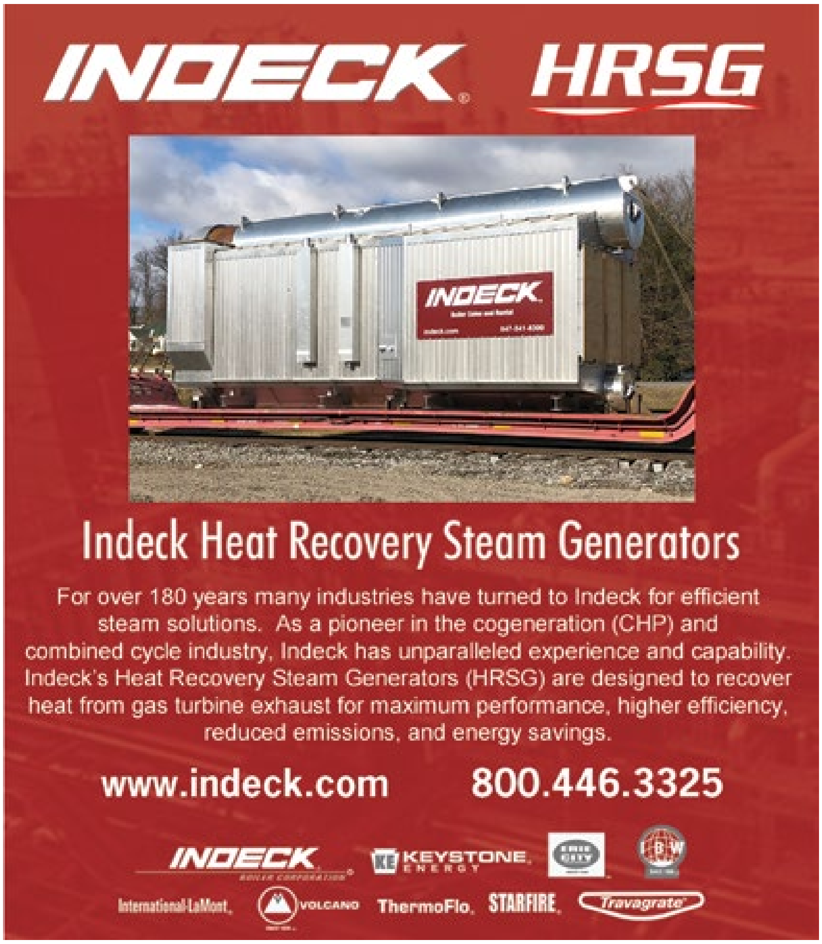
Result. A manual bypass control valve was installed and preset to a flow volume correlating to the ammonia injection rate necessary at base load. The new valve reduces the probability of an exceedance by allowing expedited restoration of ammonia flow in the case of a valve or instrument fault.

As an added safety precaution for staff operating the bypass valve, a shield was installed (Fig 8) to minimize the possibility of an operator being sprayed with ammonia accidentally in the unlikely event of a valve leak.

Site training was held on the newly installed valve and the operations required for its use, if necessary. In addition to installing the manual bypass, logic changes were implemented to make the existing automatic valves less susceptible to closing because of failed instruments. To date, the plant has not had to run with the manual bypass valve open. Presently, there is no need to replicate the automatic control and block-valve arrangement.

Project participants:
Tim Krumenacker, control room operator
Curtis Speer, control room operator
Jason Havash, I&E technician
Jeff Lellock, engineering team
Brian Kline, O&M technician





NO OUTAGE REQUIRED - EASY INSTALLATION

Type	Range	Noise	Coro...	Tone	Disch...	Arcing	RMS
Confidence	30kHz-500...	0.98	0	0	0	0	
Confidence	500kHz-5...	1.00	0	0	0	0.36	
Confidence	5MHz-30M...	1.00	0	0	0	0.15	
Confidence	30MHz-10...	1.00	0	0	0	0.07	
% Power	30kHz-500...	99.97	0.03	0	0	0	43.20
% Power	500kHz-5...	99.90	0.04	0	0	0.06	10.60
% Power	5MHz-30M...	99.95	0.04	0	0	0	22.03
% Power	30MHz-10...	99.94	0.04	0	0	0.01	51.85

Cutsforth Enhanced EMI System:

- Classifies signals associated with defects in transformers, motors, and generators
- Identifies specific failure modes without the need for experts to review the data
- Archives data including time domain waveforms
- Easily creates trend plots for future analysis

ISO 9001 Registered Quality Management

For more information, contact us:

Cutsforth.com/Contact

800.290.6458 x.1

info@Cutsforth.com

SGT6-4000F
V84.3A, 60 Hz

SGT5-4000F
V94.3A, 50 Hz

SGT6-2000E
V84.2, 60 Hz

SGT5-2000E
V94.2, 50 Hz

The V Users Group serves owner/operators of both 50- and 60-Hz engines, as noted alongside the logo above. However, at meetings in the US, the focus is on the 60-Hz models of Siemens Energy's 4000F and 2000E gas turbines. The V fleets here number about five dozen 2000Es and three dozen 4000Fs. Worldwide, the total is about 1000 engines—roughly 80% made by Siemens Energy, the balance by Siemens Energy licensee Ansaldo (50 Hz only).

Siemens Energy has hosted annual in-person conferences here for almost two decades, except for 2020 and 2021 because of Covid-19 concerns. Web meetings filled the void in information transfer until the 2022 meeting at the Hotel Monteleone in New Orleans, August 1 to 4.

This report summarizes content shared with the nearly 50 users participating in the NOLA conference. It is based on notes taken by the editors, Mike Herman, combustion turbine supervisor, Great River Energy (4000F and general sessions), and Scott Wright, technical superintendent, PowerSouth Energy Co-op (2000E), and from presentations by Siemens Energy engineers led by Service Engineering Manager Jonathan Swasey.

Wright is a member of the US steering committee, which also includes Preston Walsh, combustion turbine supervisor at Great River Energy, and J R McKinney, site supervisor, Arkansas Electric Co-op Corp. Communication among V users is facilitated by the organization's forum, hosted at www.PowerUsers.org.

Dig deeper into the Siemens Energy presentations by accessing the slide decks posted on the OEM's customer extranet portal at https://cep.siemens-energy.com (users only).

First three days

The first in-person meeting of V users in three years began with a program characteristic of the Big Easy. The only event on the Monday calendar was a vendor-sponsored welcome reception in the early evening, allowing attendees to avoid weekend travel in the ever-crazy post-Covid world. Tuesday began with a social event—golf followed by a group luncheon—giving attendees the opportunity to reconnect face-to-face after about a thousand days of isolation. Product demonstrations, a favorite on this organization's program, were conducted at the end of the day.

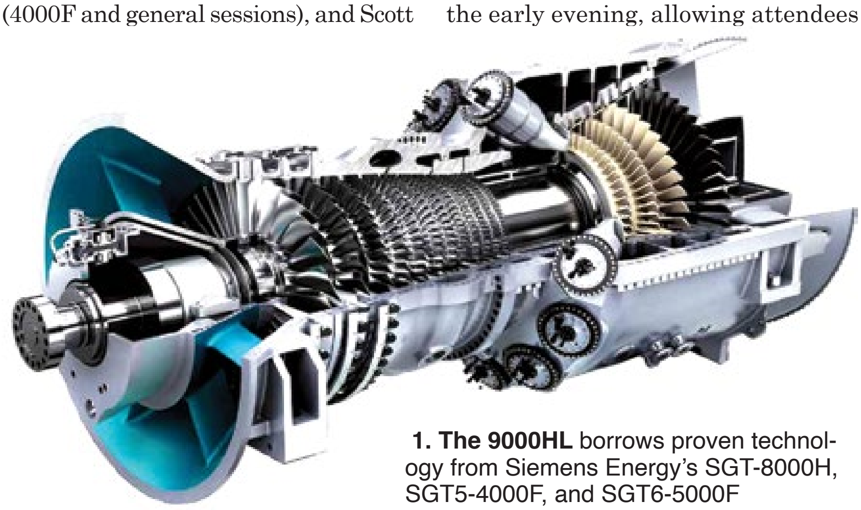
The program picked up steam Wednesday morning with a special session dedicated to the OEM's progress in commercializing one of the industry's most advanced gas turbines—the 9000HL. Attendees were told this machine is the world's largest GT—both in simple-cycle (440 MW at 60 Hz) and combined-cycle (880 MW at 50 Hz) service, as confirmed at US and UK powerplants.

The 9000HL (Fig 1) borrows proven technology from Siemens Energy's SGT-8000H, SGT5-4000F, and SGT6-5000F, validated over the course of hundreds of thousands of operating hours—including single tie-bolt, Hirth serration/steel rotor, air-cooled four-stage turbine section, and hydraulic clearance optimization.

Eighteen HL-class units reportedly had been ordered worldwide at the time of the meeting. Important features of the new gas turbine include its ability to ramp at up to 85 MW/min and burn gas with up to 50% hydrogen. Combined-cycle efficiency tops 64%.

A one-hour closed session for both 4000F and 2000E owner/operators followed, featuring a presentation by Héctor A Frare, plant manager of Argentina's Genelba Thermal Power Plant, and by Curtiss Wright on its Readily Accessible Parts Information Directory (Rapid).

Frare shared details on how his team identified and corrected a combustion-chamber issue on Genel-



1. The 9000HL borrows proven technology from Siemens Energy's SGT-8000H, SGT5-4000F, and SGT6-5000F ba's SGT5-2000E gas turbines using a methodology developed in-house (details in following article). That effort earned the plant, owned and operated by Pampa Energía SA, a CCJ Best of the Best Practices Award for 2022, which was presented at the meeting (Fig 2).

Rapid allows all plants subscribing to its service to see what parts are available through Curtiss Wright, updated daily. The virtual community is said to be used by more than 4500 supply-chain professionals to locate, buy, and sell parts for generation, transmission, and distribution assets. Prices are not included in the data. One participant said he heard that Siemens Energy would "support" the system if "multiple" users joined it.

Closed sessions for 4000F and 2000E users were conducted in parallel until lunch, closing out the morning program. Information shared is incorporated into the closed sessions for those engines on Thursday and is covered later in this article.

A general session for all users and Siemens Energy personnel was conducted in the afternoon, plus dinner offsite. Highlights of the technical program follow.

Field service. A broad-brush view of Siemens Energy's goals regarding tooling, people, and processes to assure the availability of well-trained, capable engineers and technicians to meet customer expectations. Specific technician skills are identified, standardized outage reports explained.

Some recent process improvements include the following:

- Blade-tip and tile grinders changed from 480 to 120 V.
- Casing installation guide cones for V84.2 bolts eliminate manual guiding when setting the case.
- Compressor-blade removal tool.
- New tile overlays to support V84.3Ax minor inspections.

Compressor bearing damage, caused by an interruption in lube-oil flow, was presented next as a case study that explained how the OEM's turbine services group corrected the issue. Accident details: dc lube-oil pump came on for nine seconds following a loss of power, turned off for a minute, and then resumed operation. What happened: Elevated active-side thrust-bearing temperatures were experienced.

A hardness check revealed off-spec measurements, suggesting the potential for cracks. The axial bearing surface on the front hollow shaft was machined in-situ to eliminate the hardness. Tooling developed to machine the rotor was a collaborative effort between Siemens Energy personnel in the US and Germany. Positive outcome: Off-the-shelf bearing pads still can be used, but in conjunction with shims to compensate for material loss.

2. Héctor A Frare, plant manager, Genelba Thermal Power Plant, accepts one of CCJ's Best of the Best Practices Awards for 2022 from General Manager Scott Schwieger at the V Users Group's meeting in New Orleans

A brief discussion of specific field-service capabilities for V engines—including blower blade tipping, coupling boring machine, collector-ring grinding/polishing, and compressor-seal disc mod for rows 3-5—followed the bearing case history.

Generator update. Recent outages showed a need for further evaluation into stator winding and stator core unplanned outages longer than 10 days to identify their causes. Outages attributed to stator winding/core issues have increased significantly from the January 2017 to June 2022 period compared to January 2021-June 2022.

Siemens Energy's Global Vacuum Pressure Impregnation (GVPI) technology for generator stators has many advantages according to users sharing their opinions at user-group meetings. However, a big disadvantage of the technology can be the difficulty it causes when a stator rewind is necessary.

This presentation is valuable for the information it shares on the rewinding of generators onsite using Siemens Energy processes for coil removal, laser cleaning, and rewinding with Single Vacuum Pressure Impregnation (SVPI) coils.

Another discussion point during the session: The benefit of dynamic generator cooling control for flexible operation. Reduction of the temperature differential during short standstill durations enables higher load gradients on restarts. Plus, thermal-mechanical stresses on the insulation system are reduced.

The slides on FAST Gen™ generator robotics inspections using new high-resolution cameras should be of interest to plants wanting faster turns on maintenance outages.

Steam-turbine update. Presentation likely will be of value to staff (other than the plant engineer) for its review of the nomenclature/definitions affiliated with turbine performance calculations—including availability, reliability, starting reliability.

Several slides explain Siemens Energy's TMS (Total Maintenance Services) process. It's a structured outage planning, implementation, and lessons-learned methodology said to create a win-win partnership between the OEM and its customers. It covers budgeting, communications, planning, identification of resource issues during outages, supply-chain issues, shop machine-time planning, etc.

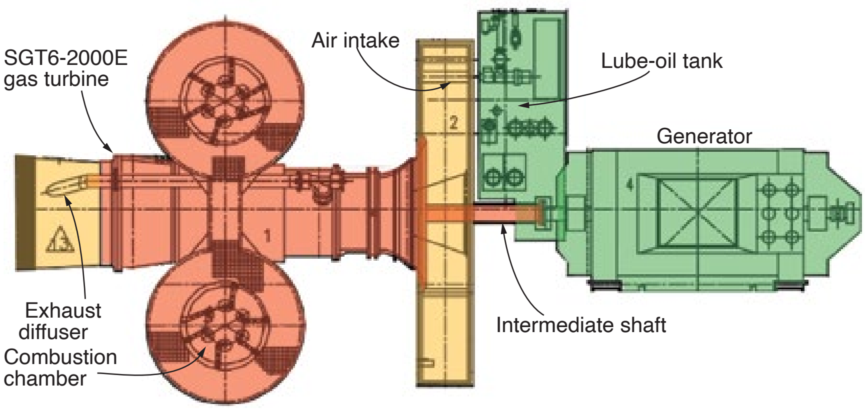
Two sidebars within the presentation address (1) part kits for fossil steam turbines (HE, KN) to help reduce outage time and (2) upgrade solutions for the SST-5000 to increase efficiency, reduce maintenance cost, and recover degradation.

Finally, the intended benefits of a barrel swap for H steamers are covered. They include outage optimization, efficiency improvement, ease of maintenance, etc.

Omnivise T3000 status update should pique the interest of anyone with controls and/or cybersecurity responsibilities. Migration from ET 200M to ET 200SP is a focus of this slide deck. Options and choices are detailed in the well-illustrated presentation.

A few slides on cybersecurity cover audit awareness and what to do in an audit situation. Primary takeaway: It's important for Siemens Energy to know whom onsite is responsible for tracking changes for NERC CIP to avoid issues. Contacts in Alpharetta are provided to answer your questions, etc.

Plant flexibility for a changing market. Plant assessments, weatherization, hydrogen co-firing, the value of emerging technologies such as bat-



3. Brownfield exchange for PowerSouth's McWilliams project is easy to understand from this illustration, where the portions of the generating unit in green were retained, those in gold modified, and the gas turbine and combustors in red replaced

teries, and solutions for grid stability are all profiled. Two examples of operational flexibility are provided to illustrate how plant owner/operators might reduce unit startup time and cost, increase starting reliability, and improve performance. A case study illustrates a plant upgrade capability assessment with the goal of determining equipment capabilities for proposed upgrades.

CEP and power diagnostics presentation stresses that the Customer Energy Portal is the single gateway for all a plant's service needs and reinforces the message that Siemens Energy is the owner/operator's most trusted partner and advisor. The slides walk users through the CEP registration process and illustrate by way of screen shots the unit dashboard, operations KPIs, etc.

Power Diagnostics® services are explained—basic and enhancements. A mobile app with live data feed and visualization connects to key operational indicators and notifies selected personnel of a plant trip. Other capabilities and bells and whistles round out the presentation.

SGT6-4000F

Thursday's program was intense, with four 90-min sessions conducted in parallel tracks for 4000F and 2000E owner/operators. Each track featured one session on mods and upgrades (M&U), one on engineering, and two closed sessions for user-only discussions. A 30-min skull session allowing Siemens Energy engineers and users to sort out sticking points identified over the four-day conference completed the technical program. A closing reception offsite followed.

The mods and upgrades sessions are particularly valuable for those users experiencing operational constraints. It's often possible to identify solutions to consider for increasing operating hours, reducing emissions, boosting efficiency and availability, etc, by listening to OEM engineers with relevant experience.

The M&U sessions in each track began with a fleet update, good for benchmarking and for seeing how your plant compares to others in terms of equipment capabilities.

Worldwide, Siemens Energy reported, the SGT-4000F fleet (50 plus 60 Hz) had a 12-month rolling average availability of 96.3%, reliability of 99.1%, and 96.6% starting reliability. At the end of 2021, 53 of the 342 operating

4000F engines were in 60-Hz service—more than half that number in the US. This segment had accumulated nearly 5-million equivalent operating hours (EOH) and more than 83,000 starts by year-end.

The SGT6-4000F began life in the US as the V84.3A frame as the 1990s drew to a close. Over the next several years, improvements extended the basic engine's capability from about 165 MW to nearly 200 MW in 2013 with the introduction of Service Package 6 (a/k/a SP6)—featuring a thermal performance upgrade and improved hot-gas-path parts. SP6 benefits from earlier upgrades, such as 33MAC (33,000-EOH interval), introduced in 2009 with its improvements in coatings and airfoil geometry and cooling.

Business case for the SP6 includes the potential for a GT power increase of up to 16 MW and simple-cycle efficiency increase of up to 0.7%. A combined cycle could gain up to 21 MW, but with an efficiency increase of only 0.4%. The OEM's CMF++ (compressor mass flow) upgrade, introduced in 2015, squeezed more power out of the machine at higher ambient temperatures than was possible with just the SP6 upgrade.

Next on the list of improvements was the burner upgrade introduced in 2018 to reduce NO_x emissions. Designs of the pilot and premix burners were improved to reduce local flame temperatures; premix flames benefitted from improved stability as well. A reduction in cooling-air consumption in the combustion chamber also contributed to lower average flame temperatures.

Part-load optimization was an important part of the presentation and very practical because this analysis makes use of real site boundary conditions—including current load profile, emissions requirements, and gas-turbine, HRSG, and SCR upgrade capabilities.

There were several slides on fuel flexibility—including guidance on the possible addition of liquid-fuel capability to a unit burning only gas. Next came a look at requirements necessary to accommodate burning varying percentages of hydrogen mixed with pipeline gas.

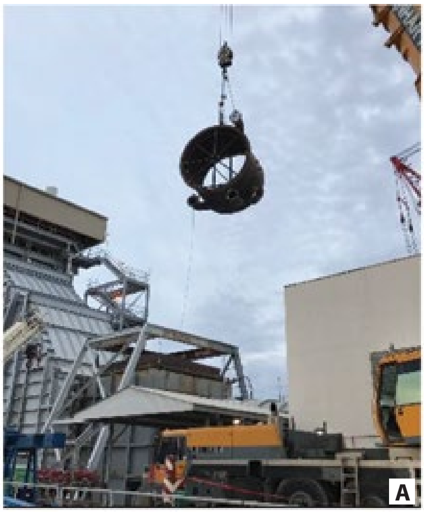
Siemens Energy's goal of continuous improvement suggested a progress report on the company's Advanced Turbine Efficiency Package (ATEP), the development of which is currently focused on the SGT5-4000F engine. Its goal is to increase the efficiency of the current machine by up to 1.5% and boost power output by up to 40 MW. Advanced materials and ultra-efficient internal cooling and sealing of critical parts are among the improvements expected to deliver on the ATEP promise. Four ATEP units have been sold for EU deployment, two for Asia. First fire was planned for summer 2022 at the time of the V users meeting.

Update. In September 2022, the first-time application of ATEP at the Enecogen combined-cycle plant in Rotterdam, Netherlands, was completed as planned. Early performance indications show outstanding values, according to Siemens Energy. Data from the extensive measurement campaign are under evaluation. The OEM expects to present results of its analytical work to the 4000F community shortly.

Engineering

The first presentation in the engineering session described Siemens Energy's efforts to review its global supply chain with the combined goals of identifying opportunities to improve the lead time for repairs, consolidate technologies, and reduce the strain on critical facilities.

Wet compression got attention for its ability to add up to about 12% power output on demand when ambient conditions are "right." System was tested at one customer site in June 2021, producing a power gain of 25 MW with 101 gpm of wet-compression flow and a compressor inlet temperature of 90F.



4. Live action photos of the work scope illustrated in Fig 3 show removal of the exhaust diffuser (A) and a combustion chamber (B), and transfer of the intermediate shaft (C) and core engine (D) from transport vehicle to plant

aSMC. Next, experience with Siemens Energy's Advanced Stability Margin Controller was reviewed. It is intended to boost unit reliability and availability while promoting more cost-effective operation. Seven installations at four customer sites (first in June 2015) are credited with preventing unit trips and unloading events associated with combustion stability issues.

Sliding fuel-gas pressure operation, discussed next, likely is of greatest interest to those users desiring more efficient fuel-gas compressor operation. Attendees were reminded that when gas pressure is too low, operators receive a warning before a gas-turbine trip is initiated. Also, that fuel-gas pressure is not required all the time because of varying operating conditions.

These three possible solutions are described in the presentation:

- Probabilistic approach. Fuel-gas pressure set points (warning and protection) are established based on "real" ambient conditions.
- I&C logic upgrade assures reliable operation by automatically adjusting the load set point according to actual fuel-gas pressure.
- "Smart" fuel-gas compressor control based on gas-turbine load.

