$15

2Q/2013

www.ccj-online.com

CCJ COMBINED CYCLE Journal

2014 OUTAGE HANDBOOK

Highlights

INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

FROM THE EDITOR

Industry, colleagues praise The Clyde—most deservedly

If you don't know generators well enough to recognize the name Clyde V Maughan, perhaps it's time to learn more about them. We'll show you how you can do this, painlessly, later. The Clyde, as he has come to be known, has been involved with generators throughout his 63-yr professional career, which began shortly after graduation from the Univ of Idaho (BSEE, 1950). After 36 years with the General Electric Co as an engineer and manager in generator and turbine design and development, service, manufacturing, and a variety of other roles, The Clyde opened Maughan Generator Consultants in Schenectady, NY. If there's something he hasn't seen or done with respect to generators, it's probably not worth mentioning.

The Clyde is honored at the ASME Power Division awards banquet July 31. From left are Justin Voss of AES, Maughan, Jane Hutt of NEC, James Wieters of SCANA, and Frank Mitchell of AEP. Voss, Wieters, and Mitchell are members of the division's executive committee

Let this be known as *The Year of The Clyde*. In 2013, Maughan has received no fewer than four significant awards, identified an oversight in an IEEE standard that has cost the industry hundreds of millions of dollars to date (see article, p 7, for details), shared his knowledge with several industry groups as a speaker, and participated virtually non-stop as a thought leader for the globally acclaimed International Generator Technical Community™ (www.generatortechnicalforum.org).

Most recently, Maughan was one of four recipients of the Combined Cycle User Group's 2013 Individual Achievement Award at the organization's annual meeting in Phoenix, September 3-5, where he spoke on generator issues for nearly two hours (presentations are available at www.ccusers.org). *Individual Achievement* recognition is earned by industry professionals who have demonstrated excellence throughout their careers in the design, construction, management, operation, and/or maintenance of generating facilities powered by gas turbines.

Maughan accepts the 2013 CCUG Individual Achievement Award from Andy Donaldson (right), VP Projects for WorleyParsons and a member of the user group's steering committee

Only a month earlier, The Clyde received a special award at the ASME Power Conference in Boston for career achievements as an engineer, mentor, and colleague. He addressed the august group on grounding issues in rotor and stator windings. The other awards:

- IEEE PES Cyril Veinott Electromechanical Energy Conversion Award, for contributions to the design, testing, and maintenance of turbine/generators.
- The first C V Maughan Rotating Machines Award, sponsored by Iris Power, for 60 years of outstanding contributions to the design and maintenance of rotating machines.

Clyde Articles

Quick Response Codes

QR codes, developed for the Japanese auto industry to track parts, paperwork, etc, enable the CCJ editors to bring a static magazine page to life by linking print to the electronic world. You will see them scattered throughout this and future issues. By simply scanning the QR codes here with a smartphone or tablet, you gain access to both Maughan's CCJ ON*screen* webinar series and CCJ articles on generator inspection and maintenance. Fast, simple, effective.

Clyde Webinars

Business Staff*

Susie Carahalios
Advertising Sales Manager
susie@carahaliosmedia.com
303-697-5009

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

Telephone: 702-869-4739; fax, 702-869-6867.

*Carahalios Media is the exclusive worldwide advertising sales organization for the COMBINED CYCLE Journal. Business offices are at Carahalios Media, 5921 Crestbrook Drive, Morrison, Colo 80465.

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

Comprehensive Pump Support
Reliable & Responsive Service

Engineered Pump Rebuilding

Since 1969, Hydro has built its worldwide pump service organization by bringing a high level of engineering expertise and quality service to the pump aftermarket. We work with our customers to evaluate and understand the root causes of pump degradation or failure and to provide unbiased engineering analysis, quality workmanship and responsive field service for improved plant operation.

