- GAS TURBINES
- STEAM TURBINES
- HRSGS
- GENERATORS
- CONTROLS
- AUXILIARIES

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COMBINED CYCLE JOURNAL

PACESETTER PLANTS

FEATURES

USER GROUP REPORTS

INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR


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PLAN FOR 2026: CCGT INDUSTRY EVENTS

7F Users Group
May 18-22
Woodlands Waterway Marriott, Houston, Tex. Details/registration at www.powerusers.org. Contact: SV Events, planning.team@sv-events.net.

European HRSG Forum
May 19-21
Monash University, Prato, Italy. Details/registration at www.europeanhrsgforum.com. Contact: Rachel Washington, rachel@meccaconcepts.com.au.

Legacy Turbine Users Group (Frames 7E, 6B, 5)
June 22-25
The OMNI Hotel, Oklahoma City, Okla. Details/registration at www.powerusers.org. Contact: SV Events, planning.team@sv-events.net.

Air-Cooled Condenser Users Group
July 14-16
DoubleTree by Hilton, Clarksville, Tenn. Details/registration at www.acc-usersgroup.org. Contact SV Events, planning.team@sv-events.net.

HRSG Forum
July 20-23
Woodlands Waterway Marriott, Houston, Tex. Details/registration at www.powerusers.org. Contact: SV Events, planning.team@sv-events.net.

Alstom Owners Group
July 28-30
TBD, Houston, Tex. Details/registration at www.aogusers.com. Contact: Ashley Potts, ashley@aogusers.com.

HA Users Group
August 3-6
Fort Lauderdale Marriott Harbor Beach Resort, Fl. Details/registration at www.powerusers.org. Contact: SV Events, planning.team@sv-events.net.

Power Users Combined Annual Conferences (CCUG, GUG, PPCUG, STUG, and LCPG)
August 24-27
Marriott Rivercenter on the River Walk, San Antonio, Tex. Details/registration at www.powerusers.org. Contact: SV Events, planning.team@sv-events.net.

Combustion Turbine Operations Technical Forum (CTOTF)
August 30-September 3
Grand Hyatt River Walk. San Antonio, Tex. Details/registration at www.ctotf.org. Contact: Christine Doyle, chrisdoyle@ctotf.org.

Wärtsilä Users Group
October 12-15
Crowne Plaza French Quarter, New Orleans, La. Details/registration at www.powerusers.org. Contact: Jacki Bennis, jacki@somp.co.

Australasian Boiler and HRSG Forum
November 17-19
Brisbane, Australia. Details/registration at www.abhug.com. Contact: Rachel Washington, rachel@meccaconcepts.com.au.

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7F Users Group ®

2026 conference focuses on fleet reliability, outages, and controls

The 2026 7F Users Group Annual Conference is scheduled for May 18-22 at The Woodlands Waterway Marriott Hotel & Convention Center in The Woodlands, Tex. The agenda combines offsite shop tours, vendor solutions presentations, user-only technical sessions, and GE Vernova sessions addressing outage execution, controls modernization, casing condition, TILs, and RCAs.

PROGRAM OPENS WITH TOURS AND VENDOR SOLUTIONS

The conference program starts Monday, May 18, with boxed breakfast for tour participants and offsite tours of Allied Power Group, Doosan, EthosEnergy, MD&A, and Sulzer. The afternoon moves to lunch, a vendor fair, and two blocks of simultaneous vendor solutions presentations. Topics include 7F performance and reliability upgrades, DLN combustion tuning, exhaust-train R3 options, heat-exchanger predictive maintenance, and controls TIL implementation.

Vendor solutions continue Tuesday afternoon with sessions on operational flexibility, replacement exhaust silencing systems, compressor bleed valves, water-wash drain valves, wet-compression tuning, turning-gear overhaul, and exhaust thermowell design. The agenda also includes a Tuesday evening social event for users and exhibitors.

2026 STEERING COMMITTEE

Chair: Brian Richardson, Florida Power & Light
Vice chair: Edwin Rivera Hernandez, Dominion Energy
Luis Barrera, Calpine
Jacob Boyd, CAMS
Scott Chapin, AES
Alex Fortman, PE, Xcel Energy
Sam Graham, Tenaska
Carroll Gunter, ExxonMobil
Clinton Lafferty, TVA
Dennis Long, Duke Energy
Justin McDonald, Southern Company
Dan McQuade, Vistra Corp
John Rogers, SRP

USER-ONLY SESSIONS EMPHASIZE OPERATING EXPERIENCE

The Tuesday user program opens with general-session remarks by Richardson, followed by an LTSA best-practices panel and a presentation on hexavalent chrome in the No. 2 bearing tunnel. Compressor content follows, including a 7F compressor Wheel 11 dovetail crack presentation, wet-compression experience, high-flow R0/S0 user experience, and a compressor roundtable. A parallel 7FA.05 compressor session focuses on general and emerging fleet issues, including several TILs.

After lunch, the auxiliaries and controls session covers optimized cooling, Bently Nevada 3500 versus Orbit 60 vibration monitoring, and an owner/operator roundtable. Edwin Rivera of Dominion Energy chairs the session.

WEDNESDAY COVERS UPGRADES, COMBUSTION, ROTORS, AND TURBINE HARDWARE

Wednesday morning starts with an upgrades session chaired by Clinton Lafferty of TVA. Presentations address affordable and reliable power needs, centralized outage coordination, and Mark VIe upgrade experience, followed by an upgrades roundtable. The combustion session, chaired by Scott Chapin of AES, includes presentations on high-dynamics combustion failure, gas-control-valve stability, and GTOP 4/Flame Sheet 2.5 implementation and results.

The Wednesday afternoon program shifts to rotor and turbine content. Dan McQuade of Vistra Corp. chairs the rotor session, which includes rotor life-extension planning, 7FA vibration variability, and a rotor panel with Vistra, Southern Company, and Calpine. Alex Fortman of Xcel Energy chairs the turbine session, which includes S1B tip-cracking fleet experience and an S3B failure after AC power loss.

GE VERNOVA SESSIONS RUN THURSDAY AND FRIDAY

Thursday is organized around GE Vernova content for users and GE Vernova attendees. The morning includes a customer portal update, 7F history and evolution, a non-negotiable scorecard update, and a steering-committee panel on thermal plants in a tight market. Three simultaneous breakout blocks address outage roles and duration goals, auxiliaries reliability and liquid-fuel solutions, plant modernization, bottoming-cycle and generator outage coordination, next-generation gas-turbine technology de-risking, and aging 7F casings.

Thursday afternoon continues with GE Vernova breakouts on 7F-200 versus 7F.05 flange-to-flange upgrades, controls modernization through synchronous condensing, and big-data applications. The day returns to general session with a panel on top technical issues for 7F users, including TILs and RCAs, followed by a user-feedback session to the steering committee with GE Vernova out of the room.

Friday closes with broader fleet and market topics, including data-center load growth, federal-policy perspectives, and how plants may operate after 2030. The program ends with a feedback survey, closing remarks, and grand-prize drawings.

TAKEAWAY FOR 7F OWNER/OPERATORS

The hallmark of the 7F Users Group 2026 agenda, consistent with the organization's mission, is its emphasis on practical reliability, maintenance, controls, and outage issues rather than broad policy or market discussion.

The program provides multiple forums for peer-to-peer exchange, including roundtables, user-only sessions, a formal feedback period with the steering committee, and GE Vernova sessions addressing fleet-specific concerns. For owner/operators managing aging 7F assets, upgrade decisions, outage execution, and the need for greater operating flexibility, the meeting offers a focused week of practical, experience-based discussion.

2025 CONFERENCE RECAP

FIRST TIMERS REAP A WEALTH OF EXPERIENCE FROM VETERANS

Among the portfolio of conferences under the umbrella of Power Users, the 2025 7F Users Conference certainly vies for the one with the most content shared directly from owner/operator (O/O) organization representatives. Which makes it especially valuable for the ~50% of attendees who were first

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timers.

Perhaps the most intriguing undercurrent to the content was the continued urging for more collaboration by O/Os to solve supply and delivery problems which, according to presenters, aren't being addressed quickly enough by industry suppliers. Backing this up was an audience survey which revealed that aging assets and current supply and demand were far and away the top issues they are facing.

While two data points can make a line on a graph, they don't necessarily support a trend but may be worth noting anyway. At least two of the largest 7F-based plant O/Os in the US have recently hired seasoned rotor experts away from the OEM, presumably to guide them through the thicket of rotor life evaluation (RLE), repair, and continued operation. One was a technical lead at the OEM, the other from the product and service team who was described as "having written most of the technical information letters (TILs) for 7F rotors.

As one of these experts noted in a panel discussion, "rotors don't offer precursors before they do bad things." Vibration analysis goes only so far.

O&M risks are not arising strictly from the major components either. One user lamented that delivery schedule to replace turbine wheel no. 1 tiebolt nuts was 57 weeks! That is, until the OEM came back with a field repair.

Another signpost of the times was a presentation on best practices for handling evidence that may support a root cause analysis (RCA) should the attendant failure lead to a legal dispute (CCJ No. 84, p. 76). The presentation was scheduled on the first morning of the first day.

Like CCJ's report last year, this one begins with near-verbatim comments by the presenters to give the reader a sense of collective sentiment about their machines:

- TILs for the 7F.05 are coming fast and furious (and are originating from the OEM responding to issues with the HA machines)
- It's a sellers' market; the OEM wants to sell HAs rather than repair 7Fs
- How do we make a boneyard (a warehouse of usable components) available to users?
- Industry collaboration is needed to push past the 144,000 hrs/5000 starts limit set by the OEM for rotor life
- The OEM does not want to make compressor discharge casings
- All LTE refurbished rotors will come from overseas factories, adding months to the delivery schedule. An HA "slot" in the OEM's US factory takes up 2FA slots.
- The OEM can do 13-15 rotors a year in its primary US facility, but these will be new units. It can do 50-60 worldwide, but that figure used to be 100+.
- Parts availability keeps us up at night
- Every part delivery is delayed, taking from 6-18 months.
- We've had ten non-conformance reports (NCRs) issued to the OEM in the last three months alone. Sometimes there are so many issues, we don't even send in the NCRs.
- The OEM doesn't want to order new parts (in this case coated segments of stator vanes) because it doesn't have them
- The OEM has not "made schedule" on any rotor sent to its primary US manufacturing and repair facility
- Technical advisors for the BN3500 vibration monitoring rack have varied familiarity with the system. The system is getting obsoleted.
- Eight to ten users noted in a show of hands that they experience elevated tem-

1. Combustor flow sleeve experienced potentially catastrophic damage from less than 10 minutes of combustion dynamics at 25 psi/170 Hz as a result of a control malfunction

2. Components damaged by a liberated generator cooling fan blade include the gas shield and stator end cap. Root cause was one bolt breaking, caused by overtorqueing, and a second bolt breaking from fatigue failure

peratures in tilted pad generator bearings, a problem “we’ve been talking about for years.”

- Non-OEM suppliers are starting to have similar problems meeting parts demand and delivery schedules.
- Axial fuel staging (AFS) upgrade hardware adds seven days for tuning compared to the DLN 2.6.

Here’s a word of warning from an O/O rep presenting on a candidate for “catch of the year”: If you don’t have the enhanced compressor components (all 7Fs with an 18-stage axial unit), do the inspections recommended in TIL1509. Staff at this site found cracks in compressor blades which could soon have led to a catastrophic event.

The mood wasn’t all gloom and doom, however. One user, facing a recovery from a nasty forced outage in the end-of-year holiday period, reported excellent experience working with the OEM to get the unit back on-line quickly. Another reported that the OEM may be able to open up space for rotors at a different US factory location.

Other non-OEM suppliers are stepping up, too. PSM, now Hanwha Power, reported that it can now “get around” the OEM lockdown on model-based controls (MBC) with Autotune and FlexSuite control products. Doosan reported that it can refurbish 7F rotors for ten or more years of service and can “LTE overhaul a rotor in three to four weeks.” Doosan and PSM are cooperating to meet the industry’s need for replacement and refurbished rotors. And one user reported that field repairable compressor stage blading is now available.

Finally, at a time when even your dumbest cousin is mouthing off about how AI is going to rock our world, some words of wisdom from a veteran presenting a primer on combustion tuning: When you use remote tuning, you don’t feel and see what is happening with your machine. Translation: Automation and remote specialists are no substitute for the hands-on knowledge acquired by a plant operator becoming intimate with the machine. Every 7F may be the result of a “standardized” design and manufacturing process, but once it enters service, it becomes unique and responds differently.

Most user presentations, summarized here, are available to members at www.powerusers.org, and share invaluable best practices, lessons learned, experiences, updates on recurring issues, new issues to monitor, and post-mortem safety events which enrich the entire community.

Read the tea leaves. Kicking off the conference with an in-depth primer on the DLN 2.6 combustor hardware, flow diagrams, and tuning, the presenter urged his audience to “learn to read the tea leaves” of your components. For example, dark areas on combustion liners indicate poor air distribution and/or too much air leakage. Leaking air is often the root cause of NOx issues.

Discussion focused on essential terminology and potential issues with fuel/air ratios, tuning constants, combustion dynamics (Fig 1), leakage in compressor bleed (CBV) and inlet bleed heat (IBH) valves, part load operation, emissions, and axial fuel staging. Combustors are not as predictable as a gearbox, says the presenter; fire still has a “dimension of mystery.”

Don’t tamper with evidence. If a failure leads to a contractual dispute, all evidence must be properly preserved. The subsequent RCA will follow some version of the scientific method which includes data and evidence collection (all information related to the event and conditions), preservation and storage; proposed hypotheses which must be disproved and discarded; fault trees; and communication among the parties involved. Slides are chock full of best practices and practical recommendations, such as training in photography to best serve the RCA. Use of third parties can often limit the inherent biases of parties to the dispute. Slides include several excellent examples of failures and RCA.

SAVE OF THE YEAR CANDIDATES

A hallmark of user conferences is the willingness of participants to share experiences involving injury or death to a worker, catastrophic or significant failures, and near misses. In the last category were two “save of the year” candidates.

On the fifth day before Xmas in 2024, operators noticed a step change in vibration from 0.07 in/sec to 0.36 in/sec on the 7FH2 generator T4 bearing (BB7 and BB8), not high enough to trigger an alarm, and coinciding with a step change in generator fan blade differential pressure (DP). Personnel hypothesized that the cause was a liberated fan blade.

Sure enough, there were no findings from a borescope inspection (BI) on the turbine end, but inspection of the collector end (T4) revealed a liberated cooling fan blade, and damage to the gas shield (fiberglass exterior with a balsa wood core) and stator end windings. What a time for a forced outage!

Nevertheless, the plant was back on-line by January 7, thanks to a coordinated effort between the O/O and the OEM, which was able to provide all the parts except the gas shield. Securing the gas shield, a challenging aspect of the recovery, was accomplished by having it repaired by a non-OEM firm and using ancillary parts from the OEM. The plant was lucky that the stator end cap could be repaired in situ.

Blade liberation was likely caused when the No. 1 bolt of cooling fan blade No. 5 broke because it was overloaded due to overtorqueing at install. The remaining No. 2 bolt could not hold the blade in place under cyclic stress forces and likely failed from fatigue (Fig 2).

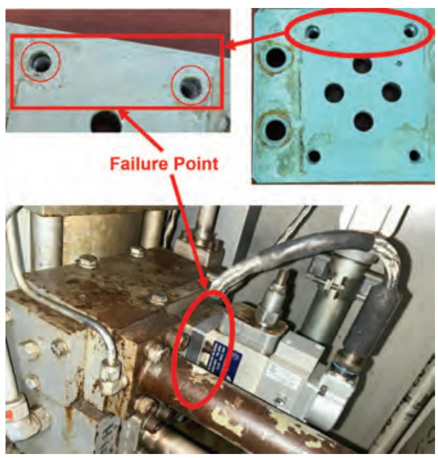
In response to audience Q&A, the presented noted that the last time these parts were “looked at” was in 2017, three years after the fan blades were installed and that they believe the unit had undergone a number of starts and hours “typical” of a ten-year period.

3. Stator Row 0 vane 34 exhibits significant crack which could have wiped out the machine if liberated. User urges others to perform TIL1509

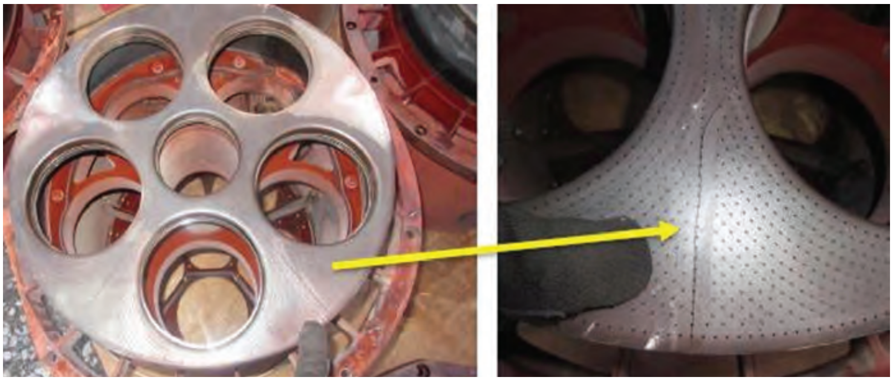
Words of wisdom from the presenter: Do not ignore the M&D alerts!

Avoiding a compressor wipeout. If your machine has non-enhanced compressor components, do the annual inspections recommended in TIL1509 R4, urges the presenter. Indications were found in one unit at his plant, with two 7F.03A peaking units, which could have resulted in a liberated S0 row vane and a machine wipeout. Those indications were not present a year ago and fifty starts earlier. Units have undergone relatively low starts and hours.

TIL1509 recommends the inspection because vanes can lock up and reduce damping, causing trailing edge distress. Locations vary between the root and halfway up the vane. Multiple cracks may be observed and several vanes may exhibit them. Vanes at bottom dead center are most susceptible. At this plant, vane 34 exhibited a significant crack (Fig 3). The plant underwent a forced outage and replaced S0 vanes and other stator rows, which had been in service for 15 years (and were “rusting”) with “enhanced”



4. Servo valve detaching from IGV actuator caused release of 1000 gal of oil, but no fire thanks to a cool enclosure. User recommends checking that pressure gages work and setpoints are properly adjusted



5. Cracks were noted on some DLN 2.6 hardware after 32K operating hours, such as on liner cap plates

compressor components.

Presenter noted that insurance company was "very interested" in seeing this upgrade occur and that other users have been "encouraged" by their insuruers to replace original vanes with enhanced ones available from the OEM and one non-OEM supplier. During the Q&A, one seasoned veteran noted that these issues apply to both the flared and unflared compressors, and that one site did not replace the S3 row when they upgraded and it ended up failing. So, change out all stages when you upgrade.

Loss of lube oil event. In the category of significant loss, O/O rep from a site with four 7FA 1x1 CC units reported on a loss of lube oil event, while all four units were in startup, which led to a two-month outage for the affected machine. Subsequent inspections revealed damage of compressor tip curls, T1 and T2 bearings (babbitt melted down, journals wiped), and generator fan blades, bearings, and H2 seals.

Unit was at full speed no load (FSNL) when the lube oil pump (LOP) tripped on loss of pressure. The DC pump started but engaged too late. Low H2 pressure led to emergency purge. DC pump was manually shut down. The lead AC pump had previously failed and the standby pump failed during shutdown. During startup, the breaker would not close while the AC pump was running. Normal rolldown to turning gear takes 30 minutes; this one took 5 min.

The AC LOP 1 motor had failed three months prior and the LOP2 motor failed days before the event. During the startup sequence, the AC LOP operation was not physically verified. Opening a breaker on operating equipment under load is not normal procedure and contrary to arc flash avoidance, but the operator "was conditioned" to act as needed to get units on-line to meet dispatch.

Slides include a list of root causes to contributing factors and corrective actions. Audience Q&A focused on frequency of swapping out spared components (weekly, monthly) and component checks. One audience member noted they do DC oil checks quarterly. Presenter suggested that his site will now swap out spares on each start.

IGV hydraulic blowout. Workers at a baseload 2x1 CC site with 7FA.03 units (2002 vintage, but initial operation 2011) noticed an oil leak in the turbine compartment during a planned shutdown. Fortunately, the compartment was cool enough that no fire occurred. Initial investigation revealed that the servo valve detached from the IGV actuator via stripping of smaller bolts holding the device together (Fig 4). Around a 1000 gal of turbine lube oil was released, with minor escape through small cracks between floor and walls (though not reaching drains or ground).

At conference time, the incident was being more thoroughly investigated, but the presenter offered a few theories, and as importantly, these suggestions:

- Make sure pressure gages on the low and high sides of the pumps are working and consider adding transmitters and trending them in the control room. At time of incident, local gages had topped out, and no trending is done, but it is believed that pressure surpassed 4000 psig.
- Ensure hydraulic PMs are conducted and confirm pressure setpoints. Periodically confirm relief valve operation.

This site replaces valves on a five-year cycle but this PM may change pending results from the investigation.

TURBINES

Imagine having CC units which now have to turn down to 22% (while still meeting 9 ppm NOx), from 58% two years ago! That's what one O/O in a fast-growing region of the country faced when it underwent a 7FA fleet advanced gas path (AGP) upgrade and conversion to DLN 2.6 + axial fuel staging (AFS) + overboard bleed (OBB)in several units.

At one site, work was performed over a ten-year period. For the most recent AGP piece conducted in 2024 and 2025, 360 contractors and nine cranes were on site during a three-week outage. Slides provide key information on upgrade scopes and pre- and post-performance gains for two separate facilities.

Important O&M detail: After 4.5 years of operation, some DLN 2.6 hardware at one site exhibited small cracks (Fig 5) and had to be recoated, but the fourteen combustions liners and transition pieces "looked good." One lesson learned is to anticipate unforeseen work, in this case exhaust frame leak repair and exhaust flex seal replacement.

At the other site (acquired in 2021), AGP, AFS, DLN 2.6, and OBB were undertaken during a massive three-month planned outage in 2024, which had to be extended by five months during the critical summer peak season. DLN tuning took 11 days, with the AFS adding seven days. Worth your time is the slide showing the additional outage scope and issues which prolonged the schedule.

7FA.04-200 UPGRADE PROS, CONS

"What the heck is a 7FA.04-200?," this presenter asked rhetorically. He knows better than most since his O/O now has 30 of them, all converted/upgraded between 2015-2017. Features include a 14-stage compressor, a DLN 2.6, AGP Tech package, three stages of variable stator vanes, increase to 32K hours/1250 starts HGP interval (from 24K/900), and field replaceable compressor stage blading.

The benefits are considerable. Total power output per unit now surpasses (without power augmentation) 200 MW with a 3% heat rate improvement and improved startup and part-load efficiency. Value of replacing compressor airfoils in-situ was demonstrated when 54 blades were damaged. After effectively reaching the 1st HGP interval, only the liner caps (uncoated) needed replacement.

Listed as cons were the 45–60-day outage period needed for the mods, potential restrictions on generator and BOP, GT auxiliaries and BOP upgrades, and cost. Also, a fourth level had to be added to the inlet air housing. A maintenance note: HRSGs need to be cleaned more often because of the higher air flow through the unit.

Slides provide much more detail in photos, diagrams, and operational data.

R4P BUCKET UPGRADE

Updating a 2024 7F Users Conference presenter, this O/O rep, referencing two peaking facilities with modified 7FA.03s (AGP Tech), described a persistent issue since 2018: premature burnup of the first-stage blade leading edges on several units after less than 500 FFS and 1-4 years operation. Cause was diagnosed as loss of tip caps. The OEM's two solutions – repair with the original tip caps, and repair with replaced caps – "appear to be effective" based on x-ray inspections.

The 2024 preso also noted another issue, platform cracks in 12 1st stage blades after 480 FFS and 5100 FFH. Since then, two additional units have undergone full S1B replacements because of this issue, one af-

ter 750 FFS/7800 FFH (installed fall 2018), the other after 420 FFS/3800 FFH (installed spring 2022). One other unit is forming platform cracks as well. The investigation process was in the RCA phase at conference time.

A third discovery was thermal barrier coating (TBC) spallation on the pressure side of the transition radius from platform to air foil. OEM attributed this to a coating process change that has since been corrected. Five sets of SB1s at the two facilities are affected. The O/O is keeping two sets in inventory in a warehouse should failures occur.

6. Condition of exhaust flex seal and replacement was one of several unexpected findings during site compressor modernization project

ROTORS

OEM VETERANS TURNED O/O SPECIALISTS

Sports fans can recall what they feel when a favorite star player is traded to a rival team. That must have been what some in the audience were feeling when two OEM rotor design and manufacturing experts led a panel discussion as newly hired specialists for two O/O organizations each with dozens of 7Fs. This is when your attendance at user conferences becomes invaluable because generally there are no slide decks submitted for panels.

A few of the more salient points (not mentioned earlier) include:

- Casing alignment issues with older units are going to “bite and bite hard” when considering whether to push units to a 4th or 5th major refurbishment outage (144,000 hrs typically represents the 3rd major).
- Stator vanes are “always an inspection component.” If they aren’t locked up and don’t exhibit pitting, they can go on forever.
- The disassembly process itself can be damaging and impact life evaluation so ask yourself how often do you want to take the rotor apart.
- Expect more leaks in cooling air piping – pipe connections and manifolds are not making it to fifteen years life.
- What drives rotor life is what you can’t see inside.
- Don’t expect non-destructive examination (NDE) technology to improve fast enough to provide more assistance in rotor life evaluation, i.e., you can’t find 5 mil cracks with fluorescent penetrant (DP) or otherwise.
- 144,000 hrs (or 5000 starts) is the OEM defining a generic risk paradigm for you; you can define your own. Where you run and how you run matter greatly, and how often you subsequently take planned inspection outages (such as 24K vs 32K hours).
- BI inspections are not consistent across the fleet; some BIs are taking 2-3 days (although some parties can do a rotor BI in a day), and at least one user is doing BIs every six months.
- Blading on F.01 and F.02s are especially prone to galling and corrosion which must be addressed.
- Failure to start exacts a price in rotor life; if you don’t full start and properly shutdown and cooldown, you will regret it.

Rotor RLE findings. Major 7FA O/O rep reviewed experience and findings from RLE investigations for two rotors at the OEM’s Singapore facility, one with 134,000+ hours and 1680 starts, the other with 133,000+ hours and 1738 starts. Both have been extended to 240,000 hours and 5000 starts.

For both units, compressor aft shafts had to be scrapped and replaced (forward bolt face edge cracks), turbine wheel No. 1 (TW1) was replaced, turbine wheel No. 2 had new lockwire tab pinholes drilled, and the rabbit fits were given high velocity oxygen fuel (HVOF- a form of thermal spray) coatings. See slides for other findings and repairs.

An audience member (O/O rep) had just completed five rotor replacements, hoping to get twenty-five years of life out of them. He said that they start planning rotor replacements around the 100,000 hrs mark.

This user noted that one exhibited cracks on the aft side of the TW1 tiebolt nut and three units exhibited cracks on the forward side of the 12-point nut. He cautioned that they expect to find similar cracks in units at other sites. Another user suggested that the O/O have the OEM return the nut cut up for analysis.

Yet another audience member said during the Q&A that after initially stating that replacement nuts would take over a year when they faced this issue, the OEM came up with a new type of replacement. Refer to TILs 1937 and 1945.

7FA.05 LIGHTNING ROUND

Discussion moved from topic to topic, and TIL to TIL, so swiftly in the 7F.05 Breakout Session, it was hard to keep up. The root of the audience’s angst appeared to be the sheer number of TILs issued by the OEM, many based on adverse experiences with the HA units.

The list of TILs referenced include the newest (at the time) 2511 (compressor stator retention key), 2467 (Compressor blade circumferential gaps and locking), 2212 (spring loaded T fairings and low speed turning gear), 2133 (stator key deformation and ring segment migration), 2476 (stator 14 inspection, ID shroud, and brush seal), 2558 (stage 1 wheel), 1937, and 2019.

Some audience comments worth pondering:

- HA crews always bring new keys (TIL2511) because they expect the existing ones to need replacing.
- OEM is focused on stage 14 (TIL2476) but should be worried about others as well.
- Will the gap growth remain linear or begin to go exponentially (TIL2467)? It “gets scary” over 1.5 in.
- You’re going to find cracks – it will “light up like a christmas tree” under fluorescent penetrant inspection (TIL2476)
- How do you view the safety risk by implementing the TIL (2511)? You don’t get a choice, it’s a safety issue, and can add two days to the outage.
- The jury is still out on stator vane coated segments, and you can expect to need new coated segments every major.
- We are considering hook fit repairs at every HGP outage.

Regarding 7F.05 combustors, “the 3-D printed, phase 2 fuel nozzles are failing, and are not repairable (cast nozzles are repairable), “we replaced all the inner support rings after one year because half of them were degraded,” but the new ones made of Inconel “are fine.” “Fuel nozzle tips in our fleet are mostly one cycle, the OEM is ‘eating it’ on the LTSA, but we can’t seem to get the hardware. The OEM has fifteen sets of our fuel nozzles right now.

With respect to transition pieces, one user reports cracks as long as 3.5 to 6.5 in., though they are not through-wall. OEM says you can operate with a “hole” in this component but, user stresses, if it liberates, you risk bucket damage in the turbine.

COMPRESSORS

A 1994-vintage peaking facility in the southeast went through a compressor modernization, converting two 7FA.01 units to .03 (both unflared). For context, it's a good idea to review the slides reviewing all the unit upgrades undertaken by this O/O over the last few years, especially the ones in question. This facility, like several others in the O/O fleet, were acquired from IPPs beginning in 2009.

However, the experiences and lessons learned are probably of most interest:

- Confirm properly sized and certified rotor lift beam
- Turbine casing bolt scrap rate of 90%
- Better coordination on turbine rotor dovetail cleaning prior to OEM TIL inspection
- Better oversight of OEM shop schedule and witnessing of shop work
- Better capital parts planning
- Unexpected modifications such as S1N inner support ring and thrust bearing
- Exhaust flex seal inspection and replacement (Fig 6)
- Auxiliary component refurbishments
- Value of third party oversight
- Need for a spare 7FH2 field for the fleet

Other major component replacements include the turning gear and the AO42 exhaust diffuser duct. The slide with the list of obsolescence/end of life concerns is also an eye-opener.

COMBUSTION SYSTEMS

FIRE IN THE HOLE?

During a session on combustion, one user described the event which led to TIL2552 addressing fire protection trips. Several months after an HGP outage, one GT at a facility with two 3x1 CC blocks tripped on fire protection. CO2 had discharged into zone 1, combustor can 13 had "violently disassembled" at the end cap, and the turbine compartment door blew off its hinges, yet there was no active fire.

Damaged components (Fig 7), such as the end caps and fuel nozzle assemblies for cans 12-14, fuel gas flex hose for can 13 (pig tails), and can 13 to 14 crossfire tube, were quickly replaced. Combustion and turbine sections went through BIs. Some cooling passages on the stage 1 nozzle were found to be clogged, requiring additional inspection work. Why and why can 13? The RCA revealed that, after the outage, the site was dealing with a hot spot swirling back to can 13 or 14 for which tuning efforts were unsuccessful. Multiple subsequent BIs revealed nothing unusual. An engineering case was opened with the OEM and active at the time of the event. Other possible contributing factors were that the compartment was only rated for 2.5 in H20 pressure, the nozzles in can 13 may not have been refurbished or flow-tested, and the compartment door had surpassed its expected life of 20 years.

One year later, the OEM issued the TIL and stated that the unit exhibited elevated exhaust spreads, though remaining below trip limits. The O/O did not recognize this as a potential contributing factor during its initial investigation. Further, the O/O is concerned that the logic changes recommended in the TIL could result in even more trips.

One audience member reported his plant ran for 3-4 months after an HGP outage and also had combustion issues. At one point, bolts sheared off, liberating whole end caps. They don't yet understand what caused the event.

Smoking a bad cigar. An undisclosed location experienced black smoke coming out of a liquid-fuel-fired (LF) unit, while the other two units on site were burning gas during a more frequent than projected dispatch schedule. Operators tuned the machine, checking the temperature spreads and pressure for every can. Cans 8 and 10 had their "candlesticks" replaced recently but they "looked like all the others," so they were not tuned. One year earlier, the same cans exhibited low pressure but no smoke.

Questions posed to the audience were: Do we pre-emptively take a scheduled outage, record pressures when we operate/test on LF, and how frequently should we tune on LF?

One audience member noted that they were looking into adding pressure transmitters to 14 lines to identify when they are coking; another confirmed that they had done this and it "proved to be valuable." It can be done for about $1000/PT using a wireless network to bring the data to the control room. A third suggested that not enough cooling air was being supplied during gas operation, which is affecting LF operation. Check the manifold, he advised. A fourth suggested check and, if necessary, repair all brazed joints on gas and LF fuel nozzles, adding that the OEM no longer makes brazed fuel nozzles.