Experience with the M77 ceramic heat-shield material followed. It is more durable than the M100 material being replaced in some areas of the combustion chamber. The group was told that SiCerm M77 has a higher resistance to hot-gas erosion and subsequent material erosion during engine operation. It is recommended for the last rows in areas susceptible to erosion. Reduced scrap rates and maintenance effort are among the expected benefits. Less material loss in the combustion chamber also reduces wear and tear on turbine-section blades and vanes.

RCIE. Rotor-Casing Inspection and Evaluation is always a topic of interest at V user meetings. The speaker stressed that RCIE is a customized approach based on unit operating history. Case studies were offered for baseload engines with up to 200,000 EOH and less than 3000 starts and for peakers with less than 6000 starts.

Presentation reviews components affected by long-term operation, the damage mechanisms expected (creep, etc), and fleet experience. Then current solutions for repair/replacement of affected components are identified along with a look at solutions under development.

One of the conclusions of Siemens Energy's work: "Statistical results have shown lesser need for replacement of casing and rotor components for baseload engines while experience with peaking engines is still limited." The speaker continued, saying that with changing markets and more demanding operating regimes, findings (and the need for component replacements), may change; also, that the OEM's programs are updated based on experience and the latest analytical results.

Brownfield engine exchange (BEX) is on the Siemens Energy agenda at many user-group meetings. The idea is to increase powerplant efficiency and operational flexibility, and reduce emissions, by replacing an existing engine with a new one, perhaps performing selected upgrades on other equipment in parallel. The "carrot": Less than the cost of a completely new plant.

The OEM's global BEX program has been successful, with 40 units participating in 10 countries—21 of them in Taiwan. BEX is not specific to the SGT6-4000F. In fact, there are no upgrades of this frame on Siemens Energy's reference list. However, four V94.3x machines have been replaced with 50-Hz 4000F engines.

Exchanges have been done on SGT6-5000F, W501FC, W501D5A, 501FD3, V64, V93, V84.2, and M701F gas turbines. Plus, general plans were presented by the speaker for SGT5-4000F replacements at plants with GE 9FA and Alstom GT26 machines.

In the US, three exchanges have been made—one a SGT6-2000E replacing a V84.2 engine (Figs 3 and 4) and two SGT6-5000Fs replaced with a later model of the same frame. The first enabled PowerSouth Energy Co-op's McWilliams Power Plant in Covington County, Ala, to boost the output of its mid-1990s SGT6-2000E(2) from 102 to 114 MW by swapping it out with a new late-model SGT6-2000E(8).

Improvements in the engine's gross simple-cycle efficiency from about 31% to 35% over the years made replacement more economically attractive than continuing to change parts and do regular maintenance upgrades. Plus, NO_x emissions were reduced to 10 ppm from 13-16 ppm.

Major work on this project, the first-of-its-kind here for the OEM, included the design/manufacture/installation of a new intermediate shaft between the turbine and generator, and modifications to the air-inlet house and exhaust diffuser—in addition to replacing the gas turbine, of course. The original generator remained as it was.

Paint update. Final topic on the program was a repair paint, in validation at the time of the conference. Use of the two-component epoxy resin was to address leading-edge coating abrasion on the first few compressor stages. The coating can be applied during a minor inspection.

SGT6-2000E

The fleet update at the front end of the SGT6-2000E breakout sessions reported the following facts:

- The 50-Hz units in the 2000E family outnumbered the 60-Hz units 223-105 based on end of 2021 data.
- The 12-month rolling average availability for the 60-Hz fleet was 96.4% based on July 2021 data. Reliability was 98.8% at that time, starting reliability 98.7%.
- The combined fleet (50 plus 60 Hz) had recorded nearly 36 million EOH and nearly 500,000 starts by mid-year 2021.

A summary slide on inner-casing lifecycle improvements pointed to the value of field feedback data in helping to maximize maintenance intervals. Nearly a dozen and a half SGTx-2000E turbines were said to have been allowed to extend maintenance intervals because of this effort.

Turbine-blading update showed 180 units worldwide operating with Si3D™ blading. Experience of 50-Hz units with first- and second-stage airfoil improvements extended to nearly 4 million EOH and 50,000 starts. For 60-Hz machines, the numbers were 1.9 million EOH and nearly 14,000 starts.

Dual-fuel conversion was an M&U topic as it was in the 4000F session, with the same basic considerations applying to both frames. Additionally in this session, users with systems that have been inactive or not used for a long period of time were advised to review their liquid-fuel infrastructure to be sure it is operational and available if needed.

Secondary fuels reviewed included fuel oil, naphtha, condensates, kerosene/Jet A, biodiesel, and methanol. The requirements for any one may be slightly different than for the others so this should be taken into consideration during your asset evaluation.

Hydrogen was part of the alternative-fuels discussion for H_2 concentrations in natural gas up to 30%. The speaker said a test site for a fuel mix of up to 15% H_2 is in development. Hydrogen would be stored separately onsite and injected via a mixing skid upstream of the GT control valves. These are just first steps for Siemens Energy, which has committed to 100% hydrogen capability for its GT fleet.

Ultra-fast-start modules were the next topic with the goal a 5-min interval from turning gear to base load for a reserve GT in Europe. If integrated into a combined cycle, a bypass stack is necessary. Another case study looked at halving that interval to 2.5 minutes.

Final topic on the M&U program was a design review of Siemens Energy's cooling-air reduced (CAR) combustion chamber, nine sets of which are in operation now, with 12 expected by year-end. CAR's many features—including optimized flame-tube bottom design, optimized tile holder, enlarged ceramic heat shield, and optimized mixing casing—contribute to a 20% reduction in NO_x emissions (8 ppm today). Early inspection feedback is excellent.

Engineering

First subject on the 2000E engineering agenda was on the OEM's improvement to the fourth-stage divided seal ring, available for all engine configurations: 50 and 60 Hz standard and Si3D. The purpose: Reduce wear between the vanes and seal ring.

The upgrade had been implemented on 113 units (37 60 Hz) by the time of the meeting. Proper installation was stressed to prevent recurrence of wear. Positive result: No increased wear or forced outages attributed to seal-ring wear had been reported by owner/operators with the latest design.

RCIE was the next topic and some of the same material covered in the 4000F session above was repeated here. Specific recommendations for this frame are the following:

- Field experience generally has presented no significant findings for most rotor and casing components between 100k and 150k EOH. Drivers for destacking include inner-casing maintenance, and replacement of the center hollow shaft.
- Recommendation for NDE at 3000 starts remains for rotor components. Service time has been extended for some machines following detailed unit analysis. Guidance on when to replace specific components on peaking engines is provided in the presentation.

A few thoughts came next on improvements to the turbine exhaust liner and diffuser to mitigate the maintenance impacts of findings reported by the user community on some units. A sketch included in the presentation identified as areas of possible concern: cracks at the circumferential weld at the engine exit, wear at the casing liner cover, cracks in the two- and four-wave compensators.

BEX and other repeats from the 4000F program. As hinted earlier, Siemens Energy rarely misses an opportunity to talk about the advantages of its Brownfield Engine Exchange offers some owner/operators. So that topic was on the 2000E program as well. Same for the compressor repair paint, wet compression, and sliding fuel-gas pressure operation presentations.

Repairs for restoring GT, ST, and generator bearings of spherical saddle design was an important presentation for anyone so challenged. Repair techniques—including metal-spray and arc-spray restoration—are covered. Techniques for the rework of axial-thrust load surfaces are included. Meaningful illustrations are included.

Mixing casing. Repairs to correct contact and material loss at the interface between the mixing casing and lower flame tube were discussed next. Bear in mind that thinning of the mixing casing scallop may lead to liberation of thinned material. A trial fix using a repair coupon was reported on. Next steps include improving coupon geometry, development of a double-scallop coupon, and application of hard-facing.

CVC3. Some mature SGT6-2000E engines have Compressor Vane Carrier 3 configurations which include cover plates and anti-rotation pins. The latest word for units with cover plates: Forget the anti-rotation pins. This should facilitate maintenance and reduce outage duration. Instructions are available on how to plug the holes.

Lift-oil hose. Last on the agenda was a look at an improved lift-oil hose that uses industry standard hardware—complete with drawings. The potential benefit of this upgrade, applicable to all existing units and standard on new, includes longer hose life (10 years).

On the minds of users

The SGT6-4000F and SGT6-2000E owner/operators each met in private for about five hours on the third and final days of the conference to cover topics not addressed by the Siemens speakers and to compare notes on their experiences with the OEM and other vendors. Brief notes on subjects discussed, best practices, lessons learned, experiences both good and bad, etc, are presented below to provide a flavor of what others are thinking/doing.

User characterization. A recent poll of V User Group meeting attendees provided the following insights:

- A typical meeting will have an audience with about 30% first-timers.
- Most important topic on the minds of users is performance improvement (mentioned by 43% of attendees).
  - Next came parts availability (a concern of one-third the users).
  - Operational flexibility (24%), outage interval extension (24%), and availability of technical support (22%) followed and statistically equal in importance.
  - Last was emissions improvement (3%).
- HEPA filters are installed on gas turbines at 30% of the plants represented at the meeting.
- As for age of electronics/controls for SES/SFC: 41% less than 10 years, 53% 10-20 years, and 6% more than 20 years. More than 60% of the users have been told their controls face obsolescence, but one-third are not satisfied with their options.

SGT6-4000F

Air inlet section. One user reported plugging of pre-filters in cold weather by hoar frost. Suggestion: Use leaf blowers as a stop-gap solution before the unit shuts itself down. Brief comments on pre-filters continued with some attendees touting disposable filters, others cleanable. Change-out of pre-filters was said to take two to three hours. The OEM reportedly told one plant not to install pre-filters in the winter.

Inlet-guide-vane fluctuations were said by one user to increase EOH, likely attributable to dynamic load. His site operates multiple units on crude oil and all are affected. Recommendation: Arrange for Siemens tuners to visit the site. A short discussion related to IGV performance improvement for load increase without fuel increase ensued.

With several upgrades ongoing at one site, staff wanted to be sure all drawings and manuals were updated. Suggestion was to put this in the contract and withhold 10% payment until updates were verified.

Wet compression discussion rambled a bit: filters failing prematurely, limitations on run time when compressor blades are uncoated, erosion not a concern but corrosion is, borescope annually to determine airfoil impacts if any.

Turning-gear talk among attendees revealed issues with the dog-bone seal on the turbine bearing at one plant, plus the need to check and adjust lift-oil pressure, and hose condition, periodically. Nothing lasts forever.

Unit trips (three times in one weekend) were traced to a 20-year-old transducer for a generator protection relay. Next, a vibration issue emerged. Siemens was said to have recommended a rotor de-stack. A user recommended that generator fan blades be checked tight.

Fire-suppression agents and systems piqued audience interest as they have at many other user-group meetings—in-person and virtual—over the last several years. Suppression agents harmful to health and the environment, as well as regulations governing their use (now and in the future), were reviewed. CO_2 was touted as being an inexpensive upgrade for some, water-mist systems challenged for the inspections and hardware they require, etc. Discussion even touched on buyback programs for regulated gases. Likely a determining factor in your decision-making will be what your plant's insurer is willing to cover.

User interest in turbine services capabilities was in evidence. There were brief discussions on blade tip grinding (allow two to three hours for one disk on person said), collector-ring grinding, and the capabilities of a coupling boring machine.

Supply-chain challenges and approaches filled air time as owner/operators shared ideas and experiences regarding the purchasing of castings in advance of need, improvements to forecasting process and tools, lead-time optimization, new-stock optimization, impediments to international business, etc.

Recent outage findings included the following:

- Generator stator rewind will change from GVPI to SVPI unless performed at site.
- Laser cleaning tool is used during an onsite stator rewind.
- A dynamic cooling mod is available for generator cooling system.
- One plant reported cracking on both generator retaining rings during a recent inspection.
- FAST Gen does not include retaining-ring inspection and testing.
- Hybrid rotating grid stabilizer conversion solution: integrate a SSS clutch.

T3000. Most current version is 8.2 SP4, which will be supported until 2028; Version 9.3 is scheduled for release in 2023.

Lifecycle of ET200M ends in 2023, although at least one user said Siemens would provide spare-part replacement modules for 10 years beginning in 2023. There was discussion of the benefits of making the ET200M modules obsolete, although some users were clearly frustrated for having to replace them with newer equipment and not sold on the benefits. This segment of the audience stressed the desire for Siemens to justify its position.

Lead times on control-system parts are becoming a concern, some participants said. The result: Plants are forced to have spare parts on hand for all control-system components—including Vibrometer.

SP6 was batted around in discussion, including burner upgrades, downstream SCR, fuel-gas preheat, etc, but the information provided was much the same as Siemens Energy had presented in its session on the 4000F.

A Vibrometer D3000 upgrade was discussed. It was said that communication is sometimes lost between the D3000 and controls and when that happens a proven fix is to disable dynamic monitoring, pull the card, and then reinsert. One user said he was looking at upgrading the plant's BN3500 rack to Vibrometer's, noting that the existing cables and probes can be retained.

Fuel-gas system issues generated vibrant discussion. Here are some of the points made:

- Parts received from the gas-valve supplier were unsatisfactory. Specifically, cage not manufactured correctly, with holes too far down on the radius, causing the unit to trip on startup. Temporary solution was to reinstall the old cage.
- Blowbacks were a problem at more than one plant. One user said they were occurring about every four starts. A fire blanket was cut up and tied to piping to mitigate effects.
- A recommendation was made to test-fire ignitors. Suggestion was to turn off lights in the enclosure when doing this. Ignitor mods to consider: resistor and mounting. Parts challenges? Someone mentioned that spark-plug ignitors share some parts with snowmobile spark plugs.

Turbine section. Discussion focused on plant experiences with OEM alternatives for V84 outage and parts support. No one in the room could recall having full-service experience with any third-party supplier, suggesting that colleagues might want to discuss that possibility with MD&A, Sulzer, and EthosEnergy Group.

A general discussion touched on the following:

- Tile inspection. Observation: Interesting how different inspectors fail different amounts of tiles.
- Rotor de-stacks have been done at some plant sites. Normally, Siemens does this work in its shops.
- Missing studs in the exhaust diffuser

promote insulation liberation. You certainly don't want that material in the SCR. A temporary solution when insulation goes downstream might be pumpable insulation.

- Other topics discussed included replacement expansion joints, windows for switchgear, leak-checking of TEWAC heat exchangers, generator flux-probe testing, transformer issues, failure to start, automatic-drain problems with knock-out drums in fuel-gas systems, benefits of performance heaters for fuel-gas systems, replacement of pecker-head-style exhaust thermocouples, and much more.

Insurance company requests. Add fire suppression capability to a hydrogen-cooled generator pit, install fire protection in the PCC sub floor, develop emergency operation procedures—such as for low lube-oil pressure, conduct a cybersecurity deep dive, and install FyreWrap® around dc lube-oil pump wiring.

SGT6-2000E

Fuel-gas control. Several users said they had, or were planning to, upgrade their fuel-gas controls with Rexa Inc equipment because the Argus® valves (Flowserve) installed were problematic.

CVC 1. Safety issues were reported with this generation of compressor vane carriers. Solutions identified: Install a safety bracket (viewed as a temporary fix) or replace.

Combustor issues were traced by some to changes in gas quality causing liquid carryover. Sulfur has been found plated-out in gas lines (hard, light-gray color); plus, there have been reports of heavy hydrocarbon buildup in those same lines. One reason is believed to be receipt of fracking gas instead of the traditional Gulf gas. Suggestion: Heat the incoming fuel to 165F.

Dual-fuel operation. Issue of greatest concern is fuel quality, with some users challenged during commissioning of fuel-oil systems after major outages. Most users reported having upgraded successfully to HR3 burners from H burners.

Emissions control. Issues with NO_x steam injection line reported. Recommendation: Keep water in the line during light-off to reduce the risk of distorting/melting the line.

Turbine-section comments were generally positive, such as:

- Blades robust. One user with 32k first-stage blades is at more than 50,000 hours and still running. Another is targeting 46k EOH; no concern with starts. Limiting factor is likely the transition rings, which can be patch-repaired to limit outage time.
- Most users agree that blades can handle two repair cycles with the repair process the determining factor.

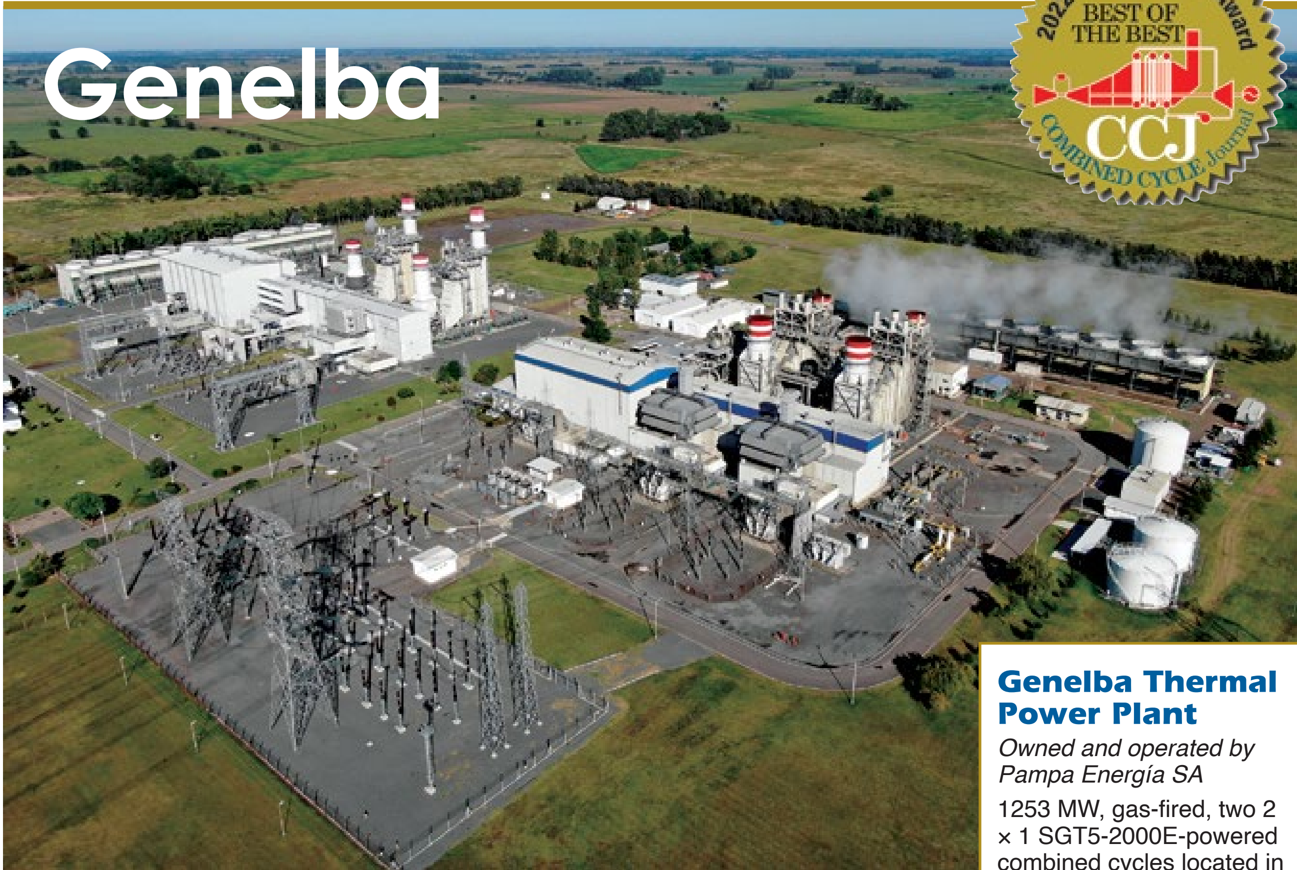
Inner-casing cracks. Some users just monitor condition; others weld-repair at outages.

Tiles. Horizontal cracks are not of concern to most users, but vertical cracks are examined closely. Some users reported using Sulzer for tile work; others their own techs with Sulzer support for condition evaluation.

Outage planning. Siemens TMS (Total Maintenance Services) process used to start 18 months prior to the planned outage, now two years. Group experience regarding auxiliaries during a major: Change out all valves at third major; all shut-off valves sent to Millennium Power Services for overhaul, actuators to Paragon Technologies. Tip: Borescope three-way valves after maintenance to be sure they are installed correctly.

Second-major recommendations: Don't replace flame tubes, repair tiles and tile holders, check F rings and bezel rings, refurbish thermal barrier coatings on hot plates and bezel rings. CCJ

Genelba



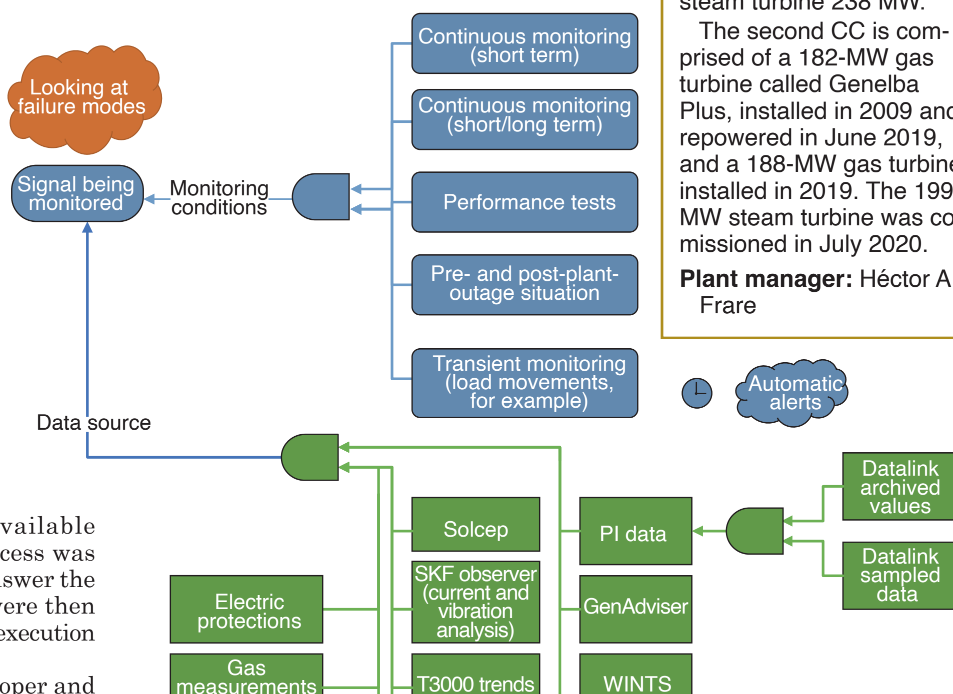
Genelba identifies, corrects combustion-chamber issue using methodology created by plant personnel

Challenge. Develop a means for monitoring critical equipment to maintain Genelba's availability and reliability at the plant's traditional high levels.