Turnkey, Field Service and 24/7 Emergency Response

Hydro's Field Service team has extensive knowledge of pumps from most major manufacturers and provides turnkey service, installation / start-up supervision, field machining, vibration analysis, laser alignment, pump system troubleshooting and emergency field response 24 hours a day, 7 days a week.

Hydro's Worldwide Network of Pump Aftermarket Service Centers

U.S. Service Centers

Hydro, Inc.
Headquarters
Chicago, IL
800.223.7867
www.hydroinc.com

HydroAire, Inc.
Chicago, IL
40th Street Facility
Madison Street Facility

Hydro East, Inc.
Philadelphia, PA

Hydro South, Inc.
Atlanta, GA

Evans Hydro, Inc.
Los Angeles, CA

HydroTex Dynamics, Inc.
Houston, TX

HydroTex Deer Park, Inc.
Deer Park, TX

HydroTex Golden Triangle, Inc.
Beaumont, TX

Hydro Pump Performance Test Lab, Inc.
Chicago, IL

Hydro Parts Solutions, Inc.
Houston, TX

Pump Parts
When you require a part and are facing a long lead time, Hydro can meet your needs in a reduced time frame through our reverse engineering, patternless casting, and integrated manufacturing processes. Hydro's engineers review and evaluate all parts to offer important upgrades and apply new technologies that will reduce wear and improve reliability.

Pump Testing - Managing Risk
Ensure your pump will perform as required. Hydro’s 5000HP Performance Test Lab is compliant to API610 and Hydraulic Institute standards and can test horizontal, vertical, and submersible pumps.

Training
Hydro teaches practical solutions and troubleshooting techniques for common pump problems and offers specialized hands-on training programs. View upcoming courses online at www.hydroinc.com.

For more information about Hydro’s comprehensive pump services for combined cycle plants, please contact John Francis at jfrancis@hydroinc.com or call 713-890-2117.

Hydro®

International Service Centers

CW Hydro
Incheon Metropolitan, Korea

Hydro Australia
Morwell, Australia

Hydro Scotford
Edmonton, AB, Canada

Hydro Middle East
Dubai, United Arab Emirates

Hydro Pump Services
Kuala Lumpur, Malaysia

Hydro Vietnam
Ho Chi Minh, Vietnam

Safe-T Hydro
Port Coquitlam, BC, Canada

Hydro Richier
Saint-Chamond, France

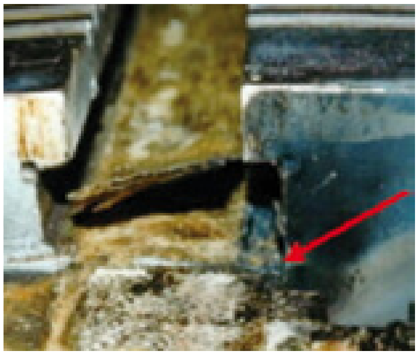
IEEE standards may not sufficiently address grounding issues in rotor, stator windings

Clyde V Maughan, Maughan Generator Consultants

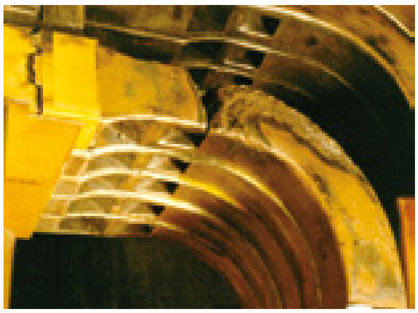
There are two, unfortunately common, generator-winding failure modes that the IEEE standards overlook: the fracture of a rotor (field) conductor and the fracture of a stator conductor. This article describes these types of failures, discusses associated negative impacts of them, and recommends corrective actions.