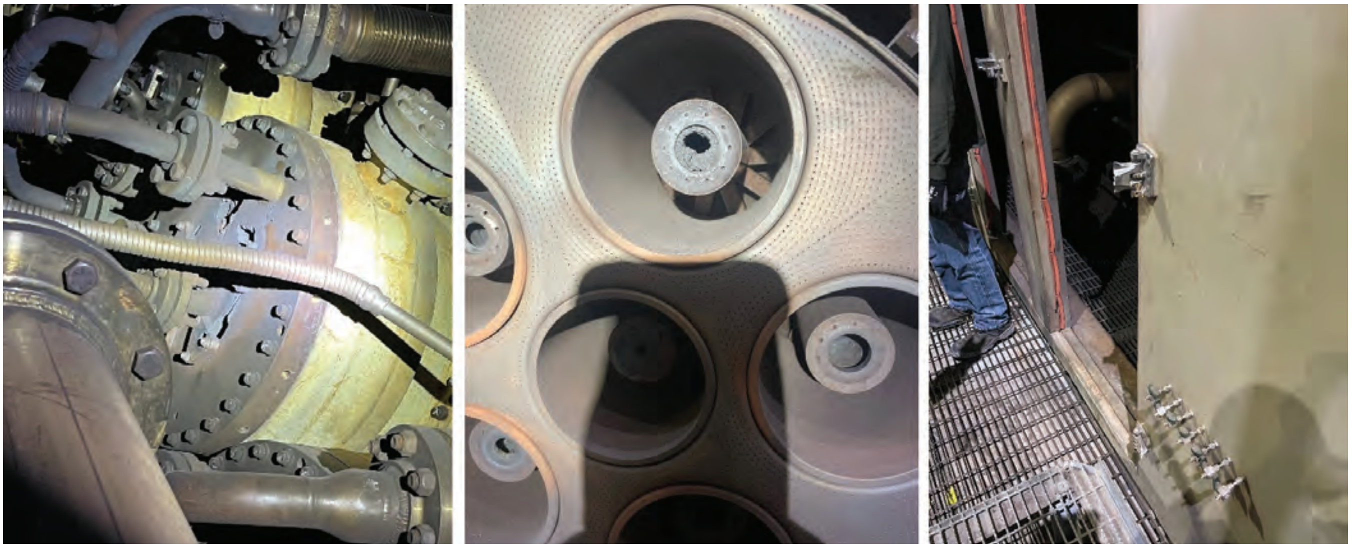
CONTROLS AND BOP

To a "triple major" outage last year, one site added a control system modernization and a complete cooling tower replacement. Scope on the controls included Mark VI to Mark VIe upgrade, migration of steam turbine/generator controls from Ovation to the Mark VIe, and an upgraded vibration monitoring package from System One to Orbit 60.

Overall performance results were impressive: 6.4% gain in net output, 2.1% heat rate improvement, 142-MW improvement in net 2x1 mode turndown, and 71-MW improvement in 1x1 mode turndown.

Challenges, observations, and lessons learned include:

- Failure of a capacitor in a digital valve positioner after 3000 hours service.
- Shortcomings in the valve hydraulics original design
- Seal failures in all six dump valves (Fig 8) in the trip manifold assembly attributed to excessive travel of the valve poppets with-



7. Combustion can hardware was damaged after one can "violently disassembled," strong enough to blow off the compartment door

8. Seals failed in all six dump valves of the trip manifold assembly during a controls modernization; prelim RCA suggested design/manufacturing defect allowing excessive travel of the poppets

in their sleeves).

- Incompatabilities between the old and new ST/G trip controls logic design philosophy
- High turnover of OEM technical advisors and varied familiarity with systems
- Incorrect sizing of the HP main level valve
- Some TILs did not get captured in the upgrade
- 10-12 days required to commission control system per unit.
- Improvements necessary for lube oil lift valve hydraulic system and bleed capability.
- Long lead times required for GT electric components, such as fan motors and circ motor rebuilds

One audience cautioned that users should ask about Orbit 60 now if they are buying a new unit and another remarked that when they ordered an Orbit 60, the OEM showed up with the old 3500 system. A third said that the Orbit 60 rack is smaller than the 3500 but still fits into the original space.

GENERATORS

BEARING TEMPERATURE CREEP

To address a persistent issue with 7FH2 B generator elliptical bearing temperature creep after every start (an issue that has been "talked about for years"), site replaced them with tilt pad bearings from a different OEM. One feature noted: The collector end has G-11 glass reinforced epoxy resin pads on the outer diameter for insulation. Replacement involved repositioning of the seismic and proximity probes, adding oil sight gages, and installing new lift oil tubing, fittings, flex hoses and attachment plate.

The slides include long-term temperature data from another user with three units which had been running with these bearings for a couple of years. Temperatures have been consistently running below 200F.

Many audience members had comments. One noted they had a third party rebuild the bearing in the shop. Eight or so users experience similar elevated temperatures and swap the bearings out regularly. One mentioned high bearing Ts on three units, and investigated the problem over eleven days with no solution. Finally, one notes similar experience with one bearing, "rolled it out" annually for several years, then did a realignment of the rotor and the problem went away. Apparently, TIL1611 addresses this issue and recommends changing the alignment to lower the rotor slightly.

A general discussion on generators revealed: six to seven audience members report replacing fields over the next five years, finding scaffolding that go 60 ft in the air and holds 40 tons is an "engineering challenge," spare field and bars may not fit because of subtle nuances depending on what shop the bars originate from, inexperienced crews are being sent by the OEM (one asked for the manual), the wrong tooling was sent out on at least one occasion, and the TIL on the H2 seals calls for finer filters but this could lead to electrostatic issues.

BALANCE OF PLANT

Engineers from one of the largest CC facilities in the world (outside US) described the relocation of an H2 vent line to solve the problem of hydrogen drifting into the GT compartment via the ventilation blower. Site was experiencing persistently elevated haz gas readings from the detectors in the compartment, though there were no shutdown events caused by haz gas alarm.

Two possible entry points were suspected and evaluated, one from a damaged expansion joint in the ductwork and the other at the blower inlet. The latter proved to be the culprit.

While TIL1598 (from 2007) addresses vent pipe height, the solution here was to move the discharge point around ten feet away from the inlet filter house while retaining original height. The mod was performed on two of the GTs at the site and no subsequent high haz gas readings have been observed in two years. Note that the work requires purging of the generator.

SMALL MODS, HUGE BENEFITS

An industrial site O/O described relatively minor BOP modifications made to a 1998-vintage FA.02 (upgraded to a .03 in 2013) to "solve problems that they didn't want to see again." According to the presenter, "Our site gets a two-day shutdown each year and that's it!"

Mods include:

- Decreased inlet fuel gas temperature from 130F to 97F.
- Upgraded compressor bleed valves - replaced OEM-supplied limit switches with more robust proximity sensors, replaced valve actuators with larger ones made of stainless steel and which use instrument air instead of compressor air.
- Modified exhaust pressure transmitter tubing with T fitting and 3-4 ft drain legs, added the lines to the operator rounds to check regularly for proper drainage.
- Replaced water-cooled flame scanners with dry-cooled versions from Reuter Stokes.
- Replaced exhaust pressure switches with Rosemount transmitters and relocated them to the roof.

Decreasing fuel gas temperature, the "biggest bang for the buck," avoids adverse combustion dynamics during cold weather ops. Replacing compressor air with instrument air avoids condensate issues when sending hot fluid into a cold line. Allowing the condensate to collect in drain legs avoids incorrect pressure readings and pressure pulsations. With respect to the water-cooled flame detectors, it was difficult to remove air from spiral wound tubing. "Water near the turbine is always bad news," said the presenter, "we worked with the vendor to improve the robustness of the design."

HIGHLIGHTS FROM VENDORS PRESENTATIONS

PSM: Full-service OEM alternative. During a review of PSM's history and product/solution suite, Katie Koch stated that the firm planned to have full PSM-manufactured 7F rotors available beginning in 2027 and that its first "fielded turbine wheel" entered service in May 2024. A "drop-in compatible" combustor is now available as an option to the OEM's DLN 2.6.

PSM bills itself as "the only non-OEM offering complete 7F upgrades."

The coming year is big for PSM, Koch continued. The GTOP4 (gas turbine optimization) offering is being commissioned, followed by three other installs. The year marks a decade of FlameSheet commercial operation. After a dozen outages and detailed assessments, FlameSheet harware "looks pretty good." Mods to the Gen IV Flamesheet have improved its emissions profile and reduced startup dynamics.

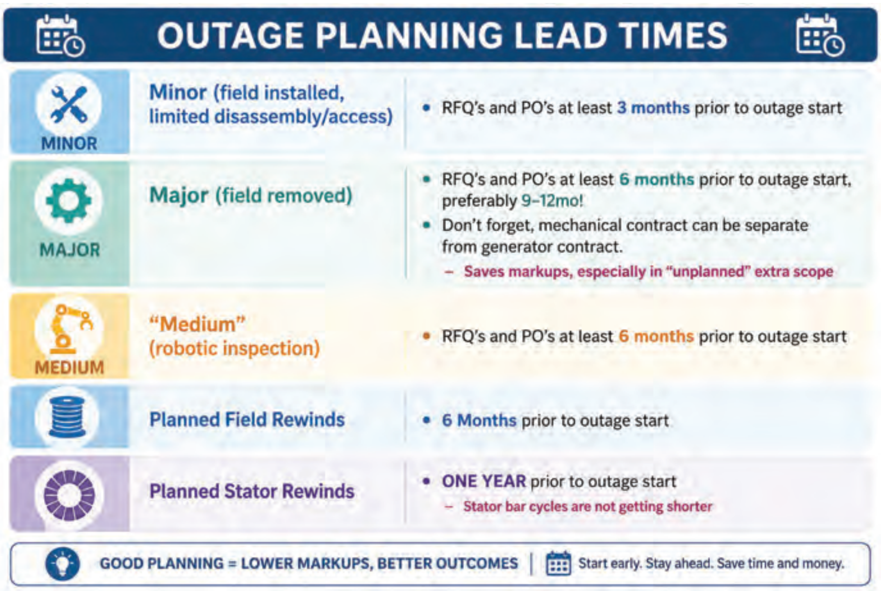
Other milestones include demonstrations of the exhaust bleed scheme (for 10% better turndown), FlameSheet upgrade with the torch circuit and micromixer technology, and the GTOP3.1 unflared compressor for 2.8% greater airflow.

Digital services now includes Autotune, FlexSuite, advanced M&D with 24/7 expert monitoring, and a replacement for the OEM's "locked-down model-based controls (MBC).

PSM is also formulating and executing on a fleet management process which includes updates to customer information letters (CILs), database for tracking life cycles of parts, and better communication updates through an on-line customer portal.

Readers are encouraged to access separate presentations, each with a stunning amount of detail, on FlameSheet, GTOP, and

Lectrodryer: Automated generator purge and H2 dryer package can be integrated with OEM H2 piping, reduces purge duration from up to half a day to less than an hour, and is initiated by control room operator or at the local HMI



AGT Services: Suggested lock-in timelines for major generator work from last year likely should be extended even more so today

the 7F rotor program.

MD&A – Latest repair, parts services. José Quiñones reviewed the company's current parts supply and repair capabilities for several machine models and OEMs, including the 7FA.03, then zeroed in on latest services for the 7FA.04, which include 1st stage blade tip inspection and repair, 1st stage shroud tile repair, 2nd stage blades and nozzles, 2nd and 3rd stage shroud block repair, and combustion liner and transition piece repair.

Quiñones highlighted the successful 1st stage blade tip repair and the low-K abradable coating for the 1st stage shroud tiles. Slides are replete with photos and diagrams illustrating both.

ROTORS

Doosan: LTE & Refurbished rotors. Company calls its long-term solution for rotor life extension DART (Doosan Advanced Re-engineered Turbine), leveraging its "major footprint" in 7F exhaust and compressor discharge casings, turbine wheels, exhaust frames and diffusers, and bearing housing. A 7F rotor can get an LTE (lifetime evaluation) and overhaul in 3-4 months, claims the firm, for ten years or more of additional life, and pointed to a project "completed a few weeks ago."

While Doosan can handle turnkey projects, it is cooperating with PSM to provide more options for rotors and investing in parts for inventory to address the current supply/demand crunch.

COMPRESSORS

CTTS fixes loose stator vanes. All GT models with square-based stator vanes are subject to vane looseness and hook fit casing cracks, and potential crashes, says Rich Armstrong. Loose vanes are most prevalent adjacent to extraction stages, at the back end of the compressor, and near horizontal joints. Slides review causes of vanes coming loose, and most importantly, what to look for. Although borescope inspection van detect some evidence, a thorough evaluation requires removal of the top of the casing.

CTTS' vane pinning solution exhibits the lowest cost in the shortest amount of down time and, critically, addresses vibration dampening and vane movement (which OEM solutions do not, Armstrong said). With 95+ compressor vanes (at conference time) so repaired since 2003, vane pinning is fully qualified and well-proven.

GENERATORS

AGT Services warns on generators. Users responsible for aging generators can get uncomfortable (but very knowledgeable) in a hurry reviewing Jamie Clark's slides on generator outages. To put it simply, supply of shop services and components and demand for repairs, upgrades, and replacements are out of sync. Review how he builds the case in the slides.

Balance of slides help users "get their minds right" regarding the different types, levels, and duration of inspection techniques; repair durations; when to lock in resources (earlier, not later) for major work (illustration); evaluating winding resistances; realities of procuring spare fields; and limitations on field inspecting and repairing only "what you can see and feel." Comparison between a robot wedge map from a spring outage and a hand wedge map from a spring outage three years later is especially illuminating.

If you only take away two things from the presentation, Clark writes, let it be (1) borescope under the retaining rings on day one, hour one, and (2) verify insulation resistance and polarization index, commonly known as the Megger test, per IEEE 43 and 95.

Lectrodryer's generator fast purge. Rob Kallgren surely got the audience's attention with photos of three catastrophic generator explosions, then proceeded to explain how a fast automated H2-purge and dryer installation (specific features covered in slides) can avoid them and reduce purge duration from 6-12 hours to less than one hour. He covered three case studies – shutdown for a hurricane, cracked H2 piping weld, and loss of seal oil. Details are not in the slides but Kallgren would be pleased to fill you in if you contact him.

CONTROL AND M&D SYSTEMS

AP4 handles I&C. Presentations takes you back to the fundamentals of thermodynamics, the Brayton cycle and gas turbine efficiency and performance calculations to emphasize that instrumentation are the health indicators and inputs to the machine control and safety systems. If not properly calibrated, they can cause outages and poor performance. Recommendation: Establish a formal performance evaluation process which includes tracking system, periodic site audits, regular maintenance, and comparison to a valid baseline condition.

BOP SUBSYSTEMS

ExxonMobil – address hot and cold varnish. Cody Evans distinguished between hot and cold varnish in lube oil systems, characteristics, how formed, where each is found in different areas of the turbine, and why it's important to test for both. Oil analysis (slides review four standard techniques) is a good predictor of cold varnish, which may not impact operation if the tolerances in the hydraulic systems are not too tight.

Hot varnish, or sheer-stress-induced deposits, is almost always the result of another mechanical or environmental cause and is best indicated by a gradual rise in bearing temperature (not caused by other factors). Oil analysis and vibration may not correlate.

Company's Solvancer additive is said to be the only one on the market formulated to adequately treat both hot and cold varnish and suitable for long-term use. Other options, in fact, like PAG with amine antioxidant, may actually aggravate varnish formation when used for more than three months.

Donaldson urges optimizing filtration. Bob Reinhardt encourages users to focus as much on operational impacts from poor filtration as they do on maintenance aspects. He stresses that all the important filtration objectives are not necessarily addressed by current industry standards. Total cost of ownership (TCO) of a GT can be optimized with modern intake air housing designs and by selecting filter materials which may have a higher first cost but pay dividends over the life of the machine (illustration).

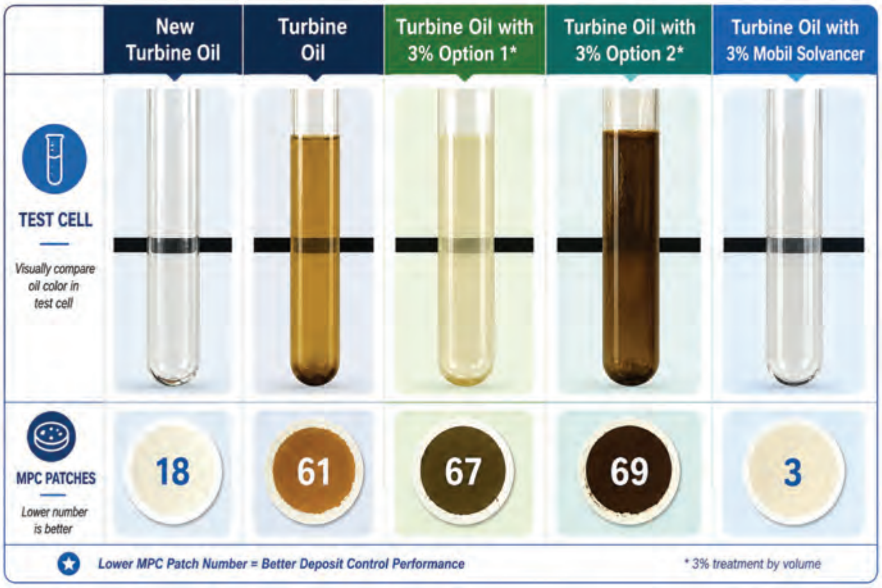
Opening slide is a stunner, an illustration of the volume of air moving through a 7FA per hour and the amount of contaminants collected (180 lbs/hr in a desert location!). Following slides show how to do a thorough TCO assessment of filters, for example comparing filters using a rating system that includes efficiency rating, water tightness, and cleaning pulse recovery rate, then plugging those values into a TCO model for the unit.

HP Leak Detection – all in the name. There's a better way to detect leaks at piping flanges than having a worker do the "flag flutter" test. Experts from HP Leak Detection explained their patented, demonstrated "CRANK" technique, in which the system is tested at 1 psi with a "balloon" clamped to the flange. The balloon deploys at 0.2 psi signifying a leak. If the flange passes the balloon test, it is ready for continuous monitoring and a gold cap replaces the balloon (illustration).

Should a leak occur during operation, the gold cap lifts off, acting as a warning flag to workers. A pressure switch/transmitter can be added to provide a signal to the control room or a remote location. Technique accommodates a wide range of gases and flange types. One important application is turbine compartment airflow. Several prominent O/Os have signed on with testimonials.

Nord-Lock offers better bolts. Removing friction-drive and shear-drive coupling bolts often isn't straightforward, and workers resort to destructive removal. The drop-in (no mods required), permanent replacement Superbolt EZFIT design offers "tremendous radial expansion and joint clamping power," thanks to a split expansion sleeve which mates with the customer's machined holes.

The advanced bolt avoids the wing-type locking feature, 50-lb tensioner device, mis-aligning the tensioner puller screw into the conical thread, dangerous windage plates/covers, and rental of specialty hydraulic equipment. Design, manufacturing, and engineering details are covered in the slides, along with several applications in GT powerplants and short list of customer sites using the technology.



ExxonMobil: Proprietary additive, balanced to address both hot and cold varnish, kept lube oil close to as clean as new

GENERAL PLANT SERVICES

CEIS IEM advocates O/E role. Benefits of employing an owners/engineer (O/E) during major projects are legion but can be summarized as receiving technical expertise during every phase of the project – planning, execution, commissioning, and start up. Services are especially valuable for facilities or O/Os with thin staffs, unfamiliarity with contractors, and/or inadequate expertise or experience with contract negotiations and overseeing contractors.

Examples are provided of projects where O/E services proved their value, and specific findings during a project (such as a water bottle and lighter found in a generator during a close-out inspection). In one testimonial, a utility project manager noted that the O/E had suggested better fixes than the OEM's for known problems. CCJ

Donaldson: Difference in amount of contaminants on compressor blade surfaces can be stark depending on the type of filter used

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Converted M501GAC reaches 50% H2 blend at Plant McDonough-Atkinson

By Jeff Porubcan, in conjunction with representatives from Mitsubishi Power, EPRI, and Georgia Power

Editor's note: Hydrogen has moved past white-paper status and onto utility hardware. At Plant McDonough-Atkinson, Southern Company and its partners pushed a converted M501GAC gas turbine to hydrogen blend levels and flow rates that matter to combined-cycle operators, not just lab programs.

Why now? Because flexibility, emissions pressure, and renewables are forcing owners to look harder at fuels that can widen operating options without replacing the asset base.

The article that follows gets into the hard part: pressure control, code compliance, safety, combustor changes, and system integration. Those are the issues that will decide whether hydrogen co-firing becomes a talking point or a valuable plant tool.

Hydrogen storage and delivery system

INTRODUCTION

In 2025, Georgia Power (a subsidiary of Southern Company), Mitsubishi Power, Certarus, and EPRI conducted a large-scale hydrogen (H2) blending demonstration on a M501GAC advanced gas turbine in combined cycle configuration at the McDonough-Atkinson power plant in Smyrna, Georgia. The purpose was to showcase the fuel flexibility and co-firing capabilities of the M501GAC gas turbine [4]. The unit, originally a 501G, was retrofitted to support H2 blends up to 50% by volume across multiple fuel circuits within the Dry Low NOx (DLN) combustion system. The demonstration achieved the highest documented H2 flow rate in a utility-scale turbine to date—exceeding 10,000 lbs/hr—enabled by a complex infrastructure comprising 11 H2 mobile storage units, four pressure reduction, skids, and a custom-designed H2 flow and blending, fuel delivery, and control system.

Independent regulation of H2 blend ratios for multiple fuel circuits was accomplished using an advanced fuel gas blending system made up of flow meters, control valves, and pressure relief devices — all automatically controlled via custom-designed logic. The system design addressed key technical challenges including pressure management, equipment protection, and safety systems under high-flow conditions. Compliance with ASME, along with other piping, storage, and safety codes, required careful interpretation to ensure overpressure protection was met while maintaining operational flexibility.

This article presents the system architecture, design considerations, and operational results from the demonstration, offering insights into the practical integration of high-volume H2 with existing gas turbine infrastructure. The findings can inform future retrofits and H2 co-firing projects aimed at decarbonizing large-scale power generation.

PROJECT BACKGROUND

Plant McDonough-Atkinson, which was commissioned in 1930 and serves the greater Atlanta, Georgia region, operates three 2 x 1 combined cycle power blocks, with a total generating capacity of more than 2,700 megawatts (MW). With Georgia experiencing extraordinary economic growth, operating flexibility of Plant McDonough-Atkinson has become increasingly important. Co-firing with H2 fuel has the potential to provide greater operational flexibility, as it increases gas turbine load turndown capability, potentially resulting in fewer shutdowns during times of low power demand and lower natural gas consumption.

Hydrogen is currently more expensive than natural gas, but during periods of low market demand, non-dispatchable power, which may otherwise be curtailed, can be used to produce and store H2 gas, thus making it more economical. H2 blending also offers environmental benefits, as its combustion does not result in carbon dioxide (CO2) emissions, as shown in the chemical reaction below:

$$[2H_2 + O_2 = 2H_2O + \text{heat}]$$

Southern Company has been at the forefront of large-scale H2 fueling applications, recognizing the impact H2 blending demonstrations can have on the industry as it moves to decarbonize. Building on a previous 20% H2 co-firing demonstration at Plant McDonough-Atkinson in 2023 [3], Southern Company had an ambitious goal to achieve 50% H2 co-firing (by volume) at the same location. Doing so required modifications to the gas turbine, primarily converting from a steam-cooled combustor to an air-cooled combustor. The conversion provides the

M501GAC combustor for hydrogen test rig

Combustor test rig in Takasago, Japan

added benefit of reducing the cold start-up time for the gas turbine (since steam warming periods are eliminated).

Increasing the pilot ratio and injecting water for NOx emissions control were the primary mechanisms for achieving 50% H2 co-firing. The success of the project was made possible by extensive combustor research and development and rig testing performed in Mitsubishi Power's headquarters in Takasago, Japan.

The project team included personnel from Georgia Power, Mitsubishi Power, and EPRI. Several specialized contractors, designers, and equipment vendors were also enlisted for support. The main goals of the demonstration were to:

- Achieve safe and reliable operation with H2 blending
- Demonstrate wet combustion at 50% H2 by volume
- Demonstrate dry combustion at 30% H2 by volume
- Determine the emissions and turndown effect from H2 introduction into the natural gas fuel stream

SYSTEM DESIGN CONSIDERATIONS

Along with gas turbine conversion, several new auxiliary systems were required for the project including (but not limited to) mobile H2 storage, H2 pressure reduction, H2 flow control stages, H2 blending, high-pressure purge air, water injection, nitrogen purge, control oil, trip oil, instrument air, etc.

The infrastructure additions for the 50% co-firing demonstration were more significant than the previous 20% co-firing project. This was driven by two main factors: 1) H2 injection into multiple fuel stages and 2) the requirement for NOx reduction system(s).

Hydrogen pressure control was challenging due to existing system constraints. A very narrow pressure window (~30 psi) exists between the required pressure for operation and the existing fuel gas piping system design pressure. While this was not an ideal operating scenario, it was manageable.

Overpressure protection is required by various codes (e.g., ASME B31.12 [7], B31.1 [6], API 521 [10], NFPA 2 [11]). It typically is accomplished using a full flow sized relief valve. However, a full flow relief valve was not desired for several reasons, including a very high-pressure safety valve (PSV) reaction force, large discharge piping size, risk of large H2 release (resulting in noise, possible deflagration, etc.), lack of redundancy, and the potential for a PSV release to trip the gas turbine.

During the previous 20% demonstration, implementation of a full flow relief valve was complicated and arduous. To avoid this during the 50% demonstration, an alternative protection method was chosen which relied on three main components: 1) tandem gas regulators, 2) a trip stop valve, and 3) a small safety pressure relief valve (sized for leakage flow only).

Ultimately, this method was used with worker and wide-open monitor pressure-regulating valves, which allowed for failure of any single control device. The tandem pressure regulator configuration creates a controlled, layered safety strategy that meets ASME B31.12 requirements for H2 systems without requiring full-area venting.

In the arrangement, the primary worker valve fails open and the back-up monitor valve fails closed. During normal operation, the back-up monitor valve pressure is set slightly higher than the primary valve, forcing the monitor valve to fully open. If the worker valve fails, the spring forces it open. As the downstream pressure increases above its set pressure, the monitor valve takes over control. Primary regulator failure is detected via an increase in the downstream control pressure.

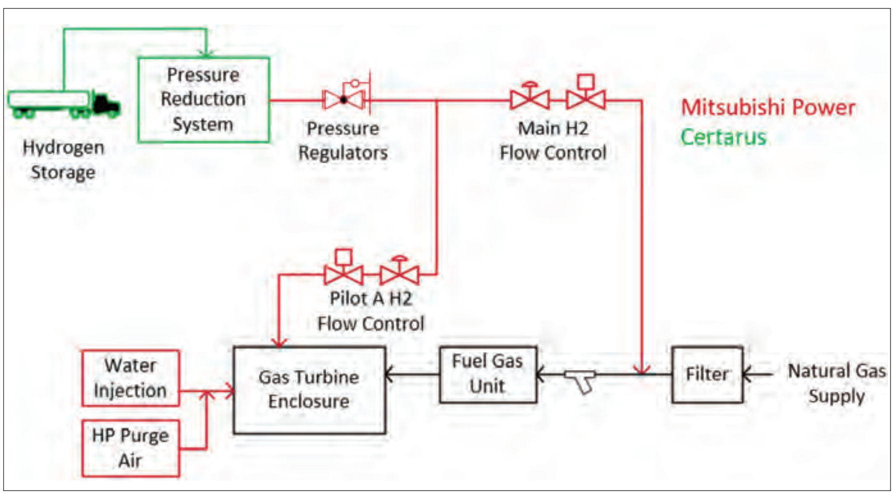
Trip stop valve(s) functionality was satisfied by adding a feature to the shutoff valve, which required a special style of solenoid valve with manual reset. Upon reaching the trip pressure, the solenoid valve, (hardwired from a pressure switch) de-energizes and locks out. The trip stop valve then slams shut and can only be opened after manually resetting the solenoid via a local reset button. This feature was intentional and required by code.

A PSV was also required to protect against leakage through the regulator valves. The leakage rating of the regulators (class II [8]) only required a small orifice, limiting the amount of H2 released. A direct-acting pressure relief valve was not feasible due to the poor seat tightness approaching the set pressure (leak-tight up to 90% of set pressure). To avoid constant leakage to atmosphere, a pilot-operated relief valve was used instead (leak-tight up to 98% of set pressure). Both types are allowed under ASME BPCV Section XIII [5].

All new H2 piping was designed and manufactured in accordance with ASME B31.12 and B31.1 codes. However, H2 gas was also introduced into many existing piping branches, which were originally intended for natural gas, and thus manufactured in accordance with ASME B31.1 code only. The existing piping was evaluated for conformance to the B31.12 H2 code using a gap analysis. Hydrogen embrittlement and stress corrosion cracking are known problems with H2 pipelines. Mitigating these risks required evaluation of existing piping hardness values, especially at weld joints and cold bends.

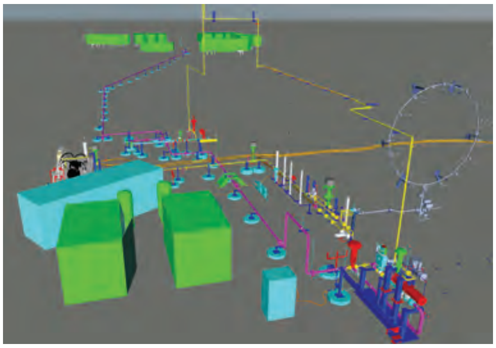
Auto-ignition (due to the high temperature) was another important risk factor that was considered in the design process. Some gas turbine fuel supply lines have transient conditions where fuel is displaced with hot combustion air. For the demonstration at Plant McDonough-Atkinson, these conditions were intentionally avoided by sequence of operations. Nonetheless, a detailed auto-ignition study was conducted in conjunction with the University of Central Florida (UCF) to evaluate the impact of fuel blend ratio, pressure, and temperature [1,2]. The results were used to determine the logic control setting values to trip the gas turbine.

Creating the new H2 system(s) presented challenges, especially considering the temporary nature of the project. Atypical system requirements included execution duration (installation and removal), lead time, space restrictions, power supply, control system compatibility, etc. These requirements were considered early in the design phase, which



System flow diagram


Testing of worker and monitor regulating valves


Temporary equipment scope


Team huddle during troubleshooting

facilitated smooth execution.

Numerous factors were considered when designing the layout of the new temporary systems, including emergency egress, new hazardous areas, NFPA 2 equipment setback distances, access for normal plant operation, and all normal service-related equipment and tooling (e.g., cranes, laydown space, etc.)

With the addition of H2 into the existing fuel gas piping, established hazardous area release points (Class I Div 2 Group D) had to be reclassified for H2 gas release (Class I Div 2 Group B). Therefore, all electrical (and mechanical) equipment and installation within the hazardous areas was studied in detail. Several electrical devices were not compatible with H2 and were replaced with suitable equivalents.

Hazardous areas onsite were originally determined using API 500 [9], which carries different definitions than NFPA 70 [12]. Two key differences worth noting are the discharge point plume radius and flange connections (API 500 does not consider flanges a leak point). Nonetheless, all flanged connections were examined as potential leakage points, and all equipment within the larger NFPA 70 radii was evaluated. This led to some additional modifications.

PLANT SAFETY

Safety was a top priority for the demonstration project. Thus, the properties of H2 gas which present additional risks relative to natural gas (e.g., low ignition energy, wide flammability range, small molecular size, invisible flame, non-odorous, buoyancy, etc.) were considered and mitigated. Hydrogen has been used for decades in plants with H2-cooled generators. The industry is familiar with designing and operating systems to support these applications. However, for the new H2 supply system at Plant McDonough-Atkinson, hazardous operations reviews were conducted, which yielded several additional safety precautions, including:

- **Equipotential bonding.** All flange joints were equipped with a metallic bonding connector from one flange to the other, including any items between the flanges. Resistance was measured and verified to be below allowable limits for all flange joints.
- **Leakage simulation.** A Computational Fluid Dynamic (CFD) model was created to evaluate H2 leaks at all flanged connections inside of the gas turbine enclosure. The result was used to improve air circulation.
- **Gas detection.** Natural gas detectors monitor the ambient air inside all enclosures that contain natural gas. These devices remained active, with an additional set of gas detectors installed to detect H2 leakage. The selected H2 gas detectors were significantly more sensitive than natural gas detectors and could detect lower explosive limit (LEL) levels. All detectors were calibrated before use with laboratory grade test gas.
- **Cleaning.** Due to the insulating and low ignition energy properties of H2 gas, any debris in the pipeline could accumulate static charge and potentially cause unintended ignition. Therefore, extensive cleaning measures were taken after fabrication, including solution passivation, manual cleaning, and air blows [13].
- **Leak testing.** After assembly, the entire H2 pipeline was leak tested at design pressure using a uniform blend of helium and nitrogen gas. Helium gas (the next smallest molecule) is an inert gas and was used for leak detection employing the soap bubble technique, along with a very sensitive helium gas sniffer device. This, combined with a robust flange torquing procedure, ensured that all connections were leak-tight prior to introducing H2. Furthermore, after H2 was introduced, the entire system was routinely inspected for leaks using sniffer probes.
- **Hydrogen sensitive tape.** All flanged joint cavities were sealed with nuclear-grade duct tape. A pin hole was placed in the tape and then covered with H2 leak detection tape. The tape allowed for visible indication of any H2 leak. No leaks were detected throughout the demonstration.
- **Purging and inerting.** A detailed process for filling the H2 piping was established and followed. Before any H2 was introduced, the piping was purged and vented with an inert gas (nitrogen) repeatedly until the oxygen content in the pipe was below the fuel/air mixture flammability level (2.76% O2). This was verified using a specialized gas sampling instrument and measuring the oxygen content in several different piping locations. Similarly, after H2 was introduced, the inert gas was displaced until pure H2 concentration was achieved. At no point was pressure allowed to drop below 5 psig, thereby preventing air from entering the pipeline.
- **Restricted access and signage.** When the system was charged with H2 gas, personnel access was restricted into the power block. Road barricades and warning signs with contact information were posted at all access points.
- **Specialized tools.** Any work that was to be performed with the H2 system online required the use of specialized "spark-free" hand tools.
- **Communication.** Clear communication was essential to successful execution. Special radios were procured for use in hazardous environments. During the first communication checks, it was found that radios could not transmit consistently between the test area and control room. Testing was halted until the issue was resolved by adding a digital signal repeater.