Solution required creating and implementing a methodology for gathering information from multiple online and offline sources, developing key performance indicators (KPIs), and analyzing them under different boundary conditions as illustrated in Fig 1.

After identifying the available information resources, a process was developed and executed to answer the following questions, which were then programmed in an automatic execution algorithm in PI:

- Is the instrumentation proper and in good working order? Are additional sensors needed to monitor other equipment failure modes?
- Baseline definition (normal behavior).



1. Methodology for monitoring critical equipment developed by Genelba personnel

Genelba Thermal Power Plant

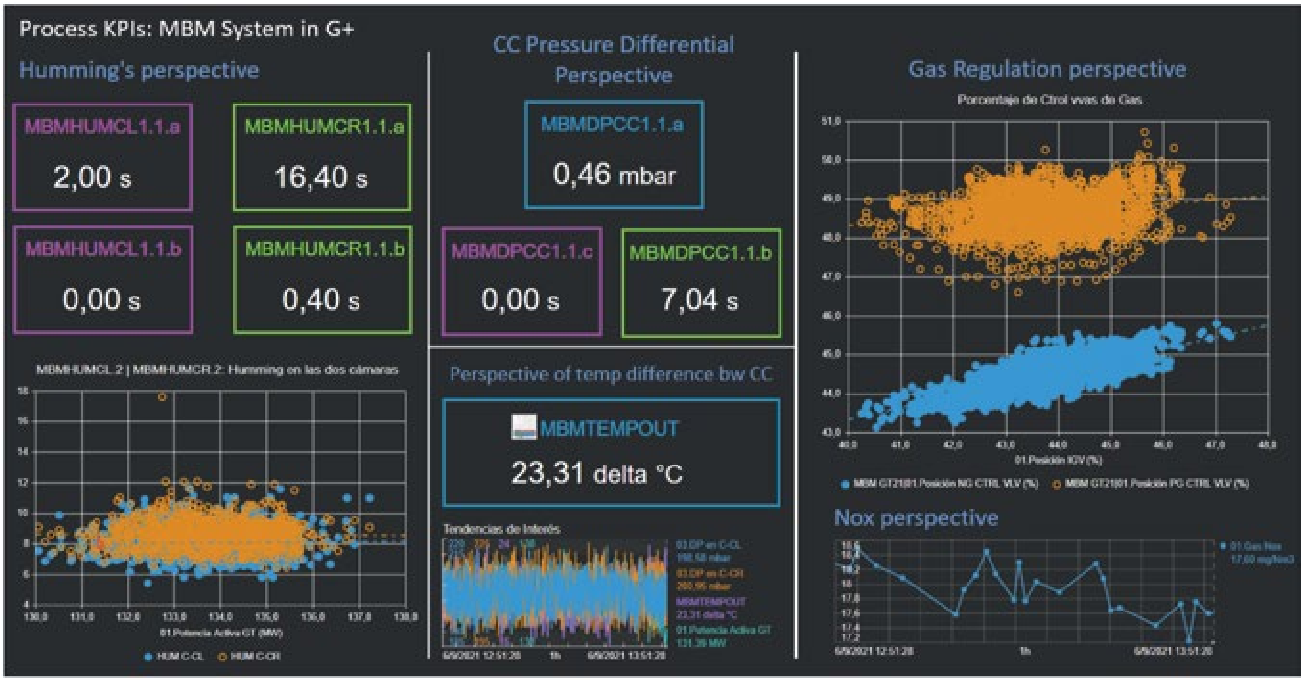
Owned and operated by Pampa Energía SA

1253 MW, gas-fired, two 2 × 1 SGT5-2000E-powered combined cycles located in Marcos Paz (Buenos Aires), Argentina.

The first CC began operating in 1999. It was repowered in October 2020 and today the gas turbines are rated 223 MW each, the steam turbine 238 MW.

The second CC is comprised of a 182-MW gas turbine called Genelba Plus, installed in 2009 and repowered in June 2019, and a 188-MW gas turbine installed in 2019. The 199-MW steam turbine was commissioned in July 2020.

Plant manager: Héctor A Frare



2. Screen shot shows key performance indicators developed for the SGT5-2000E combustion chamber

- Does the signal change over time?
- Are there alarm signals coming from that system?
- What were the equivalent operating hours at the time of analysis?
- Is there a correlation with other variables?
- What consequences does the abnormality have?
- How are the measurements on the other machines?
- Is the system showing signs of failure—for example, is there an increase in the number of work orders?

Genelba's Best Practices entry form offered the following example of how the plant's program works using the KPI MBMHUM1.1. Four binary signals from the control system are activated when the humming exceeds 20 and 30 mbar. (Recall that the plant's SGT5-2000E gas turbines each have two combustion chambers.) The indicator counts the total time that both cameras were exposed to humming greater than 20 mbar and greater than 30 mbar in the last 15 days.

Presenting the information in this manner allows staff to analyze, for example, whether the machine was exposed to higher levels of humming after an inspection (where pilot valve control could be intervened). It also affords a comparison between both combustion chambers.

Fig 2 shows the KPI dashboard developed in OSIsoft's PI Vision for the continuous monitoring of the combustion chambers. Using the methodology illustrated, and keeping in mind equipment failure modes, the plant's technical experts are able to determine if it's necessary to add more instrumentation to detect important failures early.

3. Accelerometers were installed to detect possible loosening of burner retention bolts during turbine operation

Continuing with the combustion-chamber example, staff found that addition of accelerometers could possibly identify conditions conducive to impending burner malfunction—such as the possible loosening of burner hold-down bolts. Fig 3 shows one of the sensors attached to a base that had to be welded to each burner to dissipate heat so the sensor would work within specifications.

The accelerometer is wired to a high-frequency processor box that transmits the information via the plant's industrial WiFi network to the processing server.

In sum, 18 accelerometers were installed on each engine. Information is sent to the PI system, from which a comparative dashboard was developed by sensor, camera, and gas turbine, with the goal of characterizing the cameras and determining abnormal behavior—because personnel did not have reference limits for these new measurements.

Fig 4 shows the board developed in Microsoft's Power BI, an interactive data visualization software product, for tracking acceleration measurements. The graph at the upper left shows information from all the selected sensors discriminated by turbine; that at the upper right from selected sensors discriminated by turbine and sensor. The lower graphs show trend values, humming values, and vibrations per harmonic, respectively.

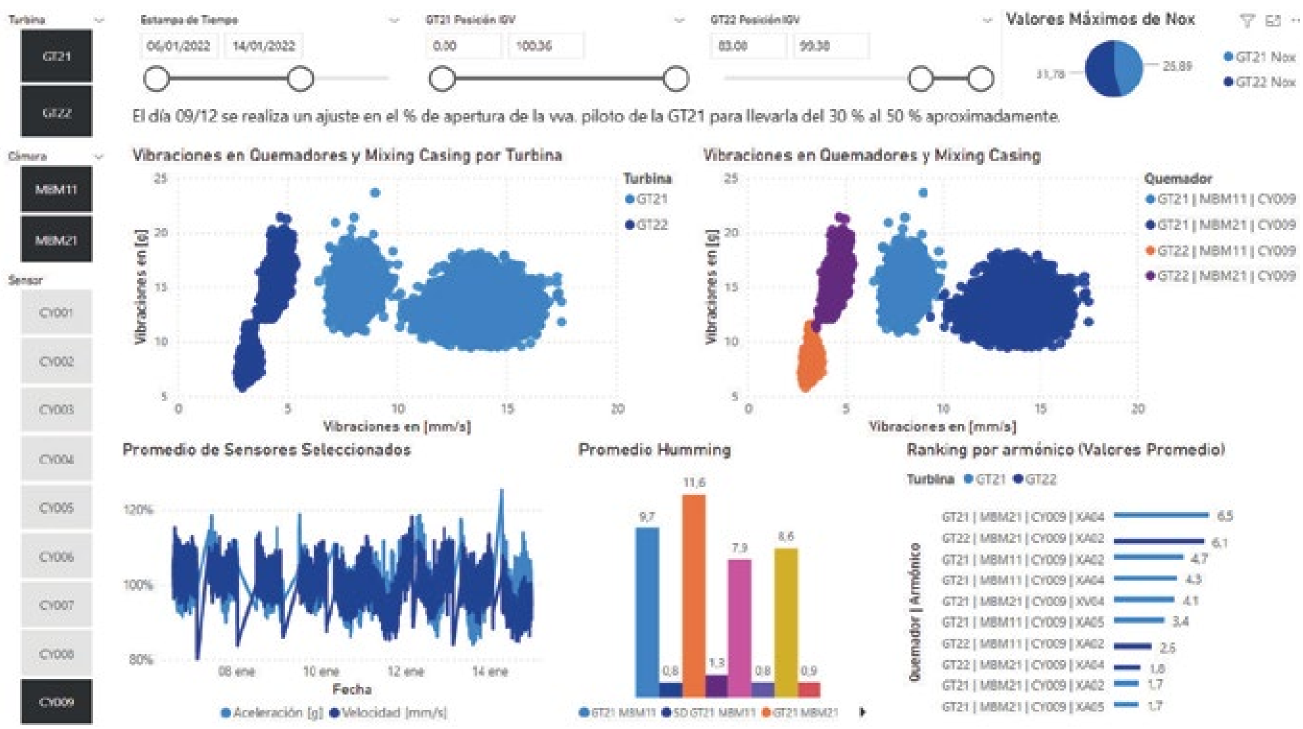
Result. A benefit of the development effort described above: One of the indicators monitored—it infers thermal balance between combustion chambers—detected a deviation in GT22 of more than 15 deg C with respect to the allowed maximum. Staff analysis determined that fuel flows to one of the chambers required correction.

Technical experts believed the anomaly might have been caused by a deformation in the right combustion chamber of GT22 that allows air to bypass the compressor, cooling it. Such a thermal imbalance over time can stress the first row of rotating blades, with the risk of fracture of some, and consequent damage in later stages.

The temporary fix implemented was to replace a gas orifice plate to redirect more flow to the combustion chamber experiencing deformation, thereby thermally compensating the effect. A permanent repair was planned for the next GT minor inspection.

The benefits of having the intel and implementing a temporary fix included the following:

- Staff could detect wear on the camera and plan resources and work in advance of the next planned inspection. Without such preparation, personnel believed an outage of at least five days would have been required to correct the problem, at an estimated cost of about $250k/day.
- Modifying the orifice plate in the gas pipe avoided progressive damage to GT22 airfoils and mitigated the risk of catastrophic failure.
- The possibility of improving instrumentation to measure humming values associated with GT protection more precisely was identified based on another of the developed indicators.



4. Dashboard created for monitoring operation of gas-turbine burners

Webinar roundup

MD&A focuses on rotor life extension, main-steam valve solutions, high-speed balancing

Summaries of MD&A's (Mechanical Dynamics & Analysis Inc) fall 2022 webinars on topics of interest to all involved in the operation and maintenance of generating plants powered by gas turbines follow. Both experienced personnel and those new to the industry might benefit from a quick read to identify topics of immediate value and then follow up by listening to recordings of the webinars of interest. All run less than an hour. Access the recordings at https://www.mdaturbines.com/resources/fall-2022-webinar-series.

Restoring your rotor when end-of-life is approaching

MD&A kicked off its fall 2022 webinar series with a presentation on rotor life extension. You'll want to take an hour and listen in if your plant has a 7F unit approaching 5000 starts/144,000 equivalent operating hours (EOH) or a 7B through 7EA unit approaching 5000 starts/200,000 EOH. Get the background on these requirements in "Heavy-Duty Gas Turbine Operating and Maintenance Considerations," GER 3620P, January 2021, available at no cost on the Internet.

Fred Willett explained that MD&A seeks a balance between a standard approach and one customized to address each user's unique machine characteristics. "All new rotors are the same, but all used rotors are unique," he said. For this reason, Willett had to answer most of the questions with "talk to our sales rep"—questions such as "What is the lead time for a 7FA rotor?" and "Can you do compressor reblading at the customer site?"

Goal of a rotor lifetime assessment (RLA) is to designate each rotor component for reuse, repair, or replace "for the continued safe and productive operation of the unit" (Fig 1). For example, thermal transients impact the back-end stages of a compressor far more than the early stages. In one example, Willett noted that new wheels were required for Stages 13-17 while Stages 1-12 could be repaired or reused.

Temperature obviously is the main factor in the stress concentrations in latter-stage wheels but Willett also dwelled on the contribution from the "dovetail skew angle" which increases from the front-to-back stages of the compressor discs.

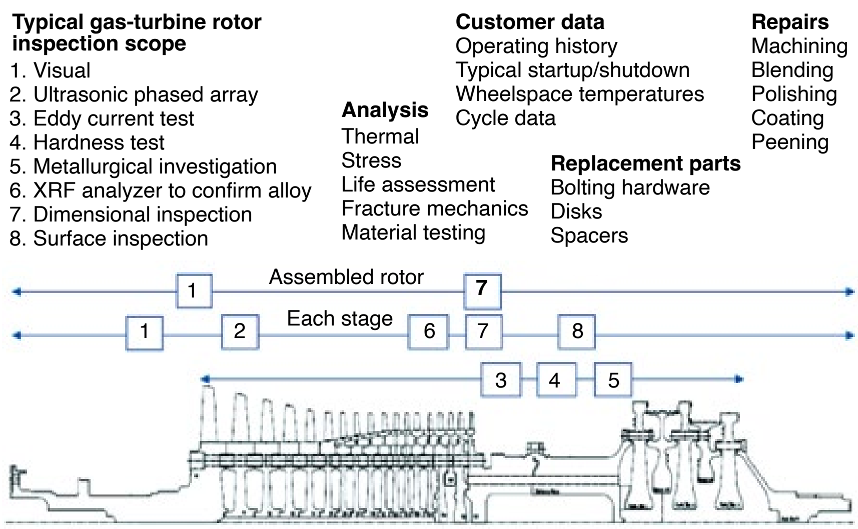
Regarding the turbine section, Willett noted that disks "have had their share of problems," and in recent years, so too failures of the 1-2 spacer, for which "there is more than one machine failure known." Importantly, MD&A offers first-stage discs with redesigned cooling slots, has patented a geometry for an upgraded 1-2 spacer, and has upgraded components for all the other rotor problem areas.

Willett touted MD&A's parent, MHI, and, as an OEM, its "deep domain expertise" in this area. MHI has conducted over 270 comprehensive rotor inspections, with shops and labs in the US and Japan. Some of that expertise was obtained by reverse engineering and manufacturing rotors which were purchased by customers but never installed or operated. When one listener asked if MD&A's upgraded components also have durability improvements, compared to the OEM, Willett's answer was an unequivocal "Yes."

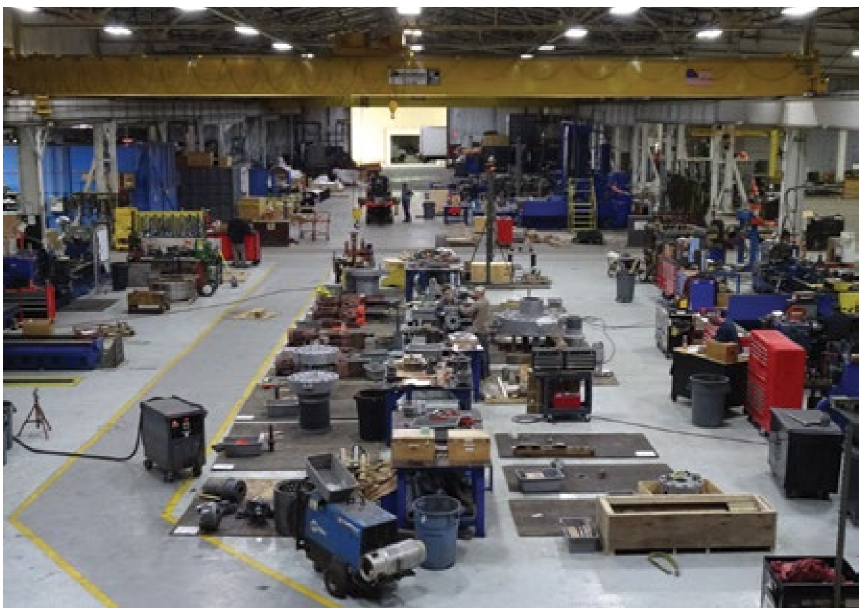
The slides include some very insightful heat maps of compressor rotors during different points along the startup and shutdown sequence, as well as detailed diagrams of component stress concentration points.

Shop offers a variety of repair options as main-steam-valve issues increase

It only takes 2-3% steam overflow to trigger a steam turbine/generator (ST/G) overspeed event, cautioned Dean Casey, project manager for machining services at MD&A, to stress the importance of main-steam-valve inspections and timely repairs. During his presentation in MD&A's fall series of webinars, "Steam Turbine Valve Outage Common Issues," Casey went on to say that the failure of the main-steam stop valve to close is the most frequent



1. Rotor lifespan evaluation is multi-disciplinary and multi-faceted, and relies on original design data as well as extensive customer operating data. A rotor unstack is required for full inspection



2. Steam-turbine valves have many complex engineered components; MD&A has developed proven repair and upgrade techniques for the most troublesome

cause of ST/G overspeed events.

Casey then led his audience through the often-arcane repair process details associated with these complex engineered components (Fig 2).

If you have main-steam valves approaching three to five years, or 25,000 hours, of operation, MD&A's minimum recommendation for inspection and repair, you owe it to yourself to listen to the webinar. This is especially true if you are past the first five years of plant operations, when valve issues begin to rise. There are no industry or independent maintenance practices for these valves, outside of nuclear plants, only OEM guidelines, making webinars like this one even more valuable.

Generally, inspection and repair are targeted at: restoring clearances to OEM specs, such as bushing removal and replacement, hardened inserts, and scale removal; achieving concentricity, so that the valve operates precisely on its centerline; sealing and resurfacing to ensure no steam cutting; and attending to foreign-object barriers, such as strainer baskets.

More specific topics and case studies Casey addressed include these:

- A bent stem which had to be replaced, along with the valve-stem bushings, and inserted into a re-machined casing fit.
- Solid particle erosion (SPE), which can cut stem life in half if not addressed. MD&A has developed a laser-cladding process for some valve stems. Seats, discs, and pressure seal heads are also affected by SPE.
- Control-valve seat replacement. Casey noted that MD&A has replaced 40-50 of these seats in one OEM's valves over the last 10 years.
- Strainer basket replacement.
- Specific repairs for spindles and sleeves in Alstom valves, and disbonding and liberation of Stellite hardfacing of Siemens KN valve seats and plugs.
- Indications (cracks, for example) in

steam chests and repair options.

With supply-chain issues affecting short-term delivery to all sites, Casey urged users to identify parts for rebuilds well ahead of the outage. Around 90% of MD&A's parts come through its Parts Div facility in Danvers, Mass, but some can be manufactured in its St. Louis shop, which Casey described as the largest non-OEM gas-turbine repair shop in the US. Examples of the latter include non-hardened bushings, inserts, and sleeves.

Capabilities in the St. Louis shop include (1) a deep-bore TIG (tungsten inert gas) welding machine designed to handle internal diameters from 4 to 30 in. and depths to 50 in.; (2) automated MIG (metal inert gas) welder for IDs from 0.88 to 27 in.; and (3) an induction machine for uniform temperature during post-weld heat treatment.

Shops with a high-speed balance machine offer clear advantages

The underlying message of MD&A's third webinar in its fall 2022 series is that a shop which has invested in a high-speed rotor balancing (HSB) machine (Fig 3) offers the user clear advantages in shortening outage schedules and avoiding the risk of having to transfer the machine from the shop where repairs are made to a shop with an HSB.

Not all rotors require HSB after being repaired, noted MD&A's Keith Collins, in his presentation entitled, "High-Speed Balance." If repairs are

3. In-shop high speed balancing isn't necessary following every set of rotor repairs, but it's the only way (1) to assure that the machine will run within spec at speed, (2) to conduct an overspeed test, (3) to achieve the primary goal of balancing (minimize 1x vibrations), and (4) for generator rotors, run the all-important flux probe test minor, a low-speed balance (LSB) will suffice, or even an onsite balance. But if the rotor has undergone journal machining, heat straightening, or weld repairs, as a few examples, you should opt for HSB. Ditto if any repairs have altered rotor geometry or local stresses.