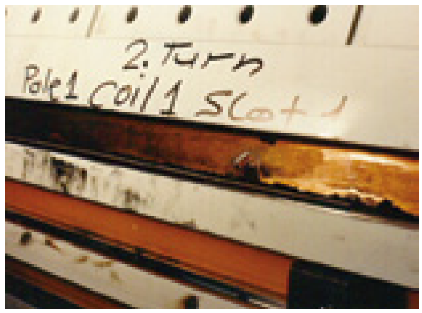
On rotor windings, IEEE Standard C37.102 implies that a single ground may not be a major concern, except for exposure to a double ground. But on turbine/generator rotor windings, experience has shown that single grounds, which result from the fracture of a rotor-winding electrical conductor, can cause dangerous burning of rotor forgings.

On stator windings, the electromechanical ground relay (59GN) commonly used in generator protection, does not respond to grounds in the bottom 5% (approximately) of the winding. Four recent failures in this portion of the winding each caused massive damage to the generator and collectively had a total cost, including repair and loss of generation, of close to half a billion dollars. But IEEE Standards C37.101 and 102 imply that this detection deficiency may not be a major concern.



1, 2. Minor rotor-forging burn damage (left) in an area of low mechanical stress is relatively easy to correct by light grinding of field iron, as shown at the right





3, 4. Single-ground failure initiated by a broken top turn (left) caused serious burning of the forging and copper (right) when current continued to flow

Rotor-winding ground protection

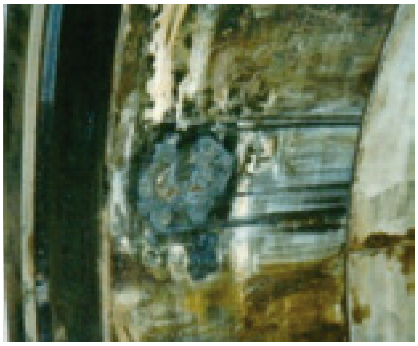
Recommended standard rotor-winding relay protection systems for generators are spelled out by IEEE Standard C37.102-2012, "Guide for AC Generator Protection." Relative to rotor windings, this recently re-issued guide states on p 46:

"The field circuit of a generator is an ungrounded system. As such, a single ground fault will not generally affect the operation of a generator. However, if a second ground fault occurs, a portion of the field winding will be short-circuited, thereby producing unbalanced air gap fluxes in the machine. These unbalanced fluxes may cause rotor vibration that may quickly damage the machine; also, unbalanced rotor winding and rotor body temperatures caused by uneven rotor winding currents may cause similar damaging vibrations." This statement does not appear to be completely accurate relative to a single ground, as is discussed below.

Except for turn shorts, ground insulation failure is probably the most common failure mode in rotor windings. Ground-fault detection in rotor windings is provided by a relay system that injects a low voltage into the (ungrounded) rotor winding. If a ground develops, this relay is activated. Based on industry guides and experience, the relay normally is set to alarm rather than trip. This is probably a rational approach—but with a caution.

A single ground can be a serious condition, if the ground results from a broken conductor (or shorted coils) rather than a simple failure of the ground insulation. Since conductor fracture is a somewhat common rotor-winding failure mode, a single ground should not be taken casually.

During a short period of time, the author was involved in the analysis of five rotor ground failures. One was a double ground and it resulted in minor forging burning in two locations. Fig



5, 6. Arc damage from shorting between two coils (left) effectively removed the coils from the excitation circuit. The single ground lasted for a significant period of time because the detection circuit was connected incorrectly. Result: Near-fatal burn damage to the retaining ring (inside diameter)

1 identifies one of those locations. The forging burn damage was in an area of low mechanical stress and easily corrected by minor iron removal similar to that shown in Fig 2.

The other four failures were single grounds resulting from broken conductors or shorted coils. Each of these failures involved forging burning of a serious nature. When the turn in Fig 3 broke, current continued to flow through a conduction path that involved the retaining ring and rotor body (Fig 4).

The conditions shown in Figs 5 and 6 resulted from shorting between the two largest coils in a large rotor. (Because the ground detection circuit was incorrectly connected, the ground persisted for a significant period of time.) These conditions would constitute a single ground, but the damage to the retaining ring (Fig 6) was extremely serious and dangerous.