A specific radio communication protocol was also established: messages were delivered and repeated, and recipients were required to provide verbal confirmation to ensure accuracy. In addition, AlertMedia was utilized to notify site personnel when testing was in progress, ensuring broad awareness and timely updates across the facility.

TEST EXECUTION AND LESSONS LEARNED

Execution of the 50% H2 co-firing demonstration did present unique challenges. Preparation for each test was careful and precise. A written procedure identifying all sequential steps and hold points was reviewed and agreed to by all parties. The procedure identified clear roles, responsibilities, and hold points for each step in the procedure. Before and after each test, the team performed a pre-brief and de-brief, where

the day's events were discussed. Emergency action plans and lessons learned were also covered, while still fresh in memory.

Several unplanned events occurred during the test period which caused delays. Some of these were external and could not be controlled, including inclement weather, lightning strike damaging controls equipment, grid demand (dispatch), and unplanned balance of plant (BOP) maintenance.

During testing, it was learned that self-contained pressure regulators should have a local vent line and a small throttle valve to bypass the main supply isolation valve. As the H2 piping pressure was increased to the set pressure, the (fail open) worker valve began to close, but slower than anticipated. During initial testing using nitrogen and CNG, the worker and monitor regulators did not respond fast enough and caused the downstream pressure to spike past the setting, opening the PSV. Consequently, the test procedure was modified for a very slow fill rate.

In addition, the narrow operating pressure window was exacerbated by the weather. When the H2 pipeline was on standby (i.e., pressurized, no flow), solar load on the piping caused the gas to expand and pressure to rise. Even with the worker and monitor regulator valves closed, the combination of leakage flow and solar loading caused the downstream pressure to slowly creep towards the trip pressure setting. While the trip stop valve and PSV were in place to protect the system from overpressure, it was preferred to keep the system active by manually venting the gas. Piping insulation may have prevented this but was not considered due to other factors.

For simplicity, multi-variable flow transmitters were used to send pressure, temperature, and flow signals to the control system. In these devices, primary signals are analog (4-20mA), and secondary, tertiary, and quaternary signals are HART burst data. Unfortunately, erratic discontinuity of HART burst messaging signals was observed. As this issue was difficult to troubleshoot and led to lost time, burst messaging in a control circuit is not recommended for future projects.

Refueling the 11 H2 mobile storage units was a challenge as well. Refueling of the tractor trailers occurred four times, each requiring four days of logistics. Between tests, the gas turbine operated in normal dispatch. For additional safety, the H2 system was completely vented and purged with inert gas after each test. The time between tests was used to carefully evaluate the previous test data and make any adjustments to control parameters.

Despite these obstacles, all primary goals of the demonstration project were achieved, and the benefits of H2 co-firing exceeded expectations. Wet co-firing at 50.2% H2 by volume was successfully completed at base and partial loading conditions, as was dry co-firing at 30% H2 by volume. Gas turbine minimum compliance load was successfully reduced to 35% with the assistance of H2 co-firing, enhancing operational flexibility. Over 25,000 lbs of H2 was consumed and over 170,000 lbs of CO2 emissions was avoided throughout the duration of the test.

Project team adjacent to H2 pressure reducing equipment

ADVANCING H2 GT APPLICATIONS

The demonstration at Plant McDonough-Atkinson represents a significant milestone in the progressive development of H2 operation within utility-scale, natural gas-fired power plants. Building on the previous 20% H2 co-firing demonstration in 2022 and other industry trials, the 50% H2 demonstration further extended the operational envelope of the gas turbine and validated advanced combustor designs, fuel blending systems, and safety strategies under real-world conditions. EPRI has been involved in numerous H2 demonstrations. The primary goal of these collective efforts has been to advance the industry forward and document lessons learned so that new knowledge can be applied on future projects.

In summary, by successfully demonstrating high mass flows and H2 blending percentage integration at scale, the co-firing demonstration at Plant McDonough-Atkinson provided critical data and operational experience that will inform future retrofits, guide combustor development, and accelerate the decarbonization of gas-fired power plants.

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1 Loving, C., Mastantuono, G., Terracciano, A. C., Rahman, R. K., Kim, G. Vasu, S. S., Pigon, T., Hernandez, A., and Cloyd, S., 2025, "Extended Testing of the Auto-Ignition Characteristics of Hydrogen–Natural Gas Mixtures for the Safety of Power Plants", ASME Paper No. GTP-24-1388

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5 ASME Boiler & Pressure Vessel Code (BPVC) Section XIII: Rules for Overpressure Protection

6 ASME B31.1: Power Piping

7 ASME B31.12: Hydrogen Piping and Pipelines

8 ANSI/FCI 70-2 & IEC 60534-4: Control Valve Leakage Classes

9 API 500: Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries

10 API 521 part I: Guide for Pressure-Relieving and Depressurizing System

11 NFPA 2: Hydrogen Technologies Code

12 NFPA 70: National Electrical Code

13 EPRI 1023628: Guidelines for Fuel Gas Line Cleaning Using Compressed Air or Nitrogen


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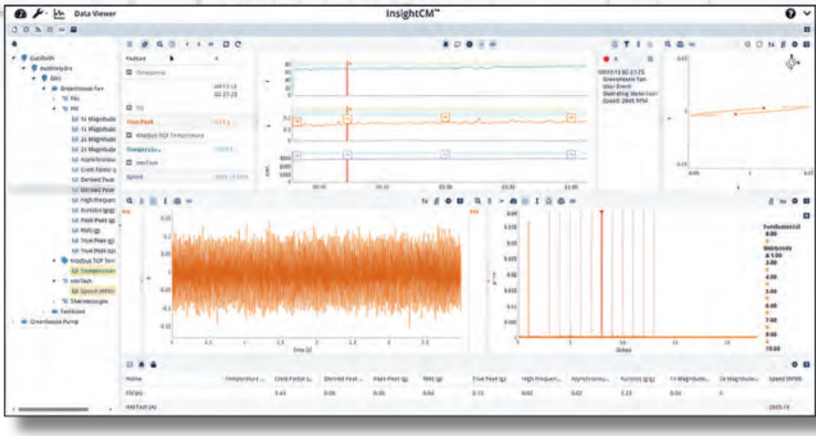

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Quantum Energía uses Altamira V outage to reset plant reliability

Quantum Energía emerged as a major player in Mexico's power sector after Mexico Infrastructure Partners along with Federal Government and Mexico's pension funds acquired Iberdrola's 13-plant portfolio in 2024. The company now manages about 8.5 GW of generation, nearly all modern combined-cycle capacity. At Altamira V, a 2025 major outage on Block 2 shows how the new owner is approaching reliability, not as a series of isolated fixes, but as a coordinated plant-wide reset looking for long term reliability.

Rather than limiting the outage to routine major-maintenance tasks, the site combined turbine work, controls upgrades, cooling-system replacement, filtration improvements, electrical-protection work, and mechanical-integrity projects in a single execution window. The result is a case study in how one outage can be used to reduce multiple chronic reliability risks, increase capacity and improve heat rate at the same time.

MORE THAN A STANDARD MAJOR OUTAGE

Altamira V entered the outage facing familiar combined-cycle challenges: aging controls hardware, steam-turbine vibration exposure, corrosion risk, recurring air-inlet maintenance, and vulnerability in essential systems during blackout scenarios.

The outage scope reflects a broad reliability strategy. In addition to major work on GTs 3 and 4 and ST 2, the plant included replacement of the GT3 and GT4 filter houses, replacement of the cooling tower, and migration from Mark VI to Mark VIe controls. That package suggests a move away from project-by-project correction and toward a more integrated view of fleet reliability.

1. Finishing touches on rotor replacement, component upgrades, generator electrical testing, combustion assembly, and unit closeout

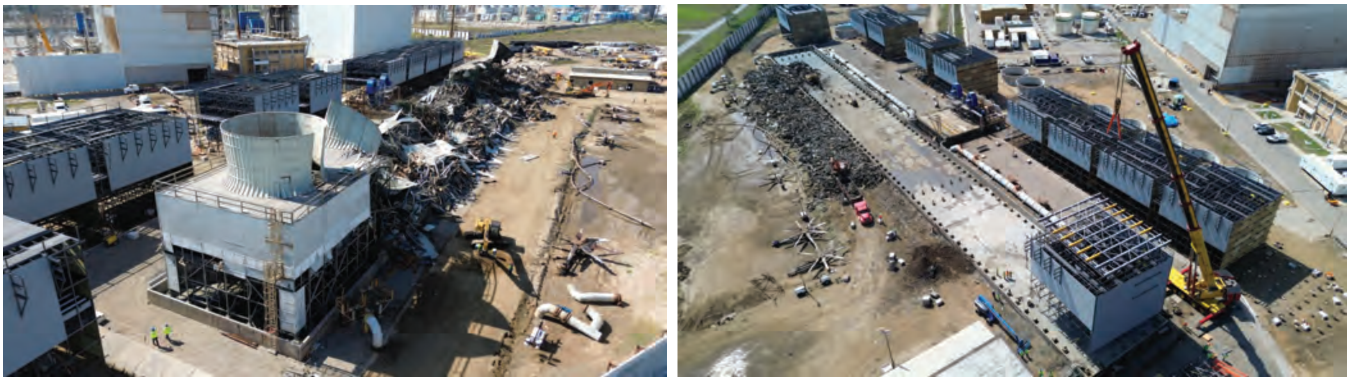
The company also appears to be reassessing maintenance practices inherited from the prior owner. In the filtration program, Quantum indicates that previous filter replacements were made every two years and hot-gas-path inspections every three years, even though AGP-standard parts were capable of about 32,000 hours. The 2025 outage was timed to align with that interval, signaling a more condition- and capability-based approach to maintenance planning.

GT UPGRADES TARGET LIFE AND DAMAGE PREVENTION

On the GT side, GE Vernova replaced the existing 7FA.03 rotor with an RLE rotor intended to provide longer operating life and incorporate updated design improvements (Fig 1). It also replaced S5 robust vanes in the compressor section to reduce exposure to blade-detachment events that can trigger major downstream damage and extended outages.

This upgrade addresses both life consumption and catastrophic risk. A rotor replacement can extend the service envelope of the unit, but the compressor hardware upgrades also aim to prevent the type of failure that turns a planned outage into a long forced outage.

Taken together, the package strengthens



3. Cooling tower replacement progresses (right) after demolition of the original wood structure (left)

the GT train in three ways:

- Extends rotor life with updated hardware
- Reduces compressor damage exposure
- Supports future availability by addressing major risk items during one planned window

STEAM-TURBINE AND CONTROLS WORK ADDRESS TWO PERSISTENT FAILURE MODES

Steam-turbine scope focused on vibration risk rather than waiting for a forced event. The OEM replaced the GEV D11 HP rotor to reduce the potential for high-pressure vibration associated in part with rotor bow seen elsewhere in the fleet (Fig 2). It also used FARO laser alignment to restore centerline geometry and reduce the risk to bearings, deflectors, and the rotor itself.

That is a practical reliability move. Vibration issues on the steam side rarely stay confined to one component, and correcting alignment during a rotor replacement improves the value of both activities.

Controls modernization was the other major lever. Block 2 was upgraded from Mark VI to Mark VIe, including the load commutated inverter and exciter. The objective was to reduce failures tied to aging circuit boards, improve processor and network performance, and restore spare-parts support.

2. Steam turbine work included centerline readings, front-standard foundation review, HP-IP rotor preparation, LP rotor installation, and steam valve maintenance

For owner/operators, the value of that migration goes beyond nuisance-trip reduction. Aging controls can slow troubleshooting, complicate support, and weaken confidence in plant response during transients. A successful migration improves maintainability as much as it improves hardware obsolescence risk.

COOLING AND FILTRATION UPGRADES REDUCE RECURRING OPERATING BURDEN

The outage also extended well beyond the turbine train. Cooling tower 2 was replaced with a fiberglass-reinforced-plastic tower from Evaptech in place of the original wood structure (Fig 3). The reported benefits are operationally significant: better saltwater resistance, lower salt-particle drift, and new mechanical equipment from established suppliers.

Filtration upgrades were handled with the same long-view approach. The plant utilized Camfil Power Systems to replace carbon-steel gas-turbine filter houses with 316L stainless-steel units and upgraded the filtration system from class F9 to F10 while retaining a two-stage arrangement also provided by Camfil (Fig 4). The target replacement interval also moved from two years to four.

4. Crews lift and position new stainless filter-house modules following removal of existing filter, pre-filter, and evaporative-section components

That combination is important because filtration performance depends on more than media efficiency. Housing integrity, corrosion resistance, sealing, and bypass control all affect actual machine cleanliness. Replacing the housings along with the filters suggests the plant is treating inlet-air quality as a system issue, not simply a consumables decision.

Quantum's stated goal is to maintain compressor cleanliness well enough to eliminate four scheduled offline water washes per year, based on prior plant experience. If achieved in service, that would reduce downtime burden while also improving compressor condition between major inspections.

RELIABILITY AND CAPACITY GAINS COME FROM LINKING SUBSYSTEMS

The strongest lesson from Altamira V is that the biggest reliability gains often come from tying subsystems together.

Better inlet filtration supports compressor cleanliness, heat rate, wash frequency and, most importantly, a significant increase in capacity due to lower inlet pressure drop. New housings protect the value of the upgraded filters by reducing leakage and bypass risk. A new rotor and upgraded compressor hardware deliver more value when paired with cleaner inlet air, modernized controls, and stronger electrical protection. Steam-turbine vibration risk is better managed when rotor replacement, alignment recovery, and related mechanical work are completed together.

The same systems view appears in the plant's essential systems work. The outage scope also included upgrades to the automatic emergency generator system, essential systems, and protection relays for the 400-kV substation and both gas- and steam-turbine generators. That broadens the reliability strategy from rotating equipment alone to plant resilience under upset

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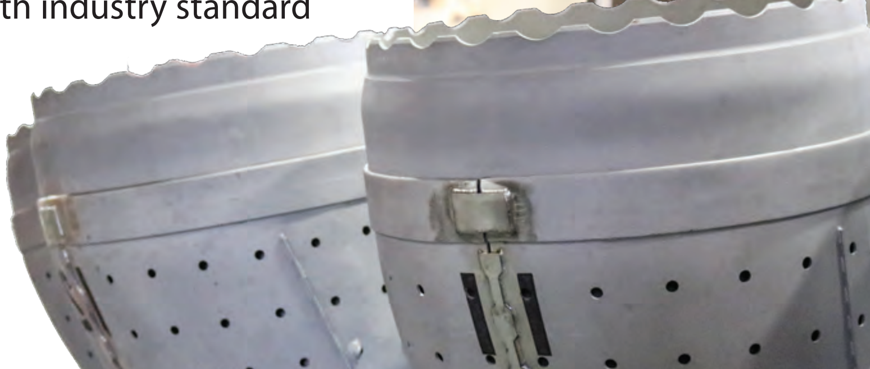

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conditions.

For plant leadership, that changes the character of the outage. The site is not simply restoring worn equipment to prior condition. It is reducing multiple future maintenance drivers at once, including board failures, vibration exposure, corrosion recurrence, fouling burden, and blackout-related equipment risk.

EXECUTION COMPLEXITY REMAINS THE TRADE-OFF

Bundling this much work into a single outage creates its own challenges. Major rotating-equipment replacements, controls migration, cooling-tower work, filtration-house replacement, and balance-of-plant upgrades all compete for schedule, labor, and commissioning attention. That is the central trade-off. A broad outage can create greater long-term value, but it also increases execution complexity and schedule pressure.

Filtration upgrades, for example, only deliver their intended benefit when sealing, drainage, face velocity, and maintenance discipline are all managed correctly. Controls migration similarly delivers better maintainability only after cutover, integration, testing, and restart are completed successfully.

In other words, a bundled outage strategy can reduce future risk, but only if outage execution remains disciplined enough to avoid creating new startup or commissioning issues.

TAKEAWAYS FOR CCGT OPERATORS

Altamira V offers a practical template for plants working through ownership change, inherited maintenance assumptions, or a growing list of recurring reliability issues.

Three lessons stand out:

- Use the major-outage window to solve linked reliability problems together
- Separate work that merely restores condition from work that reduces future operating burden
- Treat filtration, vibration control, electrical protection, and blackout resilience as core reliability issues, not side projects

For Quantum Energía, the broader message is clear. A fleet asset manager with one of Mexico's largest gas-fired portfolios cannot depend on piecemeal corrections if it expects consistent performance across multiple combined-cycle assets. Altamira V suggests the company is moving in that direction, using a major outage not just to replace parts, but to reset the conditions that drive forced outages, maintenance demand, and long-term availability.

Ramón Sánchez, director of power generation at Quantum Energía, sums it up, "These results are the outcome of an integrated approach, driven by a team with deep technical expertise and the ability to execute with precision in complex operating environments, ultimately, turning strategy into sustainable results." CCJ

Sanchez

A glimpse into Mexico's largest IPP

Quantum Energía is one of Mexico's most critical independent power producers, contributing significantly to the reliability and modernization of the country's electrical grid. As Mexico continues its energy transition toward cleaner, more efficient technologies, Quantum's fleet of modern combined cycles plays a central role in delivering reliable, affordable electricity across the national territory.

With a portfolio spanning more than 8.5 GW, operations cover key regions including Mexico's Northeast, Northwest, West, East, and the Baja Peninsula. Their strategic placement and technological diversity ensure system flexibility and resilience, particularly important for meeting peak demands and supporting intermittent renewable generation.

PLANT NAME	CONFIGURATION	TOTAL MW	TURBINE MODEL
ALTAMIRA III & IV	CCGT	1,100	7F
ALTAMIRA V	CCGT	1,155	7F
BAJA CALIFORNIA III	CCGT	325	7F
DULCES NOMBRES I-IV	CCGT	994	GT24
LA LAGUNA II	CCGT	580	7F
ENERTEK	CCGT COGEN	144	W501D5A
ESCOBEDO	CCGT	878	M501J
TAMAZUNCHALE I	CCGT	1,179	7F
TAMAZUNCHALE II	CCGT	514	M501JAC
TOPOLOBAMPO II	CCGT	917	M501J
TOPOLOBAMPO III	CCGT	766	7HA.01
LA VENTA III	WIND	102	GAMESA G52/850

GEV validates clutchless synchronous condensing on 7F.05

GE Vernova (GEV) has installed and validated a clutchless synchronous condenser solution for its 7F.05 gas turbine, enabling transition between power generation and synchronous condensing modes in minutes. This solution expands asset flexibility and grid support capability and may be applicable to other heavy-duty fleets, including E-, F-, and H-class units, following successful validation.

As power systems add more renewable and inverter-based generation, traditional sources of inertia, voltage support, and system strength are declining. GEV's synchronous condenser solutions help address this by converting proven gas turbine assets into flexible, future-ready grid stabilizers that can support the energy transition and provide long-term value. What makes this approach unique is how it builds on existing, well understood technology.

Rather than introducing entirely new equipment, GEV offers aero derivative gas turbine solutions with synchronous condenser capability that repurpose proven generators to provide essential grid services—often without fuel consumption or major plant modifications. This helps operators to meet modern grid requirements while making better use of assets they already trust.

With decades of experience in rotating machines, controls, and grid integration, GEV offers a comprehensive synchronous condenser portfolio engineered to maintain grid stability while enabling higher levels of renewable energy. These solutions are already supporting power systems across North America and Australia and are gaining traction in the Middle East and parts of Europe. By improving reliability, resiliency, and power quality, they help grids accommodate more inverter based resources without sacrificing performance.

At its core, a synchronous condenser is a generator operating without producing real power. When the gas turbine is not needed for power production, it remains physically connected, but operates unfired, while the generator continues to stay synchronized to the grid. In this mode, the equipment provides system stability and grid support by supplying reactive power and inertia to help maintain voltage and frequency.

This capability highlights the continued relevance of rotating machines in modern, renewable heavy power systems.

7F.05 synchronous condenser upgrade builds on this principle, offering essential grid support while being capable of integrating seamlessly into both new and existing power plants. More details on the 7F.05 synchronous condenser solutions will be shared at the 7F Users Group Conference, May 18–21, 2026, at the Woodlands Waterway Marriott.

Two flexible paths to synchronous condensing. To meet diverse needs, GEV offers two complementary synchronous condenser configurations for the 7F.05 platform, supporting both new installations and existing plant upgrades.

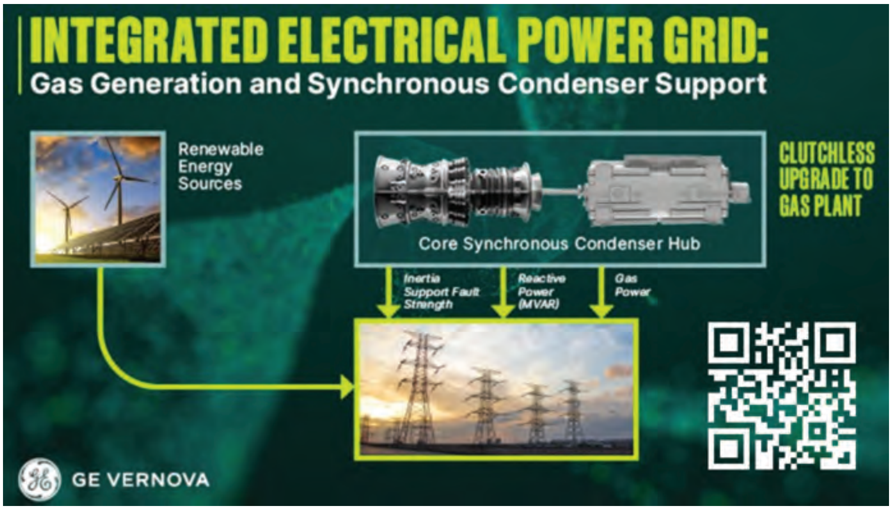
SYNCHRONOUS CONDENSING BUILT IN

For new 7F.05 installations, GEV offers a clutched synchronous condenser configuration that integrates grid support capability directly into the initial plant configuration. This purpose engineered solution expands the generator's role beyond energy production. When active power is not required, the unit can operate in synchronous condensing mode to provide reactive power and inertia without consuming fuel. By incorporating proven clutch and generator technology into the powertrain, the solution preserves the fast start capability, fitting into peaking and baseload plants. It also supports Black Start functionality, and operational flexibility associated with the 7F.05 platform, resulting in a future ready plant with a streamlined commissioning and operating experience.

UNLOCKING MORE VALUE FROM EXISTING ASSETS

For existing 7F.05 units, the clutchless synchronous condenser upgrade does not require a clutch or major mechanical redesign. It uses the existing unit configuration to provide additional grid support and can be implemented during a planned outage. This offers a practical and cost effective way to use existing assets during non dispatch periods.

This upgrade enables voltage regulation, dynamic reactive power, and fault current while providing significant inertia—up to 5.3 times more than the generator alone when compared to clutch based configurations. This transition between generation and synchronous condenser modes happens in minutes, rather than hours, and can supply up to 225 MVAR of reactive power. This capability allows plant owners to respond quickly to grid needs during non-dispatch periods. This solution has been successfully piloted by a GEV customer, accumulating more than 500+ hours of synchronous mode operation, demonstrating both its practicality and reliability. CCJ



Clutchless synchronous condenser upgrade allows a 7F.05 gas-turbine generator to remain synchronized with the grid when unfired, providing inertia, reactive power, fault-current contribution, and voltage support during non-dispatch periods without adding a clutch or major mechanical redesign

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Aging fleets, tight supply chains put user collaboration to work

The Alstom Owners Group (AOG) serves the global community of Alstom gas and steam turbine power generation equipment owners and operators. This group began in 2018 as a private user organization and has gained widespread support from third-party service providers, parts specialists and industry experts.

Sponsors were ABB, Arnold Group, Camfil Power Systems, GE Vernova, Groome Industrial, Liburdi, Hughes Technical Services, MD&A, National Electric Coil, Sung-Il Turbine, and TRS Services.

The 8th annual meeting was held July 15-17, 2025, in Niagara Falls, NY. Attendees came to learn, to share, and to network, because networking has become an operational necessity, not a conference perk. Three days of presentations, hallway conversations, and a vendor fair provided plenty to report back.

Below are selected highlights and key takeaways from that event.

DAY 1 – END-USER DISCUSSIONS

Jeff Chapin, Liburdi Turbine Services, began with a dramatic overview: "We are slammed! And the big issues now are tariffs and uncertainty." The "uncertainty" would resonate throughout the conference, uncertainty on the part of both owner/operators and parts/service providers.

This initial discussion led to some interesting data points: Some parts orders now take three to five years. One example: EV burner at 99 weeks. Turbines can take five years. And some operators are now facing more starts in the past two years than we have ever had. Very few participants said they are operating base-load units.

And "we all need people."

Parts were a key discussion topic. Attendees noted that obtaining parts has become much more difficult, and some OEMs are not even bidding certain parts. "If you have spares, keep them" was a common response.

2026 Conference and Exhibition

July 28-30
Houston Marriott Marquis
Thursday shop tour hosted by TRS
www.aogusers.com

Steering committee

- Kristi Gledhill, Capital Power
- Ross Goessl, We Energies
- Danny Slade, FMPA Sand Lake Energy
- Chris Hutson, K-Machine
- Jeff Chapin, Liburdi Turbine Services

Attendees also offered more communication among themselves (and the OAG Forum) to help the spare parts dilemma. "Networking is our top goal" became the conference theme.

Use of third parties: Most are using them, especially at commissioning. The OEM even uses third parties, some said. Reliance on third parties will become more important moving forward.

Some of the biggest operational issues are end-of-life determination, parts obsolescence, and parts availability.

Submitted questions were also a key element of day one, and throughout the conference as time allowed. Questions could also be submitted during the conference. Some submitted question and discussion examples:

- Excitation and other control upgrades.
- Replacing static switches.
- Flame detection issues.
- Vane and blade supply.
- Upgrade lessons learned, e.g. 11N1 to M.
- Exhaust temperatures and systems.
- Bearings (sources).

One significant reminder was availability of the AOG Owners Forum, available via https://forum.aogusers.com/. This forum is a private online community of Alstom turbine owners enabling individuals responsible for plant repair, operations, and maintenance to communicate directly and securely with each other. This is the online 24x7 extension of this already successful and growing annual conference.

End-user presentations

Kristi Gledhill, plant manager, Midland site, opened the user presentations with a look at cleaning old base-load heat recovery steam generator (HRSG) units at Capital Power's 1500 MW Midland Cogen Venture in Michigan (Fig 1). "HRSG leaks were the number one cause of maintenance outages," she said. Gledhill is plant manager, Midland site.

She discussed using the Pressure Wave explosive tube-cleaning process on Unit 10. Coking had become a major issue.

Midland evaluated historical outages, tube leak locations, and estimated costs per year due to the leaks. Root causes were:

- Thermal fatigue – cycling.
- Flow-accelerated thinning – water side.
- Long operating life degradation.

Between 2022 and 2024, Midland experi-

1. Midland Cogeneration Venture, Capital Power

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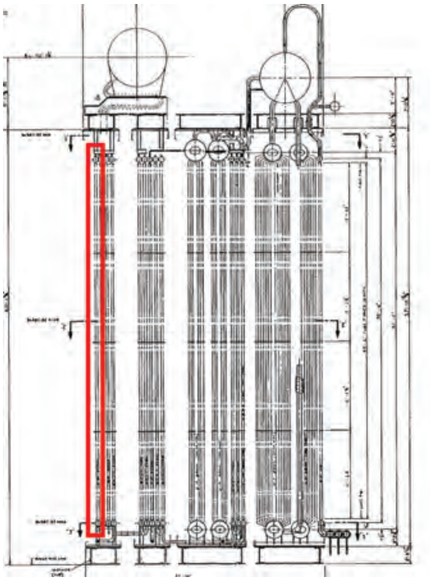


2. LP preheater at Midland

3. LP preheater damage at Midland

4. LP preheater repair method at Midland

enced 115 HRSG tube leaks. More than 65 percent occurred in the LP preheater. See Fig 2. This was the first significant cleaning in 35 years, and will now be conducted in as little as 3 years.

The cleaning was successful, Gledhill explained. Debris analysis included rust and insulation, but she cautioned that "you will never get all of the insulation out; it can be unforgiving."

An interesting takeaway: "Next time we will alert the neighbors to the noise. We got some calls."

Eric Wolf, Capital Power, returned to these issues later on Day 1. He discussed tube leaks on these 12 Combustion Engineering HRSGs, in operation for 35 years but now causing four forced outages per year.

"Butt welds break apart over time," he explained, following failure analysis by Structural Integrity. The problems stemmed from both weld procedures and post-weld heat treatment on these older units. See Fig 3.

Structural Integrity was contracted to perform detailed tube section failure analysis. Based on their results, repairs began. Quarter-chrome sleeves (Fig 4) are now being used in some locations. Baffle plate condition was also discussed and reviewed in detail.

Ross Goessl, We Energies, next discussed *Blow off valve control upgrade (GT11NM)* at a Midwest utility (see Fig 5). He covered project need, project scope, execution, emergent findings, and next steps.

In this case, "Blow off valves on multiple units stopped opening fully within three years of the major, resulting in the plant needing to force the open indication." This became a complex, multi-unit issue throughout 2024. Proximity switches failed and were sourced through the AOG Users Group. Further issues developed and workaround ideas were also found through the Users Group.

The plant pursued a valve indication upgrade from Hughes Technical Services (HTS). This involved fiberoptic sensors, reflective coating on indicator arms, additional thermocouple feedback at each stage, and a new control junction box. Extensions were added to the valve indicator flag arms to pick up open indications more quickly. See Fig 6.

The plant also pursued the HTS blow off valve control upgrade which replaced the hydraulic pneumatic safety relay with separate power-oil and control-air systems with solenoid-operated valves and pressure switches, and replaced the control air pressure regulators. Cast iron drain traps were replaced with automatic drain valves.

Work was completed during a seven-day planned outage, including commissioning. This work would be performed on the remaining units.

At this point in Day 1, more submitted questions were discussed including: EV burners and ignitors, filter house additions, system historian, inspection intervals, compressor guide vane inspections, FME programs (company vs contractor), GT11N training for new people, warm starts reliability, risks of remote monitoring, auxiliary system upgrades, and bearing temperature limits.

The day ended with a GE Field Service presentation by Jim Vono, GE Vernova, featuring a virtual/live-outage demonstration.

He noted that GE Field Service maintains nearly 40 people globally handling 15,000 questions per year as a "front line."

DAY 2 – SERVICE PROVIDER PRESENTATIONS AND DISCUSSIONS

MD&A

James Joyce, Director of Operations–Generator, at MD&A (Mechanical Dynamics &

5. GT11NM blow off valves

6. Extensions added to BOV indicator flag arms

Analysis) presented *Alstom rings-off inspection* focusing on the generator field, usually paired with a stator major inspection. This often involves field shipment to a repair facility (Fig 7).

Joyce explained incoming runouts, 3D scanning, visual and electrical testing, shrunk-on component removal (blower hubs and retaining rings), duplicate electrical and thorough visual inspection, and borescope inspections of main leads, upper slot components, blocking and end winding, and slot liner/armor. Potential repair areas are upper slot component damage and turn insulation migration, among others. He offered visual details of a single-coil rewind (Fig 8).

Details of each were presented, concluding with a discussion of shrunk-on component installation and high-speed balance. When asked if retaining rings were re-used, he answered "normally, yes."

TRS

Jared Morace, TRS Services (Turbine Repair and Support), followed with *Reviving Alstom: Advanced repair solutions for GT11 and GT13 gas turbines.*

Morace stressed that, working with Hughes Technical Services (HTS), the company provides a comprehensive Alstom repair and maintenance alternative.

Developments and repair capabilities focus on hot gas casings and furnace capital projects as well as vanes, blades, and turbine vane carriers. He featured hot gas casing modeling and fixture design.

One highlight was the TRS furnace capital project capable of heat treating up to GT13DM hot gas casings and lower combustor chambers while assembled, withstanding temperatures up to 2300F. See Fig 9.

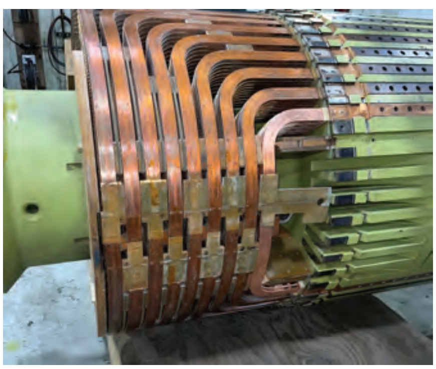
He then offered examples of completed GT11 and GT13 repairs.

Groome

Matt Cohen, Groome Industrial Service Group, then discussed *The importance of catalyst cleaning and maintenance.*

Factors that lead to non-ideal performance, he explained, are non-uniform gas flow, non-uniform NH3/NOx ratios, non-uniform temperature, catalyst deterioration, and various plant operations (including load changes). Groome often works with Environex for testing and tuning.

7. Alstom generator field



8. Generator field coil installed

9. TRS furnace

He offered cleaning examples for CO catalysts, SCR catalysts, and ammonia injection grids.