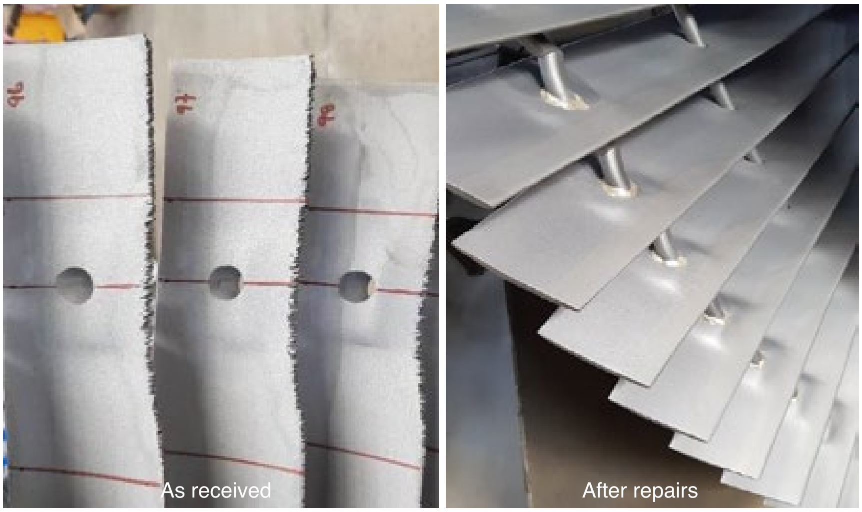
For a generator rotor, the big advantage of HSB is the ability to perform a flux probe test, the "only way to guarantee no shorts at startup," said Collins. Turn-to-turn testing in the shop cannot detect speed-sensitive shorts. "If the rings come off your generator rotor you should do a HSB. This is true for a rings-off inspection or a rewind with new or existing copper," he stressed.

For all rotors, the HSB also allows for overspeed test and comprehensive vibration analysis.

The bulk of Collins' slides offer a tutorial of sorts on topics including applicable standards, vibration measurement basics, critical speeds, modal balancing, overspeed test and balance, electrical testing, and heat and stability runs.

During the Q&A, Collins added that an onsite balance should definitely follow an in-shop HSB, with experts present to determine need for additional trim shots. On the subject of whether MD&A "heats up the GT/G or ST/G rotor in the shop for HSB, Collins replied that they typically do not, though other shops do. "We can draw partial vacuum to heat up the blades which transfers heat to the rotor for soaking," he said.

Regarding the question, "Should you do an onsite LSB after a partial re-blade," Collins replied "Yes. Do an LSB before and after the repairs." To a similar question of doing an LSB after replacing all blades in an ST/G rotor, Collins also replied "Yes."



Before and after weld-repair techniques for water-droplet erosion (above) and severe foreign object damage (below) of L-0 blades illustrate how advanced today's onsite capabilities have become. The repaired FOD blades were restored with greater erosion resistance than the originals

EthosEnergy, a leader in steam-turbine L-0 blade repairs

Sometimes it's best to start with the end. During Ethos Energy's Oct 19, 2022 webinar, "L-0 Blade Repairs," Ian Saeger, manager of project engineering, concluded by stressing that last-stage steam-turbine blade repair is usually at least 50% less expensive than blade replacement and accomplished within a few weeks, if the repair can be done onsite or in-situ.

The latter means with the blade still attached to the rotor, the former to when the blade is removed but still onsite. If blades have to be shipped to a shop, count on adding up to six months in the schedule.

Saeger began by polling the audience on primary causes of their L-0 blade replacements. Not surprisingly, 69% responded erosion, 10% root cracking, and 21% other. He then reviewed three repair case studies involving (1) water-droplet erosion, (2) cover cracking, and (3) severe foreign-object damage (photos).

During the Q&A, Saeger noted that most blades with a stainless-steel base can be weld-repaired. Titanium blades, on the other hand, can be welded but only in a shop vacuum furnace. However, not all blade damage is repairable. Damage near the tips generally is amenable to weld repair; damage at the base of the airfoil typically requires blade replacement.

Another useful nugget: In-situ repairs don't generally require high-speed balancing afterwards, if done within Ethos' specifications and airfoil geometry remains the same. When asked if there is a limit to how often a blade could be repaired, Saeger said he wasn't aware of any limit on the frequency.

Saeger's last slide went beyond the topic and identified solutions for D11 and A10 steam turbine/generators specifically—including the following:

- L-0 blade erosion and root cracking (see GE Technical Information Letter 1795)—40-in. L-0 root and airfoil modification. Note that the company's repair for root cracking caused by low-cycle fatigue is a proprietary upgrade.
- N2-packing casing cracks/leakage (see GE TILs-1627-R2 and -1749)—redesigned N2 box.
- Outer-casing joint leaks—machining of outer casing joint and hardware upgrade.
- HP/IP rotor vibration/runout/bowing—rotor straightening.
- Repetitive seal failures—EEG's Smart™ Seals.
- Diaphragm axial distortion (see GE TIL-1589)—diaphragm trailing-edge and stiffening mod. CCJ

ffs Film-Forming Substances Research Conference

FILMFORMINGSUBSTANCES.COM

Fifth International Conference

By Steven C Stultz, Consulting Editor

Co-chairs Barry Dooley, Structural Integrity (UK), and David Addison, Thermal Chemistry (NZ), organized and led this 2022 conference on behalf of The International Association for the Properties of Water and Steam (IAPWS, www.iapws.org).

Their opening greeting: "Welcome to the virtual world of film-forming substances," a specialized topic in cycle chemistry control of powerplants and steam generating systems.

The focus: Film-forming substances to protect metal surfaces from corrosion through hydrophobicity. It's part of the larger effort to control corrosion throughout the water/steam circuits of fossil and combined cycle/HRSG plants.

One-hundred forty-six paid attendees—a record—logged in from 30 countries to watch, listen, and participate in 21 technical presentations and discussions. Ten suppliers also presented their credentials and technical details. Participating sponsors of FFS 2022 were Fineamin, Kurita, Nalco Water/Ecolab, Reicon, SUEZ, and Waltron.

FFS conferences, which began in 2017, have become well known as a unique and critical opportunity for plant operators/users to raise questions relating to all aspects of film-forming substances. Dooley stressed the IAPWS goal: "To provide information freely and improve FFS guidance for owners and operators worldwide."

Below are selected highlights related to combined-cycle plants and operations.

Base definitions

In brief, the term "film-forming substances" represents two main categories of chemicals:

- Amine-based film-forming amines (FFA) and amine products (FFAP).
- Non-amine-based film-forming products (FFP).

There remains general confusion on the nomenclature, but these terms introduced by IAPWS in 2016 have quickly become the global standard.

It is important to note here that the wide range of these products and applications make research and common solutions difficult (table).

Current foundation

"Universally," explained Dooley, "we are seeing reductions in the measurement of feedwater total iron and copper corrosion products through the use of FFS. There are general visual observations of hydrophobic films in the water-touched areas (mainly feedwater and condensate) of plants, and within air-cooled condensers.

Dooley

Addison

"However," he continued, "film formation and adsorption remain questionable on steam-touched surfaces." Also important, a lack of visual evidence of hydrophobicity does not necessarily mean lack of protection.

These complexities, and the underlying understandings of oxide growth, protection, and tube failures, as well as the impact on steam turbines and other plant equipment, make this series of conferences critical for owners/operators of fossil and combined-cycle/HRSG plants, among others.

Wide range of FFS products, mixtures makes research, common solutions difficult

Product type	Film-forming products (non-amine)	Film-forming amines—pH or surfactant stabilized	Film-forming amines—homogenization/emulsions	Film-forming amines—pH stabilized and blended with dispersants
Application	Fossil/industrial	Fossil/industrial	Fossil/industrial/nuclear (ODA)	Fossil/industrial
Description	Proprietary, likely to be carboxylic acids	ODA/OLA/OLDA with neutralizing amines	ODA/OLDA	ODA/OLA/OLDA with neutralizing amines and polycarboxylate dispersants
Concentration (active)	Less than 1%	Less than 1 to 5% typically; some up to 80%	Less than 1 to 5%	Less than 1 to 5%
Chemical/thermophysical properties understood?	Limited understanding	Limited understanding except for ODA	Limited understanding except for ODA	Limited understanding except for ODA

Source: Dooley/Addison, FFS Conference 2022

1. Hydrophobic surfaces in condensate and feedwater systems are as shown above, the surface of the condensate receiving tank at the right

Cycling and layup protection

Ronny Wagner, managing director, Reicon (Germany), launched the technical presentations with *Application of film-forming amines for preservation of water/steam cycles with and without air-cooled condensers.* Wagner's overview covered FFS preservation principles for both flexible operation and long-term layup. He focused on ODA as the film-forming amine (FFA) to offer this fundamentals-only guide.

For cycling units with varying schedules, Wagner explained, a steady and continuous FFA injection at low concentration (50 to 500 ppb) should offer the best protection while offline and should have little to no long-term impact on system water quality. FFA should be injected at the suction side of the feedwater system; the condensate polishing system (if provided) can continue to operate. Any conductivity spike during implementation should return to stable.

For long-term preservation of plants with seasonal shutdown or planned outages, a high feed rate of around 2 ppm should be initiated five to 10 days before shutdown. After shutdown, a lower but steady concentration of 50 to 500 ppb then can be used for follow-up injection.

"After the next shutdown," he suggested, "it is wise to re-preserve at a high rate (1 to 1.5 ppm) beginning three to five days before the following shutdown. Normal injection is at the suction side of the feedwater system, or in the condensate lines after the polisher."

The polisher should be bypassed because it will remove the amine from the condensate. Water chemistry values will probably be affected during the injection periods.

Again, these are general rules, Wagner emphasized, "The total FFA consumption for preservation is dependent on surface area, and is both plant and product specific."

Preservation practices for air-cooled condensers (ACCs) are more complex. Most importantly perhaps, common ACC heat-exchange tubing is carbon steel with large internal surface area, typically thousands of square yards.

ACC design also requires long, large-diameter lines from the LP steam turbine outlet to the ACC upper duct (street), to handle the two-phase steam/water mixture. The tube entries within the ACC upper duct become corrosion-active surfaces for flow-accelerated corrosion (FAC), and there is normally high iron concentration downstream of the ACC during and after startup. Thus, high FFA concentrations at the ACC inlet often are necessary.

ACC case history

A 70-MW combined cycle completed commissioning, but had to idle because of a delayed grid connection. It was critical to protect the ACC. The solution was injection of FFAP (Odacon®) in front of the ACC. Following application, hydrophobic surfaces were visible in the feedwater system and condensate receiving tank (Fig 1).

After grid connection and during startup, there were no noticeable issues with corrosion.

Wagner took the opportunity here to emphasize the Dooley Howell ACC Corrosion Index for operating comparisons. Having a proper total iron baseline and use of this index for results comparisons are critical analysis tools to assess FFS impact, he explained. For a clear discussion of the DHACI, access ACC.01: "Guidelines for Internal Inspection of Air-Cooled Condensers" at http://acc-usersgroup.org/Reports.

2. Condenser surface after preservation

Case study without ACC

An 800-MW plant with drum-type HRSG and no condensate polishing unit moved to flexible operation (less time online) and a fast-start requirement. Baseline review showed high iron levels during startup, especially in the IP section of the HRSG.

Preservation was performed in several steps beginning with injection of Odacon in the main condensate line after the condensate pump. Inspection showed hydrophobic protection (Fig 2).

Startup time was halved, and iron concentration in the IP section during re-start was reduced by 70%. For the off cycles, previously-applied nitrogen injection for short-term protection was no longer necessary.

In both cases, total iron transport in the water/steam cycle was reduced.

Biofuels

Attention turned to Agata Zietec, Jönköping Energi, and a combined heat and power (CHP) plant in Sweden burning both household waste and a variety of biomass fuels in two fluidized-bed boilers.

The plant experienced feedwater system issues, including blockages, and preheater FAC. Some parts of the plant were in annual seasonal shutdown for up to five months. Traditional treatment included ammonia and phosphate.

Operators selected Odacon, largely because of positive global nuclear plant experience, and began dosing at the feedwater pump.

The required flow was calculated to be minimum rate at full boiler load and maximum rate at lowest load. To prepare for offline protection, continuous FFS dosing (up to 0.3 ppm amine) was performed from February until the end of the run season (three months).

Iron content in feedwater during startup was significantly reduced and many existing deposits were removed from the turbine area. There was no noticeable impact on online instruments. The applications seem to offer effective protection during layup.

Geothermal

Geothermal processes offer unique challenges in scaling and corrosion.

3. ACCs have a large steamside surface area

Two case studies were presented focusing on Kurita FFS geothermal technology developments in Turkey and Indonesia.

Worldwide, the most common direct use of geothermal energy is district heating. For power generation, uses include dry steam and flash steam powerplants, binary-cycle powerplants, and combined units.

Common corrosion mechanisms are high salinity, high reservoir temperatures, high gas content, and low pH. Scaling issues come from varying mineral compositions, changes in pressures and pH, water cooling in heat exchangers, and other site-specific issues.

Pilot systems reviewed showed good corrosion protection (Organic Rankine Cycle area), including reduced under-deposit corrosion.

Industrial hot water

A New Zealand dairy factory uses a 10-MW industrial hot water system of carbon-steel construction with titanium heat exchanger, introduced in 2019. After two years of operation, the system suffered tube metal loss of up to 56%, according to data provided by IRIS Inspection Services. The system was continually saturated with oxygen and iron levels exceeded 160 ppm with a reducing chemistry program.

Following IAPWS TGD11-19 guidelines regarding steam purity, Odacon was dosed at 0.5 to 1 ppm. Pumps and seals were upgraded to reduce oxygen ingress.

Results showed bulk water iron levels reduced below 1 ppm. Using three to four times the recommended saturation volume for heavily corroded systems, there was a 96.8% reduction in corrosion rate after five months.

Photos were shown of the seven-month inspection in this ongoing program.

Next steps will be an online filming amine analyzer (Waltron), reintroduction of sulfite to see if low oxygen levels have an impact on iron chemistry, change to an optical luminescent dissolved-oxygen (DO) sensor, acid cleaning, and 100% IRIS testing of tubes.

Nuclear experience

Multiple presentations focused on FFS application experience (primarily ODA, octadecylamine) at nuclear plants. ODA has been applied to nuclear facilities in seven countries, and one presentation discussed more than a decade of experience with positive results for feedwater iron levels and measurable particle-size reduction.

The two units discussed, pressurized water reactors commissioned in the early 1980s, are good examples of steam-generator replacement (1996-1997) and turbine upgrades (2010-2011) to continue operating well beyond their original service dates. Water quality becomes even more critical.

In another presentation, *Efficiency and harmlessness of film-forming amines used as alternative layup method in secondary circuit of pressurized-water nuclear power plants,* similarities also were present. The secondary circuit (steam generators, turbine, and condenser) includes carbon and low alloy steels with surfaces covered by magnetite. During refueling or other outages, oxygen and humidity can lead to generalized corrosion and require layup protection.

Traditional protection methods are either drainage and drying to a relative humidity below 40%, or filling with chemically conditioned water. Both are time consuming and can be difficult.

A presentation by EdF explained an alternative method using film-forming amines (ODA) to inhibit corrosion. Detailed background was given for ODA behavior on different oxide samples at different temperatures, methods used to better understand the related adsorption mechanisms of ODA on various surface states (including testing protocols), and simulations of film efficiencies during layup.

Specifics were presented on morphology and contact angle measurement, electrochemical impedance spectroscopy, chemical composition analysis (ATR-IR and XPS), and other methods.

Beyond these three, presentations dealt with gasket and elastomer testing, and corrosion inhibition by anionic surfactants.

4. Heavy internal evaporator tube deposits attributed to iron transport

J Fandrich, Framatome, gave an update on the IAPWS Technical Guidance Document for FFS application in nuclear powerplants, a current initiative within the Power Cycle Chemistry (PCC) Working Group. The hope is to finalize this at the IAPWS Annual Meeting in November 2022. Fandrich highlighted the differences compared to fossil water/steam cycle materials, design, chemistry, and steam-generator operation.

At the laboratory

Day Two began with a deep dive into air-cooled condensers, important because they can release significant quantities of iron-oxide corrosion products into the water/steam system serving the entire plant (Fig 3). Risks

5. Through-wall tube leaks, exterior corrosion include HRSG evaporator interior tube deposits (and failures) from iron transport (Fig 4).

Andy Howell, EPRI, took attendees to the upper ducts (Fig 5), "where the corrosion rate is high and tube-entry wall thickness is small." Corrosion-caused leaks here can draw air into the condenser. This leads to costly performance, maintenance, equipment damage, and availability problems.

In the past, reducing iron levels in the system had been through increasing pH.

Howell explained a laboratory approach to simulating the ACC steam-side (two-phase) environment at the heat exchanger tube entries. The main results were:

1. Ammonium hydroxide involves simple chemistry and is inexpensive; it has proven suitable for system pH control in many ACCs.
2. Properly selected and applied neutralizing amines can reduce corrosion in ACCs compared with ammonium hydroxide, and can be used in conjunction.
3. FFPs appear to be very effective at reducing corrosion in ACCs under the right conditions.

XPS and EIS

A takeaway mentioned during a discussion period was that university laboratories and staff can help the industry with advancing sciences related to FFS.

One presentation was a deep dive to the molecular level using x-ray photoelectron spectroscopy (XPS). Rob Lindsay, The University of Manchester (UK), offered empirical insights including trial-and-error discussions.

The key target is FFS interface characterization at the microscopic level. This is part of a Manchester research effort into adsorption thermodynamics and interface characterization.

XPS basics were explained and profiles interpreted. Results hope to offer knowledge-based development of the next-generation corrosion inhibitors.

During discussions, Dooley emphasized: "This helps provide key insights, using XPS, to prove the presence of, but not the continuity of films with potential to move away from the standard hydrophobicity tests. This would be a great future outcome for tube sampling and analysis if it can be proven to work in real operating environments."

The University of Toulouse (France) came soon after, with *Adsorption kinetics of film-forming amines on carbon steel surface using electrochemical impedance spectroscopy (EIS).* EIS is used to monitor variations of the electrochemical system over time, and to identify the processes occurring at the

6. Waltron online analyzer

metal/solution interface. The presentation focused on experimental protocols using submerged carbon steel with and without the FFS OLDA.

Work continues with in-situ monitoring of FFA barrier formation for representative industrial conditions.

As a concluding comment to these presentations, Dooley offered what he believed to be the key takeaway from the lab studies portion of the program: "For the first time at FFS conferences, basic research is presented on film-forming corrosion inhibitors [oleic-based imidazoline (OMID) and sodium lauryl lactylate (SLL)] in different corrosive environments (HCl, H2SO4) than are found in powerplants using XPS and EIS.

"It is hoped that the insights on how the filming molecules interact with metal surfaces (carbon steel) under severe chemical environments at lower temperatures can provide advancements in the studies of FFS on materials in powerplant environments."

Field-switching of FFS

As a follow-on to last year's FFS conference, and providing a long-term outlook, PacifiCorp's Gary Hoffman presented *Switching from non-amine FFS to blend of amine/non-amine FFS at the Hunter Power Station.*

The subject is Hunter Unit 3, a 430-MW subcritical coal-fired plant in Utah, designed for baseload service, that began operating in 1983. With the owner's move to increase solar power's contribution, Hunter 3 is now cycling with daily swings from full load to 10 to 15%.

The last chemical cleaning was in 2012, when nearly 5000 lb of magnetite was removed, and 400 lb of copper recovered. The full-flow deep-bed condensate polishers have been in service since the mid-1990s. Boiler tubes show some under-deposit corrosion.

Chemistry control strategies are:

- AVT(O) chemistry control, ammonia for feedwater.
- Tri-sodium phosphate and caustic for drum pH control during startup.

FFP history was given at the Fourth Annual IAPWS FFS conference in 2021 after two years of Anodamine FFP feeding. On June 28, 2021, operators switched Unit 3 to SUEZ Polyamine Plus based on economics (significant dosage reduction). The program intent remains protection while offline.

The SUEZ second-generation filming technology acts as a dual filmer (FFA and non-amine FFP) that adsorbs quickly and desorbs slowly.

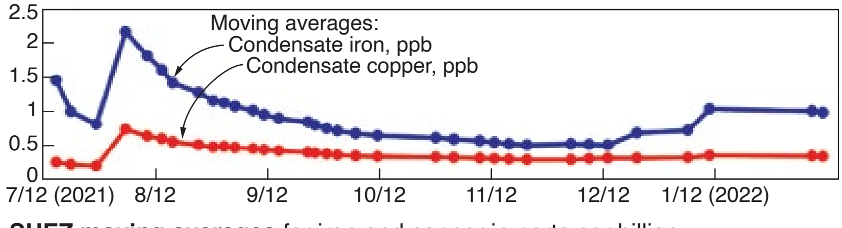
Monitoring and control currently are provided by:

- Online corrosion product sampler.
- Online Waltron 3054 amines analyzer (Fig 6).
- Corrosion coupons on the condensate-pump discharge.
- Grab samples for product concentration analysis.
- DCS controlling chemical feed pumps based on megawatt load.
- Inspections when possible.

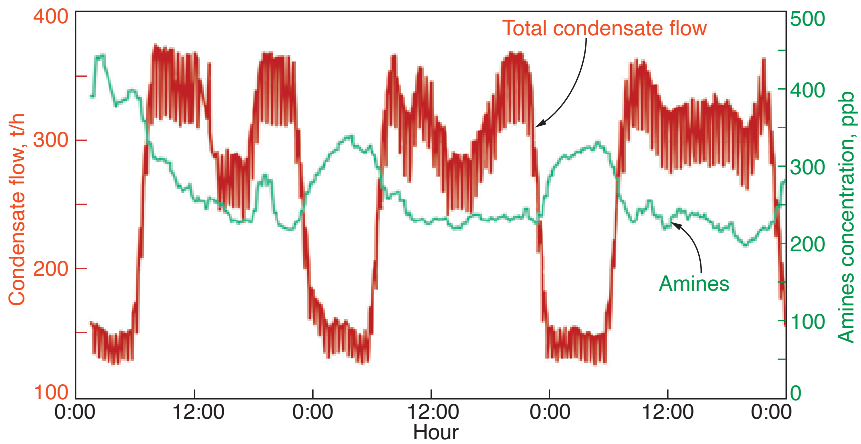
During the first eight months, the unit was subjected to eight trips, eight recorded starts, and four outages of more than one day. Moving averages of iron and copper concentrations are shown in Fig 7.