Rotor-winding ground relay system

Rotor windings operate at a low voltage, and an ungrounded design normally is used. This permits easy identification of a ground. Furthermore, the rotor-winding relay system itself is also relatively simple. If it is set up correctly, the relay will perform reliably.

On brush/collector excitation systems, the relay is connected to the rotor winding via the collector rings. On rotating rectifier rotors, however, ground detection involves complicating factors, since there is no direct method of connecting the relay system to the rotor winding. But, because ground detection is vital to reliability and safety, the connection for ground detection often is provided to the winding via a separate instrumentation slip ring or a wireless signal.

Stator-winding ground detection relaying

Recommended stator-winding relay protection systems for generators are covered by IEEE Standards C37.101-2006, "Guide for Generator Ground Protection," and C37.102-2012, "Guide for AC Generator Protection."

One of the recommended protection devices is a ground detection relay on the stator winding. Relative to this relay, C37.101 states on p 29: "The importance of detecting ground faults close to the neutral point of the generator is not dependent on the need to trip because of fault-current magnitude, since it may be negligible and will not, in general, cause immediate damage. If a second ground fault occurs, severe damage may be sustained by the machine because this may result in a short-circuit current not limited by the grounding impedance."

This statement does not appear to be completely accurate either. Historically, the common ground relay is an electromechanical relay powered by the voltage of the stator winding itself. Thus, if a ground occurs low enough in the stator winding, there is insufficient stator winding voltage to cause the relay to activate. This inactive voltage range covers about the bottom 5% of the winding.

As a result, any time a ground occurs near the bottom 5% of the stator winding, the electromechanical relay does not respond and there is no stator-winding ground relay protection at all. A generator trip does not occur until there is sufficient damage to cause other type of relay protection to become involved—generally the differential relay.

If the stator-winding ground is caused by a failure of the groundwall insulation by itself—for example, foreign object damage or badly cracked groundwall—this condition may not be particularly hazardous. There will be a current flow to ground but this circulating current returns to the winding through the high impedance stator neutral grounding system—typically a resistor-loaded distribution transformer.

The ground circuit impedance is set to limit current to a small value, about 3 to 10 amps, which cannot result in burn damage to the winding or core iron. So while the existence of a ground at any location of the winding is undesirable, consequential damage to the generator will not occur. Thus from this narrow viewpoint, omission by the standards of recognizing the condition of low-end grounds in the stator winding may be understandable.

However, the condition of failure-to-ground caused by the fracture of a stator conductor is not rare. If the failure location is in the bottom 5% of the winding, this failure mode is far from

7-9. Failure-to-ground caused by the fracture of a stator conductor is not rare; examples are shown in these three photos. Core and winding damage attributed to a burned open bar in a slot is shown in the left and center photos and the burned-away copper of a fractured connection is at the right


When parts sourcing is simpler,
so is the rest of your day.
You can now source all your aeroderivative and heavy IGT parts from one reliable provider. We stock over 15,000 high-quality GE, P&W, Rolls-Royce and Westinghouse parts. Make one phone call, pay one invoice and spend more time doing what you love.
apm4parts.com | 1.800.998.9844
ap+m

10, 11. Numerous stator-winding failures have occurred in the higher-voltage portions of windings where the ground relay successfully tripped the generator. Repairs to correct the failed phase connection above and the failed series connection at the right were relatively minor

benign. The author has been deeply involved in four such incidents in a recent two-year period. All occurred on a neutral bar or neutral connection ring and caused massive damage to the generator. In addition, three other similar failures have been reported to the author, with similar massive damage. Examples of these failures are shown in Figs 7-9.

Stator-winding ground faults

Category 1: In-service stator-winding failure-to-ground is a relatively common failure mode in generators. There are many possible causes. Some relate to mechanical damage of the ground insulation. Examples include: ground insulation wear-through from a foreign object or loose component, fracture of the groundwall because of a sudden short circuit, deficient groundwall insulation system, partial discharge combined with vibration, vibration sparking, inadvertent damage during maintenance, wet insulation attributed to a strand header water leak, and bar vibration in the slot.