Groome provides a wide variety of services including tube cleaning and repairs, welding, and labor support.

Sung-Il

Ta-Kwan Woo was on hand again this year to discuss *Blade manufacturing technology* available from Sung-Il Turbine, Busan, South Korea (Fig 10). Business lines include turbine parts (blades, vanes, segments), combustor parts, and hot gas path repair services.

He stressed the company's ongoing research and development. Capabilities include vacuum casting furnaces (vanes and blades, combustor and turbine parts), machining and heat treating, in-house ceramic core manufacturing, and thermal barrier coatings. Also, hot gas path parts repair services, inspections and evaluations are extensive at Sung-Il.

Questions included parts lead times and expected life of spare parts.

More than just insulation

Norm Gagnon, Arnold Group, joined to discuss, primarily, steam turbine warming systems using insulation and high-performance heating systems, designed largely for reduced startup times.

More specific goals are to conserve thermal energy following shutdown, control turbine casing top-to-bottom temperature differential, manage differential expansion, and improve turbine casing monitoring and diagnostics for condition-based maintenance programs.

He offered case studies highlighting stress reductions and operational savings (startup reliability and fuel savings). Gagnon also highlighted operational controls and shutdown data analysis. He ended with a view of HRSG warming (downcomer heating) in cooperation with Duke Energy, Competitive Power and EPRI. This information was new to many attendees.

National Electric Coil (NEC)

W. Howard Moudy, Managing Director, NEC, discussed *Generator rotors*.

The key word is "cycling," he said, causing "monumental problems for generators." Focusing primarily on smaller and larger air-cooled generators, he listed known Alstom rotor issues that include:

- End winding blocking/spacer block looseness and movement.

10. Sung-Il facility, Busan, South Korea

- Top turns conductor distortion.
- Slot liner cracking.
- Conductor turn joint cracking and failure.
- Pole-to-pole crossover cracking and failure.
- Main lead failure.
- Damper winding cracking and finger liberation.
- He then listed key rewind specification recommendations:
- New pole-to-pole connectors.
- New baffles.
- New retaining ring liners.
- High speed balance with overspeed, running electrical testing, and balance.

He reviewed conductor and slot configuration, copper conductor crushing and distortion, rotor conductor distortion, slot liner cracking, turn-braze joint configuration thinning and fatigue, and turn-braze joint failure.

Further details showed crossover failures, damper winding alignment finger liberation, and examples of negative sequence current. "Heat generated by negative sequence current events," he said, "can damage a rotor very quickly."

He followed with visuals of a generator rotor rewind in process. Moudy then moved to retaining ring repairs and replacement.

He stressed that the "copper supply chain is challenged," then summarized as follows:

- The pedigree of installed Alstom fleet of generators is wide and deep.
- A large portion of the fleet is at or past the 30-year design life milestone, and should be considered for life extension.
- While the Alstom rotor fleet has known challenges, those challenges can often be effectively overcome by applying proven engineering solutions, experienced labor, and diligent planning.
- Market challenges relating to skilled labor, facility availability, and key materials are important considerations which should NOT be ignored.

Camfil Power Systems: Filters and filtration.

Dakota Murillo, Camfil Power Systems, addressed his company's "Intelligent air solutions for maximum predictability and

11. Attendees treated to a closer look at Liburdi's gas-turbine component repair, damage-analysis methods, and advanced welding automation systems minimum complexity" applied to turbomachinery. As he stressed, "Ninety percent of what goes into your combustion turbine is air."

He first focused on air filtration and noise control, stressing the need to consider ambient conditions, temperature, humidity, and seasonal factors. He then moved to the impacts of operating modes, maintenance intervals, geographic location and fuels.

Filtration discussion included the impact of fouling and static pressure drop, and Camfmil's ability to analyze both new and used filters to determine performance options.

One feature was Power Eye online analysis for filter life prediction and optimization as well as gas turbine performance.

He then reviewed Camfil's systems for air intake, silencers, heating and cooling, ventilation, and support structures.

ABB Controls

George Vale, Kevin Kochirka and Ralph Porfilio, ABB – Energy Industries, discussed *Turbine control modernization*.

Key improvements include enhanced redundancy, high performance efficiency and faster response, increased flexibility, and advanced diagnostics.

They covered fully integrated turbine controls, turbine protection systems, valve positioning, synchronization and condition monitoring,

They ended with a mechanical and hydraulic overview and a look at innovative hydraulic capabilities.

HTS

Bill McDonald, Hughes Technical Services (HTS, an AP4 company), concluded the day with *Commissioning and mechanical solutions to optimize reliability and performance.*

HTS was formed in 2014 by former ABB/Alstom engineers and others with extensive experience in power generation and widely considered the the "go-to" field services organization for these units.

Focuses were on commissioning, consulting and engineering, flame and pulsation monitoring, and controls upgrades.

Working with TRS, Hughes offers parts refurbishment, repairs and testing including hot gas casings, vanes, blades, heat shields and others.

He also discussed Voith overhauls and valve servo upgrades, HRSG tuning, and control system and mechanical system training.

DAY 3 AND BEYOND

The conference concluded with a tour of Liburdi's nearby facilities in Ontario, Canada (Fig 11). More than 35 conference attendees visited Liburdi Turbine Services and Liburdi LAWS in Dundas for a behind-the-scenes look at the company's gas-turbine component repair capabilities and advanced welding automation systems.

Attendee comments point out the value of the visit, including "Didn't know y'all did so many different things," and "Good to see top-notch engineering going into flight parts." Liburdi thanked the AOG and participating owner/operators for the opportunity to host the group and support continued technical exchange outside the meeting room.

For those who were not there, the AOG discussion forum at forum.aogusers.com remains active between conferences. It is a private online community of Alstom turbine owners and operators, and it is the most direct way to connect with peers who are running the same equipment you are. If you have not joined, the conference makes a strong case for why you should.

The 2026 conference will take place in Houston, July 28-30, and details are posted at aogusers.com. Based on what was seen and heard this year, expect it to draw an even larger crowd. The fleet is aging, the supply chain is unpredictable, and the people who show up to these events are the ones who figure out how to keep their plants running. That is the value of the AOG. CCJ

Hanwha Power and the new value of the installed fleet

The recent rebranding of Power Systems Manufacturing LLC (PSM) to Hanwha Power is not a cosmetic move. It is a signal that the gas-turbine aftermarket has become strategic again, and an aggressive growth plan paired with innovative engineering is needed to keep up with unprecedented demand.

At January's PSM Asset Managers Conference, a few months before this announcement, the message was consistent from the opening session forward: the industry is not waiting for a wave of new machines to solve its near-term capacity problem. It is leaning harder on the fleet already cranking out MWs. That changes the value of retrofit work, rotor planning, controls freedom, combustor flexibility, and field execution. It also explains why Hanwha wants one brand wrapped around equipment, auxiliary systems, and service support.

Jeff Benoit, VP of clean energy solutions, put the market backdrop in plain terms. US power demand is no longer flat. Data centers, electrification, chip manufacturing, industrial load growth, weather stress, and fuel-price volatility are reshaping planning assumptions. He cited a US gas-turbine fleet approaching 600 GW of installed capacity, with gas supplying 43% of US electricity in 2024 and about 40% in 2025. He also pointed to roughly 90 GW of gas-turbine orders globally in 2025, including about 31 GW booked in the US through the third quarter.

Those numbers matter less as bragging points than as a warning. If new equipment, transformers, and EPC capacity are tightening at the same time, owner/operators will have to extract more from the machines they already own.

That is where the fresh leadership change starts to matter. Rafi Balta, CEO, introduced himself not as a brand steward but as an aircraft-engine mechanic who moved through maintenance, engine sales, and supply chain. That background fits the assignment. Hanwha Power needs to balance expansion with disciplined execution in a market where service slots, parts, and manufacturing capacity are getting harder to secure.

Balta

Chris Johnston, COO, reinforced that point by describing a wider support footprint in Florida, Houston, Maine, the Netherlands, and Abu Dhabi, along with tighter coordination inside Hanwha. His case was that the company intends to support the existing fleet for the long haul, not just sell isolated upgrade packages.

The passionate engineering heritage and evolution continues with its persuasiveness. Johnston outlined upgrade paths that can raise output by 10% to 15% in a representative 1x1 CCGT application, expand turndown, and use digital tools to support startup, ramping, and movement across a wider operating range.

Luis Rodriguez, VP of engineering, added the hardware detail. GTOP 4 on the 7F side combines a redesigned HGP, single-crystal first-stage hardware, modular additively manufactured vanes, and improved materials, with simple-cycle output moving into roughly the 195- to 207-MW range depending on baseline and scope. On the 501F side, GTOP 7XT pushes better cooling and durability into second-stage vane regions that become limiting as firing temperature rises. FlexSuite is aimed at another real constraint, controller lockout, by making aftermarket logic portable across multiple control environments. None of that is trivial engineering.

Just as important, the conference did not hide the weak spots. Rodriguez walked through FlameSheet development issues, including combustor dynamics, emissions tradeoffs, cold-fuel sensitivity, seal wear, and sleeve-resonance concerns; then showed the fixes being rolled in. He also answered a basic low-load question honestly: deeper turndown carries a heat-rate penalty.

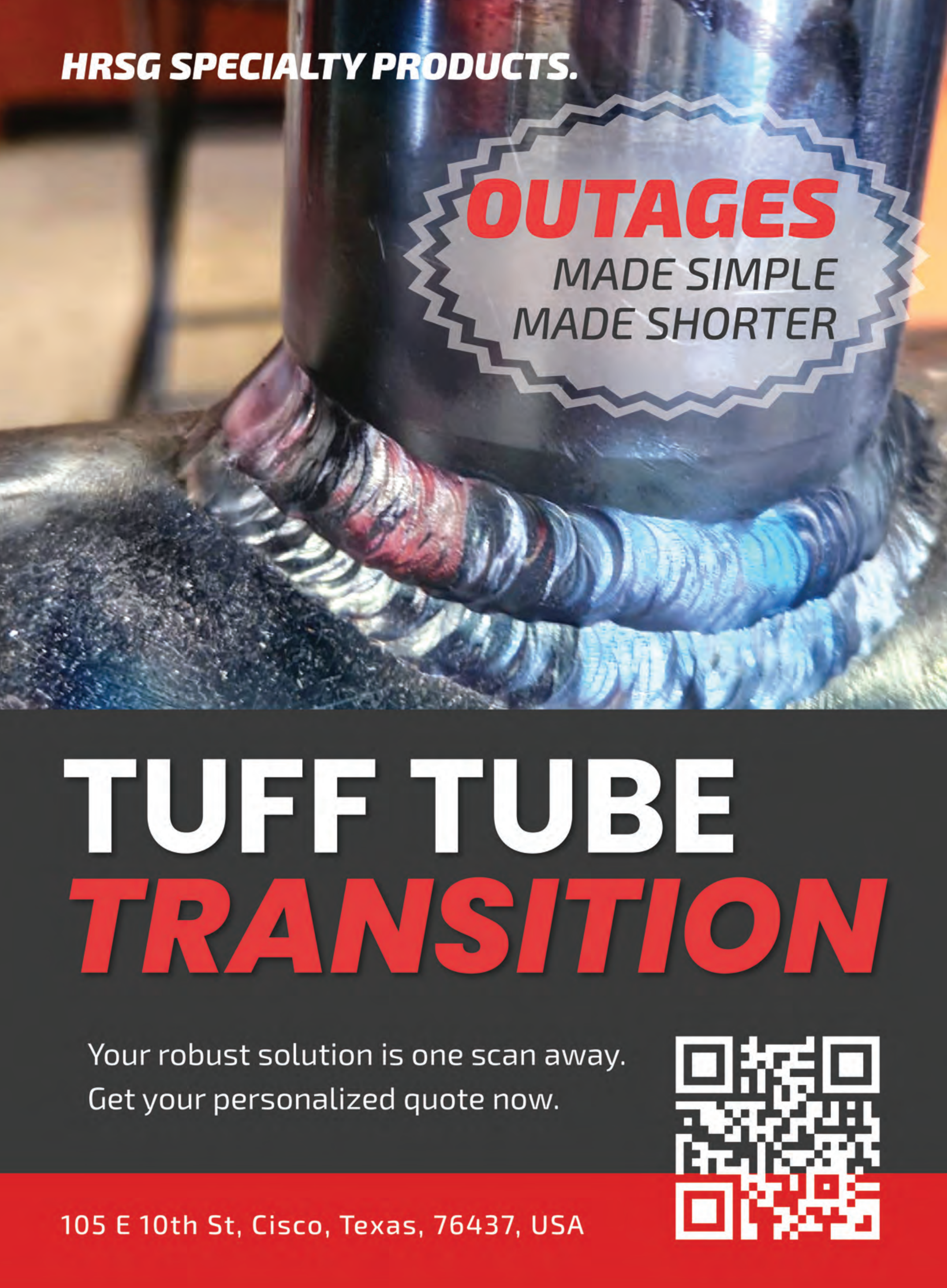
The balance-of-plant discussion made the same point from a plant perspective. A gas turbine may be ready for more output or faster ramps, but the HRSG, steam system, condenser, bypass valves, controls, and BFPs often set the first hard limit. That is a useful reminder in a market that likes to talk about megawatts before it talks about block capability.

A panel session of market experts widened the caution flag. Rotor queues are filling into 2028 and 2029. Nickel hardware, forgings, machining, and shop access are measured in years, not months. Workforce depth is thinning across plants, OEMs, EPCs, and service firms. Claims investigators are still seeing equipment pushed past effective end of life and human-performance issues that experienced staffs once would have caught.

Hanwha Power's timing, then, is the point. The market needs new capacity, but it also needs practical, near-term answers for the installed fleet: more megawatts from proven assets, wider operating windows, faster starts and ramps, improved parts durability, greater controls independence, and service execution that recognizes how constrained the outage, rotor, and supply-chain environment has become.

If Hanwha Power can pair its growth ambitions with disciplined implementation, its value will not be measured only in rebranding or market share. It will be measured in how effectively owner/operators can convert existing gas turbines into more capable, flexible, and profitable assets at the exact moment the grid needs them most. CCJ


cutit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Maximizing the lifespan of CO catalyst

For many gas-turbine users, CO-catalyst trouble shows up first as a compliance headache: stack CO starts climbing at low load, differential pressure changes, and the plant is forced to decide whether it is looking at a cleaning issue, a system issue, or end-of-life catalyst. That decision now carries more economic weight than it did a few years ago. During a recent webinar hosted by Groome Industrial Service Group and Environex, Inc, presenters Jason Sobotik, Andy Toback, and Ryan Esposito argued that operators should not jump straight to replacement. Their message to plant managers and OEM engineers was practical: diagnose the failure mode first, because a chemically targeted rejuvenation wash can, in the right case, restore CO-catalyst performance at a fraction of replacement cost.

What follows is a recap of the webinar presentation. For those interested in diving deeper, the nearby QR code can be scanned to access the on-demand recording.

The economics alone justify a harder look. Sobotik said a new CO catalyst for a frame-size unit can approach $750,000, with platinum pricing remaining the main cost driver. By comparison, he put a representative rejuvenation-wash project at roughly $250,000, creating a potential savings of about $500,000 before accounting for derate risk or lost generation. Lead time widens the gap. Where replacement once might have taken only a few months, webinar speakers said current lead times are more typically 10 to 12 months, while a rejuvenation project can be executed as soon as an outage window and logistics are in place.

That does not mean every weak catalyst should be washed. The first technical point in the webinar was that poor CO performance often starts with conditions outside the catalyst chemistry itself. Sobotik pointed to physical fouling, bypass, and deactivation as the three main buckets operators should separate. Fouling raises differential pressure and blocks exposed surface area, reducing the number of active sites available to oxidize CO. It also can drive erosion when insulation particles or boiler rust lodge in the passages and abrade the washcoat. Bypass tells a different story. Bad gasketing, damaged seals, loose modules, or holes in the catalyst can let gas take the path of least resistance, producing poor conversion without the same DP signature. Deactivation, by contrast, is a chemistry problem and is where the rejuvenation discussion begins.

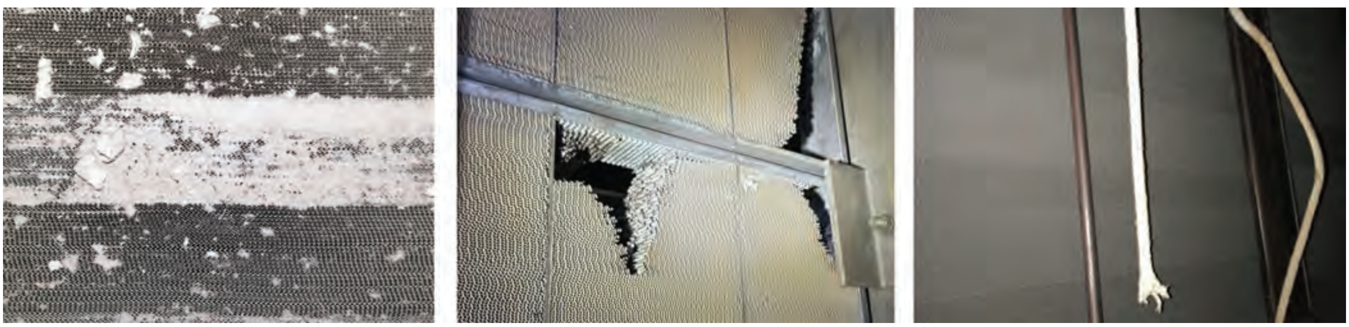
Toback explained the mechanism in simple terms. A CO catalyst works by oxidizing CO and unburned hydrocarbons to carbon dioxide and water on a thin washcoat applied to metal or ceramic foil. Most of the action happens in that porous coating, not in the substrate. If the pores are blocked by deposits, performance falls because mass transfer is restricted. If platinum active sites are contaminated by sulfur, zinc, or phosphorus, performance can fall for a different reason. The shape of the catalyst light-off curve can help distinguish the two. A generally depressed conversion curve may indicate fouling or removable contamination, while a shifted curve can suggest more permanent poisoning or aging. That distinction matters because wash viability depends on what is actually sitting on the catalyst surface.

The webinar's strongest examples came from lab test results. Environex simulates actual exhaust conditions using plant-specific inputs such as oxygen level, temperature, exhaust flow, and catalyst volume, then measures conversion across the operating range. In one case, a poorly performing catalyst that was missing a roughly 70% conversion target responded to acid washing and returned to near-fresh performance. In another example, hot-acid and base-plus-acid washes pushed conversion back above the plant's requirement after the original sample had fallen well short. But presenters also showed failed studies. Some samples saw little or no improvement after water, acid, or combined washes. Their point was blunt: blindly washing a catalyst is not a strategy; testing is.

Esposito then walked through what that means at the plant. His recommended sequence was to use the next planned outage to perform mechanical cleaning, inspect seals and hardware, and pull a representative sample for testing. Turnaround for the initial catalyst test was presented as roughly six to eight weeks, with another four weeks for a rejuvenation study if the sample looked like a candidate. If the answer is no, the plant can move toward replacement with real evidence. If the answer is yes, the plant can often schedule a field wash in the next outage instead of waiting most of a year for new catalyst.

Field execution has its own details. Groome said a typical project needs a staging area of about 50 x 50 ft, containment for wash operations, and a plan to minimize module handling. On some units, catalyst modules are hand-carried through lower access doors, so scaffolding and lift paths have to be thought through early. Esposito also flagged hardware condition as a recurring issue. On studded-frame designs, plants may be able to reuse many washers, but damaged studs often need replacement. Retaining-bar designs bring their own handling constraints. None of this is complicated in theory, but all of it can burn outage time if ignored.

The follow-up action for users is straightforward. If stack CO is rising, do not assume replacement and do not assume cleaning alone will solve it. Use outage access to gather information: inspect for fouling, check for bypass paths, verify hardware condition, and pull a catalyst sample before the unit closes up again. For plant managers, that creates an evidence-based economic decision. For OEM engineers, it creates a cleaner technical basis for deciding whether the problem is mechanical, chemical, or both. The webinar's bottom line was credible because it avoided overselling the wash option: rejuvenation is not universal, but when testing shows the right contamination mechanism, it can buy back meaningful catalyst life, avoid long replacement lead times, and protect compliance at much lower cost. CCJ



Physical fouling, flue-gas bypass, and catalyst deactivation can reduce CO conversion, increase differential pressure, disrupt flow distribution, and accelerate localized catalyst damage. Common contributors include gasket failure, loose or damaged modules, wash-coat failure, and poison accumulation.

Beyond the turbine: Managing the CCGT new unit and retrofit boom

The 2026 HRSG Forum returns to The Woodlands, Tex., July 20–23, with a program aimed at the issues now shaping CCGT projects and existing HRSG fleets: new unit builds, construction execution, material selection, cycle chemistry, inspection, and the effect of gas-turbine upgrades on downstream equipment.

The meeting is scheduled for The Woodlands Waterway Marriott Hotel & Convention Center. Registration is open, and the conference welcomes end users, OEMs, service providers, consultants, and other participants involved in HRSG-equipped powerplants.

Why attend? Practical exchange amongst all stakeholders.

The value proposition for attendees remains the forum's broad, technical mix. Recent HRSG Forum programs have brought together end users, HRSG manufacturers, service providers, consultants, designers, and fabricators for practical presentations, question-and-answer sessions, and facilitated discussion.

That structure matters in 2026 because HRSG reliability questions increasingly cross traditional boundaries. New-build design decisions affect commissioning and maintainability. Gas-turbine upgrades can change exhaust conditions and thermal response. Cycle chemistry and drain-control issues can produce failures that appear mechanical at first inspection. The agenda reflects those interdependencies by pairing presentations, panels, open-floor discussions, and exhibit-area networking across the four-day program.

MONDAY: TOUR AND FIRST VENDOR FAIR

Monday is organized as a tour day, including an interactive visit to the GE Vernova Houston Learning Center, followed by the vendor fair and networking reception in the exhibit area. The tour should give attendees direct exposure to the training environment supporting gas turbines, steam turbines, generators, controls, and related service work.

For HRSG Forum attendees, the tour has added relevance because many agenda topics sit at the interface between GT capability and HRSG duty. Training assets and hands-on environments provide a useful backdrop for discussions about upgraded GTs, controls, startup behavior, and the resulting pressures on downstream heat-recovery equipment.

NEW CONSTRUCTION, CONSTRUCTABILITY, AND MATERIALS

Tuesday's program opens with a market update, then moves into HRSG design evolution and constructability. The agenda includes a discussion of the owner's and contractor's roles in constructability, a panel on new construction lessons, a low-load operation presentation, a materials/new-build topic, and a material-selection panel.

The timing is appropriate. New combined-cycle projects face the familiar technical questions of pressure-part design, catalyst access, drain systems, bypass equipment, and maintainability, while also facing newer concerns around supply chain, material availability, and construction sequencing. The program is designed to bring those issues together, not treat them as isolated procurement or engineering decisions.

Tuesday also includes sessions on alternatives to isolation-valve hardfacing and design-for-maintainability lessons from HRSG and catalyst cleaning in advanced-class combined cycles. Those topics connect early design choices to future outage duration, access planning, and maintenance cost.

CHEMISTRY, INSPECTION, AND DAMAGE MECHANISMS

Wednesday's program turns to several recurring HRSG reliability concerns: damaging thermal transients, film-forming substance application, pressure-part failure analysis, liner and exhaust-diffuser repair or replacement, HRSG cleaning, and bypass-valve wet-steam erosion.

Cycle chemistry remains central to those discussions. Prior HRSG Forum coverage has grouped chemistry impacts into tube damage and failure mechanisms, corrosion-product transport, and steam-turbine deposits or damage. The 2026 agenda's focus on film-forming substances and failure analysis should help attendees connect chemistry program decisions to inspection findings, metallurgical conclusions, and corrective actions.

2026 Conference and Exhibition

July 20-23
The Woodlands, TX

Steering committee

- Scott Wambeke, Xcel Energy
- Albert Olszewski, Constellation Energy
- Michael McCartney, ExxonMobil
- Nick Ruscillo, CAMS
- Bob Anderson, moderator
- Barry Dooley, moderator

Special guests

- David Addison, Thermal Chemistry Ltd
- Tom Freeman, Gas Turbine Coach, LLC

GT UPGRADES AND DOWNSTREAM HRSG EFFECTS

Thursday's agenda focuses on the combined-cycle system as a whole. Sessions include commissioning of automatic high-pressure superheater and reheater drain control, GE Vernova experience with aging-fleet reliability issues, electrode-boiler technology, gas-turbine exhaust-diffuser replacement case studies, the Duke Osprey GT upgrade case study, and planning for GT upgrades while managing effects on HRSG equipment and operations. The day closes with a GT-upgrades panel.

This is a practical emphasis for owner/operators evaluating uprates, component replacements, controls changes, or emissions-related modifications. A GT upgrade can improve output or operating flexibility, but it also can shift HRSG inlet conditions,

startup gradients, attemperator duty, drain behavior, casing and liner exposure, and bypass-valve service conditions. The agenda's structure gives attendees a chance to consider those effects before the outage plan is fixed.

VENDOR ACCESS AND OPEN PARTICIPATION

The forum also provides concentrated access to more than 50 exhibiting vendors that support HRSG maintenance, inspection, cleaning, component repair, construction, controls, valves, chemistry, and outage execution. Exhibit time is built into receptions, breakfast, breaks, and lunches, giving attendees opportunities to test technical questions against multiple service approaches.

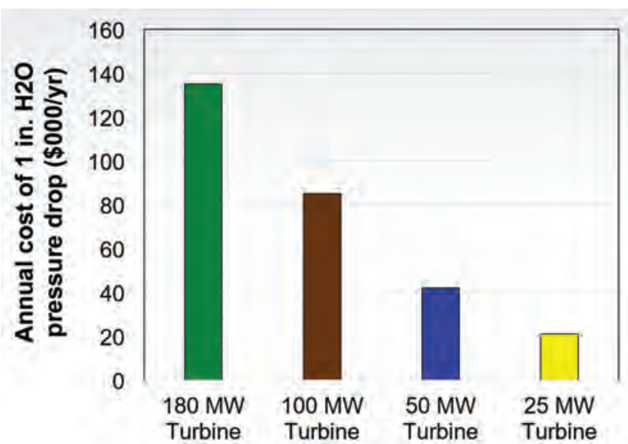
The conference is open to end users, OEMs, service providers, consultants, and others with a role in HRSG-equipped plants. There are no "closed" sessions.

CALL TO ACTION: BRING PLANT-SPECIFIC QUESTIONS

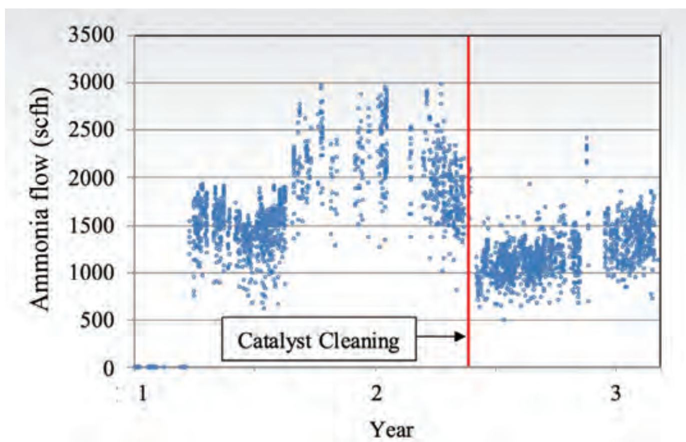
Attendees will get the most value by arriving with specific plant questions. The world's foremost experts will be on hand to answer them. Useful preparation includes recent cycle-chemistry data, inspection findings, drain and attemperator operating history, gas-turbine upgrade assumptions, unresolved materials questions, and lessons from current or planned new-build work.

HRSG FORUM 2025

HRSG Forum 2025 was held in July at The Woodlands Waterway Marriott, The Woodlands, TX. This included a full-day workshop, two days of owner/operator and service provider discussions, a day of EPRI Technology Transfer, and a final-day tour of ValvTechnologies in Houston. The Forum was again co-chaired by Bob Anderson,



1. Annual cost of 1 in. pressure drop by turbine size



2. SCR catalyst cleaning results

Competitive Power Resources, and Barry Dooley, Structural Integrity Associates.

Sponsors for 2025 were Precision Iceblast, EPRI, ValvTechnologies, GE Vernova, Zepco, Tuff Tube Transition, Arnold Group, Gas Path Solutions, SVI Bremco, Vector Systems, DEKOMTE, Nooter/Eriksen, Environex, Structural Integrity, Groome Industrial, Vogt, Millennium, and Vogt Power International. CCJ is the journal of record.

Bob Anderson stated the following: "What truly sets our Forum apart is the active participation of the entire HRSG ecosystem: users, OEMs, service providers, consultants, and component suppliers. Non-users are not only welcome – they are essential to the success of this event."

All participants were invited to all discussions, presentations and activities. Also note that previously-submitted and on-site-submitted questions and concerns were discussed in detail throughout the week-long event. More than 50 product and service exhibitors were also present.

DAY 1 WORKSHOPS

Day 1 workshops focused on emissions control systems, state of the industry, and gas turbine upgrade impacts on HRSG systems.

EMISSIONS CONTROL

Ryan Esposito (Groome Industrial) and Andy Toback (Environex) began with *Managing and monetizing your emissions control system*, conducted in four sessions: emissions systems economics, catalyst system evaluation, system maintenance, and a case study on complete system evaluation.

They began with an overview of SCR, CO and CEMS systems in a typical installation, a solid overview of components and common terminologies (including ammonia injection). They then discussed backpressure (exit gas velocity effect on pressure drop) and typical pressure drop cost to plants (Fig 1).

They continued with typical current capital and operating costs of SCR and CO catalysts with F-class turbine examples. This section ended with a look at how the overall system works, and primary considerations for design and operation.

Questions and discussions included impact of fuels, use of dual catalysts (SCR and CO), and optimization vs cost insights.

Session two focused on catalyst system evaluation, beginning with a chemistry review and a look at preferred SCR and CO catalyst temperatures. Typical dual-function configurations (and performance) were discussed.

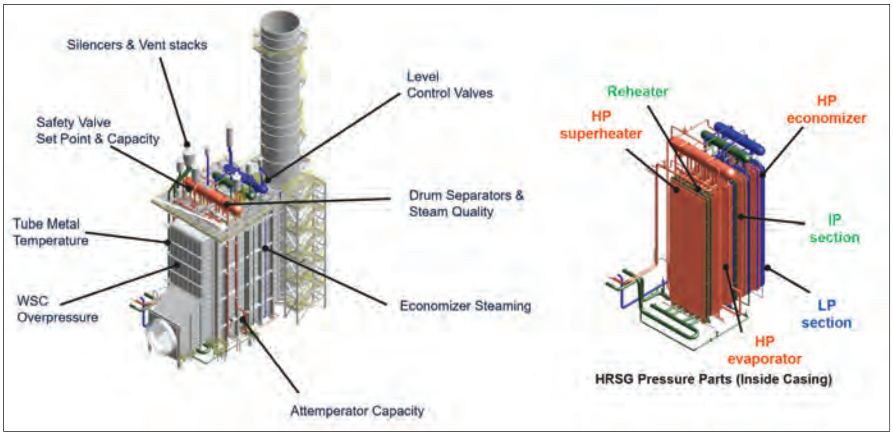
An interesting analogy: dual-function catalysts are similar to all-season automobile tires, which have limited functionality at the extremes.

Visual inspections followed, noting the most common catalyst types, beginning with CO catalyst plugging, pressure damage and frame migration. Next was the ammonia injection grid (AIG) showing grid, nozzle and lance plugging, and flow-control unit and riser deposits. Common SCR catalyst types were next with discussions on plugging, brick shifting, seals and bypass. Esposito then held a session on system maintenance and cleaning for CO, AIG and SCR (Fig 2).

Attendee questions included the impacts of cycling, catalyst cleaning schedules, outage durations, and the impacts of cleaning on downstream HRSG components and total backpressure.

SCR and CO replacement discussions followed including methods and typical work processes. For SCR there was an emphasis on additional sealing to minimize bypass. Presenters noted that "Top seals are critical, but adding a pillow seal (Fig 3) can further help prevent bypass around the catalyst frame." CO replacement methods and tim-

3. Pillow seals can help prevent bypass around SCR catalyst frame



4. Focus areas for HRSG assessment

ing were then shown.

AIG cleaning and tuning followed, stressing that proper tuning is an iterative process. "It takes time for the AIG/SCR system to achieve steady state after valve adjustments," Toback noted. This ended with a discussion of a permanent sampling grid (both benefits and potential pitfalls).

Session 4 was a case study for complete emissions system evaluation.

ENERGY'S GREAT AWAKENING

Tom Freeman, Gas Turbine Coach LLC, followed with *Energy's great awakening: simplifying drivers and impacts*. He summarized his talk as "An agenda of threes."

- Three industry bubbles.
  - Bubble #1 1965-1975, following first Brayton gas turbine in 1949.
  - Bubble #2 1995-2005, following natural gas deregulation in 1980.
  - Bubble #3 2025-2040, following Clean Energy Standard Act of 2012.
- Three industry streams (supply chain).
- Three megatrends.

Supply chain: New builds are being approached with the same raw materials and suppliers. Existing assets have the same casting and forging houses. And heavy industries have the same installation and craft expertise. Hovering above, stated Freeman, is "a tropical storm named datacenter, stalled over the top."

Megatrends: Three megatrends are in focus: asset age, load growth rate, and resource adequacy.