All testing coupons are sent to Lehigh University (US) for XPS analysis. Results confirm the presence of both FFS actives on the surfaces of the coupons. The summary given by Hoffman notes excellent corrosion results during normal operations, with minimal corrosion spikes at startups. The key result is that there was no noticeable difference.

This is an ongoing project, which will also move to other units within the owner's system. Work continues to measure results and optimize feed rates



7. SUEZ moving averages for iron and copper in parts per billion



8. Waltron analyzer performance, SUEZ Steamate PAS 6079®

(currently 1 to 1.5 ppm total product).

One question during discussions pointed to a need for further industry research. That question: "Did you fully remove the first FFS (non-amine) before using the blend?" The answer: "We do not know."

Dooley later offered a broader perspective: "Further plant and laboratory studies will help confirm the similarity of film properties and protection formed with the wide range of FFS currently on the market." He invited participants to consider and encourage additional test sites worldwide. In closing the discussion on this topic, Dooley said, "This information was one of the key results from this conference."

Instrumentation

Waltron's Hal Stansfield, chief chemist, presented *Instrumentation and FFS: the good, the bad, and the ugly.* The content was two-fold: development of instruments to measure and control the applications of FFS, and growing concerns that FFS are having damaging effects on existing instrumentation.

On the positive side, Waltron's online analyzer is effective at monitoring total condensate flow versus the concentration of amines (Fig 8). On the negative side, FFS are creating issues with ion-selective and pH electrodes, dissolved oxygen sensors, and colorimetric analyzers. There are lab reports of sodium electrode failures.

These issues, and proposed solutions, were reviewed. The conclusions: Instruments must be protected, and improved, because FFS have an important place in water and steam chemistry programs. Research is ongoing.

Baseline, due diligence

As a prelude to planning the use of any FFS, a proper baseline is critical. As stated in IAPWS TGD8-16(2019) p 7, "If plants have not previously made thorough assessments of the chemistry used, the consequences of using an FFS cannot be clearly demonstrated."

Co-chair Addison stressed attention to detail. "Good planning is absolutely critical," he emphasized. Failure to do proper due diligence can lead to:

- Suboptimal FFS selection.
- Incorrect application of an FFS.
- Failure to obtain full benefits of an FFS.
- Consequential plant issues including equipment failures.

- Excessive application costs with little or no technical benefit.

The key starting points should always be the IAPWS technical guidance documents, available for download and at no cost. The relevant documents for this discussion are these:

- Instrumentation, TGD2-09(2015).
- Corrosion product sampling, TGD 6-13(2014).
- Steam purity, TGD5-13.
- Film-forming substances for fossil, combined-cycle, and biomass plants, TGD8-16(2019).
- Film-forming substances for industrial facilities, TGD11-19.

Section 8 of TGD8-16(2019) p 18, provides operational guidance for operators/users for the continuous addition of an FFS. Your due diligence should include a review of the following:

1. Local regulations and suppliers.
   - Is the product approved and available in your area?
   - How will the product get to you, and are there supply-chain risks?
2. Supplier competence and willingness.
   - Will supplier engage with you technically?
   - What are supplier's technical resources?
   - Will supplier support you in testing (coupon bench tests, etc)?
3. Annual cost estimates:
   - Projected FFS consumption.
   - Flexible operation rates (often two to five times greater).
   - Dosing required at shutdown.
   - Your plan versus what others are doing.
4. Robust residual analysis methods: Do they work? (bench tests and online analyzers).
5. Does the selection impose any technical/commercial/legal restrictions to your site?
6. Can you discuss experiences with others one-on-one or at technical conferences?
7. Can you use third-party experts for support?

Many of these concerns were highlighted in the final discussions section of the conference.

Path to needed research

The wide range of FFS products, mixtures, and suppliers make research and common solutions difficult. Much of the current industry work is on metal surfaces rather than the oxide surfaces that form within plants. Fundamental research targets are:

- Effect of FFS on growth mechanisms of iron, copper, and chromium oxides in water and steam.
- Effect of FFS on boiler and HRSG tube failures (under-deposit corrosion, corrosion fatigue) and stress corrosion cracking.
- Film formation, kinetics, structure and porosity of water- and steam-touched oxide surfaces, to include changes of FFS.
- Uncertainty of thermal degradation, stability limits, and decomposition products for FFA—and especially FFP—under oxidizing and reducing conditions.
- Uncertainty of adsorption onto oxide surfaces for all FFS (FFA, and especially FFP).
- Protection of superheated-steam surfaces with all FFS (FFA, and especially FFP).
- There is evidence of increased steam-turbine performance for amine-based FFS (ODA), but what about other FFAs and FFPs?

Upcoming conferences

The research needs for film-forming substances are a major topic for the next IAPWS Annual Meeting, Nov 27 to Dec 2, 2022, in Rotorua, New Zealand. Dooley serves as executive secretary for IAPWS, David Addison as chairman of the IAPWS Power Cycle Chemistry Working Group.

Mark your calendar: The Sixth IAPWS FFS International Conference will be held Mar 21- 23, 2023 in Prato, Italy. Details will be announced on www.iapws.org as they become available. CCJ

McIntosh Power Plant (Unit 5)

Owned and operated by Lakeland Electric

405 MW, gas-fired 1 × 1 Siemens 501G-powered combined cycle located in Lakeland, Fla

Plant manager: Stephen Reinhart

HRSG mod allows an increase in backpressure to boost power output

Challenge. Maximum allowable duct pressure for the HRSG in Lakeland Electric's (LE) McIntosh Power Plant (MPP) Unit 5 combined cycle was 28 in. of water column (in. H_2O).

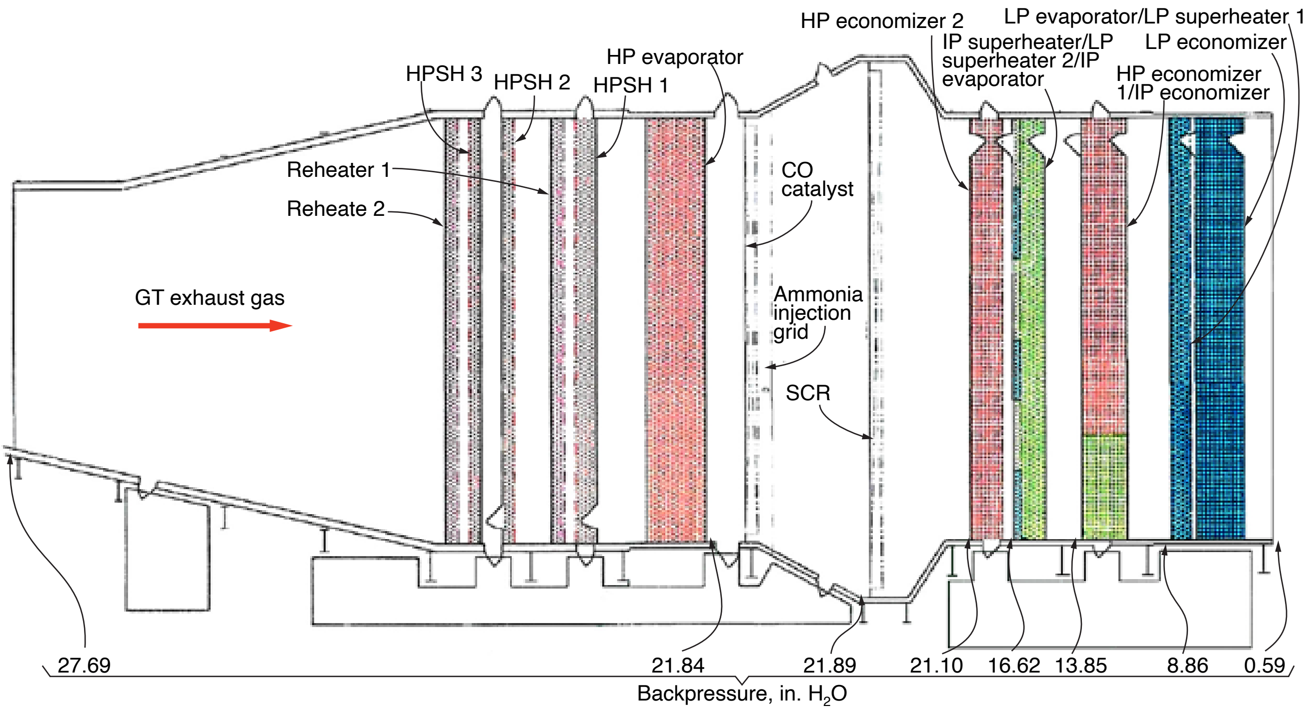
After 20 years of operation, pluggage of the LP economizer in the Nooter Eriksen boiler caused high backpressure on the gas turbine/generator and limited its ability to operate at full load. High backpressure led to a derate of up to 14 MW. Cleaning of the economizer was ineffective in reducing backpressure because of HRSG design idiosyncrasies.

Multiple pressure transmitters were installed on Unit 5 for analysis of the pressure drop across the HRSG to understand when heat-transfer sections are experiencing pluggage and where to focus cleaning efforts during outages (Fig 1). In LE's case, cleaning did not significantly change the ability to reach full load with an original alarm point of 24 in. H_2O and a runback set at 26 in.

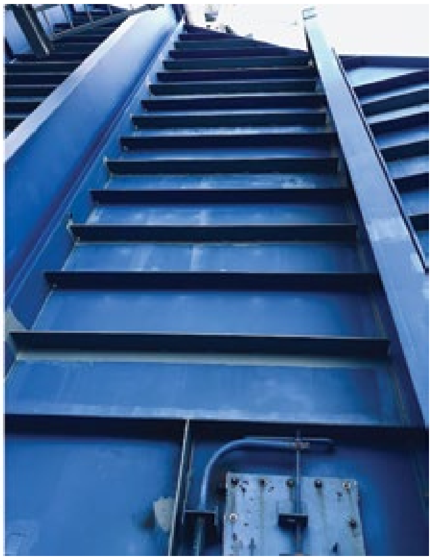
Solution. Several modifications brought the allowable backpressure to 29 in. H_2O, with the alarm point reset to 27 in. and the runback to 30 in. Testing showed a significant efficiency gain by allowing Unit 5 to run up to the alarm point. At 27 in. H_2O, Unit 5 had an increase in output of 15 MW, eliminating the derate. Testing and analysis indicated the HRSG would require stiffeners in various locations to increase the design limit from 30 to 45 in.

An engineering firm was engaged to analyze the HRSG and to come up with an adequate solution to increase Unit 5's allowable duct-pressure limits. The consultant recommended adding 245 stiffeners throughout the HRSG. Stiffener spacing, size, and design were evaluated using best engineering practices.

The engineering firm divided the



1. McIntosh Power Plant's Unit 5 HRSG experienced plugging in the low-pressure economizer section, increasing backpressure on the gas turbine and limiting output



2. Stiffeners for Area 1 were designed to accommodate a duct pressure of 45 in. H_2O

3. Stiffeners for Area 2, which extended to the exhaust stack, also were designed to accommodate a duct pressure of up to 45 in. H_2O

required stiffeners into these two areas:

- Area 1: HRSG inlet, reheaters 1 and 2 and HP superheaters 1, 2, and 3 (Fig 2).
- Area 2: HRSG outlet, the HP evaporator and remaining heat-transfer sections downstream to the exhaust stack (Fig 3).

For Area 1, the engineers evaluated casing stiffener spacing based on biaxial bending (plate theory) to accommodate a duct pressure of 45 in. H_2O. For Area 2, the stiffener spacing was based on large deflection/diaphragm stresses to accommodate a duct pressure of 45 in. H_2O; this evaluation was used as the basis for stiffener design.

The distinction between Area 1 and Area 2 is based on experience that indicates the former should have more stiffening to avoid liner and pin problems as casing pressure is increased.

The design procedure used came from the fourth edition of Roark's Table :X, which takes into account plate action when designing the casing for internal pressure. This analysis does not include finite-element analysis of the casing, but rather uses traditional mechanics of material theory. The initial design procedure relies exclusively on plant bending in two axes. Another approach is large deflection/diaphragm stresses. This approach recognizes the plate will resist the stresses in bending in both axes but there also is additional resistance—a membrane stress, or direct stress.

Results. Testing and analysis showed Unit 5 had a significant improvement in efficiency and eliminated the derate load output by increasing the allowable duct pressure in the HRSG. To accomplish this, LE completed the following:

- Performed an engineering analysis of the HRSG to determine how many stiffeners and at what locations stiffeners would be required to accommodate an increase in duct pressure.
- Performed a test to show that increasing the duct-pressure limit would significantly improve Unit 5 efficiency by eliminating derates caused by pluggage.
- Added 245 stiffeners during an outage.
- Increased the operating backpressure limit to 27, 28.5, 29, and 29.3 in. H_2O for alarms and 30 in. for runback.

As a result of these improvements, Unit 5 no longer was derated because of HRSG pluggage and was able to make full load when required.

Project participants:

Todd Green, mechanical maintenance supervisor

Jim Adams, electrical maintenance supervisor

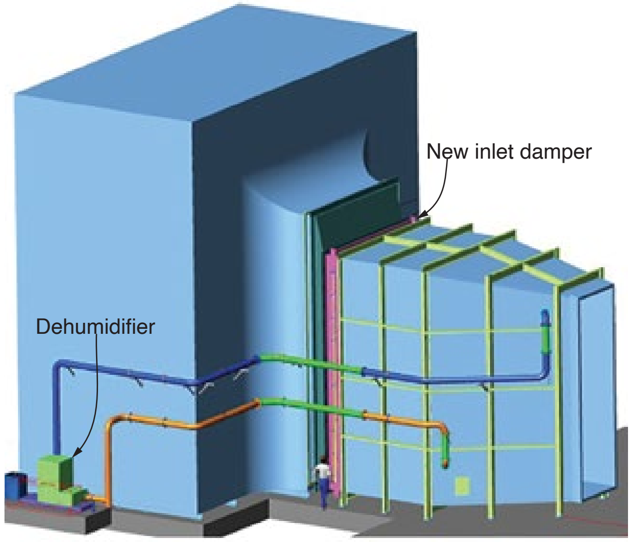
LE's mitigation efforts to protect the through bolts on its W501G turbine rotor

Challenge. McIntosh Power Plant (MPP) is home to the first W501G gas turbine to experience a turbine-rotor through-bolt failure. LE worked closely with OEM Siemens to complete an investigation to determine the failure mechanism. While this lengthy process unfolded, the utility invested in several mitigation efforts to minimize the potential for future through-bolt failures. This best practice focuses on one of the mitigation actions—dehumidification—and lists other ideas that were implemented.

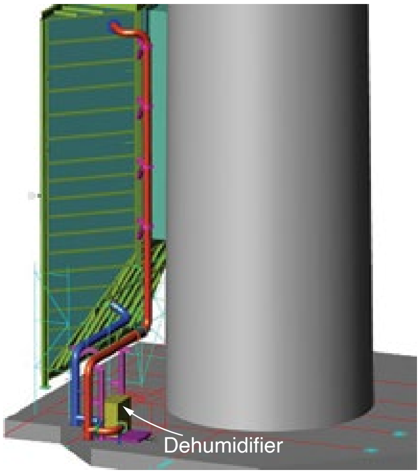
There had not been a turbine through-bolt failure in more than 30 years of operating gas turbines of essentially the same design. Therefore, starting from scratch on a root-cause analysis (RCA), early indications pointed to a high stress riser at the Row-1 disc area, where the fracture occurred (Fig 4). An in-depth investigation of all significant materials provided important facts regarding the incident but did not identify a sole root cause.

The theory was that moisture in the rotor air cooler (RAC) circuit could be carrying debris to the Row-1 disc area and creating a debris pack between the rotor and disc. Based on the concern for moisture and debris in the RAC circuit, Lakeland Electric researched possible mitigation efforts and implemented the most promising.

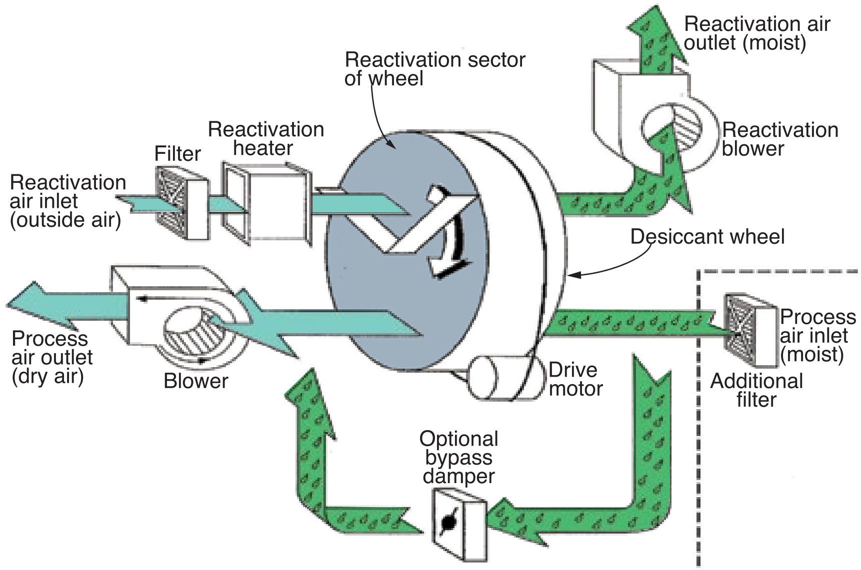
4. Through-bolt in McIntosh Unit 5's turbine section suffered the first bolt fracture in the W501G fleet



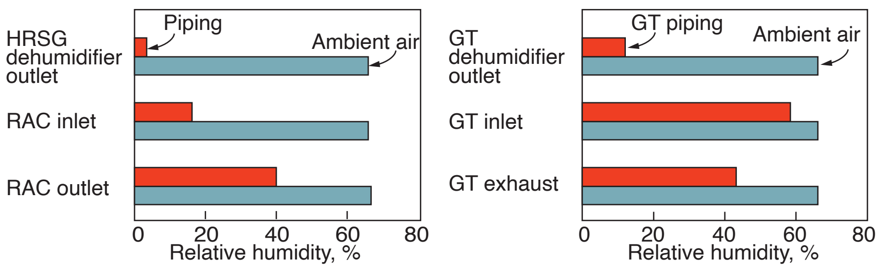
5. Dehumidifier and new damper were installed at the gas-turbine inlet to minimize the amount of moisture entering the unit



6. An additional dehumidifier at the LP end of the HRSG at the exhaust stack was equipped with a tap to supply the LP rotor air cooler and associated piping circuit



7. Dehumidifier's desiccant wheel removes moisture from the humid air



8, 9. Tests determined the reduction in humidity achieved at the gas-turbine inlet and in the RAC piping with the dehumidifiers in service

Solutions. The utility's first initiative, to eliminate the sources of moisture in the RAC circuit, was to engineer a dehumidifier application for the gas-turbine inlet and add a damper to minimize moisture from entering via the GT inlet (Fig 5). LE also added a dehumidifier to the LP end of the HRSG at the exhaust stack with a tap to feed the LP RAC and associated piping circuit (Fig 6). A damper was not required at the stack because one had been installed previously.

When Unit 5 was brought offline, the new damper allowed LE to "bottle up" the unit. Then the dehumidifiers would be placed into service to help prevent moisture from condensing because of the humid Florida air. This prevented the RAC piping from sweating, creating moisture, and causing corrosion in the RAC piping circuit.

Fig 7 shows how the dehumidifiers work. They are equipped with a desiccant wheel to remove moisture from the humid air; desiccant reactivation is by application of heat to the wheel. Tests were performed to determine the reduction in inlet and RAC-piping humidity. Figs 8 and 9 provide test results to illustrate dehumidifier effectiveness.

Other mitigation efforts also were initiated to help control moisture and corrosion in the RAC piping circuit, thereby protecting the rotor through bolts—including the following:

- Developed a hydro procedure for RAC leak inspections and repairs (outage standard).
- Added a thermocouple to the RAC to detect water from a leak. This point was brought back to the plant DCS.
- Added RAC manual drains that are checked during startup of Unit 5.
- Automated the RAC drains to open during turbine startup to blow any moisture to the blowdown tank.
- Installed an additional RAC startup strainer.
- Changed the RAC piping from carbon steel to stainless to eliminate debris.

These enhancements enabled a cleaner RAC circuit and less debris transport to the turbine rotor.

Result. Use of an investigative process enabled LE to implement multiple solutions for reducing moisture and debris from the RAC piping circuit.

Specifically:

- The utility implemented solutions developed by its personnel and several suggested by Siemens.
- Siemens eventually redesigned its 501G rotor through bolts and Lakeland has implemented the latest OEM technology and rotor through-bolt design in its rotor upgrade program.

These shared technology advancements have been implemented throughout the W501G fleet and there have not been any rotor through-bolt failures since.

10. Trailing-edge erosion of L-0 blade after 10 years of operation is typical

11. Periodic inspection of blades, visual and die-penetrant, is recommended to identify such problems as inclusions (circle in photo), tunneling, and cracking which could lead to a failure

Project participants:
Kevin Robinson, operations manager
Guy Tayler, mechanical engineer
Steve Reinhart, plant manager

Use online monitoring, NDE to monitor the condition of steam-turbine blades

Challenge. How to monitor the steam turbine/generator to determine proactively if repairs are needed.

Solution. To ensure the Unit 5 steam turbine is available when the unit must operate, Lakeland Electric personnel focus on preventive-maintenance activities to avoid a failure. The steamer is monitored continuously for backpressure on the L-0 blades (especially during shutdowns) and those airfoils are inspected for potential inclusions, and erosion (Fig 10) and tunneling, during operation.