Category 2: Other failures relate to the fracture of the conductor with the resulting burning away of the groundwall insulation. Examples include these: fracture of bar copper from high-cycle fatigue associated with vibration, fracture of bar copper attributed to gross overheating of the copper, melting of core iron, failure of a bolted connection, failure of a brazed or welded joint, and failure of a series or phase connection.

Category 1 failures generally should be benign. Unless a second ground occurs, the current flow to ground is limited to the 3-10-amp range and no peripheral damage is likely to result from this ground current itself. However, there is always the possibility that a second ground may occur simultaneously. The probability increases if the first ground is on a higher-voltage bar, thus elevating the voltage on the high-voltage bars of the other two phases. Two such simultaneous grounds guarantee that massive arcing will occur at each of the ground locations.

Category 2 failures in all situations, almost certainly will be highly destructive to the generator. These failures involve fracture of the current-carrying copper. When a conductor breaks, current will temporarily continue to flow within the stator-winding groundwall insulation, as in a welding arc; the heat generated will be extremely intense. This current will flow inside the insulation until the insulation is mechanically destroyed. Experience has shown that the copper will be vaporized for perhaps 8 to 12 in. before the internal arcing breaks through the insulation wall and becomes an exposed and widespread arc—and involves ground.

If the failure occurs in the slot, and is in a low-voltage portion of the winding, protective relays still will not trip. But if the failure is in a higher-voltage location, an immediate trip will occur; however, there may be significant damage because the arc will continue while the rotor current decays.

If the failure is in a low-voltage portion of the winding, a generator trip will not occur until some other relay system recognizes there is a problem—for example, core melting damage progresses to the point where bars at higher voltage become involved, arc current bypasses a current transformer and differential relay trip occurs, or arcing becomes so widespread that other portions of the winding become involved.

Root-cause investigation of stator windings that have failed because of a broken conductor generally is very difficult. This is because there is always massive burning and arc damage. Usually the actual cause of failure will be destroyed by the resulting arcing. In virtually all cases, the root cause only can be deduced from circumferential inference—that is, condition of similar components within the winding, conditions of similar generators, conditions of nearby portions of the failed components, engineering judgment, and engineering intuition. Obviously, each of these "inference" tools includes some inherent uncertainty. Regardless of root cause, the resulting damage is likely widespread and very costly in terms of repairs and loss of generation.

Costs of recent stator-winding failures

It is of interest to determine the direct losses associated with non-functioning ground relay systems. Looking only at the four largest incidents, and based on the author's engineering judgment and input from the plant personnel, the following values result:

Actual costs of the four incidents:

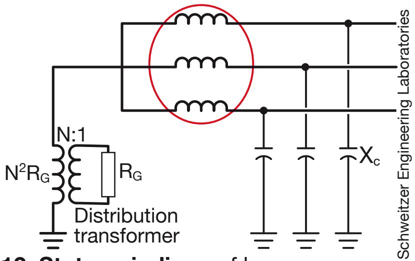
- Repair costs, $104 million.
- Realistic estimate of loss-of-generation costs, $378 million.
- **Total, $482 million.**

Estimated costs, if the ground relay systems had been functional:

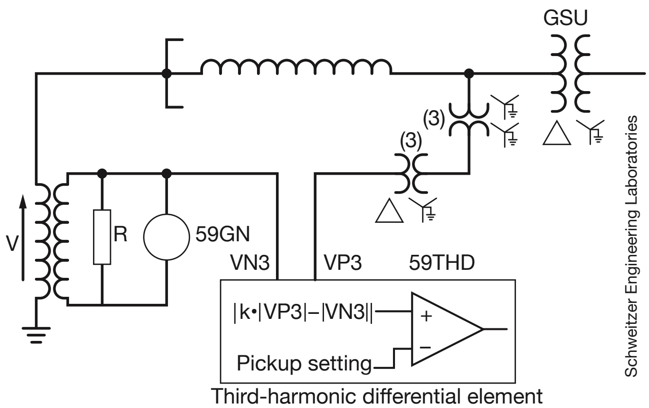
- Repair costs, $30 million.
- Loss-of-generation costs, $128 million.
- **Total, $158 million.**