He then looked at the impact of data centers in what he called "visualizing demand." If someone on their home computer asks the question, "What is the appeal of a Ford F150 truck?" This one search uses 0.3 watt-hours of electricity. If the question is, "What about the appeal of a Ford 150 for post-midlife crisis individuals living in the suburbs? (looking for answers like image, comfort, adventure, etc.) the search uses ten times the power, or 3 watt-hours of electricity. And finally, if the query is "Create an image of a post-midlife crisis person contemplating buying a Ford F150," the power required increases to 10 watt-hours, or more than 30 times the original search.

This is background for the current datacenter boom. As Freeman pointed out, "This activity along with computer games at night, with no solar backup, makes it worse!"

To the younger people in the room, he summarized this as an historic challenge, and told them "Don't go anywhere!" meaning, your jobs are in a good field.

One interesting follow-up discussion dealt with the need for system upgrades. One important point: historical upgrades focused on base load; now they have to focus on cycling.

GT UPGRADES

Karl Stevens, GE Vernova, followed with *The anatomy of a gas turbine upgrade* focused on HRSG improvements. He looked at the key areas for HRSG assessment, beginning with the fundamentals (Fig 4). Case studies followed for HRSGs with and without duct firing.

Stevens then held a session on *Upgrades for flexibility, reliability, and GT upgrades*. This included a section on pressure part replacement. A number of specific questions followed including piping, valves, and the benefits of modeling.

Marc Babine and Katie Koch, PSM, discussed *The impact of gas turbine upgrades on total balance of plant*. They began by reviewing turbine upgrades and options, and modifications to achieve wider operating profiles.

This covered, in detail, HRSG systems including pressure parts designed to support elevated pressures, condenser reliability, gas-side pressure drop, controls, and reduced heat rate. Emissions were also covered.

Vignesh Bala, Vogt Power, followed with *Anatomy of a retrofit – planning and execution*.

He began with Vogt's GT upgrade studies including thermal and mechanical analysis. Vogt is an HRSG OEM that has expanded into retrofits and services, regardless of OEM. This includes GT upgrade studies, inspections/diagnostics, planning and engineering, material upgrades, fabrication, delivery, and outage services including constructability.

Bala covered planning and engineering, replacement-in-kind vs redesign, and material upgrades. "Keep in mind that some of these units can be 30 years old," he noted.

He then moved to construction considerations, with a particular look at side vs top lifts, rigging for bundle vs individual lifts, and various lifting frames. He cautioned, "You need to also consider engineering lead times, especially now."

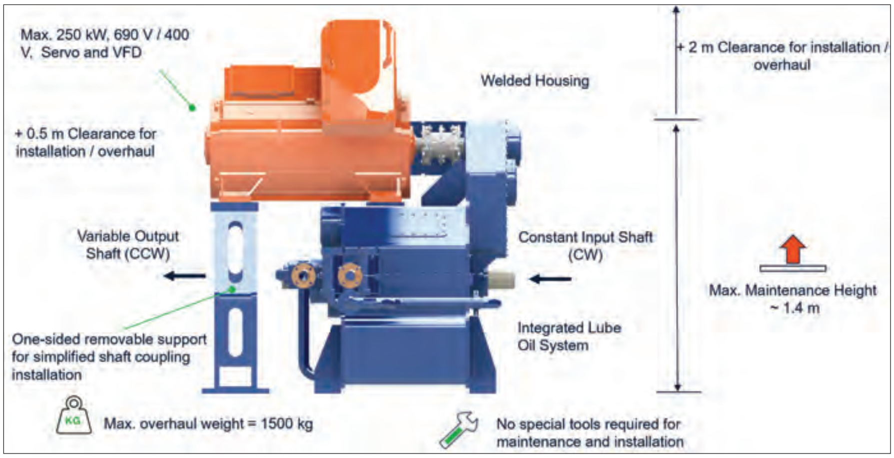
This led to discussions on sourcing, fabrication, and shipment methods.

CCJ has published a series of three articles by Bala on this issue, accessible by searching "Vignesh Bala" at www.ccj-online.com. His message: The HRSG need not be a limiting factor in a GT upgrade.

David Crossley, KSB Pumps, ended Monday sessions with *Boiler feed pump upgrades*. He stated, "Good units can be made even better; optimize pump systems with retrofits."

He offered a case study project in Austria to upgrade performance, improve efficiency, and simplify operation. Scope of supply included:

- Bearing upgrade to eliminate forced oil lubrication system.
- Special baseplate design.
- Installation of KSB mechanical seals.
- New Siemens E-Motors with frequency



5. SETCON® gearbox platform design

converters.
- KSB installation and startup services.

He ended with a discussion on SETCON® Gearbox Platform Design that can "boost pump power and speed by 10 percent without replacing the main motor." See Fig 5.

TUESDAY SESSIONS

Bob Anderson, Competitive Power Resources, opened the session presentations and discussions noting that more than 50 percent of attendees were attending for the first time. Total attendance exceeded 300. Sessions would be moderated by Anderson and Barry Dooley, Structural Integrity.

Jake Waterhouse, DEKOMTE de Temple, first presented *Side wall large movement penetration seal replacements*. He discussed both GT exhaust expansion joints and HRSG penetration seals.

Due to temperature and movement and corrosion, he noted, the expansion joint is the weakest link in the chain. His first example, the hot casing at GT exhaust/HRSG inlet. He discussed his company's "cycling solution suitable for large duct movements and all GT applications."

One case study was a GE 6FA transition DEKOMTE fabric expansion joint with internal insulation. He then moved to the GE Flex Seal vs a DEKOMTE solution for longer life, more predictable maintenance, and reduced adjacent temperatures. He then moved to penetration seals and a bellows-to-fabric retrofit (formed vs. flat fabric).

This led to a review of a combination seal solution installed in 2023, focusing on insulation integrity in the casing and around each nozzle (Fig 6).

A number of questions and discussions focused on metallic vs fabric designs.

An interesting topic appeared during the participant questions. Waterhouse summarized that standard HRSG OEM manuals do not discuss the finer points of subsystem maintenance. More inspection and maintenance activities are probably required. He continued: "You need to look beyond what you bought. Look at what you need now, especially with cycling."

Ryan Geist, Alpha Generation, discussed *HP evaporator header cracking and HRSG issues behind H-class GTs*. He began with lower header repairs.

At the 2 x 1 Keys Energy Center in Maryland, an HP evaporator header failed near the end cap in late 2024 (Fig 7). Externally, the crack was approximately 3.5 in. in length and 3 to 4 in. from the header end cap. Field NDE revealed the length of the wasted area internally was 5 in.

Structural Integrity (SI) performed the failure analysis. Chlorine was concentrated along the center of the crack oxide deposit. Said Geist, "SI surmised that the failure mechanism is likely chemistry influenced, exacerbated by heavy collections of iron oxide sludge and deposits allowing localized chemistry conditions to potentially affect the base metal." The HP evaporators include lower capped drain connections (or inspection ports) that are also developing leaks.

6. DEKOMTE combination seal

A repair plan was developed working with both Vogt and EPRI using SA-106 Grade C, 8.25 in. OD and 1.25 in. thick. A core was removed from Unit 12 Evaporator 4. Repairs were then made (Fig 8).

Issues were found on another unit in Spring 2025. HP/IP evaporators included lower capped drain connections developing leaks, and similar repairs were made.

Contributing factors were identified:
- Potential for flow instability in an area or individual tubes.
- Low or no flow at the tubes near the header end caps.
- Lower heat flux and flows through this evaporator section, more likely to collect iron oxide.

Potential solutions:
- Perform a flow evaluation of the evaporator tube harps.
- Add new 1.5 in. drain lines to the existing lower header pipe.

Geist then presented two case histories of "issues behind H-class gas turbines." One was elevated ammonia slip at low loads on natural gas after firing a liquid fuel oil. The cause was determined to be AIG grid failure. The grid was modified allowing thermal growth, guide tubes/receivers on the left-hand side, and guide tubes/receivers extended by 3 in.

Another unit was struggling to maintain CO in compliance, and inspection showed the catalyst to be bowed. Four of nine total supports had come out of their guides, allowing the middle portion to migrate downstream. Lances were also re-aligned and half-cup receiver extensions were added to maintain engagement of the lances. For the casing, an I-beam was placed across the vertical stiffeners. This was seen as a thermal issue.

Questions and discussions included end cap welding procedures, use of borescope inspections, material expansion issues, and the potential impact of film-forming substances.

Scott Baumann, Thermic Systems, offered *Improved duct burner technology and SCR vaporization*. Thermic Systems has engineering roots in HRSG OEMs, turbine systems and valves. One specialty is improving heat rate.

Baumann first described the Gemini Tan-

7. HP evaporator header failure

8. Final repair method Unit 12

dem Element Duct Burner featuring:
- 50 percent shorter flame length.
  - Doubles isometric mixing zone.
  - Eliminates flame impingement on RH tubes and liners.
- Fully self-supporting elements.
- Advanced metallurgy; 40 percent higher oxidation threshold.
- Proprietary tempering; 33 percent improved thermal emissivity.

In his example, no side wall impingement has been evident after 16 months run time.

Questions focused on geometry, the use of baffles, and gas velocity.

He then presented the HRSG-IRS Intelligent Recirculation system. The goals:
- VFD with existing recirculation pumps.
- Dew point sensing.
- Dew point control through local monitors to drive pumps.

He covered other innovations including steam drum density monitoring, and SCR ammonia vaporization/dilution air thermal energy optimization.

Groome's Steve Houghton then presented *KinetiClean at Linden Cogen*. He discussed Linden plus other case studies on the use of kinetic energy (explosive) tube cleaning.

He covered the mechanics and system components, frequency and location of explosions, and resulting backpressure data related to other cleaning technologies.

Nick Ruscillo, CPV St. Charles, next demonstrated the use of *Drones for HRSG inspection and maintenance* at the Competitive Power Ventures 745 MW St. Charles Energy Center in Maryland, operational since 2017. The original driving forces, he said, were access and personnel safety, among others.

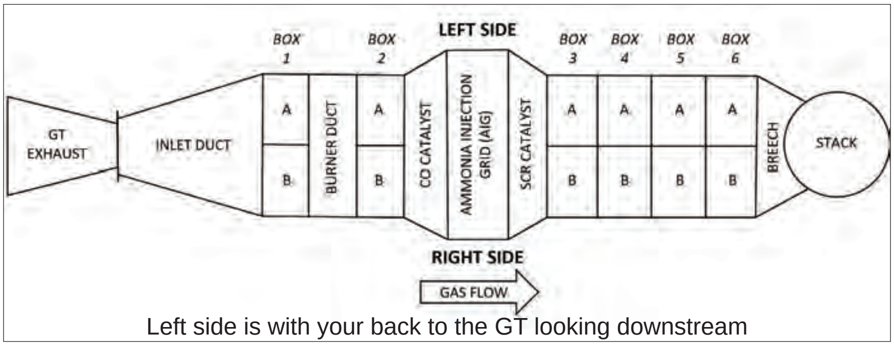
He covered both internal and external uses, stressing that a primary benefit as "a proactive planning tool" that can save inspection time, schedule and cost. Drones can also be a useful guide for site contractors (space availability, locations, etc.).

Questions included use for inspection of vent silencers and condensers. Flight times and flight programming (using GPS) were also discussed.

Eugene Eagle, EPRI, ended the day discussing *HRSG offline inspections*. He focused on offline internal HRSG inspections to "find small issues before they become large."

Typical scope, he noted, is extensive: "GT exhaust expansion joint to the exhaust stack, drums, external areas, blowdown tanks, attemperators, and evaporator tubes (borescopes)." He added "it is important to inspect/test attemperator piping and nozzles regularly." He also recommended scheduling a drone inspection and scheduling NDE as needed.

Eagle highlighted unit orientation to properly record findings and establish inspection continuity, noting that the standard for numbering (including tubes) is left to right, front to back. See Fig 9.



9. Example of boiler orientation to document inspections

"Annotate as you go," suggested Eagle, "and take photos." He showed selected examples of typical findings.

Most questions focused on specific system components and inspection frequency.

WEDNESDAY SESSIONS

Barry Dooley, Structural Integrity and Forum co-chair, delivered *Flow-accelerated corrosion: the basics* calling flow-accelerated corrosion (FAC) "the leading tube failure mechanism in combined cycle/HRSG plants."

A few interesting points of introduction:
- "The mechanisms and important locations of FAC in HRSG plants have been completely understood for more than 20 years."
- "FAC in generating plants is influenced and controlled by the cycle chemistry. The mechanism is well understood to be wall thinning due to rapid mass transport of dissolved magnetite."

He followed with examples in both vertical and horizontal HRSGs.

"Single and two phase require difference chemistry solutions," he summarized. He offered three fundamental (starting point) rules:
1. Keep water's oxidizing potential positive (for single phase); no reducing agent.
2. Elevate pH to control for two phase FAC.
3. Monitor iron properly.

He also presented the IAPWS (International Association for the Properties of Water and Steam) corrosion product decay map and available IAPWS guidance. For more on this, search the CCJ site for "cycle chemistry corrosion monitoring in flexible and fast starting plants."

Matt Beaty (TVA) and Shawn Gowatski (TesTex) gave an overview of *FAC best practices and inspection results*. Beatty offered some "hard-learned lessons and recommendations" from a variety of TVA units.

TVA's overall fleet includes 22 HRSGs at 9 sites (with 3 more under construction) from a wide range of OEMs. Vintage of current units is from 2002 to 2018.

In early signs of FAC issues, Beaty explained that several sites have seen discoloration or wall loss of the steam separators in the LP drums, "indicating a potential FAC

10. Pad weld leak in LP evaporator

11. Penthouse sidewall removal for HP evaporator rear header inspection

issue."

The risk profile showed that "based on the age of units and materials of construction, and the design conditions, some of the highest risk components are the LP evaporator upper tubes and LP evaporator headers/risers." Digging deeper found the risk in the LP evaporators on the leading tubes, specifically at the ends of the headers.

In case histories Beaty said a wet spot was found on the floor under an LP evaporator, traced back to the penthouse with a thin-edged hole found on a tube. TVA made a temporary repair. Then, the pad weld began

12. TesTex HRSG internal access tool

leaking in multiple locations "likely lining up with all the previous FAC pits." See Fig 10.

A more conventional repair was performed using both windows cut in the headers and tube plugs. The next step was flat plate plugs.

Access to the LP evaporator is difficult on this unit. Inspection required cutting a wall section out of the penthouse and removing the header end plate (Fig 11).

Inspection by TesTex "indicated fairly widespread FAC and "a curious difference between the left- and right-hand sides of the unit," he noted.

Gowatski (TesTex) then presented *Inspection of HRSG tubes using the internal access tool*. See Fig 12.

A case history inspection found that 27 tubes had at least 50 percent wall loss. Other units were inspected with similar findings.

"TesTex is currently working with both EPRI and Bob Anderson (Competitive Power) to develop a mechanism to measure the thickness of deposits in HP evaporator tubes that will be attached to a modified version of the Internal Access Tool," Gowatski said.

He noted another benefit of tool use: it can help determine an exact location for any tube sample removal.

Gowatski requested tube samples from the attendees for this development program.

Bill Kitterman, SVI Bremco, followed with *FAC repairs: before, during and after*. He listed the typical areas of concern for FAC:

- HP economizers especially tubes with bends.
- HP economizer headers.
- Jumper piping.
- Feed piping.

He stressed understanding the design: J-bevel, socket seat, extruded header, etc. "Understand how your headers are built," he said.

He also covered pre-repair notifications (jurisdictions/inspectors) and verifying contractor qualifications.

He then provided information on FAC repairs, header replacements, and complete tube replacement, highlighting National Board requirements.

Discussions focused on unit design variations, local rules on investigations, and material specifications in light of global sourcing.

Rafid Al-Mohammadi, Saudi Electricity Company, Rabigh Power Plant, discussed *Valve positioner improvements and modifications*. The plant suffered multiple pneumatic control valve malfunctions and loss of generating load after two years of operation. High ambient temperature was a significant issue.

Thermal insulation has been added to valves, he said, to keep them cooler.

Ghazi Alshammaari, Saudi Electricity Company, followed with *HRSG associated thermal risk: comprehensive evaluation and advanced mitigation strategies*.

He focused on primary operation stress factors for HRSGs in Saudi Arabia:

- High ambient temperatures.
- Frequent start/stop cycles.
- Aging infrastructure.
- Fluctuating (unstable) load conditions.

Proposed strategies discussed included:

- Condition-based monitoring.
- Advanced materials and creep-resistant alloys.
- Attemperator optimization and steam temperature control.
- Water chemistry optimization and FAC prevention.

He also offered six areas of risk control:

1. Mitigate thermal cycling and fatigue. Install sensors to track metal temperatures.
2. Prevent spray water damage and condensate shock. Limit water injection at low steam flows.
3. Ensure steam quality to protect downstream equipment. Install analyzers to continuously track trace contaminants.
4. Maintain instrumentation accuracy and reliability. Use smart sensors with diagnostic features and built-in drift compensation.

13. Behind-the-scenes look at severe-service valve manufacturing, component inspection, and the quality practices supporting zero-leakage performance in demanding power-generation applications

5. Minimize corrosion and chemistry imbalances. Adapt water treatment programs to operating conditions.
6. Avoid pressure buildup and hazards. Fit pressure relief devices on all piping sections.

Yves Schweizer, Solventum, discussed *Dissolved gas control for the power industry*. He presented the 3M™ Liqui-Cel™ membrane.

He described hollow-fiber membranes, cartridge manufacturing, and the Liqui-Cel radial flow design with central baffle. Applications include dissolved O2 and CO2 removal.

THURSDAY – EPRI TECHNOLOGY TRANSFER DAY

A team from EPRI conducted the *EPRI Heat Recovery Steam Generator (HRSG) Technology Transfer Day* with this agenda:

- HRSG program overview.
- State of the industry; summary of challenges.
- Gas turbine upgrades.
- Flat end cap damage update.
- Backend fouling.
- New HRSG specifications.
- Update on valve hardfacing.

Tom Sambor, EPRI Pressure Parts Area Leader, began with an organizational overview stressing that EPRI is 'independent, unbiased, and dedicated to the advancement of information."

Discussing "project deliverables," he focused on two timely areas: the EPRI Fitness for Service (FFS) Handbook with procedures for analyzing component geometry, and the FFS Handbook on analysis of operating data.

The overall goal, he said, is "to enable continued operation of an ever-aging fleet amid increasing challenges with the supply chain."

He mentioned the Boiler Reliability Interest Group (BRIG), which is now labeled the Boiler, HRSG and Piping Interest Group (BHPIG). He then offered the HRSG Program Overview.

Damage Mitigation research offers documents on turbine upgrades, optimizing HRSG drains and FAC assessment, among others. A focus is evaluation of thermal transient issues.

Improved Performance research focuses on gas turbine advancements/upgrades, improved HRSG flow distribution, and other areas of thermal performance.

Life Management prepares foundational case histories on methodology, and provides periodic workshops.

Flexible Operations examples include purge procedures to reduce startup time, best practice operational strategies, and the reduction of gas turbine impact on HRSGs during flexible operations.

HRSG Innovations includes methods of steam conditioning beyond traditional attemperation, novel gas turbine exhaust attemperation concepts, and research into new materials and features (e.g. dissimilar metal welds).

Sambor then presented *State of the industry: summary of challenges*.

Citing the Edison Electric Institute (EEI), he stated that both gas turbines and combined cycles show continued growth, but the operating combined cycle fleet is aging. By 2050, 75 percent of the fleet will be more than 31 years old. At the same time, utilities are reducing key personnel.

His summary:

- Increasing: flexible operations, material complexity, supply chain challenges, alternative repair solutions, and fitness-for-service requirements.
- Decreasing: O&M budgets, Codes/standards awareness, service provider expertise, and engineering and support staff.

This leads to EPRI's Integrated Life Management Strategy. EPRI offers "a suite of available documents that focus on HRSG fundamentals" and a member benefit known as "EPRI Assist."

He offered a side note about non-destructive evaluations: "The first question to ask any NDE service provider is: are you participating in EPRI's Generation Proficiency Assessment Program?" Proper NDE techniques and documentation are essential to life management, he stressed.

Eugene Eagle, Senior Technical Leader, Pressure Parts, followed with *Gas turbine upgrades: considerations and case studies*. The main topic was "the impact of gas turbine upgrades on heat recovery steam generator components."

These impacts, he said, are often overlooked:

- GT exhaust gas temperatures and mass flows entering the HRSG.
  - Typically, a 1 to 1 correlation of exhaust mass flow to steam flow.
- Moisture content (can increase the energy input).
- Emissions.
- Low-load operation issues.
- GT ramp rates.

"Therefore, a critical step," he said, "is to perform a GT upgrade assessment of the HRSG."

He reiterated potential HRSG impacts:

- Exceeding design temperatures.
- Exceeding maximum allowable working pressures.
- Increased steam generation; rate and pressure could exceed the stamped nameplate capacity of the HRSG.

"Keep in mind," he said, "that an HRSG is three boilers in one."

Other impacts discussed in detail included insufficient safety valve relieving capacities, steam drum separators exceeding design capacities, tube metal temperature increases, impacts on creep life, oxide growth and exfoliation, attemperator performance, duct burner capacity derates, GT backpressure, water and steam velocities, SCR and CO catalyst performance and longevity, evaporator flow, control valves, boiler feed pump capacity, and impact on non-pressure parts (liners, etc.). He then offered Case Studies.

Sambor then returned to discuss *Flat end cap damage*, a subject of the 2024 Technology Transfer Day. Search "2024 EPRI technology transfer day" at CCJ.

Eugene Eagle next presented *Backend fouling: summary and future work*. He reviewed the primary current technologies for gas-side tube cleaning along with those being further studied including pressure wave, det (detonation) cord, and foam-based (newest for HRSGs).

Initial EPRI studies considered pressure wave and dry ice blasting. Pressure wave has been tested at the Explosive Research Laboratory at the Colorado School of Mines, followed by in-depth metallurgical analysis of tubes. "No damage was observed in the tube samples tested," he noted. Det cord has also been vigorously tested.

Foam-based uses a nucleated foam technology, a spray-on that expands on the tubes to loosen debris. This method, he said, has been used "at numerous refineries, including those that have highly restrictive water ecological/conservation regulations, including but not limited to the Puget Sound area, California, and the Mississippi River." EPRI field tests are planned for Fall 2026.

Will Siefert then gave a *Coated finned tubes project update*. Tubes were coated and placed into service in 2022. The coating was used for anti-stick properties, to shed foulants in lower temperatures of the HRSG. Questions now being asked: are there also anti-corrosion properties, and are there any plant efficiency effects from thermal conductivity? Siefert's summary: "This is just the beginning. Results are promising, with a number of questions. It's a line-of-sight process at the moment," he said.

Eagle then returned with *Recommendations for new HRSG specifications*.

His outline:

- Life management challenges and considerations including startup/shutdown/ramp rates.
- Components typically of utmost concern:
  - HPSH/RH attemperators.
  - HPSH/RH drains.
  - Final stage HPSH/RH headers and manifolds.
  - Drum nozzles.
  - Large branch connections.
  - Duct burners.

He also stressed that "premature pressure part damage and failures attributable to thermal mechanical fatigue are common in HRSGs, particularly those equipped with advanced gas turbines, exposed to periods of frequent start-stop operation, and rapid startup.

He offered an in-depth review of an EPRI publication, *Heat Recovery Steam Generator Procurement Specification*, from 2013 (EPRI Report 3002001315).

This report lists "critical features that should be included in every specification covering topics such as pre-commissioning chemical cleaning, an auxiliary boiler of sufficient capacity, freestanding stack insulated up to a remotely controlled damper, seamless HP SH and RH piping/manifolds/headers/tubing, unrestrained thermal expansion of all pressure parts, steam piping/manifolds/drains with a minimum continuous downward slope of two percent, automatic drain system, proper casing access doors, nitrogen blanketing system on HP/IP/LP drums, and steam sparging system for HP/IP/LP evaporators (among others)."

He covered a number of other important questions to consider dealing with HRSG specified life, interstage and final attemperators, drain systems, drum nozzle design, piping and manifolds, duct burners, and purge credit hardware/software. All and more were discussed in detail.

Many questions followed including freeze protection, thermal gradients and shutdown, non-ASME Code issues, and penthouse design to protect instrumentation around the drum.

The EPRI specification document is available at no cost by searching for "Heat Recovery Steam Generator Procurement Specification" at www.epri.com.

The final EPRI presentation, by Will Siefert, Engineer IV, Pressure Parts, was an *Update on valve hardfacing*.

He noted that Stellite welding is becoming a lost art, as are other specific welding skills.

A solution is important to those experiencing valve hardfacing cracking and disbanding (liberation). Siefert noted that this is not restricted to one design, component, or manufacturer.

EPRI performed a preliminary, independent evaluation of service exposed (~100k hours, 2,500 cycles) valve components with an alternative to Co-based hardfacing, termed an HVOF (High Velocity Oxygen Fuel) coating. Evaluation of HVOF revealed no signs of local coating delamination, and the bond integrity appeared to be retained after indentation testing. EPRI intends to perform more detailed evaluations.

FRIDAY TOUR

On the final day, ValvTechnologies hosted the first ever HRSG Forum shop tour giving attendees a behind-the-scenes look at the company's processes, people, and quality-control practices (Fig 13). With more than 35 years of experience, the company has focused on helping customers address both daily valve problems and broader system-wide challenges safely and efficiently. CCJ

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Compression strength	6700 lbs
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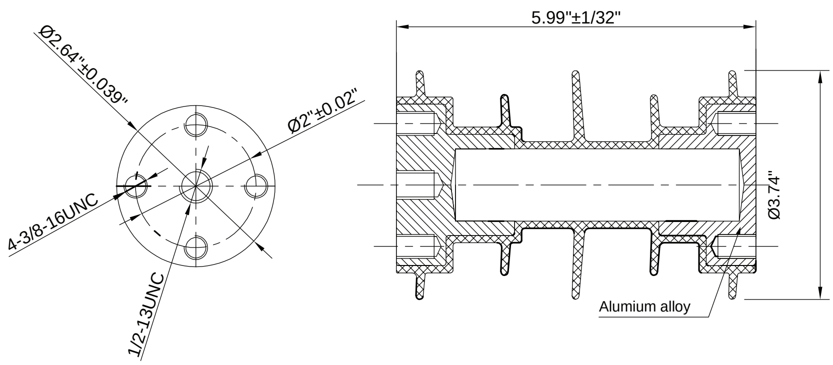
Min creepage distance	11.8inch
Acring distance	6.14inch

The color of weather sheds is light gray

Standard applied: ANSI C 29.1

2.5lb



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LTUG 2026 brings legacy-frame users to Oklahoma City

The 2026 Legacy Turbine Users Group Annual Conference will be held June 22–25 at the Omni Oklahoma City Hotel, with the 7EA Users Group, Frame 6B Users Group, and Frame 5 Users Group sharing one conference platform. The agenda continues its focus on how to keep mature gas-turbine fleets reliable, where outage dollars should be spent, and how to compare OEM guidance, independent repair options, and user experience before the next inspection or life-extension decision.

LTUG was formed by Power Users to bring the 7EA, Frame 6B, and Frame 5 communities together while maintaining independent steering committees and user forums. The model gives companies with mixed fleets the benefit of multiple meetings in one trip.

PROGRAM OPENS WITH SHORT COURSES, OEM UPDATES, AND VENDOR FAIR

The technical program opens with a GT Intro Short Course, applicable for all users, led by John F D Peterson, PE. The afternoon includes a GT "Next Level Course," a Baker Hughes session, and 7EA-focused presentations on predictive maintenance using AI and data and component life extension through advanced repairs and upgrades. Monday closes with the vendor fair.

The first-day structure is useful for both first-time and returning attendees. Newer users can level-set on fundamentals. Experienced users can move into asset-health, component-repair, and OEM-alternative discussions. Plant personnel can match conference topics to outage, maintenance, and capital-planning questions.

7EA TRACK EMPHASIZES INSPECTION, EXHAUST FRAMES, GENERATORS

The 7EA program reflects the shift from general aging-fleet concern to specific life-cycle decisions. Tuesday sessions include key maintenance practices to avoid downtime, outage-efficiency support from owner's engineers, compressor bleed valves, root-cause-analysis case studies, in-situ 7A6 generator stator core replacement, legacy turbine exhaust-frame assemblies, borescope-inspection findings and associated risk, generator protection relaying, and critical-bus maintenance mitigation.

Those subjects follow issues highlighted at LTUG 2025, including exhaust-section degradation, inspection quality, controls health, generator condition, diffuser cracking, flex-seal distress, torque-converter starting problems, flame-monitoring behavior, and selective lifecycle spending.

The 2026 agenda gives users another opportunity to test those concerns against case histories and peer discussion. A generator stator-core case study, exhaust-frame presentation, and borescope-risk session should help plant managers evaluate where continued repair is defensible and where larger replacement, refurbishment, or life-extension planning may be required.

FRAME 5 AND 6B USERS JOIN FORCES

Frame 5 and 6B users have dedicated user-only and OEM-participation sessions. Tuesday's Frame 5 content includes an open roundtable, a rotor in-situ aft compressor-case removal presentation, and a Sulzer roundtable on Frame 5-specific repairs. GE Vernova and Baker Hughes breakout sessions cover rotor repair and life extension, advanced gas path for extended intervals, component repairs, controls hardware, auxiliary systems, balance-of-plant equipment, hot-gas-path configuration, generators, diesel starting, torque converters, outage planning, and core asset rejuvenation.

Wednesday adds peaker/emergency-use maintenance, predictive maintenance and on-site rotor solutions, inlet and compressor roundtables, combustion roundtables, effects of peaker cycling on generators, exhaust-frame assemblies, controls, reliability practices, and gearbox operation and maintenance. Thursday closes with roundtables on turbine, generator, safety, and maintenance planning.

OEM PARTICIPATION REMAINS CENTRAL

GE Vernova and Baker Hughes have substantial roles in the 2026 agenda. Baker Hughes has a Monday session covering fleet

LTUG STEERING COMMITTEES

7EA USERS GROUP

- **Co-Chair:** Tony Ostlund, Puget Sound Energy
- **Co-Chair:** Mike Vonallmen, Clarksdale Public Utilities
- Dale Anderson, East Kentucky Power Cooperative
- Tracy Dreymala, EthosEnergy
- Matthew McCafferty, Golden Pass LNG
- Shane Rouse, East Texas Electric Coop
- Walt Steimel, Shell Project and Engineering Services
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- John F D Peterson, retired, BASF
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- Aaron Beadle, Calpine Corp
- Michael Maris, ExxonMobil, Baytown Refinery
- Kyle Miller, Fayetteville Public Works
- Brian Worthington, Fayetteville Public Works

updates, counters, product features, engine and auxiliary options, case studies, technical bulletins, and the repair network. GE Vernova participates in Tuesday Frame 5/6B sessions and leads Wednesday 7EA sessions on industry status, current 7E status, new-unit and services trends, AI impact, TILs and RCA updates, combustion capability, new DLN1+ configurations, hydrogen projects, radial diffuser development, reliability recommendations, and LNG breakouts.

CYCLING, PEAKING, AND AI

The 2026 program reflects how legacy-frame operation continues to change. Predictive-maintenance sessions address AI and data. Peaker and emergency-use roundtables focus on operations and maintenance. Generator sessions address cycling effects on generator life extension. Breakouts include trip-reduction programs, availability improvements, startup issues, combined-cycle applications, and maintenance-interval questions.

Many legacy units no longer operate under the assumptions that shaped their original maintenance programs. Starts, load changes, standby duty, seasonal peaking, fuel flexibility, emissions requirements, and staffing constraints now influence how failures develop. The better question is whether today's operating profile has made an old assumption unsafe, uneconomic, or unsupported.

LTUG 2025

USERS COMPARE NOTES

Last year's conference in Minneapolis again demonstrated why user-group meetings still matter for mature fleets. LTUG is not where owner/operators go to hear that legacy machines are old. Everyone in the room already knows that. They go to compare notes on which components are aging out gracefully, which ones are becoming outage traps, and where the most practical fixes are coming from users, independent suppliers, owner's engineers, or the OEM.

A few themes cut across the week. First, cycling duty is still changing the failure map for legacy machines. Starts, part-load operation, and dispatch volatility continue to show up in vane looseness, combustion instability, accessory-system wear, and inspection urgency. Second, exhaust-section degradation is no longer a side issue. Diffusers, flex seals, inner barrels, and associated structural cracking are moving toward the center of many fleet life-extension decisions. Third, users are becoming more selective about where they accept OEM framing and where they want alternate repair or replacement paths. And fourth, everyone is trying to make smarter choices about what to repair, what to upgrade, and what to stop nursing along.

FLEET HOUSEKEEPING DRIVES RELIABILITY

The Frame 5 and 6B user material focused on maintenance planning, peaker operation, auxiliaries, combustion hardware, compressor sections, control systems, generators, safety, and turbine hardware. That may sound basic. It is not. Mature fleets are often lost not because operators lack a strategic vision, but because the everyday systems surrounding the turbine stop getting disciplined attention.

The maintenance-planning and peaker-operation material made that point clearly. Users emphasized tracking and projections, interval drivers, outage timing, repair planning, spares, shop-space constraints, capital-part replacement planning, and life-cycle decisions for controls, wiring, casings, ducting, and auxiliaries. They also highlighted familiar peaker-specific pain points: oil circulation, ratchet operation, cranking performance, FSNL behavior, synchronization and low-load operation, and how all of that changes maintenance scope and timing.