On large steam turbines, the LP section's L-0 blades can experience cracking because of off-specification operation, including excessive backpressure from the condenser—especially during a shutdown event. Thus, the utility has instituted continuous monitoring of backpressure on the steam turbine that initiates an alarm thusly:

- Offline—alarm at 4.5 in. Hg; trip at 5.5 in. Hg.
- Online—alarm at 7.0 in. Hg; trip at 8.0 in. Hg.

Additionally, the steam-jet hogger air ejector automatically comes into service if there is a steam-turbine trip—this to ensure backpressure is maintained.

To verify there are no inclusions in the L-0 blades (Fig 11), LE has instituted periodic inspections (annually at a minimum). The inspections are completed in situ by completing nondestructive examinations (NDE) of the blades. These inspections revealed that erosion was occurring at the trailing edges of the L-0 blades.

The inspections include visual and die-penetrant inspections, and molds are completed. All inspections are done in situ from the steam-turbine hotwell to verify the potential for tunneling and/or cracking that may lead to a failure of the L-0 airfoils.

Results. Use of continuous monitoring and NDE of L-0 steam-turbine blades have helped determine what blades are most susceptible to failure. These are the steps the utility has taken:

- Follow OEM recommendations regarding testing intervals—at a minimum.
- Conduct periodic in-situ NDE of the L-0 blades to ensure they can meet the desired service interval.
- Implement alarms to notify when a backpressure event may have occurred.
- Implement control logic to automatically put the hogger air ejector into service if there's a potential for a backpressure event on the steam turbine.

The benefit of this activity is that the steam turbine continues to operate at desired service intervals.

Project participants:
Scott Cox, NERC engineer
Steve Reinhart, plant manager

Power Users is the umbrella organization for managing and coordinating the technical programs for the industry's leading User groups

POWER USERS™

CCUG™ COMBINED CYCLE USERS GROUP

FRAME 5 Users Group™

GUG GENERATOR USERS GROUP™

Frame 6B Users Group™

7EA™ Users Group

POWER PLANT CONTROLS USERS GROUP™

7F Users Group®

HA™ 7HA & 9HA USERS GROUP

STUG STEAM TURBINE USERS GROUP™

HRSG FORUM

Low Carbon Peer Group

Conferences

Visit https://www.powerusers.org/home/annual-conferences/ for the most updated conference dates for each group.

Forums

Visit https://www.powerusers.org/forum/ for a full list of User Group discussion forums. Users must be logged in to have access to the forums.

Power Users Group is a non-profit company managed by Users for Users. It is designed to help Users share information and get solutions to power-production problems.

www.PowerUsers.org

The 501F Users Group returns to Reno (Nev) and the Peppermill Resort and Spa for its 23rd annual conference, Feb 19-23, 2023. The 501G Users Group will co-locate, as it has done previously. A technical program was not available at press time. Get that, plus registration/hotel information, via the web at https://forum.501Fusers.org as details are finalized.

2022 conference review

A Covid outbreak a week or so before the 2022 meeting was to start at the Hyatt Regency in New Orleans, February 20, reduced the number of attendees, both user and vendor. Recall that this conference was the group's return to an in-person program following a virtual meeting in 2021.

Perhaps the most important announcement made at this year's conference, from an organizational perspective, was that Russ Snyder, president and chairman of the 501F board of directors, and long-time leader of the user group, had retired from his day job as VP generation operations at Cleco Power LLC on Jan 1, 2022.

No longer a user, he turned over the organization's keys to Ivan Kush, principal CT and controls engineer at Charlotte-based Cogentrix Energy Power Management. Snyder was lauded by both the owner/operator and vendor communities, and the OEMs, for his positive mindset and tireless efforts over the years to build one of the industry's premier user organizations.

Overview

Day One featured the annual safety roundtable and 30-min Vendorama presentations by many of the exhibiting product/services providers listed in the sidebar (p 86). These presentations were arranged in five tracks, each beginning after the morning break and running until end-of-day. Summaries of what was said are presented in the pages that follow. Use the QR codes to access the abstracts of interest in one click. Alternatively, you can visit the 501F website and scroll through the list.

Day Two began with the generator roundtable. Presentations by Siemens Energy and PSM followed and ran until the closing bell.

Note that the Siemens Energy presentations are not posted to the 501F website. The OEM's engineers had the podium for only two hours and encouraged those wanting more detail to attend the company's Large Gas Turbine Conference (formerly the Siemens Energy F, G & H Conference) this coming June (details in the 2023 calendar of events on p 3 of this issue). Alternatively, visit the OEM's customer extranet portal at https://cep.siemens-energy.com.

PSM held the floor the entire afternoon and treated attendees to dinner. The company's execs and top engineers participated, presenting on recent 501F projects completed and those in the pipeline, 501F FlameTOP (FlameSheet™ and GTOP7), operational flexibility, hydrogen initiatives and roadmap, supply-chain issues and mitigation, 501F repairs (focus on R1 blades and vanes), product-line update (rotors, exhaust, diaphragms), troubleshooting, and service engineering.

While these presentations are not posted to the 501F website, you can request them from your plant's PSM representative.

A PSM presentation you probably would not want to miss is the one by Katie Koch, global product manager, who shared "Fuel and operational flexibility: Hydrogen capabilities and the latest on 501F upgrades and developments" with 501F users in a virtual meeting at the end of September. It summarizes the important points of the PSM afternoon in New Orleans, February 22. Plus, it highlights some of the 501F fleet activities and R&D projects that PSM will update the membership on at the next annual meeting in Reno. These include the following:

- Exhaust bleed installation and implementation for turndown.
- First dual-fuel FlameSheet.
- First 50% hydrogen blend (by volume).
- FlameSheet expansion to five frames.
- Production of upgraded R4 blades

Officers and Board of Directors

President and Chairman of the Board
Ivan Kush, *principal CT and controls engineer, Cogentrix Energy Power Management*

Vice Chairman
Carey Frost, *program manager, Duke Energy*

Secretary and Board Member
Brian Berkstresser, *plant manager, Liberty Utilities*

Board Members:
Blaine Gartner, *principal engineer, Xcel Energy*
John Burke, *O&M manager, Cottage Grove Power Plant, NAES Corp*
Dave Gundry, *senior engineer, Xcel Energy*
Greg Dolezal, *managing director, Klamath Energy LLC (Avangrid Renewables)*
Jaime Oliveira, *O&M senior manager, Norte Fluminense, EdF*

for the 501FD3.

- Improvements to GTOP for F4/F5 and M501F.
- Completion of all compressor disks to complement rotor lifetime-extension programs.
- Study of peaking operation on rotors having reached end of life as determined by the OEM.
- Launch of PSM's digital twin under Intelligent Data Platform.
- In-house manufacturing of ring segments (improved capacity and lead times).
- Expansion of additive manufacturing (improved lead times and enhanced cooling features).

Click the QR code to access Koch's recorded presentation from the 501F virtual Vendorama program at the end of September.

Day Three featured four roundtables in the morning: inlet and exhaust, compressor, rotor, and hot gas section. There also was a breakout session in the morning for advanced-frame users. The afternoon was dedicated to presentations by engineers from Mitsubishi Power, also not posted to the 501F website.

Day Four was a half day that featured roundtables on combustors, auxiliaries, and outage planning and conduct. The conference ended at noon.

Finally, note that GE did not participate in the 2022 Conference of the 501F Users Group. The company is expected to reconnect with this community of users at the upcoming Reno meeting.

User presentations

Nearly a dozen user presentations were incorporated into the various roundtables. Highlights will appear in the next issue of CCJ. However, you can access the PowerPoints now at https://forum.501Fusers.org. You will find them in the "2022 Conference Materials" folder (click on the magnifying-glass symbol at the top right-hand side of the page). Only registered users are admitted to this portion of the website.

Vendor presentations

The seven vendor presentations highlighted immediately below were made, along with the PSM preso abstracted above, during the 501F virtual Vendorama program at the end of September. These are updates of what the vendors had to say during the in-person Vendorama program in February 2022. Access both the slides and recordings using the QR code in the left-hand column.

Environment One Corp, *Generator condition monitor for air-cooled machines,* discusses the technology's application and contribution to higher reliability—covering principle of operation, system description, sample applications, and design considerations.

Arnold Group, *Advanced single-layer turbine warming system.* Detailed system description, operating experience, and value proposition are presented in the following article (p 88).

Braden Filtration, *Air inlet pulse filters: Are you keeping pace with the industry?* A thorough assessment of pulse-type filtration systems for maximizing gas-turbine performance. Includes details on fibers, chemical coatings, and membranes.

Catalytic Combustion, *Effects of sulfur on CO catalyst when operating at lower temperatures,* offers solutions for protecting against catalyst degradation by sulfur contamination.

National Electric Coil, *Aeropac I generator challenges, failures, and recovery,* provides two case studies

Vendor partners

Many of the companies exhibiting at the 2022 vendor fair (list below) will return in 2023. No details on this year's participants were available at press time. Follow the user group's website at https://forum.501Fusers.org for updates.

Advanced Turbine Support
AGT Services Inc
Allied Power Group
Alta Solutions Inc
American Thermal Solutions
Arnold Group
BBM-CPG Technology Inc
Bearings Plus
Braden Filtration LLC
Brüel & Kjær Vibro
C C Jensen, Oil Maintenance
Catalytic Combustion Corp
Conax Technologies
Conval Inc
Crossby Systems Inc
Cutsforth Inc
Donaldson Company
Doosan Turbomachinery Services Inc
Dürr Universal Inc
EagleBurgmann
EMW filtertechnik GmbH
Environex Inc
Environment One Corp
Falcon Crest Aviation Supply Inc
Filtration Group
Frenzelit Inc
Freudenberg Filtration
GE Power
Groome Industrial Service Group
Hilco Filtration Systems
HRST Inc
Hy-Pro Filtration
Industrial Air Flow Dynamics Inc
Intertek AIM
ITH Engineering
JASC
Koenig Engineering Inc
LPG Industries Inc
Macemore Inc
Mee Industries Inc
Meggitt/Vibro-Meter
Mitsubishi Power
Moog Industrial
National Electric Coil
Nederman Pneumafil
Nord-Lock Group
NRG Energy Services
ORR Protection Systems Inc
Parker Hannifin Corp
PowerFlow Engineering Inc
Precision Iceblast Corp
PSM
Rochem Technical Services
ROMCO Manufacturing Inc
Schock Manufacturing
Sensatek Propulsion Technology Inc
Shell Oil Products
Siemens Energy
Sulzer Turbo Services Houston Inc
SVI Industrial (SVI Dynamics/ Bremco)
Tetra Engineering Group Inc
TOPS Field Services
Trinity Turbine Technology
TRS Services LLC
Umicore Catalyst USA LLC
Veracity Technology Solutions
Viking Turbine Services Inc
Voith Turbo
Voom LLC

with guidance on developing a repair plan and identifying major milestone progressions.

C C Jensen Inc, *De-mistifying varnish: Why the CJC VRU varnish removal unit is the safest and most efficient technology*. A tutorial that includes varnish characterization, impacts of turbine operation on varnish formation, importance of oil analysis and tests of greatest value, methods of varnish removal, online condition monitoring, etc.

EagleBurgmann Static Sealing Solutions, *PulseBreaker™ technology for high-efficiency units and 501F/G maintenance tips*. Shares why this new type of gas-turbine exhaust joint is more capable than the company's traditional quilted design: The latter keeps insulation in place, the former offers better protection for insulation media. Focus is on design details.

The companies making the following presentations during the February in-person Vendorama program chose not to participate in the virtual Vendorama session in September. The slide decks for these presos can be accessed by clicking at the nearby QR code. The February program was not recorded.

Cutsforth Inc, *Case study on electromagnetic interference (EMI) monitoring* illustrates the company's ability to validate an event and prevent a failure. Presentation shows how information from high-speed waveforms, spectrum scans, and data analyses captured from shaft ground monitoring and EMSA were used by SMEs to identify the source of high voltages and arcing and allow repair before the generator experienced significant damage.

EMW filtertechnik, *Better filtration pays for itself—Part 2*. This is a follow-on to the company's 2021 presentation, offering a deeper look into the main KPIs of the filter industry and updated results from several gas-turbine projects.

APG-Allied Power Group, *501FD2/3 Row 3 turbine-blade repair and life extension,* is vintage Aaron Frost, an industry leader in the subject matter presented. Reviews historical R3 blade designs, inspections, findings during those inspections, characterizations of defects and where they are located and materials affected, and much more. Presentation is particularly valuable for its level of detail and photography. You can go through the slides multiple times and still find things of importance you weren't aware of.

Doosan Turbomachinery Services Inc, *501F Row 1 blades: Operational and historical repair experience*. Focuses on the many design differences among Row 1 blades made over the last 25 years with emphasis on OEMs, materials, and coatings. Advantages and disadvantages from a repair-management point of view are provided, in addition to standard repair recommendations and other considerations for maximum lifecycle management.

B K Vibro America, *A method for calculating complex asymmetric distributed weight splits*. If a turbine rotor has a significant number of existing balance weights where an additional balance weight is needed, a complex asymmetric weight distribution can be used instead to help minimize the total number and mass of weights needed versus a single simple weight split.

Environex Inc, *Is your SCR/CO system ready for turndown?—Part 2* is a follow-on to the company's presentation in February 2020. Back then the focus was how higher NO_2/NO_x ratios in exhaust gas were increasing SCR system performance requirements. However, recent field data show another phenomenon is causing even higher NO_2/NO_x at the SCR catalyst inlet: Lower VOC emissions requirements. Goal of the preso is to help operations personnel better understand what to look out for when specifying SCR and CO catalysts.

Frenzelit Inc's *Expansion joint upgrades for legacy 501FD and 5000F units* brings you up to date on product improvements to eliminate the root cause of cracking and premature expansion-joint failures.

HRST Inc's *Considerations for fast ramping and peak capacity* walks you through these topics: optimal startup procedures, gas-turbine purge time calculation, purge credit feasibility, steam-turbine considerations, HP-drum ramp rate, tube metal temperature, and nameplate capacity. Goals include helping users (1) avoid startup damage from water pooling in the reheater and superheater when offline and (2) mitigate pressure-part stress from rapid temperature changes.

JASC's *Zero-emissions equipment* provides operational readiness for liquid-fuel operation and allows the testing of the liquid-fuel system without burning oil in the turbine. Company's technology enables fuel-transfer rates approaching 100% and fuel-system flow-control functionality which only requires service at intervals of four to five years.

Moog Industrial, *Improvements and upgrades to fuel-gas control-valve assemblies.* Describes Moog W501F/G actuator/gas-control-valve lineage and model variations, and control system trends and their impacts on fuel control valves. Plus, benefits and advantages of the company's new chrome coating process for cylinder bores, and its explosion-proof-rated solenoid-activated dump valve.

Nord-Lock Group, *The four-way-joint leak solution* described is said to be a robust fix which incorporates hydraulic and mechanical tensioning techniques, and internal seal with adjustable retainers, and improved bolt-hole and flange sealing system. Result: Zero leaks.

Sensatek Propulsion Technology Inc's *Turbotrack™* monitors the actual condition of rotating parts. The company's on-blade temperature/strain sensor system can be deployed without continuously dismantling the engine, rapidly accelerating testing while reducing costs.

Shell Oil Products, *Healthy machines through real-time lubricant condition monitoring.* Describes the company's program for monitoring oil and equipment condition 24/7 to give advance notice of impending mechanical failures while providing continuous remote data-gathering.

Sulzer Turbo Services Houston Inc, *Maintaining 501F rotors,* shares company's robust, repeatable repairs and solutions to the following issues, among others: broken alignment fits of forward stub shaft, compressor through-bolt failures, fretted air baffles, and significantly worn disc seal arms. Plus, how Sulzer conducts shop rotor inspections, evaluates findings, and plans steps forward.

SVI Industrial, *Repair procedures: The good, the bad, and the ugly,* shows through a series of photos how to evaluate HRSG weld repairs. Topics include how to find the leak, Code repair concerns, identifying repair methods, raising/lowering panels for tube repair, plugging tubes, jacking panels, Code requirements for stress relief, key Alloy 91 weld features, post-weld heat treatment, welding method 6, and supplement 8.

Voith Turbo, *Collaboration in the "new normal,"* discusses the following: improving starting-system availability and reliability, maintenance updates for legacy units, system safety developments, and other topics as well.

COMBINED CYCLE Journal

CCJ No. 72 (2022)

Index to advertisers

7EA Users Group 97
7F Users Group....39
7HA and 9HA Users Group 78
Advanced Filtration Concepts 11
Advanced Turbine Support LLC 15
AGT Services Inc 33
AGTSI....99
Arnold Group 8-9, 31, 55, 77, 85
Braden Filtration 35
Caldwell Energy 75
CCJ Generator Training 40
Combined Cycle Users Group (CCUG) 67
Chanute Manufacturing....43
Crown Electric 23
Cust-O-Fab Specialty Services 58
Cutsforth Inc....50-51
Dekomte 69
Donaldson Company Inc....59
Doosan Turbomachinery Services 25
Filter-Doc Corp 29
Frame 5 Users Group 97
Frame 6B Users Group 97
Gas Path Solutions....26-27
Generator Users Group (GUG) 67
Groome Industrial Service Group....37
HRSG Forum....52
HRST Inc....74
Indeck Power Equipment 49
International Generator Technical Community 91
JASC 19
KinetiClean (Groome)....100
Legacy Turbine Users Group (LTUG) 97
Low Carbon Peer Group 67
MD&A 2
Millennium Power 60
Mitsubishi Power 4-5
Mitten Manufacturing....74
Mobile Excitation Services 62
National Breaker Services....23
National Electric Coil 49
Noxco 21
PIC (Precision Iceblast Corp)....13
Power Plant Control Users Group (PPCUG) 67
Power Users....67
Power Users, Forum 72
Power Users, Umbrella Organization....83
Schock Manufacturing....65
Steam Turbine Users Group (STUG)....67
SVI Industrial 56
Taylor's Industrial Coatings 28
TesTex 82
Tetra Engineering Group 44
Trinity Turbine Technology....61
Umicore Catalyst USA Inc....17
ValvTechnologies....45
Zokman Products Inc 68

Warming system, advanced insulation increase operating flexibility, reduce asset stress, cut costs

Modification of combined cycles designed for base-load service to produce power reliably and efficiently when wind and solar energy are not available to "fuel" renewables generation has been ongoing for about a decade.

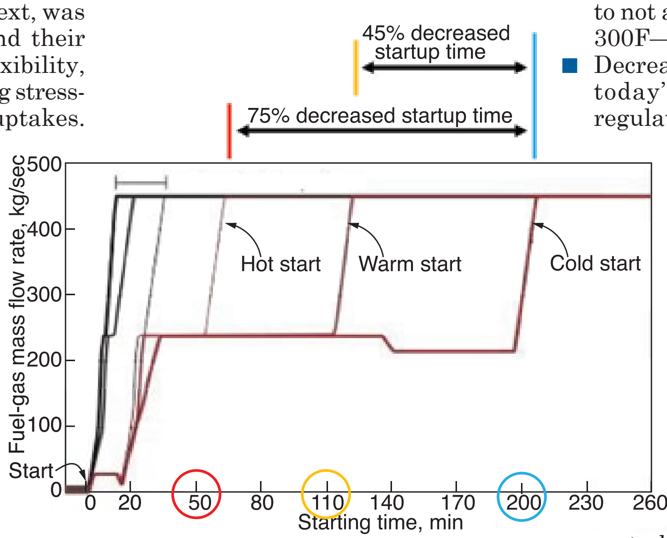
The first step was to achieve faster starting of large frame gas turbines and enable those machines to more quickly respond to changes in electrical demand. Accomplished. Next, was to provide steam turbines and their valves greater operational flexibility, while at the same time reducing stresses seen from recent cycling uptakes. In progress. Still to come: Building more operational flexibility into heat-recovery steam generators and steam systems.

This article focuses on the success of Germany's Arnold Group in developing a highly engineered turbine warming system capable of mass customization to complement the flexibility of today's gas turbines in satisfying the unique operational requirements of any combined cycle. The information presented here was sourced from discussions and presentations at user-group meetings, and interviews, both formal and informal, with plant personnel having relevant experience.

Turbine warming systems are not new. But until the Arnold system was introduced to the market about five years ago the products available typically resembled your grandfather's electric blanket—heating wires incorporated into the fabric (insulation). Issues included less-than-ideal fit-up to the turbine casing (contributing to "heat leakage" and uneven casing stress) and relatively poor long-term durability (because of their susceptibility to step and other damage).

By contrast, Arnold marries the turbine warming system with an independent insulation system featuring interlocking high-performance blankets that conform perfectly to the turbine surface. More on the Arnold designs later.

When Norm Gagnon, Arnold's lead product manager in North America, spoke before the 7F Users Group last May (2022), he raised the level of respectability for warming systems saying their purpose was turbine thermal conservation, stress risk mitigation, and cycle optimization—rather than merely a method for heating metal. He was followed on the program by Pierre Ansmann, global head of marketing, who spoke about the company's technically advanced insulation system.