Estimated net savings if a functioning ground relay system had been in place:

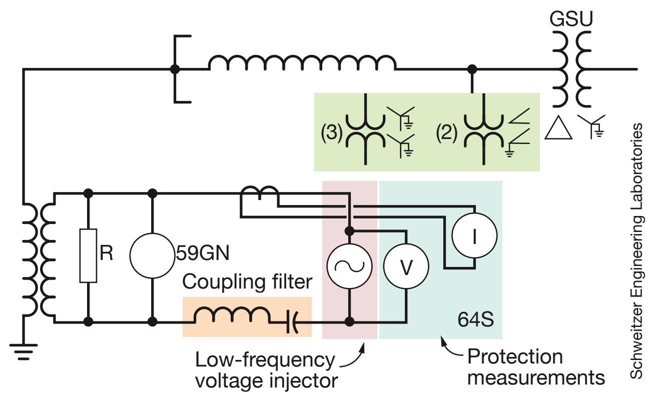
- Repair costs, $74 million.
- Loss-of-generation costs, $250 million.



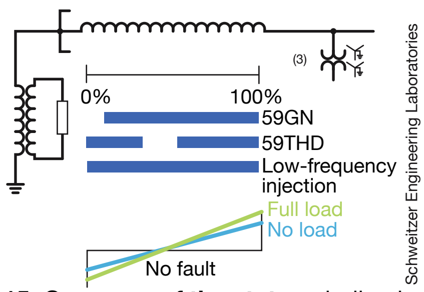
12. Stator windings of large generators typically are wye-connected and high-impedance-grounded through a distribution transformer



13. Combining electromechanical (59GN) and third-harmonic (59THD) relays protects 100% of the winding



14. Voltage-injection ground protection can be functional when the generator is shut down (standstill or turning gear), during startup, and at speed offline or online



15. Coverage of the stator winding is provided by the three relay systems described in Figs 12-14

■ **Total, $324 million.**

The $324 million is an incredibly large number. For comparison purposes, there have been numerous stator-winding failures in the higher-voltage portions of windings where the ground relay trip operated correctly. Two such failures are shown in Figs 10 and 11. Following each incident, repairs were relatively minor. In one case, the contamination was sufficient to require a field rewind. In both cases, the stator repair was accomplished without a rewind. Outage time was in the order of one month for each failure.

Obviously, it is not possible to accurately estimate the savings of having a functioning ground relay system. But $324 million is a huge sum. A saving of an order of magnitude less would still be $32 million—a non-trivial amount of money.

Stator-winding ground relay systems

The stator windings of power station generators are typically Y-connected, and high-impedance grounded through a distribution transformer. The impedance is controlled by the magnitude of the resistor connected across the transformer. This impedance is selected to allow a maximum of about 3-10 amps to flow in the event of a ground at the high-voltage end of the stator winding (Fig 12).

Historically, an electromechanical relay (59GN) is placed across the resistor, which is powered by the voltage of the stator winding. The characteristics of this electrical circuit and relay are such that the relay does not respond to the voltage of the bottom 5% of the stator winding.

This weakness of the electromechanical relay has been recognized for many years. By the early 1970s, in Europe, most generators larger than 100 MW also were protected by a third-harmonic relay (59THD). Third-harmonic relay protection was first applied in the US in 1980. The combined relay system protects 100% of the winding (Fig 13). But most generators in North America apparently are still protected only by the 59GN relay.