That framing is important for plant managers because peaking service has a way of disguising reliability erosion. A unit that runs fewer hours can appear healthy while accumulating starts-related wear, accessory-system distress, and control-system fragility. LTUG's user discussions suggested that several fleets are now treating peaker maintenance as its own discipline rather than as a lighter version of baseload maintenance. That is the right move. Ratchets, starting systems, oil systems, and low-load behavior deserve their own review cycle when dispatch patterns change.

The auxiliaries session reinforced the same point at component level. Users worked through starters, torque converters, clutches, ratchet systems, accessory gears, load gears, lube-oil systems, oil-mist separators, hydraulic systems, and cooling/ventilation hardware. Nothing in that list is glamorous, but nearly every item can delay a start, complicate an outage, or trigger a trip if it is allowed to drift into the background. Mature fleets tend to accumulate tribal workarounds in these systems. User groups remain one of the few places where those workarounds get compared openly.

The combustion session also stayed grounded in hardware realities: fuel nozzles, liners, flow sleeves, transition pieces, crossfire tubes, ignitors, flame eyes, and associated piping and cans. Frame 5/6B fleets are increasingly being asked to do work they were not optimized for decades ago—more starts, wider operating windows, and, in some cases, tougher emissions or fuel-flexibility demands. Combustion sections therefore sit at the intersection of reliability, compliance, and life-cycle spending.

The compressor, controls, and generator sessions showed a similar pattern. Users centered their discussions on inlet air systems, IGVs, rotor and stator issues, extraction points, online/offline washing, control-system support and upgrades, gas-valve behavior, DLN tuning, exciter hardware, TEWAC leak detection, and general generator condition. None of these are new topics. But the recurring need to revisit them is itself a signal: the fleets that are still performing are not assuming that "basic" systems will take care of themselves.

The safety session, covering fire suppression, halon, CO_2, water mist, heat detection, hazardous-gas analyzers, lockout/tagout, confined-space entry, turbine compartments, and filter-house considerations, added a useful reminder. As legacy fleets age, maintenance and reliability decisions increasingly overlap with personnel exposure. Accessibility, degraded housings, aging fire systems, and outage-work density all raise the penalty for a casual safety culture. In practical terms, the reliability discussion is not separable from execution discipline.

Taken together, the Frame 5/6B user presentations pointed to one broad conclusion: owner/operators still have substantial leverage over reliability outcomes through routine planning and execution.

FRAME 5 AND 6B VENDOR PRESENTATIONS

If the user presentations emphasized day-to-day operating reality, the Frame 5/6B vendor presentations emphasized optionality. Controls specialists, rotor-life-extension providers, exhaust-system repair firms, winding manufacturers, and combustion-upgrade vendors all made the case that there are still economically rational pathways to keep legacy machines relevant. The question for readers is not whether those pathways exist. It is which ones are grounded in the condition of a given asset and which ones are being sold as broadly applicable solutions.

AP4's controls-reliability assessment talk framed one end of that market. The presentation argued that routine panel cleanup, voltage checks, alarm review, and junction-box inspection are not enough by themselves. The more important questions involve decision matrices by control platform, EEPROM strategy, human-machine-interface support, technical information letter applicability, multi-unit audit exposure, single points of failure, spares, ground-fault exposure, diagnostics, and calibration discipline.

The case studies were useful because they showed how mundane-seeming logic or hardware conditions can create hidden risk. One example involved lube-oil heaters and a welded main contactor; the corrective action was not just replacing hardware but eliminating a logic dependency and revising LOTO practices. Another example challenged an operator's assumption that unstable exhaust temperature was necessarily a combustion problem. The larger message was that controls health assessments need to be framed as trip avoidance and latent-risk discovery, not as housekeeping.

EthosEnergy approached the conference from the rotor side, presenting data-driven risk assessment for life extension and reframing rotor limits as an evaluation problem rather than an arbitrary end-of-life boundary. That is consistent with where much of the aftermarket is moving: away from simplistic age-based replacement arguments and toward condition-based life extension backed by engineering review. For owner/operators, the attraction is obvious. New-machine supply remains constrained, capital budgets are finite, and some legacy assets still make money. But the discipline required is equally obvious: life-extension decisions are only as credible as the inspection basis, the operating history, and the assumptions behind the risk model.

Exhaust and combustion hardware. Gas Path Solutions reviewed MS5000 and MS6001 exhaust systems and highlighted typical components—expansion joints, covers, plenums, diffusers, and exhaust frames—before drilling into known fleet issues. Expect increasing repair costs over time, material degradation, repairs not achieving desired operating intervals, cooling-air loss, and cracking in multiple locations, including horizontal parting joints, outer diffusers, aft diffusers, and turning vanes. That is a serious message because exhaust problems tend to present as "repairable" right up until they become schedule and scope problems.

BFI Automation's flame-monitoring pitch was simple: legacy UV-based flame-monitoring hardware brings non-fail-safe behavior, limited repairability, unpredictable expiration, and replacement constraints. The alternative on offer was optical hardware with self-checking capability, trendable output, and field-replaceable electronics. Readers should recognize both sides of that story. The vendor claim may be valid. But the more durable takeaway is that flame monitoring has become an operational reliability issue, not just an instrumentation detail, especially where false trips or liquid-fuel service are involved.

The PSM FlameSheet presentation expanded the conversation from simple repair into performance repositioning. Here, the most notable claims involved low-NOx combustion over a wider operating range, sub-9-ppm NOx and CO performance, stable operation down to 27% load in one example, and use of refinery off-gas or hydrogen-containing fuels. The strategic implication is real: some legacy fleets are being asked to do a more flexible, fuel-diverse job than their original hardware packages support. But users should evaluate such offerings with care. Emissions, operating window, and fuel-flexibility claims often depend on application-specific constraints, tuning margin, and site fuel composition.

National Electric Coil's Tyler Gaerke made a different point in his stator-winding presentation: replacement quality matters as much as availability. As rewinds and life-extension projects grow more common, owner/operators are navigating supply-chain pressure and a widening quality-expectation gap. That is a reminder that "replace" is not automatically the conservative choice. On older fleets, replacement hardware introduces its own risk if quality systems, design assumptions, or inspection criteria are weak.

7EA END USERS TALK SHOP

The 7EA user presentations had a slightly different character. They read less like broad roundtables and more like snapshots of the actual questions plants are carrying into outages and troubleshooting sessions right now. That makes them especially useful.

One cluster of discussions centered on inlet cooling and performance management. A user asked whether anyone was operating evaporative coolers below base load on 7EA units because the OEM had set the equipment permissive at base load even though the plant was rarely there. The responses suggested that at least some peers still operate evaporative coolers only at base load. A related discussion on inlet fogging reported that one 7FA site was seeing a 10- to 15-MW increase during summer operation and that one owner had fogging systems on eight 7EA units, with decent performance but significant maintenance demands in below-freezing weather.

Another cluster involved combustion and flame-detection problems. One user described repeated flameouts at 10 to 15 MW shortly after synch. Gas flow, bleed valves, and IGVs looked acceptable; compressor discharge, load, and exhaust temperature then fell off until flameout. Peer suggestions included checking rebuilt bleed valves for incorrect installation, checking inlet filters, and verifying IGV angle physically rather than trusting indication. The eventual cause was neither an obscure compressor defect nor a hidden plenum obstruction. It was a malfunctioning NOx water-flow meter, likely damaged by a lightning event, reading no flow and effectively drowning the flame.

Flame monitoring surfaced again in a separate exchange on optical flame-detector fouling during liquid-fuel operation. One respondent pointed to condensation issues with water-cooled detectors and said air purging resolved the problem. Another reported replacing OEM water-cooled scanners with alternate hardware and eliminating the issue.

The exhaust section generated some of the strongest discussion. One user was planning to replace the exhaust diffuser on a 2001 7EA because of excessive cracking and was looking for lessons learned. Another reported extensive vertical cracking around the inner barrel, had the material evaluated metallurgically, and found sigma phase. That finding matters because when sigma phase develops, the material becomes more brittle and more susceptible to thermal and mechanical fatigue cracking with continued exposure. The presentation further distinguished between a traditional one-piece replacement diffuser, which requires stub-shaft removal between turbine and generator, and a split-design alternative intended to simplify installation. User responses indicated that some plants are still living with annual inspection and weld-repair cycles, and that related failures such as flex-plate separation and stack-silencer distress may be linked to diffuser degradation.

Additional user material reinforced the sense of a fleet managing through component-specific distress. One plant described internal flex seals downstream of third-stage buckets shifting badly enough to create an opening approaching 40 in. at the 11 to 12 o'clock position, with the seal stuck in the upper exhaust-case groove and the user trying to avoid a window-weld process. Another described a refurbished torque converter that would not break away at startup despite apparent oil pressure and normal cranking-motor behavior, causing the output shaft to turn only about 180 deg before tripping. Yet another site saw a mid-run step change in two exhaust thermocouples, roughly 100F down, followed by a sharp CO increase and a small generation loss of about 0.5 to 1 MW, without obvious leaks or visible borescope evidence.

7EA VENDOR PRESENTATIONS

The 7EA vendor presentations expanded on many of the same issues but with a sharper emphasis on inspection methodology, repair pathway, and upgrade economics.

AGT Services' generator-testing presentation was one of the clearest examples of a vendor message aligning closely with user needs. The central argument from Jamie Clark was that experienced generator specialists remain indispensable; dirt tells a story and should not be cleaned away before inspection; speed does not equal quality; and extending inspection intervals is proving detrimental to generator reliability because newer replacement assets often have less margin, less mass per MW, and cheaper materials. The detailed list of what to inspect—end-winding support systems, wedge systems, gas-gap baffle studs, stator core tightness, vent-duct blockage, rotor cleanliness, arcing, tooth-tip hot spots, retaining-ring condition, collector rings, fan damage, and copper dusting—reads like a reminder that generator failures still reward fundamentals. For managers deciding whether to save outage time on inspection scope, the message was blunt: shortcuts are a false economy.

Entrust's borescope-report interpretation session made a similar argument for the turbine itself. The presentation stressed that borescope value depends on inspection quality, access, interval selection, and correct interpretation of what is seen. It identified typical failure modes across the inlet, compressor, combustion, turbine, and exhaust sections: IGV deposits and erosion, IGV cracking and bushing migration, forward-casing distortion, first-stage erosion and cracking, combustion-liner bulging, transition-piece cracking, nozzle cracking, tip lifting, knife-edge seal damage, strut-heat-shield cracking, inner/outer barrel cracking and separation, flex-seal cracking, and broken thermocouples. One practical example described mitigating risk through borescope inspections every 25 starts to bridge a unit to a planned combustion inspection. That is the kind of operating decision owner/operators have to make constantly, using inspection frequency as a risk-management tool, not just as a compliance interval.

CTTS's compressor stator-vane looseness presentation was another standout because it tied changing dispatch duty directly to mechanical consequences. Starts and part-load operation were cited as drivers of increasing looseness. The presentation challenged the sufficiency of the OEM "big foot" approach, described a pinning solution installed on six units over the past two years, and warned that casing cracks and escalating repair costs can follow if looseness is ignored. It also emphasized that borescope inspection can detect some issues, but that upper-casing removal is often key to proper risk assessment. Whether readers agree with the vendor's preferred repair solution or not, the core message is credible: stator-vane looseness is a condition that can move from nuisance to structural risk if deferred too long.

IPS focused on exhaust-frame assemblies and identified a fleet burdened by rising repair costs, material degradation, cooling-air loss, parting-joint separation, aft-diffuser cracking, turning-vane cracking, and inner-barrel circumferential cracking. The presentation explicitly posed the central owner/operator questions: Has a detailed inspection been performed? How long has crack repair been going on? Are you already planning an internal alignment? Are you in a position to replace, refurbish, or continue repairing? Those are the right questions, and they mirror what users were already discussing in their own sessions.

MD&A's lifetime-extension presentation approached hot-gas-path decisions with a repair-process lens. The extracted text points to specialized inspection, phase-array and x-ray evaluation, CT-scanning support during repair development, process controls, and examples of first-nozzle and combustor-liner repairs involving crack removal, welding, brazing, and coating restoration. The presentation also highlighted the economic logic behind repair versus replacement and repeatedly tied repair credibility to inspection depth and process control. Again, readers should separate marketing from usable takeaway. The important lesson is not that one shop has every answer. It is that HGP life-extension decisions should be built on inspection capability, defect detectability, and known process controls—not on generic price comparisons.

Crown Electric's Bruce Hack went "all-in" for his breaker retrofit presentation to emphasize that not all legacy-fleet problems are inside the turbine. Main bus duct and generator circuit breakers were described as weak links nearing or at end of life, with cooling challenges and under-rated legacy hardware creating risk. Turnkey retrofill replacement of older breaker designs may sound like an electrical niche, but it fits the conference pattern: more plants are discovering that the practical limit on asset life is often set by support systems, not just the turbine rotor.

Finally, several presentations addressed broader operating context. The owner's-engineer talk from Gulf Turbine Services emphasized quality control, attrition mitigation, and project-management support. MD&A's "Safety Differently" presentation argued that safety and productivity can reinforce one another if organizations learn proactively rather than trying to "change behavior" by slogan.

WHAT'S NEXT?

Three practical conclusions emerged from LTUG 2025 that will undoubtedly continue this year and beyond.

First, inspection quality is becoming the dividing line between rational life extension and wishful thinking. That applies to generators, exhaust systems, borescopes, controls, and compressor hardware. Plants that know the condition of their assets in detail still have options. Plants relying on old assumptions are more likely to discover their limits in the middle of an outage.

Second, users should treat exhaust systems and associated structural hardware as strategic assets, not as endless repair candidates. Diffusers, inner barrels, flex seals, and turning vanes are showing up repeatedly in both user concerns and vendor offerings. Once cracking is persistent, metallurgical degradation is confirmed, or repairs stop lasting to the desired interval, the decision framework has to widen from repair procedure to fleet strategy.

Third, dispatch reality is now inseparable from hardware strategy. Peaking duty, low-load operation, wider cycling, fuel flexibility, and emissions pressure are affecting how legacy machines fail and what upgrades are worth considering. LTUG 2025 made clear that many of the best responses are still practical ones: tighter maintenance planning, better condition assessment, smarter control-system audits, more disciplined troubleshooting, and a willingness to challenge inherited limits when the operating profile has changed. CCJ

Stack dampers and startup reliability

Stack dampers are simple on paper yet pivotal in practice. If they do not open cleanly at light-off, exhaust flow can choke, startup timelines slip, and HRSG parts see higher thermal stress. If they leak or stick during shutdown, stored heat bleeds away and the next start begins colder. In ISO-driven markets where starts and ramps are scheduled, these minutes and degrees translate to cost and wear. The points below adapted from SVI Bremco field experience, target fewer holds, more repeatable starts, and lower pressure-part fatigue.

WHAT STACK DAMPERS DO DURING A START

In a normal sequence the damper should offer minimal resistance as turbine exhaust moves from near zero to full flow, then seal effectively during shutdown and layup to retain heat. When travel is incomplete or inconsistent, two penalties follow: longer time to temperature and uneven heat delivery to upstream HRSG surfaces, which increases tube and header gradients. Reliability depends on reaching full open on cue, sealing when commanded, and repeating stroke time predictably so operators can coordinate purge, light-off, and warm-up logic.

WHY DELAYS MATTER IN CYCLING

Frequent starts drive fatigue on equipment often designed for steadier duty. Late starts use more fuel, deepen temperature non-uniformity, and accelerate wear. Dampers are not the only factor in slow starts, but they directly control how heat is retained and released from cycle to cycle, so weaknesses show up quickly in plant performance.

FAILURE MECHANISMS

Most damper issues trace to the drive train and alignment. Marginal power, tired gearboxes, worn seals, or contaminated pneumatics cause partial strokes or stalls. Even small losses in torque or pressure can halt motion as exhaust backpressure rises. Misaligned or racked blades then add drag against the shell or stiffeners. Witness marks on the liner, shiny rubs, and uneven seal wear are common clues. The added friction loads the actuator, stretches stroke time, and evolves into repeated start holds. Misalignment seldom locks a damper immediately; it produces slow, inconsistent motion that increases actuator stress and erodes sequence predictability, leading to more manual intervention and occasional aborts when permissives are missed.

DESIGN CHOICES THAT REDUCE STARTUP PAIN

Good design and installation make dampers more tolerant of dirty air, icing, and thermal growth. A fail-open configuration, where it fits the safety case and local codes, prevents exhaust restriction on loss of motive power. Weighted assist that allows opening at very low differential pressure, often near one inch of water column, reduces the risk that early exhaust meets a partially closed blade. Stiff, square frames with true hinge lines and positive stops help keep blades parallel to the shell. Allowances for thermal growth at anchors and hinges, supported by high-temperature bushings or bearings, accommodate slight misalignment without binding. Drives and linkages should be laid out for easy lubrication, seal replacement, and limit-switch adjustment so a cold start does not reveal a sticky mechanism.

CONTROLS AND PROOF THAT HELP OPERATORS

Instrumentation and permissives matter as much as mechanics. Use independent open and closed limit switches plus an analog position transmitter to trend stroke time and end-of-travel margin. Build timing checks into the logic and alarm when the damper is slow to open or slow to close so degradation is caught before it becomes a start hold. Verify closure during layup to preserve heat and moisture control. Adjust purge, light-off, and ramp permissives seasonally to account for winter conditions when lubricants stiffen and seals contract.

COMMISSIONING AND ACCEPTANCE CHECKS

Before turning a new or refurbished damper over to operations, record the measurements that anchor future comparisons. Measure stroke time for opening and closing at ambient conditions and again after the stack is hot. Document drive torque or actuator pressure at end of travel with margin noted. Check blade-to-shell clearances at several positions, verify any specified leakage rate, and store limit-switch set points along with the analog zero and span in the DCS change log.

CUT DOWNTIME

A short maintenance routine prevents the slow creep toward unreliable starts. During outages, verify frame squareness, re-shim hinges, replace worn bushings, clean and re-grease linkages with high-temperature lubricant, and re-set limit switches. Confirm torque switch or regulator settings against the acceptance record. Before return to service, run a cold functional test to measure stroke time and smoothness, then verify again hot after several hours online and watch for drift as the frame grows. In service, trend analog position versus command to catch slowing movement. Log minutes from open command to open proved as a KPI and investigate increases. After nuisance holds, check actuator output pressure or current under load and inspect for new rubs or witness marks.

PLANNING AND INSTALLATION TIPS

Schedule discipline lowers critical-path risk. Prefabricate where possible, using pre-assembled frames and access platforms to reduce on-stack time. Coordinate staggered shifts with HRSG, burner, and stack teams so damper work does not block other crafts. Plan rigging and scaffolding early to secure temporary access and avoid conflicts with SCR or liner activities. CCJ

Outage inspection focuses on root causes, checking actuator performance, blade alignment, and shell-contact witness marks; early fixes prevent repeat failures, start delays, and safety risks.

LEGACY TURBINE FORUM, NO. 7 IN A SERIES

Cooldown procedure options for legacy frames

By Luke Williams, PE, Consultant
www.geLegacyGasTurbineSupport.com

IN THE BEGINNING

Engineers who joined the GE gas turbine department in the early days often came from steam turbine design, where cooldown procedures were essential to prevent rotor thermal bow, a condition that can lead to vibration on startup.

Several approaches were available to cool the unit adequately and avoid rotor bow. Early criteria focused on rotating the rotor for an extended period using turning gear. The turning gear engaged the rotor shaft and rotated it at low rpm using an electric motor.

Turning gear was evaluated but had drawbacks. Because the MS5001 was conceived as a black-start unit, the turning-gear motor would need to be DC. A smaller DC motor could be considered, but it might not overcome breakaway torque. Estimates suggested that a 5.7-hp motor would be required to meet turning-gear requirements.

If the unit tripped during a black start, the emergency lube-oil pump would be required to maintain lube-oil pressure during coastdown. If the outage continued, the battery and charger would have to power both the 5-hp emergency pump and the 7.5-hp turning gear. Combined draw was estimated at about 60 DCA, while the battery charger was nominally rated at 35 DCA. The result was rapid battery discharge.

The solution was development of the accessory-gear hydraulic ratchet. The ratchet used a push-pull hydraulic cylinder to index a gear on the No. 1 shaft of the accessory gear. A pneumatic piston pushed the ratchet gear into mesh with the accessory gear. At the end of the forward stroke, the ratchet gear disengaged and retracted. The system indexed the shaft 45 degrees every three minutes.

Design considerations for the original hydraulic ratchet system included the following. The ratchet cycled every three minutes. The permissives for ratchet operation were lube-oil pressure above 63QL, 6 psig, and zero shaft speed. The ratchet disabled as soon as shaft rotation was detected to prevent damage to the accessory gear and the ratchet. Recommended cooldown time was 48 hours. A cooldown timer was not provided. If the AC cooldown pump failed to start, the emergency pump was enabled for both turbine coastdown and ratchet operation. To conserve battery power, the DC pump operated only during the three-minute ratchet cycle.

FUEL REGULATOR UNITS MS5001D, E, G, H, J, K, L, AND LA

Problem. What if the AC cooldown pump failed to start on shutdown?

Solution. The DC cooldown pump was sequenced by the ratchet timer to provide lube-oil pressure during ratchet operation.

Problem. Troubleshooting the ratchet.

Solution. The ratchet design was straightforward. Components such as the solenoid valve, limit switch, and actuators were easily accessible by removing the ratchet cover. As a result, the ratchet was reliable, easy to troubleshoot, and rarely caused problems.

Problem. Cold lube oil could result in low lube-oil pressure during a black start

Solution. To ensure that 63QL and 63QT could be picked up, a boost circuit was added to the DC pump MCC. The boost increased bearing-header pressure to pick up 63QL, lube-oil pressure low, at 6 psig, and 63QT, low lube-oil pressure trip, at 9 psig, avoiding a trip on low lube-oil pressure.

Problem. How black start worked with cooldown enabled.

Solution. With cooldown enabled, the ratchet stroked every three minutes, with the DC pump enabled by ratchet timer 2HR and ratchet position 33HRX. A start signal enabled continuous DC pump operation through relay 1Y-2. Boost output increase was enabled when the pump started and disabled when 63QT picked up at 9 psig on rising pressure with a four-second time delay. The ratchet was also enabled for continuous operation.

FUEL REGULATOR UNITS MS3002F

The MS3002F five-bearing design was not expected to be subject to rotor bow because rotor span was relatively short. Therefore, a hydraulic ratchet was not provided. However, the mid No. 2 and No. 3 bearings between the compressor and HP turbine were subject to high temperatures on shutdown. A cooldown timer ran auxiliaries for four hours to cool the bearing housings.

Problem. What if the AC pump failed?

Solution. If the AC cooldown pump failed, the DC pump started on low lube-oil pressure, 62QL. Expected draw of the 5-hp DC pump was about 29 DCA. The charger was rated for 35 DCA, which could support the cooldown period.

SPEEDTRONIC MARK I AND II UNITS MS5001M, N, AND P

Mark I was introduced in 1968 with the MS5001M. Accessory equipment, including the piggyback AC/DC lube-oil pump and accessory-gear-mounted ratchet, remained the same on the 5001M. The 5001P was upgraded to Mark II in 1980 and adopted the torque-converter-mounted ratchet. Ratchet hardware and cooldown logic remained broadly similar to fuel regulator units, with incremental improvements.

When Mark I was upgraded to Mark II in 1980, the cooldown sequence used in Mark I was not carried over. The elementary index listed 62CD cooldown on sheet 3F, but the logic was not present. The sequences for the hydraulic ratchet and lube-oil pumps also did not include cooldown logic.

Problem. The cooldown logic was energized to run.

Solution. Mark I introduced 1Z-1 to replace 1X-1. The key difference was that 1Z-1 was normally closed to enable cooldown. This made cooldown logic fail-safe in the event of relay failure.

Problem. Could the cooldown sequence be turned off?

Solution. With 1Z-1 enabled, both the AC cooldown pump and ratchet sequence were disabled. Cooldown could be terminated by selecting Stop after the unit reached zero speed, 14HR. Cooldown could be re-enabled by Master Select OFF and START.

Problem. On older units, the clutch

and ratchet could enable before the shaft stopped rotating.

Solution. Addition of the zero-speed relay, 14HR, addressed multiple issues related to clutch and ratchet engagement before the unit reached zero speed.

Problem. When the ratchet cycle indicated retracted, rotor rotation continued and disengaged the clutch, resetting the sequence and causing a double cycle.

Solution. Delete the 33CSE normally closed contact in the 33HRX rung. If the clutch failed to close, ratchet permissive 4RP disabled and ratchet trouble alarmed 30 seconds later.

Problem. New ratchet components included 20CS for clutch engagement and ratchet pump, 72HR, sequence solenoid valve 20HR, and ratchet position limit switch 33HRF. How could the ratchet be troubleshot when the mechanism was internal to the assembly?

Solution. A screeching noise from the ratchet pump indicated relief valve VR5-1 had lifted at 1325 psi. Check clutch engagement, install a 1500-psi gauge on the F forward-stroke port, and verify hydraulic pressure. If pressure was satisfactory, suspect an issue with the hydraulic cylinders or possible rotor-to-stator contact. Disable 20CS and manually close 33CSX-1, then enable the ratchet with the clutch disengaged. If the ratchet cycled, rotor-to-stator contact was a likely cause. If the unit remained hot, allow it to cool while engaging the ratchet every 15 minutes in an effort to break the unit away. Solenoids could be checked by forcing them on and off and confirming movement.

Problem. Fuel regulator control specifications recommended 48 hours of cooldown. Mark I and II specifications did not provide a recommendation.

Solution. Select from the cooldown procedures described above and disable cooldown when the hottest wheelspace reached 200F or after five hours, whichever occurred first. Cooldown logic could be disabled by a Stop selection, disabling the ratchet and AC and DC pumps. Cooldown could be enabled by Master OFF and START.

SPEEDTRONIC MARK I UNIT MS3002J

The MS3002J four-bearing design was not expected to be subject to rotor bow because rotor span was relatively short. Therefore, a hydraulic ratchet was not provided. However, the mid No. 2 bearing between the compressor and HP turbine was subject to high temperatures on shutdown. A cooldown timer ran auxiliaries for four hours to cool the bearing housings.

Problem. Did the DC pump back up the AC pump in case of failure?

Solution. If the AC cooldown pump failed, the DC pump started on low lube-oil pressure, 62QL. Expected draw of the 5-hp DC pump was about 29 DCA. The charger was rated for 35 DCA, which could support the cooldown period.

Problem. The MS3002J experienced HP rotor vibrations early in the program.

Solution. Tests and data analysis concluded the issue was not rotor bow but was related to the balance procedure in use.

SPEEDTRONIC MARK II AND IV UNIT MS5002B

The MS5002B HP turbine was similar to the MS5001P. The hydraulic ratchet was mounted on the torque converter, and the sequence included a 10-hour cooldown timer. Timer 62CD picked up cooldown logic 1Z-1, which disabled the ratchet sequence and the AC cooldown pump.

Problem. What if the AC pump failed during the cooldown period?

Solution. If the AC cooldown pump failed during the 10-hour cooldown period, the DC pump started on the ratchet cycle, 20CS, and low lube-oil pressure, 62QL.

SPEEDTRONIC MARK II UNIT MS6001A

The MS6001A was introduced in 1979 with Mark II. Sequencing was essentially the MS5001P approach, with ratchet hardware upgraded to the torque-converter-mounted design. Cooldown logic was listed in the elementary index on sheet 03F, but 62CD did not appear on that sheet. No cooldown time recommendation was provided in the control specification. It appears that a cooldown timer similar to the MS7001 was considered but not implemented.

SPEEDTRONIC MARK II UNIT MS6001B

The MS6001B was introduced in 1981. Changes included a full-size AC lube-oil pump. The unit experienced startup vibrations, often above the alarm level of 0.5 ips. As the unit warmed, vibration tended to decrease, usually to below 0.5 ips. The situation was similar to the MS3002J. The issue was investigated, including design and manufacturing processes, but root cause was not immediately evident. Early Mark IV MS6001B elementaries listed cooldown logic in the elementary index on sheet 03F, but 62CD did not appear on that sheet. No cooldown time recommendation was provided in the control specification.

SPEEDTRONIC MARK IV UNIT MS6001B

The MS6001B Mark IV was introduced in 1984. Changes included a self-sequencing ratchet, which eliminated the 20HR solenoid. Cooldown logic was listed in the elementary index on sheet 03F, but 62CD did not appear on that sheet. No time recommendation was provided in the control specification.

Problem. How to troubleshoot the self-sequencing ratchet when major components were built into the assembly.

Solution. To support troubleshooting, the ratchet was supplied with plugged taps on all four hydraulic-cylinder ports. Pressure gauges could be installed on the forward and return ports to check operation of the internal 33HR transfer valve. As outlined in the MS5001P procedure, checking clutch engagement, confirming lifting of relief valve VR5-1, and operating the ratchet with the clutch disengaged typically identified the cause.

Problem. Cooldown logic appeared in the elementary index, but 62CD and a time recommendation were absent.

Solution. Select from the cooldown procedure options below and disable cooldown when the hottest wheelspace reached 200F or after five hours, whichever occurred first. Cooldown could be disabled by selecting COOLDOWN OFF, disabling the ratchet and AC and DC pumps. Cooldown could be enabled by selecting COOLDOWN ON.

The presence of cooldown logic, 62CD, in the Mark II, IV, and V elementary indexes indicates that a cooldown timer was considered for the MS5001 and MS6001. A cooldown timer was implemented in the MS7001. However, logic termination similar to the 10-hour timer on the MS5002B was not added. One suggested reason for vibration on the MS6001 was that customers were taking units off cooldown prematurely, resulting in thermal bow. The decision was made not to add cooldown-timer logic to the MS6001. If a customer experienced startup rotor vibration, insufficient cooldown time was a likely contributor.

SPEEDTRONIC MARK V UNIT MS6001B

The MS6001B Mark V was introduced in 1992. There was no reference to cooldown logic in the cross-reference, CSP, or control specification. Startup vibration remained an issue, but both frequency and amplitude became less pronounced after 1995. The root cause remained unresolved.

Some speculation centered on the compressor-to-turbine rotor distance piece. Historically, rotor designs used a cylindrical distance piece. The MS6001 distance piece was tapered, possibly to accommodate canted combustion liners. The theory was that machining of the tapered distance piece was not always consistent, introducing balance variability. It is believed that machining processes were investigated and improved around 1995.

Problem. Could the cooldown sequence be turned off?

Solution. Select from the cooldown procedure options below and disable cooldown when the hottest wheelspace reached 200F or after five hours, whichever occurred first. Cooldown could be disabled by selecting COOLDOWN OFF, disabling the ratchet and AC and DC pumps. Cooldown could be enabled by selecting COOLDOWN ON.

COOLDOWN PROCEDURE OPTIONS

Standard cooldown. Monitor wheelspace temperatures and disable cooldown when the hottest wheelspace reached 200F. The Mark V MS6001B control specification, ratchet section, recommended a minimum five-hour cooldown to prevent damage to bearing babbitt.

Forced cooling. Forced cooling was developed on the factory test stand when the test stand was the critical production facility. Cooldown could be reduced from several hours to a few hours. Engineering determined that cooldown could be terminated when the hottest wheelspace was less than 200F.

Forced cooling was also used when a unit had a problem and required disassembly for corrective action. Because starting-diesel operating time was not limited, the unit could be put on crank and run until cooldown criteria were met. With an electric start, the starting motor was limited by a 60C temperature rise. In that case, a thermometer was placed in the motor exhaust, and cooldown was paused to allow motor cooling. In most cases, wheelspace criteria were met before the motor reached 60C.

Intermittent cranking. Intermittent cranking could be used if the diesel or starting motor was limited. One example was high diesel cooling-water temperature on hot days exceeding cooling-system capability. The same approach could be used for the starting motor. Pause cranking and allow the motor to cool by 10C, then crank until 60C was reached, and repeat as needed.

Warm-start procedure to work out rotor bow. If the rotor could not be moved because of a major failure, such as a lube-oil-system failure, correct the failure and place the unit on the ratchet for 24 hours. Then attempt a start. If vibration reached the alarm level of 0.5 in/sec, shut down. Attempt another start and repeat. After two warm starts, vibration should begin to decrease. Continue starts until the unit reached FSNL with vibration below 0.5 in/sec.

This warm-start approach was often successful in working bow out of the rotor. Two examples requiring warm starts included an accessory-base fire caused by a failed torque-converter hose that tripped the unit at base load, and an accidental energizing of both AC and DC piggyback motors that disabled both. CCJ

Closing the inspection gap on switchyard high-voltage assets

Tip: Implement a structured visual inspection program for switchyard high-voltage equipment between scheduled maintenance intervals, supported by periodic thermal and acoustic diagnostics, to catch early indicators before they become forced outages.

Bryan Miller of RATTLIR LLC recently called CCJ editorial offices to flag something he keeps seeing at gas turbine sites: a significant gap between what standard compliance programs cover and what is actually happening to high-voltage equipment in plant switchyards.

PRC-005-based maintenance programs are solid. They confirm that protection schemes will operate correctly during a fault. Relay tests, battery inspections, CT and PT validations, and trip circuit checks all serve essential functions. Miller is not disputing that. His concern is narrower: these programs were not designed to track how equipment is aging or how mechanical stresses are developing in the months between test cycles.

The switchyard is full of mechanical interfaces. Bolted connections loosen under thermal cycling. Disconnect blades lose contact pressure. Grounding components corrode. Surge arresters absorb moisture. These are slow-moving degradations, not sudden failures, and they often escape detection until something trips or fails outright.