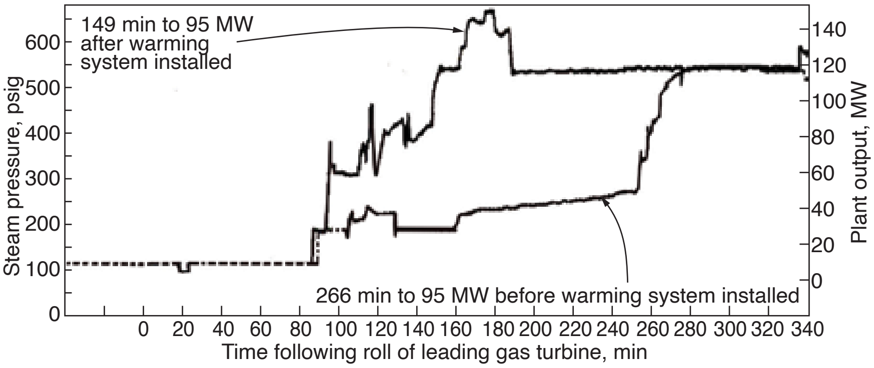


1. Steam-turbine starting times differ dramatically for hot, warm, and cold starts

Benefits of warming. Gagnon began by asking, and then answering, the question, "Why does anyone need a turbine warming system?" The former maintenance manager for an F-class combined cycle said there's need for optimization in the startup cycle to do the following:

- Reduce turbine-casing stresses to accommodate high-cycle operations and avoid costly major-component replacement and/or long-downtime repairs.
- Decrease the startup time to improve in-market availability. Just what can be achieved depends in large part on the sophistication of the heating system and the mass of metal involved. Most important is to not allow the turbine to go below 300F—or "cold."
- Decrease emissions to meet both today's restrictions and future regulations. Regarding the latter, Gagnon cited the Regional Greenhouse Gas Initiative (RGGI, pronounced "reggie") for the Northeast, which is planned to go live in 2030. It will increase the challenges associated with operating fossil-fired generation in this area of the country.
- Enabling a plant to capture the real-time market when an opportunity exists, by making unit operation more predictable.
- Reduce fuel and startup costs by not having to use a gas turbine to warm the steam turbine throughout the entire start cycle. A real-world example provided by Ansmann: For a 2 × 1 combined cycle with a cold-start time of seven hours, use of a warming system to half the start time reduced the cost of a startup by about $20,000 based on gas at $8/million Btu.

Regarding the reduction in starting time possible by use of a turbine heating system, Gagnon shared Fig 1. However, he believes the conventional terms "cold, warm, and hot starts" will slowly disappear from the lexicon, replaced by a focus on shell temperature to manage thermal fatigue and with hot starts becoming "standard"



2. Warming system reduces by nearly two hours the time for a D11-equipped combined cycle to achieve 95-MW output following a 100-hr outage

given the advantages stated in the bullet points above.

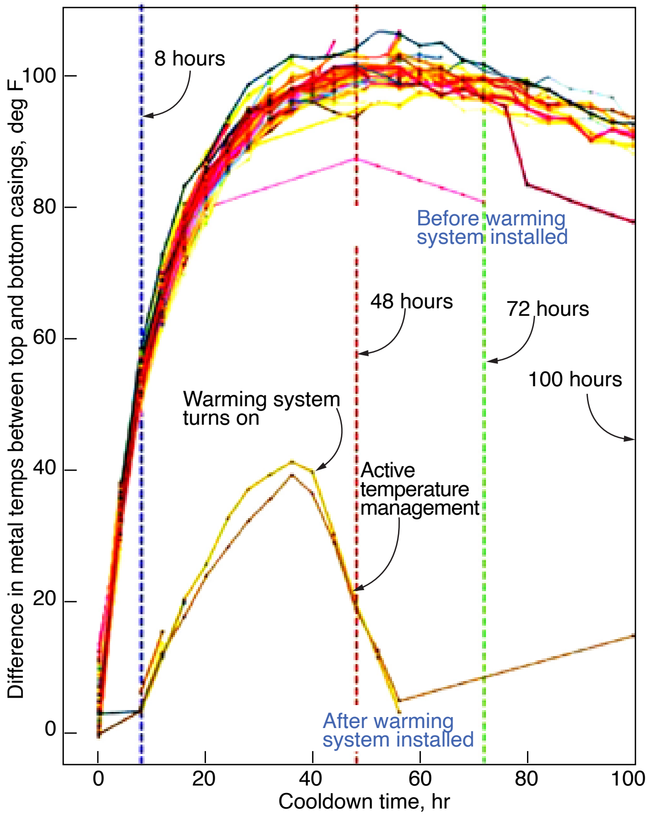
Arnold says its combination warming/insulation system is the only one commercially available worldwide capable of maintaining turbine casings at hot-start temperatures on D11-style combined-HIP-casing units for at least 10 days after a unit shutdown.

Fig 2 presents real-world data from a 2 × 1 7F-powered combined cycle with a D11 steam turbine that shows use of Arnold's warming and insulation systems cut between two and three hours from the time it takes for the unit to achieve 95-MW output after a 100-hr outage. This was cited as "typical" by the supplier, which has more than five dozen similar systems operating, being installed, or on order worldwide.

Operational flexibility. Gagnon spent a significant portion of his podium time at the 7F meeting discussing the critical need to maintain all turbine sections at near-equal temperature during the shutdown period to allow restarts on demand without damage caused by rubs, rotor bow, etc.

The Arnold system has proven its ability to keep upper and lower casing halves to a ΔT of only a few degrees, as well as to control rotor shrinkage and casing axial growth to avoid so-called "rotor-short" and "casing-long" conditions.

These benefits are achieved by use of a network of independent thyristor (analog)-controlled heating zones—about two dozen for a D11. Use of an analog system for this purpose is much more precise than traditional on/off digital controls. Approximately 100 thermocouples, fixed to the casing exterior surface, verify that each



3. Absent a turbine warming system the difference in temperatures between D11 top and bottom casings would militate against a restart from about four to 12 hours after a turbine shutdown. Difference in ΔTs between the top and bottom sets of curves before the heating system is activated is attributed to the superior quality of the Arnold insulation

zone is responding correctly and is at the specified temperature. The t/cs also confirm even heating and casing stability across the unit.

Gagnon pointed out that after shutdown, and absent a heating system, the temperature of the upper casing stays warmer than that of the lower casing for several days because heat flows from hot areas to colder ones and top-casing insulation offers less heat-flow restriction than the thicker bottom insulation.

Fig 3 compares the temperature differential between upper and lower casings of a Spanish D11 before the Arnold warming and insulation systems were installed (curves at top) and after installation (curves at bottom) on the same machine. The difference in the ΔT between the upper and lower sets of curves before the warming system was activated is attributed to the superior quality of the Arnold insulation. Note, too, that with the warming system in operation, the ΔT for a weekend outage was less than 10 deg F.

Of particular importance from an O&M perspective is that the heating system for the lower half of the steam turbine is mounted on the casing and is "permanent" (Fig 4). A heat-reflecting shield over the heating cables maximizes system effectiveness; redundant heating circuits enhance the solution's reliability. The heating system for the upper casing is form-shaped to the specific casing onsite and is removed as necessary to accommodate maintenance.

Warming and insulation systems can be installed in 50 days (standard) or less (expedited) and can be operational within the confines of a steam-turbine major without impact to the typical outage schedule—given parallel activity integration into the mechanical outage work scope. The insulation is guaranteed for up to 15 remove/replace cycles with the only requirement being that an Arnold technical advisor is onsite to support that activity and ensure the quality of installation meets Arnold's strict standards.

Gagnon worked with the editors to integrate text with video, enabling a more efficient way to provide information of value to decision-makers. The first, and longest, of the five videos recorded, "Warming-system familiarization," provides a peek "under the hood" in less than eight minutes, enabling you to see the various system components and to understand their purpose. Access the videos at https://www.ccj-online.com/arnold-warming-system/ or simply click on

4. Permanent placement of redundant sets of heating wires on the casing below the split line, plus the use of a heat-reflecting shield over the wires, assures optimal effectiveness and reliability of the warming system

the QR code with your smartphone or tablet.

"How the Arnold steam-turbine warming system works" walks you through the basics in less than four minutes. For example: What does the system do when it turns on? When does it turn on? How does it turn on? How does it turn off?

Next thing you're probably interested in is "Integrating the turbine warming system into plant operations" to take maximum advantage of the information created. This runs less than two minutes.

What's the cost? If the introductory material provided above and in the accompanying videos piques your interest perhaps a preliminary cost estimate would be of value to the people in your organization responsible for capital budgets. Some of the information required to get started is the following:

- Current gas and power prices.
- Additional in-market availability time that the warming/insulation systems would provide, and revenue expected from that IMA at real-time elevated prices during critical grid events.
- Heat rates for simple cycle, 1 × 1, and 2 × 1 plant arrangements.
- Megawatt setpoint for unit soak.
- Plant cost per kilowatt-hour when offline.
- Cost of demin water and auxiliary power.
- Estimated number of cycles longer than 48 hours for the next three years.

A cost estimate shared by Arnold for warming and insulation systems, on a 527-MW, 2 × 1, 7F.04-powered combined cycle operating on $9/million-Btu gas with a current market power price of $53/MWh, would be about $1.5 million (including costs associated with scaffolding and installation of electrical and installation systems). Thus, payback could be in as few as 75 warm/cold starts—or less than a year if you have contracts/conditions demanding operational flexibility.

The fourth video, "Information required to design and estimate the cost of a warming system for your steam turbine," might assist in this effort.

Case history

First-hand installation and operational knowledge of the Arnold steam-turbine warming and insulation systems was shared with the editors by the top managers of a nominal 400-MW, 1 × 1 combined cycle across a table in the plant's break room. This axial-flow unit began commercial operation 20 years ago without a warming system.

But it took eight hours to start the unit, and temperature differences between the rotor and casing on starts caused an unacceptable number of trips. The presumed solution, a heating system for the HP section of the turbine, was installed in 2004. It could heat that casing to about 550F and reduced the cold-start time to about five and a half hours.

The plant was on the right track. However, the system installed was marginal operationally. For example, it could not manage casing temperatures as required. Plus, it was either on or off; blankets could not be controlled individually. The blankets also were not sufficiently robust to withstand the wear and tear of plant service and ground faults occurred too frequently as they aged.

About the time the pandemic revved up, an L-0 blade failure knocked out the entire steam turbine/generator train. OEM Siemens suggested that the plant install Arnold warming and insulation systems during the outage.

The advice was good, because clearances in the rebuilt turbine were much tighter than in the original machine and Arnold's eight-zone heating system allows independent control of temperature in each section (see last video attached, "Steam-turbine-warming case history").

However, the tighter clearances contributed initially to high vibrations on hot starts and roll-ups at around 1500 to 2000 rpm. The gremlin was high differential temperature between the upper and lower casings. The innovative and cost-effective fix: Turn on heating blankets earlier (bottom first), as soon as the unit is put on turning gear, to maintain the optimal ΔT during the cooldown period prior to temperature hold for warming, and to maintain these negotiations of ΔT, differential expansion, and casing average temperature until the next start.

Precise temperature matching eliminated the vibrations, allowing the turbine to perform as designers intended. Reliable operation with no rubbing means less maintenance over time. Bugs eliminated, the system works problem-free, the plant management team said. "Just turn it on and forget it." There are no PMs.

Little training was required. The Arnold system has its own control system that interfaces with (not integrated with) the plant's T3000 system, as Gagnon mentioned in the videos. To be sure all plant personnel had access to the required level of operational knowledge, Arnold provided some easily accessible instructional videos and circulated them among staff—in-person training during the height of the pandemic being a challenge.

Today a cold-turbine start can be completed within four and a half hours, nearly half the time as starting without a warming system in place and with no trips and restarts, which are detrimental to a steam turbine's maintenance frequency. An appropriate question: What can be done to further reduce the combined-cycle startup time? In this case, and at this time, Arnold is working with others to introduce its proven heating technology into other high-stress areas, such as the HRSG drums and harps. CCJ

Expand your knowledge of generators at no cost

Many comments were posted this past summer to a roundtable discussion forum at www.GeneratorTechnicalForum.org by powerplant owner/operators worldwide concerned with what they believe to be a decrease in generator quality in recent years. Recall that this website is operated by the all-volunteer International Generator Technical Community (IGTC) with more than 5200 members worldwide (details below).

While most participants posted details on issues they had experienced, little was shared about what they did to deal with the decreasing quality—perhaps thinking there's little that an individual power producer can do to influence changes in an OEM's shop.

Even less commentary was offered on how other participants in the roundtable might more effectively deal with their issues. This is unfortunate because the sharing of knowledge and experiences through open discussion benefits most everyone.

Be aware that at least four important tools have become available in the last decade or so to support power producers affected by quality issues both in the manufacture of new generators and in the repair and upgrade of older machines. They are:

- The IGTC website, with emphasis on the last two words: *Generator Community*. Thirteen years ago when National Electric Coil began developing what would become the IGTC, the company could not have realized the importance of what it was creating. The IGTC became a source of great help to power producers worldwide.
- The Generator Users Group (GUG), https://www.genusers.org. The eighth annual Generator Users Conference was just held, Aug 29-Sept 1, 2022. These conferences are a highly valuable place for power-producer personnel to present, and discuss, generator problems such as those resulting from quality issues.

- The generator expert Skill Register. Initiated two years ago, the Skill Register offers a location where power-producer personnel can connect with the limited number of independent generator consultants.
  - Generator experts register on https://www.ccj-online.com/generator-expert-skill-register.
  - Power producers search on https://www.ccj-online.com/generator-experts/
- Finally, remote assistance. Until recently, remote assistance to an outage was impractical. But because of the incredible recent progress in internet communications and digital photography, remote assistance is now practical in many situations.

Individually and as a group these tools offer great assistance to the generator community.

—Clyde V Maughan

Generators: A brief history

By Clyde V Maughan, Maughan Generator Consultants (retired)

Editor's Note. This historical perspective on turbine-driven generators is based on Clyde Maughan's recollections from a 72-year career in turbine/generator design, manufacturing, and service—half that time with General Electric Co, the remainder as an independent consultant (CCJ No. 71, p 92).

Having joined GE in 1950, and having worked closely with the "old timers" of that day, his direct knowledge base goes back into the teen years of the 1900s—a span of over a century. No guarantee is offered that all the information is exactly correct, but the essence should be acceptably close to give a general understanding of the difficult evolution to the present designs of generators.

Because the major OEMs of the day kept pretty close (informal) watch on each other, the industry was generally well informed on the designs, and troubles, of each. Thus, the information here on non-GE machines should be reasonably accurate.

The focus of this article is on the materials and structural configurations, and associated service issues, of generators installed from about 1960 onward, with little insight provided as to why specific materials were selected or why the configurations were needed.

This material should be of particular value to owner/operators of GE Frame 5, 6B, and 7B-EA gas turbines, some of which date back to the late 1950s, as well as to users at combined cycles equipped with steam turbines repowered from mid-century coal-fired powerplants.

Electrical insulation systems

Stator windings

Groundwall insulation. Before the turn into the 20th century, insulating materials were natural products: shellac, cotton, paper. The rudimentary stator-winding designs were at low voltage and low temperatures, and apparently functioned fairly well as long as duties were kept sufficiently low. With inevitable trends to larger generators, with higher voltages and higher thermal and mechanical duties, much better materials were required.

Somewhere around this time, mica flake was discovered to have remarkable electrical and thermal properties. But still with shellac, cotton, and other relatively primitive materials incorporated in the systems, troubles continued. By the mid-teen years (1915) it was discovered that by using a vacuum-pressure cycle, mica/cotton tapes could be impregnated with a hot asphalt compound to obtain a major electrical duty improvement. Asphalt/mica systems served the industry well for 35 years.

About 1950, Westinghouse developed the first "hard" groundwall system—Thermalastic, a polyester resin system. This was a remarkable accomplishment, particularly in view of the relatively primitive resins available at that time.

Shortly thereafter, all OEMs developed hard groundwall systems, including the following: Micapal (a polyester-like epoxy), Micapal II (a true epoxy), Thermalastic-Epoxy (a true epoxy), and Micadur.

All these insulation systems rely on mica because of its remarkable partial-discharge (PD) resistance properties. (No man-made product begins to have the incredible PD resistance of mica. Bear in mind that PD is inevitable in the rectangular configurations of stator bars.)

But mica brings with it poor mechanical properties—brittle, non-extensible, no mechanical strength whatever in cross-grain tension. Thus, stator groundwall insulation systems remain with limited mechanical properties, and when subject to bending stress—short-circuit forces, for example—fracture about like glass.

In the 1990s, a global vacuum pressure system for the stator winding was introduced by Siemens. The GVPI system has major cost advantages and is used extensively on indirect cooled designs. Many of those stators have been produced and quality has been good. But if failure occurs, rewind is difficult.

Groundwall voltage stress levels. The stress on the groundwall has a dramatically important impact on electrically related problems associated with stator windings. The significance of this impact is better understood by realizing that duties associated with stress have been found to be in the range of a seventh- to 11th-power function of the stress level. For example, if the design stress is increased by 20%, the duty increases by 1.2 to the ninth power, or about 500%. Recognizing this attribute, design engineers have increased stress relatively slowly over the years.

By 1950, the stress level on the asphalt-insulation systems was about 45 volts/mil (vpm). With the advent of hard (polyester-type) systems, the stress level was increased to around 54 vpm. By the mid-1960s, improved (epoxy) systems were being used, and the stress levels increased to the low 60s. Today, stress levels exceeding 90 vpm are being used. The magnitude of 90/60 to the ninth power is about 3800%, an increase hard to contemplate. Expect electrical groundwall failures to become more common in the future.

Problems associated with groundwall voltage stress. The predominant problem associated with groundwall stress, PD, sometimes is incorrectly called "corona." The stress gradient within the groundwall results in electrical breakdown in the tiny voids in the groundwall. These mini-arcs tend to eat through any insulation system without the PD resistance of mica.

If the outside surface of the groundwall is not adequately grounded, there will be discharges of much higher energy. This, in turn, can result in surface PD. This condition, captured in Fig 1, appears very serious, but careful examination and scraping with a thumbnail would find little or no penetration into the mica groundwall.

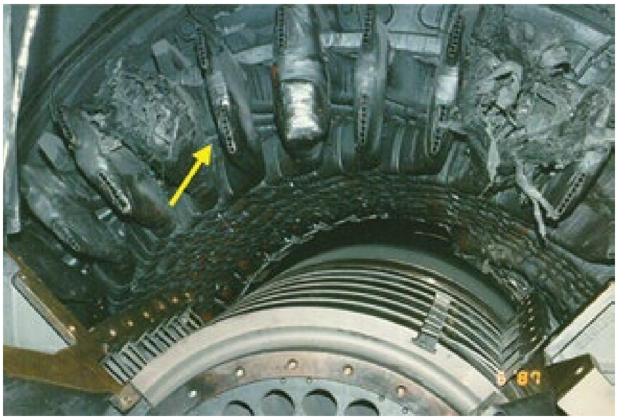
Nevertheless, it cannot be ignored, especially in air-cooled generators, where ozone generation will be significant. Also, there is no assurance that penetration of the mica may not eventually begin.

Furthermore, the increased capaci-

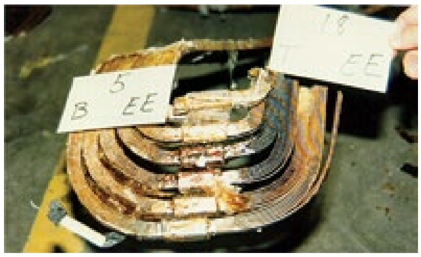
1. Partial discharge (PD) indication at the slot surface

2. Burning at the junction of the grading/grounding system

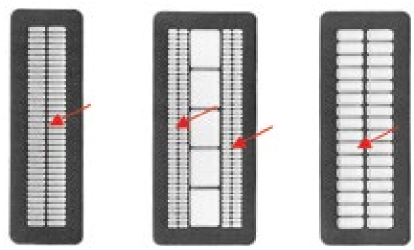
3. Failure at another of the phase-break locations



4. Bare conductor exposed at each series and phase joint (yellow arrow)



5. Major winding failure from shorted strand groupings



6. Vertical separator in three bar designs (red arrows). Strand insulation can be seen as the small separation between strands

tive energy increases the duties on endwinding grading systems—for example, at the junction between end-arm grading and slot grounding paints (Fig 2).

The damage at this junction is often regarded as PD but is actually burning because of an inadequate interconnection to carry the capacitive current from the end-arm grading system.

Where non-mica insulation has been used in endwindings, reliability sometimes has been seriously compromised. Example: Fig 3, where phase joints were insulated with non-mica potting compound and Nomex.

A large number of generators rely on physical spacing to hold the voltage stress. So long as the surfaces are clean, operation is satisfactory. But when surface contamination occurs, massive arcing can occur (Fig 4).

A final observation: Stator-winding electrical-arc damage normally accompanies stator-winding failure, but the actual root cause is usually mechanical—for example, vibration, fracture, foreign object, and contaminants. To this point in time, generator failures caused by purely electrical duties are uncommon.

Bare bar stranding. Because eddy-current losses would immediately melt a stator bar made of solid copper, a stranded design has always been required. On coil windings, no special transposition is needed—that is, the top and bottom bars of a coil automatically tend to cancel out the voltage difference between the top and bottom strands in the half-coils. (In this article, the term "bar" is used to define a half coil. For convenience the term "bar" is used almost exclusively.)

On bar windings where it is usual to solidly connect all strands at each end of the bar, this cancelation of radial flux difference in the slots does not occur. Very early (in 1912) a Swiss engineer, Louis Roebeled, invented an elegantly simple way to construct this transposition on bars.

His invention, the Roebel bar, was no great scientific discovery, but rather a remarkably simple way to accomplish a very difficult task—construct the transposition. It is so manufacturing friendly the Roebel transposition system is universally used by all OEMs, with the exception of those few who have manufactured smaller bar windings without consolidating the strands at the ends of the bars.

The standard Roebel transposition effectively compensates the radial flux-density gradient in the slot portion of the winding. But on larger generators of non-coil design, the radial flux gradient in the endwindings becomes sufficiently large to cause problems—a concern automatically eliminated in coil windings.

Several approaches have been used here. The simplest is that of a 540-deg Roebel rotation in the slot. (Note that Roebeled's invention was single 360-deg rotation.) The somewhat complicated 540-deg rotation performs a correct compensation in the slot while inverting the strands at the two endwindings beyond the core.