Miller developed a high-voltage visual inspection checklist specifically for switchyard equipment at gas turbine sites (scan QR). He also assembled a failure modes reference table that describes what these failures look like in the field and, critically, why they are often missed (scan QR). CCJ reviewed both documents along with Miller's white paper on switchyard visibility and predictive maintenance. The picture that emerges is consistent: early indicators are there. Plants are not always seeing them.

The worst-case scenario. Proactive transformer monitoring, testing, and maintenance can greatly reduce the risk of a catastrophic loss

What the failures look like

Miller's failure modes table documents seven categories of high-voltage assets and the early symptoms each typically produces before a fault occurs. Several entries share a common trait: the equipment looks fine during normal operation and inspection, but heating, degradation, or both develop under load or over time.

- **Conductors and terminations** show increased resistance from strand fatigue, oxidation, or poor compression. Early symptom is uneven or localized heating under load, sometimes presenting as phase imbalance. The failure is easy to miss because the hardware appears visually intact. Heating may not be present during no-load conditions.
- **Disconnect blades and jaw contacts** lose contact pressure or suffer surface degradation. The early symptom is phase-specific heating at the blade-to-jaw interface. Again, the equipment operates normally in most respects. The heating signature only becomes apparent during load transfer or sustained operation at elevated output.
- **Bushings,** both transformer and breaker types, degrade from internal cracking, moisture ingress, or surface contamination. Early symptoms include subtle partial discharge, localized heating, or tracking visible under wet conditions. Because the damage is internal, the exterior often appears normal. Escalation can be rapid once underway.
- **Surge arresters** develop moisture ingress or seal degradation. Early symptom is localized heating or external cracking. Miller notes that arresters often look intact after moisture ingress begins. Failure may not occur until a surge event triggers the compromised unit.
- **Grounding and bonding components** corrode or develop high-resistance connections. The early symptom is no visible symptom at all. These components are considered non-energized and often fall outside routine inspection scope. A failed ground does not announce itself until a fault event.
- **Structural components,** including masts, air terminals, and supports, corrode or loosen gradually. Early indicators are minor. Damage may be internal or weather-dependent, and deterioration progresses slowly without producing obvious operational signals.

Miller's inspection checklist covers all of these asset categories. The checklist is organized in the sequence an inspector would encounter equipment walking through a switchyard: GSU, auxiliary and station service transformers, surge arresters, braided connections, CTs, electrical disconnects, circuit breakers, conductor and buswork, VT/PT, insulators, and station structures. Each section includes specific prompts.

For disconnect blades: look for signs of arcing, audible noise, ozone odor, or corona activity. Check whether blades are fully seated and aligned evenly across all phases.

For transformers: record winding and oil temperatures against historical maximums, check bushing oil levels, look for tracking or contamination on bushings, inspect desiccant breathers.

For conductors: look for broken strands, excessive sag, and abnormal movement or contact with nearby structures.

For insulators: check for cracks, chips, contamination buildup, and proper corona ring alignment. For station structures: verify lightning rods and ground wires are intact, look for animal nests or vegetation that could affect clearances.

The goal of this checklist is not to replace established maintenance procedures. It is to help operators and maintenance personnel recognize early indicators of abnormal equipment conditions between scheduled maintenance intervals, when compliance-based programs are not looking.

Thermal and acoustic imaging add coverage

Visual inspection alone has structural limits. Much of the critical switchyard hardware sits elevated. Ground-level observation can confirm gross condition, but it cannot clearly evaluate connection surfaces, contact integrity, or subtle changes at height. This is where periodic diagnostic assessments provide complementary value.

Thermal imaging is most effective as a comparative tool. NETA and NFPA standards reinforce this by focusing on temperature differentials, delta T, between similar components under similar loading conditions. A 10-degree differential between phases on the same bus structure warrants investigation. A 15-degree differential may warrant corrective action. Absolute temperature is less useful; delta T under controlled load conditions is the diagnostic signal. In the field, thermal imaging can reveal high-resistance connections from looseness or corrosion, load imbalance across phases, degraded contact surfaces in disconnects, deteriorating compression terminations, and localized heating at developing failure points.

Ground-based thermal inspections provide a useful baseline. Aerial thermography, typically performed using drones, improves the evaluation of elevated components by reducing the influence of ground-level background temperatures and allowing closer approach to specific connections and hardware interfaces. This is not a replacement for ground-based inspection. It is a complementary tool that increases confidence in the assessment of hardware that cannot be clearly seen from below.

Acoustic imaging addresses a different failure mode: electrical discharge that does not present as heat. Corona, surface tracking, and partial discharge can occur on energized equipment without obvious visual or thermal indicators. These conditions are influenced by contamination, moisture, insulation condition, and environmental exposure. They develop at connections, insulators, and terminations throughout the switchyard. Acoustic imaging detects the high-frequency sound signatures associated with electrical discharge, allowing inspectors to locate and assess areas of electrical stress directly.

Miller's white paper makes a practical observation about the cumulative value of these approaches. When diagnostic information is available ahead of a planned outage, maintenance scope can be better defined, materials more accurately planned, and resources more effectively allocated. Unexpected findings during the outage are reduced. In some cases, identifying a degrading component early allows it to be addressed before it fails and forces the outage itself. Preventing a forced outage avoids the operational disruption, safety risk, and cost associated with reactive work.

Applying this at your facility

Miller's checklist and the supporting failure modes table are tools designed for use during routine walkdowns. The checklist is straightforward to integrate into existing operator and maintenance routines. It does not require special access, additional clearance, or outages to execute. It requires someone walking the switchyard with a checklist, adequate light, and enough familiarity with the equipment to recognize when something looks different than it did last time.

The thermal and acoustic diagnostic layers are periodic assessments rather than continuous monitoring. Miller recommends incorporating these into the maintenance plan on a schedule aligned with unit cycling patterns and historical failure experience. Aerial thermography, where permitted by site safety and regulatory requirements, is particularly useful for pre-outage inspections where it can influence scope decisions before maintenance teams are on site.

The inspection hierarchy Miller proposes is: structured visual walkdowns as the consistent baseline, thermal imaging to identify thermal anomalies and phase imbalance under load, and acoustic imaging to detect electrical discharge activity that thermal methods do not capture. Together, these approaches cover more failure modes than any single method alone.

Risks and caveats

No inspection program eliminates failure risk. These approaches improve the probability of detecting early indicators before they become forced outages, but several conditions reduce their effectiveness.

Thermal imaging requires adequate load on the equipment being inspected. Inspections performed on lightly loaded or offline equipment will not reveal the heating signatures that indicate developing resistance or imbalance. Consistent loading conditions across inspection intervals are necessary to make meaningful comparisons over time.

Acoustic imaging is sensitive to ambient noise and wind. Results are most reliable during low-wind conditions and may require repeat assessment if initial findings are ambiguous.

Visual inspection quality depends heavily on the inspector's familiarity with the equipment. An inspector who does not know what normal looks like is less likely to recognize early indicators of change. Cross-training operators and technicians on what to look for improves consistency.

Grounding system degradation, which Miller identifies as one of the most frequently missed failure categories, produces no pre-fault symptoms that visual, thermal, or acoustic inspection can detect. Periodic ground resistance testing addresses this gap but falls outside the routine walkdown scope.

Corona ring orientation and electric-field grading hardware are not visually obvious failure modes. Damage develops gradually and may not affect equipment appearance. Acoustic imaging provides the best coverage for these conditions.

Animal intrusion and vegetation growth can produce rapid deterioration in clearances, but the triggering event may not occur during a scheduled inspection window. Regular inspection intervals, rather than infrequent or event-driven walkdowns, provide better coverage for these dynamic conditions.

Bottom line. The gap Miller identified is not a compliance gap. PRC-005-based programs confirm fault response correctly. The gap is a condition-monitoring gap: slow-developing mechanical degradation in the switchyard is not always visible to the programs designed to confirm protective function. Structured visual inspections, periodic thermal imaging, and acoustic diagnostics together provide broader coverage. They shift the inspection focus from obvious failures to early indicators of change, which is where planned outages beat forced outages every time. CCJ

Inspection checklist

Failure modes

FlameSheet™, wet compression give 7F.03 operators a faster path to more MW

The gas turbine fleet is being asked to carry more load, and in many cases to do it quickly. The U.S. had 42 GW of generation capacity at the end of 2025, according to Industrial Info Resources, with another 32 GW under construction. Forecasts point to more than 90 GW by 2030. Even that buildout may fall short as load grows with new manufacturing, expanding communities, and hyperscale data centers.

That leaves owner-operators with a practical question: Where do the incremental megawatts come from when OEM production slots are spoken for and nuclear additions remain years away? One answer is to get more out of installed machines. For many plants, that means looking hard at aftermarket upgrades that can be installed on outage schedules measured in days, not years.

Hanwha Power, formerly PSM, and Mee Industries are making that case with a package aimed squarely at GE 7F.03 units equipped with DLN 2.6 combustion. Mee Industries wet compression can add substantial output, 15-20% per turbine. Hanwha Power's FlameSheet combustor upgrade addresses the dynamics and emissions limits that often prevent those machines from taking full advantage of that water flow.

MECHANISM

Wet compression or "high fogging" injects demineralized water as very fine droplets into the gas turbine inlet. More droplets are introduced than can be fully evaporated in the inlet air stream. The immediate effect is lower inlet-air temperature and higher mass flow. Additional carryover into the compressor provides an intercooling effect that reduces compressor work and boosts output.

Mee Industries says wet compression can deliver a 5% to 10% power increase for each 1% of water injection. Systems spraying more than 2% of air mass flow have been installed. On a 100-MW plant, 1% wet compression can add about 10 MW; 2% can push the gain toward 20 MW. The attraction is straightforward: the equipment can be installed in a few days and costs far less than a new gas turbine or combined-cycle block.

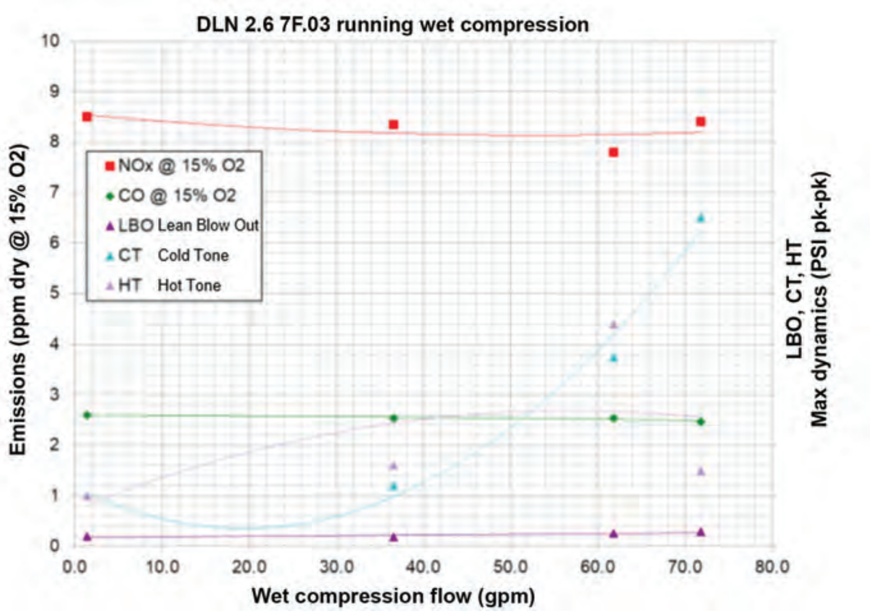
The idea is not new. Jens Williams Aegidus Elling used interstage water injection on a gas turbine as far back as 1903 to produce compressed air for a manufacturing plant. Similar principles later were used to increase takeoff thrust in aircraft. In the power sector, Mee Industries installed its first wet compression system in the United States at Ralph Green Power Station in 1996 under an EPRI capacity enhancement program. That system cooled inlet air, injected about 0.5% of air mass flow as liquid water, and delivered almost a 6% power boost on a GE 7EA. Several hundred systems have since been deployed worldwide.

The limiting issue on a 7F.03 is not whether wet compression works. It is whether the DLN 2.6 combustor can tolerate the cooler compressor discharge temperatures that come with higher water flow. According to Mee Industries, combustion dynamics on that combustor become more sensitive as wet compression reduces compressor discharge temperature. Those dynamics arise from the interaction of fuel-air mixing, heat release, and acoustic pressure waves in the combustion system. Left unchecked, they can drive instability, hardware damage, flame blowout, and emissions spikes (Fig 1).

Mee Industries' practical limit on a 7F.03 with DLN 2.6 typically is 1% wet compression unless the plant has either an SCR or an emissions permit that allows higher NOx. The reason is simple. More water lowers firing temperature. To break through the resulting dynamics zone, operators may have to raise firing temperature again, and that can push NOx above the permit limit. Mee Industries notes that other OEM DLN systems generally can operate at higher flows, and on other OEM gas turbines the company has successfully run wet compression levels of 2%.

Hanwha Power's answer is the FlameSheet combustor. The design uses a two-stage, radially inflow combustor-within-a-combustor arrangement that supports staged operation over a wide load range. At high load, both combustors fire, with the outer combustor forming a broad annular flame around the inner one. At low load, the outer combustor does most of the work. Hanwha Power says trapped-vortex stabilization helps maintain flame stability and generate enough heat at low load to consume CO, which otherwise can limit turndown. The package also includes main inline fuel injection, a dome turn for better mixing, and an advanced liner coating.

On a 7F.03, Hanwha Power reports several benefits beyond wet-compression compatibility: up to a 30% improvement in gas-turbine low-load operating range with single-digit NOx, CO below 9 ppm, turndown proven as low as 26% on a recent 7F-class application, inspection intervals up to 32,000 hours or 1,250 starts, and fuel flexibility up to 60% H2 by volume in blends. The upgrade is compatible with existing turbine



1. Testing on a 7F.03 with a DLN 2.6 combustor running wet compression found that as the amount of wet compression increases beyond 40 gpm of wet compression, combustion dynamics rise sharply, introducing instability and the potential for hardware damage and flameout controllers, Hanwha Power's AutoTune system, and current fuel skids.

OPERATIONAL IMPLICATIONS

For operators, the real story is how the package changes the tuning window on a 7F.03. Mee Industries cited a case with no SCR and a 9-ppm hourly average NOx limit. In that configuration, 1% wet compression lowers compressor discharge temperature by about 100F. Beyond that point, combustion dynamics become unacceptable. The DLN 2.6 combustor cannot tune them out, and restoring firing temperature enough to clear the dynamics zone pushes NOx above the permit limit. Result: wet compression is capped at 1%, even though that still adds about 10 MW.

A nearly identical 7F.03 with no SCR but a 15-ppm hourly NOx limit had more room to maneuver. When dynamics appeared at 1% wet compression mass flow, operators could raise firing temperature back to 2420F, break through the dynamics zone, and move to 2% wet compression. That unit gained 16 MW. Same machine class, same basic wet-compression concept, different answer because the combustion system and permit envelope set the boundary conditions.

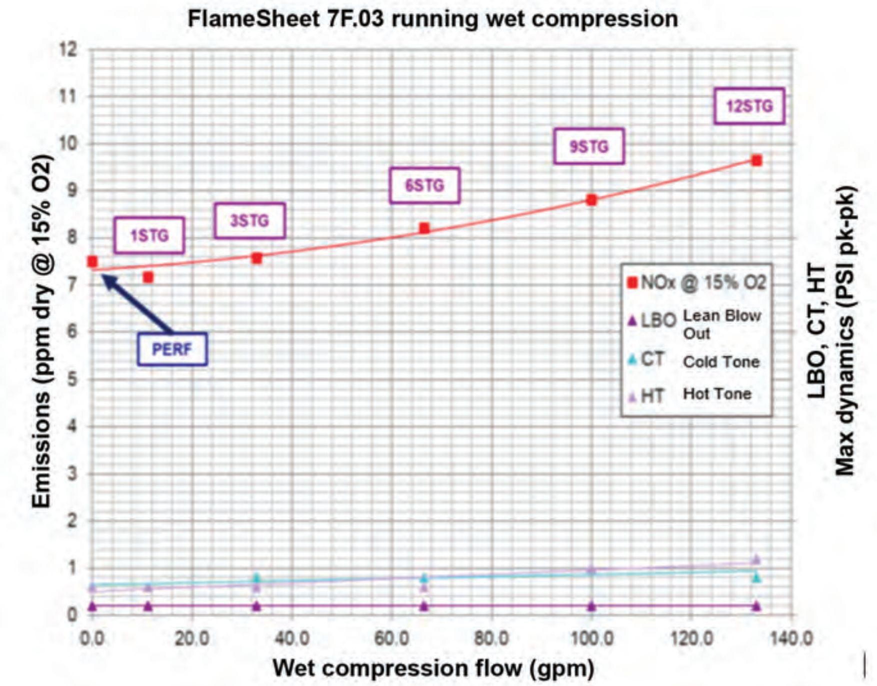
Hanwha Power argues FlameSheet changes that equation. Testing on a 7F.03 with DLN 2.6 showed combustion dynamics rising sharply once wet-compression flow exceeded 40 gpm on the OEM combustor. With FlameSheet in place, Hanwha Power says water flow can be pushed to 140 gpm while keeping NOx below 10 ppm (Fig 2). The company attributes that to multiple fuel-injection stages inside the combustor and to the AutoTune system, which shifts fuel distribution among stages to hold dynamics at acceptable levels.

The commercial effect can be material, particularly for plants in capacity markets. On a 7F.03 with the OEM combustor, Hanwha Power says 1% wet compression is about the practical ceiling if the goal is to avoid a NOx increase and damaging instability. That still can yield roughly 12 MW. With FlameSheet, the same machine can reach 2% wet compression, keep emissions below 10 ppm, and add about 22 MW. For a plant selling dependable capacity into PJM or a similar market, that difference is not academic.

Hanwha Power said a combined FlameSheet and wet-compression upgrade recently was completed on two 7F.03 units at one plant. Based on those results, the remaining six 7F.03s at the site are being added to the program.

OPTIONS AND TRADE-OFFS

Plants looking for more output from existing turbines have options, but each comes with a different set of constraints. One path is to stay with the OEM combustor and install wet compression only. That is the quickest and least intrusive route, and on some units



2. NOx stays below 10 ppm during wet compression when FlameSheet is deployed yielding a sizable increase in added MW output as water flow increases to 140 gpm

it still may provide around 10 to 12 MW. But on DLN 2.6-equipped 7F.03 machines, that approach can leave a good deal of value stranded if combustion dynamics or permit limits pin the machine at 1% water flow.

Another option is to pursue other aftermarket upgrades focused on efficiency, controls, or low-load operation. Those may improve dispatch flexibility or reduce lifecycle cost, but they do not necessarily solve the specific dynamics problem created when wet compression drags compressor discharge temperature down. For plants whose objective is immediate capacity gain, the decision point is whether the added combustor work is justified by access to a higher wet-compression limit.

That trade-off depends on plant configuration. An SCR, a higher NOx permit ceiling, or a different combustor platform can change the economics. So can market structure. Plants participating in capacity markets may value another 10 MW very differently from plants with less opportunity to monetize the gain. The right comparison is not upgrade cost in isolation. It is outage time, emissions flexibility, tuning margin, and how many additional megawatts the plant can actually sell after the work is done.

ACTIONS AND LESSONS

For 7F.03 owners running DLN 2.6, the first step is to treat wet compression as a combustion-system question, not just an inlet-cooling project. Review permit limits, determine whether SCR is present, map the unit's dynamics behavior against compressor discharge temperature, and quantify the real output available at 1% and 2% water flow. If the machine is boxed in by emissions and dynamics, a combustor upgrade may be what turns wet compression from a modest bump into a meaningful capacity addition.

Hanwha Power says FlameSheet can be installed in about 10 days during a planned outage, with maintenance intervals extended to 32k hours or 1,200 starts. Wet compression hardware can be installed at the same time at the compressor inlet and completed on site in about three days. For plants that need more MW before new-build options arrive, that is a timetable worth examining. CCJ

Applying FFS in power cycles: Benefits, risks, and best practices

Presenters: David Addison (Thermal Chemistry Ltd), Wolfgang Hater (H2O Training & Consulting), Barry Dooley (Structural Integrity).

Film forming substances (FFS), including film forming amines (FFA) and other proprietary non-amine based FFS, are increasingly used in steam and HRSG cycles to reduce corrosion during operation and, especially, during shutdown and layup. In a January 27, 2026, CCJ-hosted webinar, the IAPWS Power Cycle Chemistry (PCC) committee explained what current guidance supports, why results vary from site to site, and how plants can reduce risk when evaluating these products.

Read on for a full report on the webinar. For those looking for more details, scan the nearby QR code to access both the presentation recording and presentation slides at the CCJ website.

A consistent theme ran through the session: FFS is a supplement to a well-controlled base chemistry program, not a substitute for it. The presenters emphasized that deposit condition and corrosion-product transport must be understood before dosing begins, because several adverse outcomes reported in the industry are linked to applying FFS into cycles already trending toward repeat chemistry issues.

Addison first outlined IAPWS and the PCC committee's role in developing technical guidance documents intended to translate research and field lessons into practical direction for power producers. He noted that the webinar focuses on application fundamentals, monitoring considerations, and, importantly, the risk controls IAPWS recommends before and after an FFS change.

There are two Technical Guidance Documents (TGD) freely available on the subject at the IAPWS website (www.IAPWS.org).

FFS AND WHERE IT FITS IN CYCLE CHEMISTRY

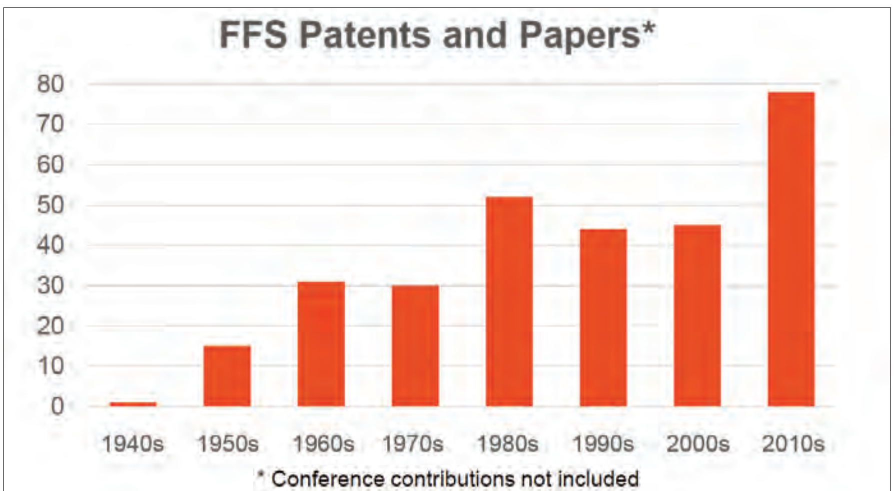
Hater defined FFS as an online and offline corrosion inhibitor that adsorbs on metal or oxide surfaces. These organic compounds are applied at low concentrations; volatility and steam transport depend on the specific molecule and formulation.

The webinar differentiated two common approaches:

- **Supplemental dosing** of an FFS while continuing a base program (for example, AVT, OT or PT).
- **"Full treatment" packages** in which the FFS is blended with other components intended to provide an entire treatment approach.

TERMINOLOGY MATTERS: FFA VERSUS FFP

The presenters stressed that many published studies and field analytics focus on film forming amines (FFA), while film forming products (FFP) may be non-amine proprietary formulations with limited molecule-specific information in the open literature (Fig 1). That gap affects both risk screening and the plant's ability to monitor what is actually circulating in the cycle.



1. FFS performance claims should be evaluated carefully in power cycles: the research record is growing, but it is still weighted heavily toward FFA, while many field applications involve proprietary FFP formulations with less published research detail

COMMON MECHANISM MODEL

Hater described a widely used conceptual model: a hydrophilic portion of the molecule anchors to the surface and a hydrophobic portion orients outward, creating a more hydrophobic interface. The practical goal is reduced metal water contact, which can reduce corrosion, particularly during shutdown and layup.

The presenters cautioned against treating hydrophobicity as proof of protection. Contact-angle and droplet observations can be misleading, and hydrophobic response alone does not confirm film integrity, coverage, or durability in all parts of the cycle.

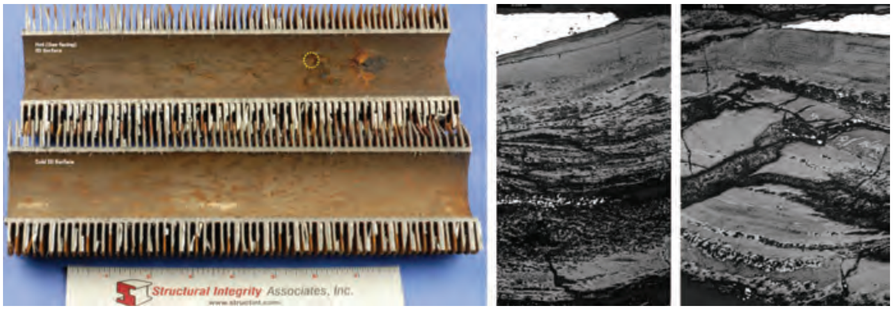
RESIDUALS, SURFACE CONFIRMATION, DECOMPOSITION IMPACTS

Because a portion of the applied product adsorbs on surfaces, water-phase residual does not directly quantify surface coverage. Monitoring typically combines conventional cycle-chemistry indicators with residual measurement and, when warranted, surface confirmation methods. For FFA, the webinar discussed established analytical approaches based on Bengalrose and noted that more definitive surface verification can be performed with specialized laboratory techniques.

The presenters also noted that film-forming organics can decompose in hotter areas of the cycle, creating species such as ammonia and low-molecular-weight organic acids that can influence steam purity indicators. Practical implication: plants should anticipate these effects and manage them within established steam and water chemistry control limits.

DOSING LOCATION, OPERATIONAL CAUTIONS

The session supported automated dosing at typical condensate or feedwater locations,



2. HP evaporator deposits and corrosion products after FFS application without a preliminary "Section 8" review in an HRSG operating on AVT(O). This has resulted in heavy deposit and a multi-laminated scale morphology which is consistent with rapid UDC mechanisms

with rate tied to flow. The presenters emphasized conservative dosing and avoiding overdosage. They also advised confirming compatibility with materials and elastomers in the dosing system, and ensuring product constituents do not create unacceptable risk for turbine contamination if non-volatile components are present.

BENEFITS OBSERVED IN SERVICE

Dooley summarized benefits frequently reported in combined-cycle and fossil applications:

- Lower iron transport in feedwater and condensate, with copper reductions often present in mixed-metallurgy plants.
- Improved shutdown protection on water-touched surfaces.
- Hydrophobic surface response that may be consistent with filming, but is not by itself proof of protection.

He also flagged an important limitation: film formation and protection on steam-touched surfaces remain questionable, because oxide growth on steam surfaces is not controlled in the same way by cycle chemistry.

PRE-APPLICATION SCREENING

A large portion of the webinar focused on adverse experiences reported in the industry when FFS are applied without understanding baseline conditions. Dooley listed outcomes that have been associated with poorly controlled application in some plants: increases in internal deposits, under-deposit corrosion and tube failures, gel-like deposits in drums and non-heat-transfer areas, turbine deposits, and plugging of strainers and filters.

CLEANING EFFECTS

Hater noted that some FFS products appear to "clean" by loosening porous oxide or mobilizing particulate, which can reduce transport after the initial period. The risk is that mobilized material can redeposit, accumulate as gels or agglomerates, or contribute to under-deposit corrosion in susceptible HRSG and boiler sections. The practical message is that deposit condition must be assessed before dosing begins; referred to as a Section 8 review as delineated in the IAPWS TGD.

EVAPORATOR DEPOSITS, TUBE FAILURE RISK

Dooley presented HRSG HP evaporator deposits and tube failures that occurred after application without adequate up-front review. He emphasized that deposit loading and deposit character in these circuits should be assessed using IAPWS tools before any FFS decision. He also noted that some recent failures suggest mechanisms that merit further research and broader industry sharing (Fig 2).

ACC FAC: SOMETIMES IMPROVED, NOT GUARANTEED

The webinar highlighted air-cooled condensers as a special case because two-phase FAC at tube entries can be visually tracked and indexed. Dooley provided an example in which an FFS program aligns with improved ACC indicators, while also stressing that many cases exist where neither FFA nor FFP arrests ACC FAC. Plants should treat claims of universal ACC improvement with caution and rely on site-specific monitoring (Fig 3).

BASELINE, SCREENING, VERIFICATION

The presenters repeatedly framed FFS as an engineered change that should be implemented with defined objectives, staff training, and clear verification methods. They described "Section 8" as a structured path to reduce risk and to determine whether an FFS program is delivering value.

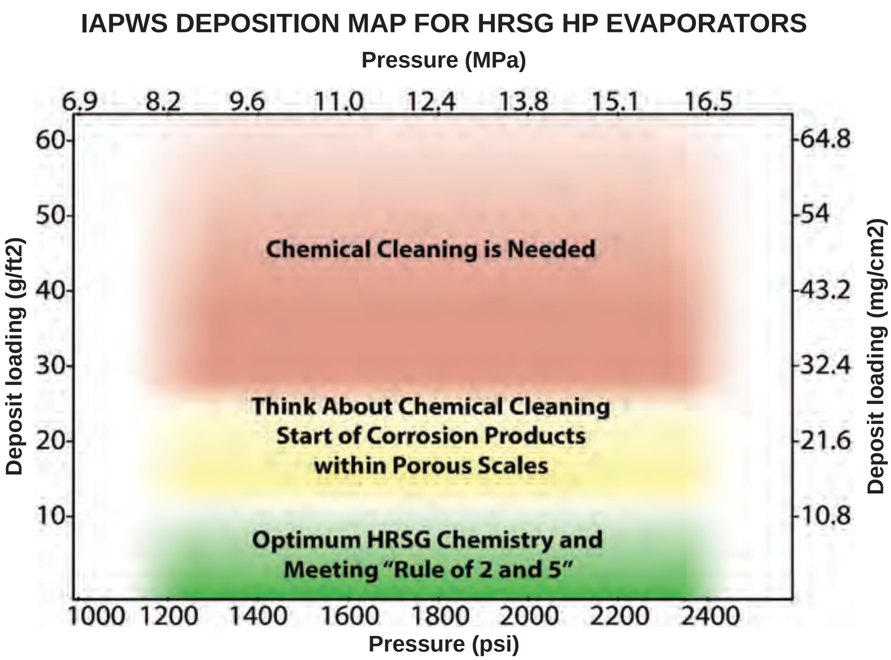
Key elements include:

- **High quality corrosion product monitoring.** Methods must include full digestion and detection limits suitable to resolve meaningful improvements.
- **Achievable iron targets.** Total iron levels should be compared to "achievable" benchmarks for the plant's treatment approach and configuration (including ACC units). Values above benchmarks indicate repeat cycle chemistry situations that require correction before adding FFS.
- **Flex-operation tools.** For frequently started units, the webinar describes tracking iron decay during startup and comparing performance to an IAPWS decay map.
- **Deposit screening.** For HRSG HP evaporators, deposit loading should be assessed and compared to IAPWS deposit mapping guidance. Plants in a repeat cycle chemistry condition should not proceed with FFS until underlying issues are corrected. It was also shown that deposit analyses are equally applicable for fossil plant waterwalls (Fig 4).

PRACTICAL TAKEAWAYS FOR OWNER/OPERATORS

The webinar's message can be summarized as: FFS can provide benefits when used as part of a disciplined chemistry program,

3. Two recurring field lessons from FFS programs: (1) gel-like deposits ("gunk") have been documented (left) in LP drums when products are applied without an up-front Section 8 review, and (2) ACC two-phase FAC (middle) can show improvement in some cases, evidenced by reduced DHACI and lower condensate iron (right), but many plants see little to no arrest, so claims of universal ACC benefit should be treated cautiously



4. IAPWS deposit map for HRSG HP evaporators separates "good" (green) from "bad" deposit conditions and highlights when deposits (in the red area) indicate a repeat cycle chemistry situation. Plants should evaluate deposit loading and character before adding FFS, and avoid proceeding when deposit conditions fall into the red zone until underlying transport and chemistry drivers are corrected

and they can increase risk when applied into cycles with unmanaged transport and deposits.

A practical checklist from the session:

- Optimize base chemistry first, then evaluate FFS as a supplement.
- Establish baselines for iron transport, deposit condition, and key chemistry parameters before dosing.
- Dose conservatively, avoid overdosage, and use fit-for-purpose analytics for residuals and (when needed) surface confirmation.
- Use IAPWS screening tools, including achievable iron targets, flex-operation indicators, and HRSG and boiler deposit assessment, before committing to full-scale application.
- If switching products, avoid mixing formulations and manage the changeover methodically.

Much research is still needed to fully understand FFS with particular emphasis on FFP. IAPWS will shortly publish an IAPWS Certified Research Need (ICRN) which delineates the main research needs. Contact Barry Dooley (bdooley@structint.com), Wolfgang Hater (wolfgang.hater@t-online.de), and David Addison (david.addison@thermalchemistry.com) to participate. CCJ

ACCUG 2025: Corrosion, wind, and gearboxes drive the next wave of ACC improvements

The 15th annual meeting of the Air-Cooled Condenser Users Group (ACCUG) was held July 29-31, 2025, at the Lake Granbury Conference Center in Granbury, TX. Participants included owner/operators as well as leading suppliers and international consultants gathered to discuss improving unit and system performance, share valuable lessons learned, and reduce overall operating expense. Those interested can easily access the source material for the following presentation recaps (as well as prior years) at the ACCUG website. The ACC Users Group (acc-usersgroup.org) was established in 2009.