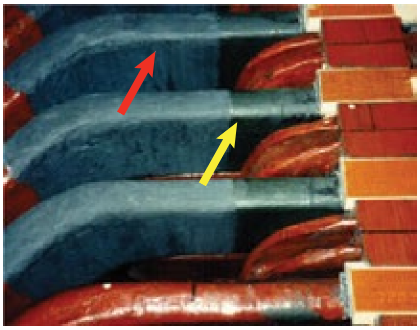
Another approach for endwinding radial-flux compensation has been to sub-group the bar strands into bundles of strands; bundles may range from as few as one strand to as many as 14, or more. These "bundles" are maintained throughout the entire phase belt. Bundle design greatly complicates the winding manufacturing process and has been accompanied by numerous service problems (Fig 5).

Strand insulation. A small voltage exists between adjacent strands, probably always less than 1 volt, and the strands must be individually insulated. Originally, cotton would have been used, then glass, and now commonly Dacron-glass. The last material is thin, typically 1 to 3 mils/side.

A higher voltage exists between tiers of strands. Here a "vertical separator" is inserted between tiers. The stress may be as high as 15 volts and the thickness may be about 15 mils (Fig 6).

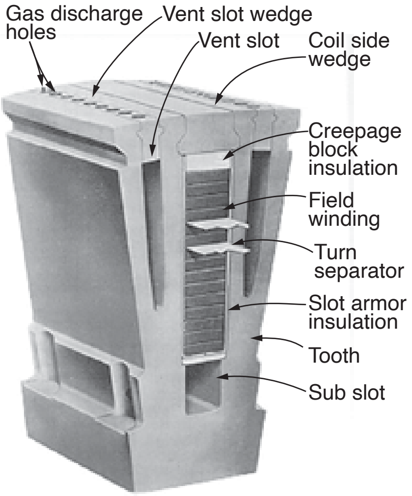
Voltage grounding and grading. If the outside surface of the groundwall is not tied electrically to ground, PD will exist between the bar surface and ground. Consequently, a semiconducting (low resistance) paint is applied to the outside surface of the slot portion of the bar (and usually about 2 in. beyond the slot at each end). If properly applied, and of good quality, this paint will eliminate the PD by grounding the outside surface of the bar insulation to the slot iron.

More complicated is the necessity to "grade" the voltage of the grounding



7. End-arm grading (red arrow), slot grounding (yellow arrow)

8. Failed asbestos-mica field slot liner



9. Early design of a typical non-direct-cooled field slot

10. Slot liner with damage from an electrical creepage failure

paint at each end of the slot (Fig 7).

The engineering principles here are complex, but the mechanics are relatively simple. Originally, asbestos tape was applied for a distance of perhaps 7 to 12 in. beyond the end of the slot grading paint, depending on winding voltage. In the 1960s, the industry went universally to silicon carbide—both to eliminate the hazard of asbestos, but because silicon carbide offers a more effective approach to grading.

Series/phase joint insulation. It is common to insulate these joints with mica tapes. Beginning about 1970, some designs used synthetic resins inside a non-metallic box. This is a marginally acceptable method at the phase connections because the voltages here are high.

Physical spacing also has been used by some OEMs. This design approach is safe—providing the creepage paths remain uncontaminated, and providing there is not a conductive plasma resulting from arcing of a failing electrical connection. In the event the insulating capacity is violated, a "ring of fire" can result (refer back to Fig 4).

Field windings

The duty differences between stator and field insulation systems could hardly be more different. On stator windings, the voltages are high but the mechanical stresses are low. On fields, the voltages are low, less than 700 Vdc, but the mechanical duties very high, in the order of thousands of psi.

Because of the low voltages, and the need for direct contact between cooling gas and winding copper, isolation using electrical creepage surfaces is common. So long as the insulation remains in place and does not become contaminated with conductive materials, the systems tend to perform well. But because the mechanical duties are high, problems can occur. They typically result from fracture, cut-through, and shifting of location of the insulation components. Result: Service problems relating to insulation failure are common on fields.

Slot liners (ground insulation). Until about 1960, ground insulation for coils consisted of enclosing the coil with cotton or asbestos cloth for mechanical stability and mica flake for insulating properties (Fig 8).

This composite structure served adequately because of the low-voltage stresses. More recently, Nomex, glass/epoxy fabric, and composites of glass/epoxy and Nomex have become popular. Generally, this ground insulation is in a U-shape, closed at the top by a creepage block (Fig 9). These ground insulation systems have been subject to failure primarily because of contamination, fracture, migration, and cut-through (Fig 10).

Turn insulation. The voltage between turns is low, typically 1 to 5 volts. Historically, mica tape was used, but since about 1960, thin glass/epoxy laminate has been in common use for turn insulation. So long as physical spacing is maintained, turn shorts are unlikely. However, the integrity of the space can be violated by fracture or migration of the material, or by conductive contaminants bridging the spacing. Failure of turn insulation is relatively common.

Endwinding insulation. Under the retaining rings, sheet laminate of heavy-weave asbestos cloth and mica was the historic insulation system. Again, around 1960 transition was made to a laminate structure of heavy glass cloth and epoxy resin. The laminate is degraded somewhat when the 300C retaining ring shrinks down onto the epoxy glass; however, the materials used are sufficiently thick and thermally stable that the electrical strength remains adequate for single use.

Insulating-block material is used to hold coil shape and to insulate the axial locations of the endwindings, as shown later in Fig 15.

Winding support systems

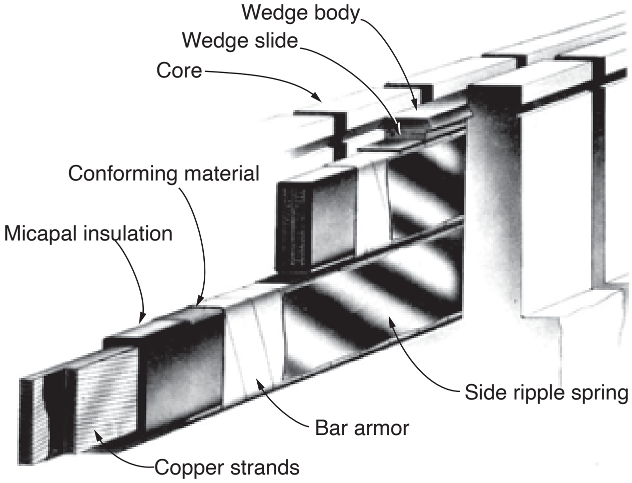
Stator windings

Slot support systems. From the beginning, stator bars were held in the slots by wedges of treated paper or hardwood. The electromagnetic forces were low (almost non-existent), the groundwall insulation was soft, and bars had little cause to vibrate. The wedges held the bars in the slots and kept them from falling out of the slots in service, and perhaps kept the bars from being thrown out of the slot in the event of a sudden short circuit.

The wood materials used during the industry's first 50 years were satisfactory. But wood inevitably shrinks, and the resulting looseness of wedges was a concern. With the advent of man-made resins, in the 1950s transition was made to resin/cotton, resin/asbestos, and then resin/glass materials.

But when hard groundwall systems were introduced in the 1950s, a shocking condition surfaced—bar vibration. (You could walk by the generator and hear the noise from the impact of the bars in the bottom of the slots.) Needless to say, windings failed relatively fast, from mechanical wear and impact, and from vibration sparking. An immediate fix was implemented: Wedging with tight downward pressure on the bars.

This electromagnetic force (EMF) essentially is all radially downward in the slot, but if radial clearance



11. Wedging system developed in the mid-1960s by GE

existed in the slot, the bars would bounce off the bottom of the slot and vibrate vigorously. Also, if excessive side clearance existed, the bars would rattle in the slot.

Relatively simple wedging systems were satisfactory on indirect-cooled windings, but the slot EMF on the direct-cooled windings was much higher, and vibration recurred. GE solved this situation by adding side pressure springs (Fig 11).

But most other manufacturers continued to rely on side packing and tight wedges. Finally, the industry added the radial pressure spring almost universally on large generators.

Slot bar vibration incidents continue to occur. But, in general, if the wedging system remains tight vertically, if clearance does not exist under the bottom bar, and if excessive side clearance is not permitted, problems are unlikely.

Endwinding support systems. In the early years, the endwinding EMF was so low that almost anything was going to be alright. The top and bottom bars in the endwinding, if tied together, form a rather strong mechanical structure. It remained primarily to support the bars (or coils) during installation.

The parameters relative to slot wedging and endwinding support have little in common. The endwinding EMF is lower but still substantial—roughly one-third to one-half that of the slot forces. Because the opportunities for supporting the bars in the endwinding are minimal, endwinding vibration has been more difficult to successfully address than slot vibration.

Also, until recently there has not been available instrumentation to safely and accurately measure magnitudes of in-service endwinding vibration. Design engineers have not had tools to directly assess the success (or failure) of their new designs. Thus, engineers have had to rely on intuition and best judgment in producing new designs, and await accumulation of service experience to determine if the design change was successful.

However, as generators increased in size, the EMF became so great that endwinding vibration became ubiquitous. Starting about 1960, OEMs went into major development programs, spending millions of dollars developing designs that would hold the extremely high sudden short-circuit forces as well as the significant normal operation forces.

In spite of these huge OEM expenditures, endwinding support remains an ongoing problem. Parts become loose and wear holes in groundwall insulation. Connections become resonant and break off or fracture the bar (Fig 12).

Sudden short circuits can crack bars. It is doubtful that any design today can experience a worst-case short circuit without damage to the bars in the endwindings (Fig 13).

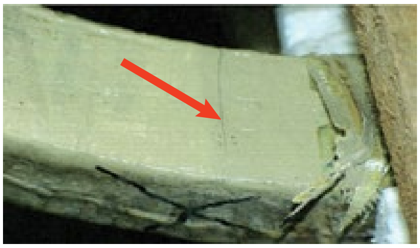
Stator endwinding concerns will remain into the future, particularly from local or general loosening of the systems allowing component wear to occur and resonances to develop. However, it can be expected that with the new capability to safely and accurately measure endwinding vibration, the designs will improve and reliability will increase.

Field windings

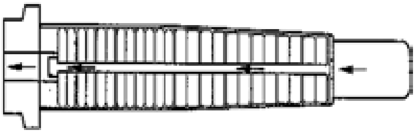
The mechanical forces on field windings are extremely high—resulting from up to 8000 g of centrifugal force acting radially at the tops of the slots. Metallic wedges can hold copper coils in the slots, and there are stable insulating materials that generally can function acceptably against these steady-state radial forces. It is the cycling duties resulting from start/stop and load changes that are the primary source of problems.

Winding copper is a main contributor to service issues. Copper has poor mechanical properties, even at room temperature. Yield strength is low, fatigue properties poor. At elevated temperature—above about 130C—these marginal properties begin to fall off. Unlike steel, copper only can be work-hardened; it cannot be hardened by quenching. With such poor mechanical properties, and high mechanical duties, engineers have been challenged to design support systems that successfully restrain copper coil dimensions and prevent their movement in position.

12. Series connection was broken off and found lying under winding



13. Fractured stator bar reveals a tiny, but deep, crack at arrow



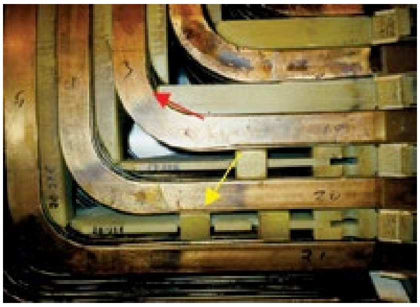
14. Direct-cooled field slot is typical for relatively small, modern generators

An indirectly cooled slot support design was shown earlier in Fig 9. In this design, heat losses must pass through insulation and forging iron to be removed by the flow of cooling gas. These indirect-cooled designs were used until direct cooling was required for higher generator outputs, starting around 1960. A typical direct-cooled slot is shown in Fig 14.

Electrical isolation in all field designs relies on "creepage" (voltage tracking over an insulated surface) and on "puncture" (voltage penetrating directly through an insulating material). Creepage isolation is used much more on the directly cooled windings, which makes them more vulnerable to contamination.

The radial blocking (red arrow) attempts to prevent both coil distortion and axial movement (Fig 15). Axial blocking (yellow arrow) primarily attempts to prevent coil distortion. But because the coils are not blocked continuously (to allow for cooling gas flow), and because of copper's poor mechanical properties, distortion is common (Fig 16).

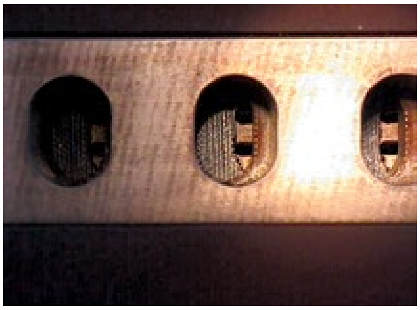
Because of the poor high-temperature properties of copper, significant



15. Endwinding blocking arrangement under retaining ring

16. Badly distorted top turn on smallest coil

17. Two largest coils shorted together; attributed to extensive contamination



18. Insulation/copper-turn misalignment in the slot

over-temperature can result in fatal changes in coil dimensions. The result will be an immediate forced outage.

As windings lose position, the insulating materials tend to wear and crack. Grounds and shorted turns/coils result from damaged and contaminated insulation (Fig 17).

Further complicating reliable field operation is the need for uniform cooling of the coils in the rotor body. In Fig 18, the turn insulation and/or top creepage block have/has shifted axially out of correct location. This partial blockage of some slots and not others will result in bowing of the field (acting as a bimetallic strip). The resulting bow will cause a "thermal unbalance vector," and as it grows over time, may force attempts to rebalance the field. If the conditions continue to deteriorate, eventually a field repair or rewind will become necessary.

Generator cooling methods

Originally, generators were cooled by once-through open air flow. Contamination problems led to closed ventilation systems, with water-to-air heat exchangers to remove the thermal losses—the TEWAC cooling system (Totally Enclosed Water-to-Air Cooling). This type of system is still very popular for small generators.

But by the 1930s, ratings were reaching a size where the ability of cooling with air was limiting further increase in rating. Engineers recognized that use of hydrogen gas as the atmosphere had important advantages: low density, high specific heat, and the high thermal conductivity. In particular, windage losses were reduced to about one-fourteenth that of air. Also recognized: hydrogen gas is highly explosive, unless hydrogen purity (freedom from oxygen) was kept out of the range between about 4% to 94% oxygen, by volume.

A high-level development program produced the necessary hydrogen shaft seals and system controls to permit the first hydrogen-cooled generator to enter service in the USA in 1937. By coincidence, this was the year of the Hindenburg hydrogen-filled airship disaster. But there was no OSHA at that time, and hydrogen cooling came into common usage for large generators.

Over the years there have been a few hydrogen accidents involving serious plant damage, and personnel injury and death. The nature of a hydrogen fire is such that damage can be dramatic—that is, hydrogen tends to detonate and produce a high-pressure wave that can blow the siding off an entire building and bend a steel door.

Size limitation came again at around 200 MW in the mid-1950s and manufacturers began development of "direct-cooling" methods—that is, the cooling media in direct contact with the copper electrical conductors of the stator and rotor.

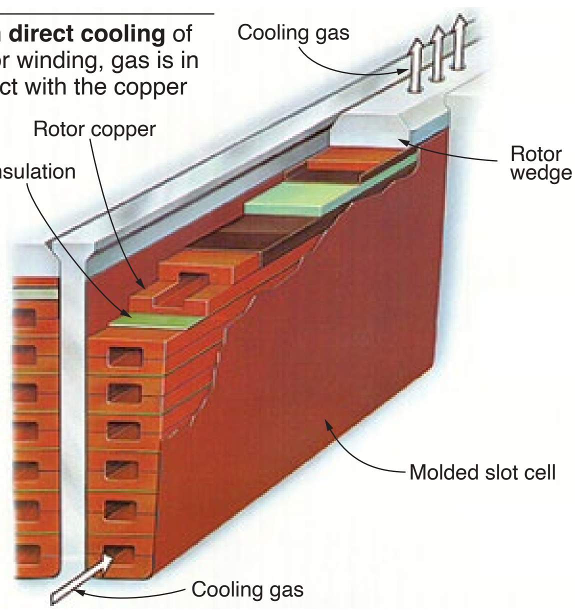
In rotor-winding indirect cooling, gas flows in passages within the forging, thus cooling the forging. The cooled forging then cools the copper by conduction. With direct cooling, the gas is in direct contact with the copper (Fig 19).

Stator windings until about 1960 were cooled indirectly (Fig 20 left). Two types of direct cooling were developed during the late 1950s and are in present usage, center and right bars in Fig 20.

With indirect cooling, all thermal losses must traverse the thickness of the ground insulation. Given that electrical insulation is an excellent thermal barrier, there was incentive to pursue direct cooling methods.

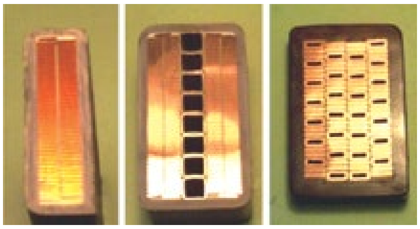
With direct gas cooling, only the strand and tube insulation must be traversed. These barriers are thin and offer little thermal resistance. The bar mechanical structure becomes rather complex in this type of cooling, but a very large number of direct-gas-cooled generators are in service and the design has generally has performed well.

19. In direct cooling of a rotor winding, gas is in contact with the copper

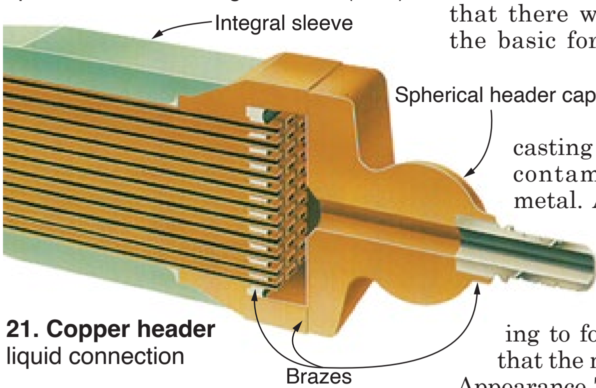


With the common method of direct liquid cooling, the coolant is in direct contact with the heat-generating copper. Usually, a mix of hollow and solid strands is used with all strands brazed as a unit into a copper alloy strand header (Fig 21).

Less common is the use of stainless-steel tubes individually welded into a stainless header



20. Indirect, direct-gas, and direct-liquid stator-bar cooling methods (l to r)



21. Copper header liquid connection

22. Tube header of stainless steel

separate from the copper strand connection (Fig 22).

The direct-liquid-cooled designs have had OEM-specific service problems, but in general have performed well.

Generator rotor forgings

The mechanical duties on rotor forgings are extremely demanding on the high-speed generators typically coupled to gas and steam turbines, and great effort has gone into development and optimum application of these forgings. Thus, a few words on this topic are in order here.

Rotor body forging

The main rotor body forgings reached a crisis point in the mid-1950s. During a factory high-speed balance, a body forging failed catastrophically in the OEM's balance facility. Fortunately, the failure occurred during night shift and few workers were in the plant. But the two young test engineers operating the facility were both killed.

A few months later a field body forging failed in an operating powerplant. Damage was considerable, but there were no casualties.

In 1956, a third rotor failed in an operating powerplant. (The writer would have been onsite at the time of failure had he been home to answer the phone.) This failure severely injured three or four persons and destroyed the unit (Fig 23).

The resulting investigations found that there were huge inclusions in the basic forgings—perhaps larger than 10 in. in diameter. These inclusions were inherent in the casting processes due to heavy contamination in the liquid metal. As the ingot cooled, the impurities percolated toward the ingot center and top.

Further contributing to forging vulnerability was that the materials had a Fracture Appearance Transition Temperature (FATT) of about 40C. This was totally unacceptable because it means that the material had poor ductility (behaved as a brittle material) below 40C, and was intolerant to fatigue stress cycles associated with start/stop duty.

Within a very short time the steel mills were able to produce forgings of much better quality and no further large-field forging failures occurred.

Retaining-ring forgings

Retaining-ring materials also went through a complex evolution. Originally rings were magnetic steel, but as size of generators increased a point was reached where rings of non-magnetic material would be highly beneficial. (This need is based on complicated electromagnetic design challenges related to excess end-of-core heating as load moved toward the leading-power-factor region.)

The most common of the non-magnetic rings was the 18/5 (18% manganese/5% chrome) material. It was found susceptible to stress corrosion cracking—that is, under high tensile load and in the presence of water, intergranular cracking occurred. This condition led to several ring failures (Fig 24). Needless to say, that stator winding damage was thorough.

Stress-corrosion damage progresses quickly. The ring in Fig 24 had been removed and given a full nondestructive test 18 months earlier and found trouble-free.

The problem with 18/5 material was recognized in the 1970s. Around about 1975, an OEM/steel-mill joint development program was initiated. From that effort the 18/18 (18% manganese-18% chrome) alloy was developed. The material, characterized by high and stable tensile strength, is highly specialized and can be produced only in relatively few facilities worldwide.

The 18/18 alloy is not nearly as vulnerable to the stress-corrosion phenomenon as the 18/5 alloy, and has been reliable in service since its introduction. It is now the industry standard material for this application.

Wrap-up

Clearly, this article provides a very general overview of generator history, with more left unsaid than said. No doubt there are errors of omission as well as commission. But hopefully the reader has gained a better appreciation for the efforts that went into the generator designs of today.

The evolution of the large generator has presented many difficult challenges to the engineers who design them and to manufacturing personnel who make them. Progress will continue, but with continuing increasing sizes and continuing cost pressures, old problems will recur, present problems will continue, and new problems inevitably will develop.

Keep current on new generator developments of importance by attending meetings of the Generator Users Group (www.genusers.org), conducted under the umbrella of the Power Users Group (www.powerusers.org), and by participating actively in the online forum hosted by the International Generator Technical Community (www.GeneratorTechnicalForum.org). The IGTC is a global self-help group with over 5000 members sharing generator challenges and solutions. CCJ

23. Visual damage at non-drive end of the generator after forging failure

24. Failed 18/5 ring from the mid-1990s