2025 sponsors included Chemted LLC, Conco Services, FanTR, Galebreaker Industrial, Groome Industrial Service Group, MVM EGI, Projectile Tube Cleaning and SPG Dry Cooling, along with support by the International Association for the Properties of Water and Steam (IAPWS) and Combined Cycle Journal.

Barry Dooley (Structural Integrity), session co-chair, opened the event with a detailed discussion of *Corrosion and cycle chemistry* issues specific to air-cooled condensers, focusing first on the serious consequences of corrosion/flow-accelerated corrosion in these units.

A useful feature was his explanation of the Dooley, Howell Air-Cooled Condenser Corrosion Index (DHACI), a specific and user-friendly guideline for internal inspections. He highlighted visual and microscopic inspection results to assess damage over time. He then turned to monitoring condensate iron to categorize corrosion and track improvements. A highlight of this discussion was a review of the IAPWS Corrosion Product Decay Map. Dive deeper into corrosion monitoring in flexible and fast-starting plants by scanning the nearby QR code.

He ended with an update review of film-forming substances, and valuable information freely available through https://iapws.org/

Brian Courtright, Anodamine, followed with *Film-forming chemicals for ACC corrosion mitigation*. He featured four identical H-class 1x1 CCGTs at two sites, with triple-pressure HRSGs. Since 2021, all units have been running Anodamine AVT(O) with ammonia.

Tracing chemistry evolution back to 2017, he stated that chemistry had been the root cause of many ACC (and other system) corrosion issues. Specific to the ACCs, he showed corrosion before AVT(O) Anodamine, related to the DHACI (Fig 1). Similar examples were given for turbine extraction ducting and the LP steam turbine.

Next was Sean Cusick, SPG Dry Cooling, discussing *Baseline FAC inspections at the Hunterstown Generating Station* in Pennsylvania. The inspections occurred just before Anodamine addition to the steam cycle. Inspection methodologies included ultrasonics for tube thickness analysis. The baseline was established to monitor the effects of Anodamine over time.

In an interesting global overview, Andy Howell, co-chair, then presented a survey of *Primary problem issues with air-cooled condensers*. The ACC Users Group had conducted a survey of users to capture priority concerns from ACC operators, to focus ACCUG efforts on areas of greatest need for

ACCUG 2026
July 14-16 | Nashville, Tenn

Highlights: Visit to new TVA Cumberland CCGT. Special focus area on the latest developments in ACC technology and commissioning. Contact Andy Howell, aghowell19@gmail.com, for more information.

1. ACC before and after Anodamine

2. Dry cooling tower at GaoHe 1320 MW thermal power plant

problem resolution.

Of the 17 resulting issues, 4 were listed as primary:

1. Generation losses in hot weather (possibly compounded by air in-leakage).
2. Generation losses due to wind. (The 3 m/s ACC design standard is often not adequate for actual site conditions.)
3. Air in-leakage/air removal.
4. Gearboxes. This includes oil leaks and seals, bearing column durability (and shaft failures), and general gearbox failures.

Other areas of concern included leak repairs on ACC tubes, vibration, water washing systems, fan blade reliability, noise, and others. All were discussed by conference participants in detail.

György Budik, MVM EMI, then showed the largest hyperbolic dry cooling tower in the world, a 220 m high tower serving two 660 MW units (Fig 2). Budik showed more conventional units in his global review, including hybrid wet/dry units.

His focus then turned to dry cooling at nuclear power plants, a promising application that has rarely been implemented.

Jeff Ebert and Gary Mirsky, Galebreaker, then discussed *Wind effects on an ACC at a geothermal power station*. See Fig 3.

John Moore, Moore Fans, next offered a presentation on *Mechanical design of axial flow fans for air-cooled condensers*.

The focus was on durability, noting the unique mechanical stresses, both static and dynamic, for ACC applications. His process overview covered aerodynamic design, structural design and analysis, and testing and evaluation.

Benefits discussed included high aerodynamic efficiency, optimum structural design, fatigue resistance, use of corrosion-resistant materials, ease of installation, and reduced maintenance.

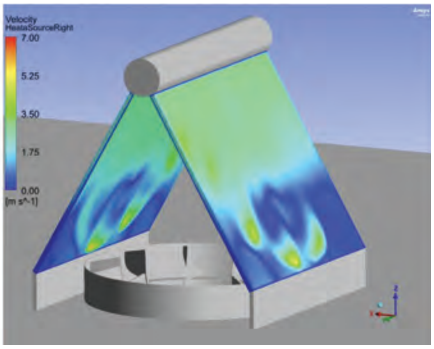
Andy Howell, co-chair, then offered a presentation submitted by Mohamadreza Vaghar, Mapna Development Company, Iran, on *Fluid flow analysis in the air-cooled condenser system*.

This covered investigations of air flow modifications over tube bundles to improve efficiency, and a technical evaluation of the absence of wind walls.

The goal of the first is to improve air flow uniformity. The proposed solution is stator blades with and without a shroud. Use of the shroud (Fig 4) produced a more uniform flow profile and increased average velocity.

Howell then facilitated a discussion of *Misting for megawatts* addressing a primary ACC concern of reduced generation during hot weather (elevated backpressures in ACCs). Misting has specifically been under-utilized due to its inherent inefficiency (droplets not fully evaporating) and the traditional assumption that only highly demineralized water can be used to avoid mineral deposit buildup. These assumptions are valid but their possible reconsideration was discussed.

Traditional actions to improve vacuum have included air in-leakage reductions, adding ACC rows, increasing fan speed, reducing wind effects, and fin cleaning. These



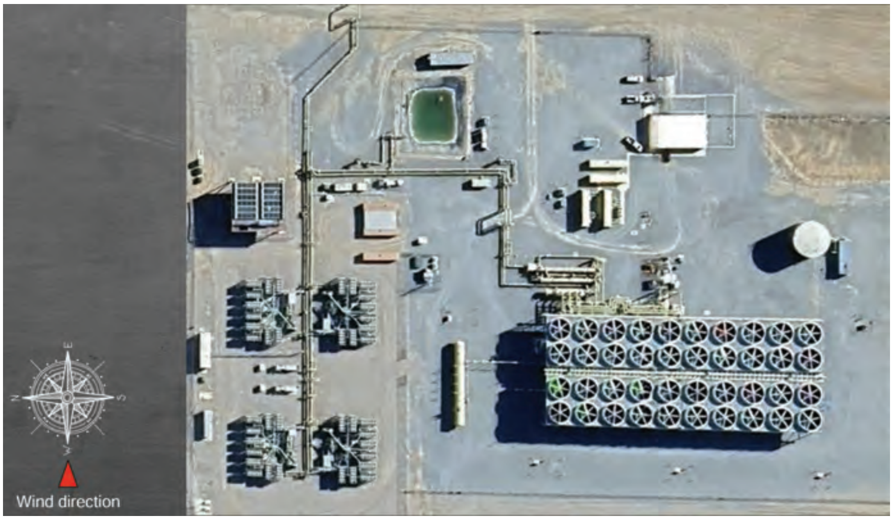
4. ACC design with stator blades and shroud

steps can significantly improve ACC vacuum in many cases but are limited from achieving full load in hot weather.

Options available to achieve full load must include evaporative cooling, including water misting, parallel cooling with a water-cooled condenser, and use of a deluge system. However, evaporative systems may come up short in achieving adequate backpressure for full load if other factors are not also addressed, such as wind effects, air in-leakage and fin cleaning. A complete evaluation with recommended improvement steps is necessary to fully recover lost generation in hot weather.

Dewald Visser, Asset Performance Partners, offered *Towards a broad-spectrum approach to testing modern air-cooled condensers*. He covered early and modern ACC designs, air in-leakage testing methods and equipment improvements, liquid ring vacuum pump challenges, dephlegmators, condenser operation, dissolved oxygen level management, and a generalized broach-spectrum approach to testing and analysis.

Bernardo Navarro, Fan Technology Resources (FanTR) and Jared Miller, Evapco Dry Cooling, discussed an *Innovative*



3. ACC at geothermal site subject to high seasonal winds

5. FanTR installation

fan blade with aerolastic design. The focus was a new cooling fan blade named X-flow, designed for "extremely high efficiency." Other benefits of this unique aerodynamic design are lower operational costs, reduced vibration, and an interchangeable hub with all FanTR models (Fig 5).

The manufacturing process is one-shot vacuum infusion for increased durability. This monolithic construction eliminates adhesives or bonded parts.

The final design result is less stress on gearboxes and structures, less influence by cross winds, reduced maintenance costs, and longer life.

Jason Sobotik and Gerald Frank of Groome Industrial Service Group presented a practical approach in *ACC fan life-cycle maintenance* that treats reliability as a system issue in which blades, balance and alignment, drivetrain health, and structure interact. They began with common vibration drivers, including particulate impingement, blade damage, and erosion, then link these to owner impacts such as rotor imbalance, lost fan efficiency, and accelerated wear. Recommended corrective actions focus on field work: vibration analysis and balancing, routine inspections, cleaning, and blade resurfacing to recover performance before considering replacements.

They provided an "operator's translation" of vibration data: displacement for peak-to-peak movement and velocity, in inches per second or millimeters per second, for trending and severity calls. Response guidance scales with risk. Minor vibration often indicates cleaning or alignment needs. Significant vibration warrants balancing, alignment checks, and looseness investigation. Major vibration may justify fan, motor, or gearbox replacement when risk is unacceptable.

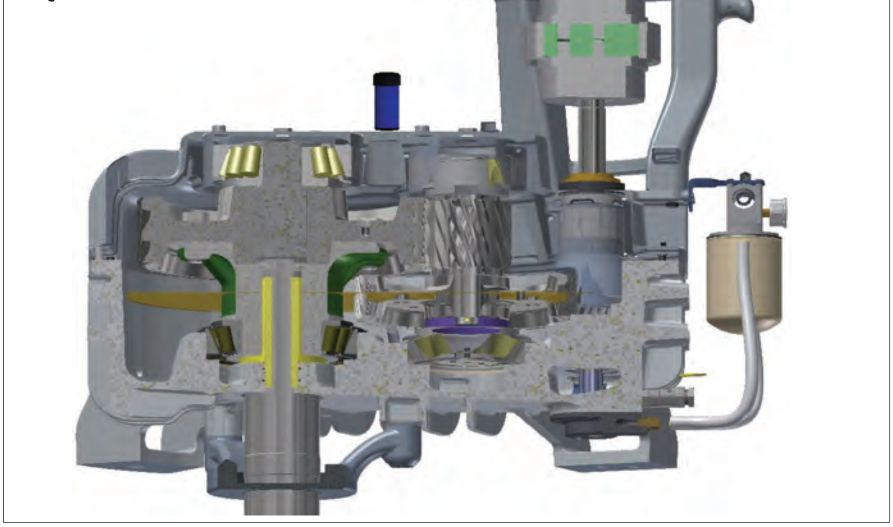
They widened the lens to drivetrain and structure. For gearboxes and motors, root causes include oil-system gaps, misalignment, bearing wear, and overloading. Structural contributors include resonance, wind and weather, corrosion, and fan-to-shroud contact.

The preventive cadence is clear: monthly visual checks, quarterly vibration and torque checks, annual full-system inspections with oil changes, pitch checks, and cleaning, plus gearbox overhaul or replacement every 3 to 5 years. Benefits include reduced downtime, higher reliability and efficiency, lower parasitic load, improved safety, and better compliance.

Patrick Saussus, Evapco, and Bob Neely, Amarillo Gear Company, addressed *Common problems with gearboxes* and offered details on solutions. The items discussed included oil leaks (output and input shaft), gear tooth wear and breakage, bearing failures, and oil pump malfunctions.

The Amarillo Quantum Q500 (Fig 6), designed specifically for ACC application, features no oil seals (no replacements), the output shaft bearings located in the oil sump

6. Quantum 500 half view



(no grease or regreasing required), and no lip seals in the input shaft (for reduced maintenance).

They offered details on gearbox design and manufacturing, castings, gear design specifics, tapered roller bearings, lubrication benefits, and leak-free design (input and output). They then addressed retrofit options and benefits, including installation examples.

Dan Rosseljong, Sumitomo Drive Technologies, presented *Top five considerations for maximizing ACC gearbox return on investment*.

1. Starting torques. Due to frequent starts and stops, this discussion addressed comparisons of parallel gearbox (forced-draft ACC) and right-angle gearbox (induced-draft ACCs) designs as well as use of variable frequency drives to limit starting torque.
2. Maintenance-friendly gearbox sealing and lubrication.
3. Proper installation and alignment.
4. Regular inspections and inspection points.
5. And the Sumitomo policy of open support, namely no charge for asking questions.

Andy Howell then concluded with a *Focus topic: cold-weather ACC operation*. Potential concerns are startup with cold lines, condensate freezing, and the general impacts of offline system freezing. Air in-leakage can also bring sub-freezing air into the condensate and air extraction pathway.

The discussion centered on key indicators of potential or existing problems, preventions, and responses.

Wolf Hollow II: The conference concluded with an ACC tour at Constellation's 1115 MW Wolf Hollow II Generating Station in Granbury, TX (Fig 7).

Again, additional information on the Air-Cooled Condenser Group is available at https://acc-usersgroup.org/. CCJ

7. Wolf Hollow II Generating Station, Constellation Energy

Stop compressor debris at the source with field-applied HVTS

"Stop debris at its source, not after it forms," cautions Eric Duvekot, VP of Engineering at Integrated Global Services (IGS), as he explains how field-applied high-velocity thermal spray (HVTS) addresses oxide flaking in the hot, high-pressure compressor sections of advanced-class gas turbines, and outlines proof points from OEM testing and fleet experience (Fig 1). The webinar session, viewable by scanning the QR code, includes application methods, scope options and Q&A on components and materials.

Background. Rising compressor pressure ratios in advanced frames drive late-stage compressor temperatures above 500C, exposing low-chrome steels in casings and other internals to accelerated oxidation. The resulting oxide scales lose tenacity and exfoliate as flakes that migrate downstream. These flakes can plug cooling passages, erode thermal-barrier coatings and contribute to hardware distress (Fig 2).

Challenge. Users report visible flaking in multiple fleets and OEMs, with severity influenced by operating conditions. In some cases, oxide exfoliation occurs simply from daily thermal cycling—sun heating by day, cooling at night—without machine operation. Consequences range from S1 vane damage to shovel-worthy accumulations of debris during inspections (Fig 3).

Solution. HVTS is presented as a preventative "stop-at-the-source" measure. The process applies a non-diffusion, mechanically bonded superalloy cladding at 250–500 µm thickness (10–20 mil) to low-chrome steel surfaces susceptible to oxidation. Adhesion strength typically exceeds 60 MPa, with OEM lab, thermal-cycle and third-party testing completed. As Duvekot explains, "The more area coated, the less debris travels in the machine."

Field application method. IGS designs masking and isolation tailored to each frame type, enabling coating during HGP or major outages with the rotor in or out. Surface prep uses tightly controlled abrasive blasting to achieve cleanliness and anchor profile, followed by spray application in upper- and lower-half configurations under strict FME controls. Typical on-site scope duration is about one week per unit. Thickness is tracked post-service with eddy-current magnetic liftoff mapping because the coating is non-ferrous.

Components addressed. Common gas-turbine targets include compressor discharge casings, vane carriers, diffusers and air splitters; the approach extends to torque-tube covers, rotor discs and selected turbine-side components with alternate material sets. Outside the engine, condensers, steam-turbine casings, piping and fuel-gas heaters are also candidates.

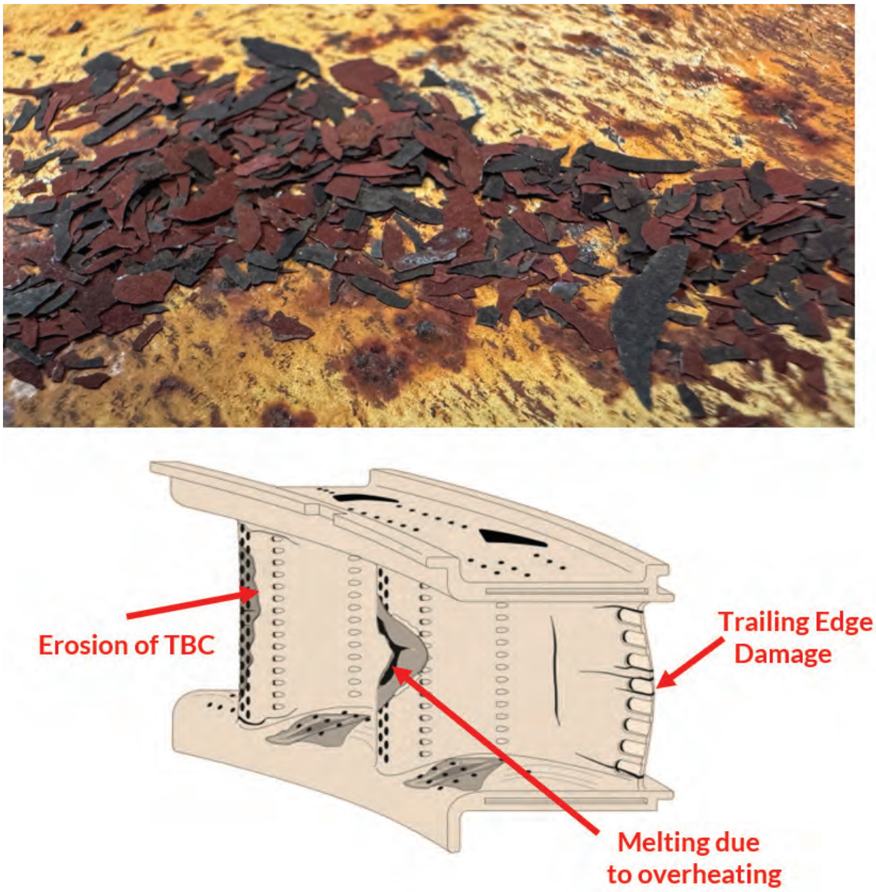
Results and fleet experience. IGS reports more than three years of runtime on the longest-running H-class application, with adoption by multiple users as a permanent upgrade viewed as life-of-machine. The key operational value is eliminating debris generation rather than attempting to trap or divert it downstream.

2. Flaking or spalling debris from unprotected low-chrome surfaces travels downstream causing premature wear and plugging

1. Oxide particles from H-class gas turbine

In the follow-on Q&A, discussion focused on surface prep, access with rotors in place, material choices, transitions, atmospheric controls, maintenance intervals, costs, and broader outage-repair options, highlighted below.

- *Condenser and wet-side service.* Condensers face moisture-driven corrosion rather than high-temperature oxidation. IGS deploys lower-demand HVTS alloys and other corrosion-resistant materials from a ~100-alloy library. HVTS has proven effective against wet-steam impingement and erosion by eliminating or sharply reducing metal loss.
- *Surface prep and lower-half access.* Prep relies on controlled abrasive blasting to specified cleanliness and anchor profile. For large frames, in-situ lower-half application is feasible even with the rotor installed, using extensive masking and isolation. Tight-clearance features, including blade-tip interfaces, are excluded; abradables may be used there.
- *Clearances and fit-up.* No assembly or disassembly issues are reported when plans avoid machined mating interfaces. Masking is critical to prevent coating where it is not desired; coatings are placed on cast areas or non-mating machined surfaces.



3. Iron-oxide debris attacks rotating and stationary HGP components

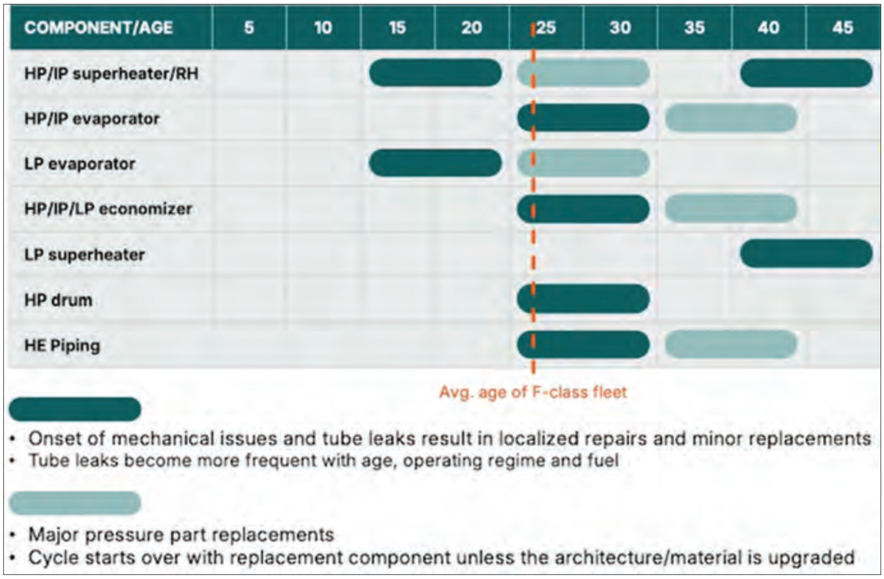
4. HVTS process executed in the field within 6-10 days

- *Steam-turbine erosion and titanium.* IGS does spray materials containing titanium, but does not currently coat titanium LP blades with HVTS. Candidate cases can be evaluated through the Richmond lab's wet-steam erosion rigs to screen solutions and accelerate selection.
- *Edge design and transitions.* Coating edges use tapered terminations from full thickness to zero, preventing stress concentrations. On inspection, oxidation often stops at the coating edge, confirming the barrier effect.
- *No post-coat heat treat.* Unlike slurry/diffusion systems, HVTS requires no bake-out or post-weld heat treatment. Metallic splats solidify on impact; coatings are service-ready after completion and inspection.
- *Application window and environment.* Ambient conditions influence oxide formation on uncoated steels in service. During application, IGS controls humidity and can dry the work area; HVTS has a broad window compared to liquid coatings, so full air-conditioning of the unit is seldom necessary (Fig 4).
- *Process portfolio and field limits.* IGS has not performed field diffusion or TBCs to date but is investigating field-applied TBCs. The broader toolkit includes HVOF, HVAF, and plasma, selected case by case for outage repairs.
- *Piping and FAC.* HVTS is applied inside piping for corrosion and flow-accelerated corrosion, using ROVs and automation within geometry limits. It is proven on nuclear steam piping to preserve wall thickness by preventing persistent oxide stripping.
- *OEMs and fleet coverage.* Details are confidential, but solutions exist across major OEMs and G-class equipment. Rollout began on advanced frames and has broadened fleet-wide; scopes remain site-specific.
- *Maintenance and cost.* On casings and large castings, HVTS is treated as a long-term upgrade without a defined rework mechanism; erosive services may align with planned outages.

As compressor temperatures rise in advanced-class-frame gas turbines, oxide generation in low-chrome internals intensifies. Field-applied high-velocity thermal spray (HVTS) offers a practical outage-window intervention to harden susceptible surfaces, protect cooling integrity and reduce downstream risk to hot-gas-path hardware. CCJ

Raiders of the Lost Heat: How to capture "hidden" megawatts across HRSG, steamer, and generator

In a demand-heavy, renewables-rich grid, the fastest and lowest-risk capacity gain often comes from assets already on the pad. A recent GE Vernova webinar discusses practical ways to uncover incremental output and reliability by treating the combined cycle as a single system. The session was moderated by Matt Foreman, and featured technical perspectives from Jason Bowers and Joe D'Amato, moving step-by-step from the HRSG to the steam turbine and, finally, the generator that must carry those gains to the bus.



With HRSG pressure parts typically designed for 25–30 years, much of the F-class fleet is at or near end-of-life

WALK THE CYCLE: START AT THE HRSG

Any gas turbine performance change shows up first in the HRSG. Foreman stressed the value of a structured impact study, starting with desktop engineering and progressing to on-site validation, often supported by 3-D scanning. The goal is to confirm what the boiler will actually see after a GT upgrade and to map scope to risk and return.

Depending on condition and operating margin, outcomes can range from no changes required, to targeted modifications, to major replacements. Common paths include:

- Valve and attemperator resizing to protect code limits and maintain steam conditions.
- Pressure-part replacements, such as superheater or reheater harp replacements, to eliminate bottlenecks, support uprates, and reset life on critical components.

A recent turnkey example points out the execution side of the equation. Rigging plans, clearance checks, and piping reroutes were locked down early, keeping a complex harp replacement on schedule and incident-free. That level of pre-planning becomes essential when HRSG scope is coupled to a GT outage window.

Why the urgency? Much of the F-class HRSG fleet is now past 20 years, and many units are entering a repair cycle characterized by more tube leaks, header cracking, and forced derates. When leak frequency and tube plugging begin to accelerate, owner/operators should evaluate whether continued repair-and-plug approaches still make sense versus scoped replacements that remove chronic pain and align the HRSG with planned or potential uprates.

RESIZE STEAM PATH TO "SWALLOW" MORE STEAM

Once incremental exhaust energy is converted into steam, the steam turbine has to take it. Bowers framed Advanced Steam Path upgrades as more than a reliability refresh. The intent is to deliberately resize buckets, diaphragms, and clearances, typically in the HP and IP sections, to increase swallowing capacity and convert additional steam flow into delivered power.

Construction type and basic design differences matter less than selecting the right steam path package to match new conditions and constraints. In output-driven applications, advanced steam path work can deliver meaningful gains, but where LP or casing limits exist, the upgrade package must expand accordingly.

Two case examples illustrated the system effect:

- 2×1 CCGT with a D11-class steam turbine: approximately 20 MW from the two GTs and roughly 19 MW from the resized steam path, showing near one-for-one follow-through when the HRSG and steam turbine are not limiting
- 3×1 CCGT with a larger D11-class unit: approximately 143 MW from three GT upgrades and about 33 MW from the steam turbine once LP limits were addressed in scope. Larger GT steps can drive proportionally larger steam turbine scope, but the payoff scales with the uprate

GENERATOR IS OFTEN THE LIMITER

Plants frequently discover they are generator-limited only after the GT or steam turbine has been upgraded. D'Amato emphasized looking beyond traditional rotor or stator rewinds and thinking in integrated packages that move generator capability in step with prime-mover increases.

Examples discussed included:

- Higher cooler flow and hydrogen pressure changes to improve thermal headroom
- Gas-cooled high-voltage bushings and electrical path upgrades
- Connection-ring and flex-lead improvements to reduce thermal-mechanical stress under cycling duty
- Rotor upgrades, including seal design improvements that reduce hydrogen losses and improve durability

For schedule and risk reduction, refurbished exchange fields, balanced and tested, can compress outage exposure and avoid shop surprises on aging rotors. The throughline was clear: match generator scope to the upgrade trajectory of the GT and steam turbine so capacity, durability, and outage plans move together.

AGILITY, INSPECTIONS, LIFE EXTENSION

The group also addressed how to capture value without trading it for accelerated wear:

- Faster starts without added life consumption. Agility packages and warming systems can reduce cold-start durations dramatically while maintaining life usage, a strong fit for markets that reward faster ramping and lower start emissions
- Right-sized inspection cadence. HRSG minor and major inspection intervals should reflect duty cycle and what trending reveals. Rising leak rates and tube-plug counts are actionable signals to shift from reactive repair toward replacement planning
- Resetting the clock where it counts. Advanced steam path upgrades fit within existing shells, effectively zeroing life on replaced internals while retained casings remain on condition-based management.

Taking the noise out of turbine monitoring

High-temperature pressure sensors and accelerometers rarely get much attention when they are doing their jobs. But when a combustion dynamics channel goes noisy, a cable loosens, or a monitoring system starts throwing spikes, the consequences can move quickly from nuisance to risk.

That was the practical takeaway from Dave Martin, business development manager at PCB Piezotronics, during CCJ's recent webinar on high-temperature sensor systems for turbine monitoring. Addressing plant personnel responsible for reliability, emissions, and outage planning, Martin spent less time on sensor theory and more on the realities of field performance emphasizing signal quality, proper installation, and disciplined troubleshooting.

For gas-turbine users, the starting point is combustion dynamics. Martin described combustion instability—still called "humming" by some veterans—as pressure oscillations in the combustor that can damage hardware, shorten component life, increase fuel consumption, and in the worst case force an unplanned outage. Monitoring those oscillations gives operators another way to protect the machine while also supporting combustion tuning, emissions compliance, and unit availability. In his words, the value goes well beyond emissions alone. Martin said one large power producer realized millions of dollars in fuel savings over several years after getting combustion-dynamics systems working properly and upgrading weak legacy installations.

The webinar also reviewed how combustion-dynamics sensing has evolved over time. Early remote and close-coupled configurations relied on tubing, purge systems, and inline or near-line sensors. While these arrangements functioned adequately, they also introduced several paths for compromised data. If purge tubing was not kept clean, dry, and properly nitrogen-purged, unwanted frequencies could enter the signal. Vibration in the tubing and prolonged exposure to high temperatures added further opportunities for measurement issues.

By comparison, sensors mounted directly on the turbine at the combustor avoid many of those complications (Fig 1). Designed to withstand temperatures approaching 1400F, these on-turbine sensors eliminate the need for purge systems, reduce maintenance requirements, and provide clearer signals. Martin noted that major OEMs now widely adopt these sensors for precisely those advantages.

Installation details matter. Sensors are typically mounted on the combustor casing, with the tip positioned either at the casing surface in a recessed mount or at the liner surface in a flush mount. Mounting methods include clamp nuts, screws, Swagelok fittings, and threaded sensor bodies torqued to specification. Martin showed examples from GE 7FA and Siemens 501F applications, along with cabinet hardware used in newer combustion dynamics monitoring system retrofits that replace older purge-box arrangements (Fig 2). The hardware chain itself is straightforward: high-temperature dynamic pressure sensor, extension cable, differential charge amplifier or signal conditioner, power supply, and the monitoring or data-acquisition system. But getting each link right is what determines whether the operator sees useful information or chases bad indications.

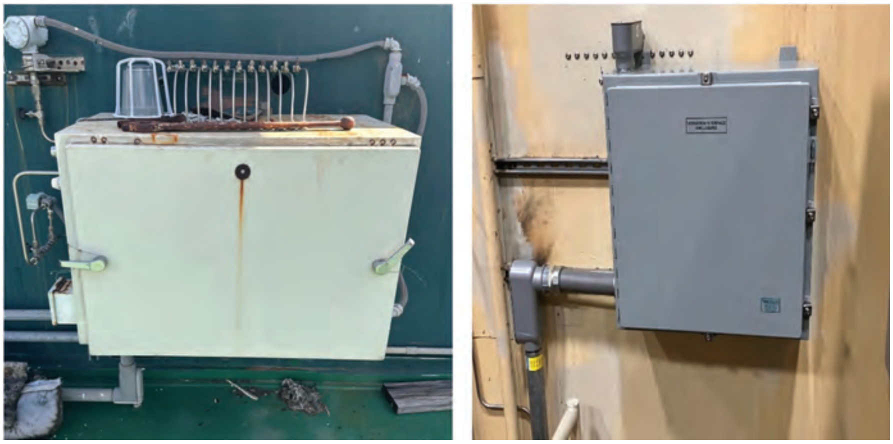
Martin also spent time on high-temperature accelerometers, which face a similar challenge. Standard IEPE devices are constrained by built-in electronics and generally cannot survive turbine hot zones. High-temperature charge-mode accelerometers move the electronics out of the heat and, in turbine service, are typically specified in differential charge designs to improve noise rejection. The point, he said plainly, is to keep noise out of the signal. Differential architectures cancel common-mode electrical interference that can plague charge systems in harsh plant environments. For users dealing with vibration monitoring near hot sections, that design choice is not academic; it is often the difference between a trusted channel and a misleading one.

Martin's troubleshooting guidance was among the webinar's most practical takeaways. When a pressure-monitoring channel starts acting up, his first advice is not to blame the sensor. In his experience, high-temperature sensors rarely fail under normal operating conditions. More often, the issue lies somewhere along the measurement chain—most commonly in the cable. Loose connections, damaged extension cables, sections that have melted after resting on hot surfaces, and grounding errors are frequent sources of trouble.

For pressure systems, Martin recommends checking the integrity of the chain with a charge/ICP simulator connected at the extension cable. This allows technicians to verify the signal path from the cable through the charge amplifier to the data-acquisition hardware. If that pathway checks out, only then does it make sense to suspect the sensor and send it out for testing. He offered the same practical advice when addressing CDMS noise and signal spikes: start by looking for grounding issues and loose connection

The Q&A session reinforced the webinar's practical, field-focused tone. Martin noted that PCB supports legacy turbine applications like the GEV Frame 6B and can assist plants in identifying replacements for Meggitt Vibro-Meter components, often providing drop-in alternatives. He also challenged

1. A useful GEV 7FA comparison: legacy tube-mounted hardware feeding a purge box versus a direct-mounted high-temperature sensor installed on the combustor housing



2. Cabinet photos show the transition from bulky dual purge boxes to a cleaner CDMS kit that consolidates signal conditioning and simplifies installation

the idea of fixed replacement intervals for high-temperature sensors, arguing that if sensors are removed and handled properly during outages, they should not be retired simply because a calendar says so.

For plant managers and OEM engineers, the broader takeaway from the webinar was clear: improving turbine monitoring does not start with purchasing more hardware. It starts with understanding the entire sensing chain, minimizing avoidable sources of noise, and approaching installation and troubleshooting as core reliability tasks rather than routine instrument housekeeping. For more detail, view and share the webinar recording by scanning the nearby QR code.

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