A third-harmonic relay system requires initial calibration with the generator operating offline and online to properly set the relay responses; this calibration work can involve significant cost and inconvenience to the plant. Furthermore, some generator designs may not produce sufficient third-harmonic voltages to allow reliable ground-fault protection schemes based on third-harmonic signals. Finally, the third-harmonic relay system has been found to occasionally perform unreliably due to subtle changes over time in the power-system third-harmonic voltages.

Because of these concerns, there is a trend toward developing and installing voltage-injection relay systems (64S). With the injection relay system, ground-fault protection can be functional when the generator is shut down (at standstill or turning gear), during startup, and at-speed offline or online (Fig 14).

A subharmonic sinusoidal voltage is injected continuously, typically at 15 or 20 Hz on 60-Hz systems. The resultant sub-harmonic current is measured via the 64S relay and, if a ground fault occurs anywhere in the three phases of the stator winding, the current in the relay increases and causes the relay to operate.

The injection relay system is self-monitoring and the sensitivity is independent of the power-system voltage, load current, or frequency. This system has improved sensitivity (compared to the 59GN or 59THD relay systems) because of the higher impedance path of the generator capacitances at these lower frequencies. Also, because the 64S relay system integrates over a half cycle of the subharmonic frequency, there is no contribution from the signals of system base frequency and harmonics—that is, 60, 120, and 180 Hz. Thus these frequencies do not influence the 64S relay performance.

The cost associated with providing and maintaining a reliable injection source is a disadvantage, but this may be small compared to the costs associated with calibration efforts required on the third-harmonic relay system.

Coverage of the stator winding provided by the three relay systems is shown graphically in Fig 15. The 59GN relay gives reliable protection, but only on the top 95% of the winding. The bottom 5% remains completely unprotected. In some cases, this has proven

to be a near-fatal deficiency, based on the experience discussed earlier.

The 59THD relay does not protect a mid-portion of the winding and must be used in conjunction with an additional relay system. Thus even if fully reliable, the third-harmonic system could not be considered as adequate protection by itself.

The cost of the signal generator is a disadvantage of the injection relay system (64S), but this system can reliably protect the entire winding, by itself. It has these further advantages: It can detect open circuits in the grounding transformer primary or secondary and is self-protecting for a grounding-relay system problem or loss-of-injection voltage source.

Concluding recommendations

Because of the hazards associated with either rotor or stator winding grounds, the ground protection systems for both components should be reviewed and any deficiencies found corrected.

The ground protection systems for rotors are relatively uncomplicated, but the alarm/trip decision may not be uncomplicated. If a rotor is known to have marginal or suspect ground insulation, and if the generator is important to the power system, a ground should not be allowed to exist for more than a brief period—that is, minutes, hours, or a few days at most.

On stators, the historic stator-winding ground protection relay (59GN) should not remain as the sole protection system on any generator of importance to the power system. Based on the industry experience reported here, it is advisable to upgrade the ground protection to include 100% of the stator winding.

Unfortunately, the third-harmonic relay (59THD) has proven to occasionally perform unreliably, because of insufficient or changing third-harmonic voltages. It can also cause a false positive trip—thereby incorrectly removing a turbine/generator from power production. These concerns would seem to make the third-harmonic relay unattractive, unless the reliability issues can be resolved.

Based on operating experience and the current state-of-the-art for relay systems, it appears that an injection stator winding relay system (64S) should be installed on any generator where high reliability and low cost exposure are considered important.

Finally, IEEE Standards C37.101 and 102, relative to ground protection of rotor and stator windings, should be revised to reflect the broken conductor failure mechanism. **CCJ**

Innovations abound at Maryland Heights Renewable Energy Center

An experienced powerplant engineer would probably approach Ameren Corp's Maryland Heights Renewable Energy Center (Fig 1) thinking, "this is a public relations nightmare." It's a landfill gas (LFG)-to-megawatts facility in a densely populated suburban community outside of St. Louis, Mo, adjacent to a public high school with 2500 students, and sandwiched between two major Interstates.

In no time, however, you'd change your mind. This nominal 15-MW facility has clearly raised the bar for community partnership and safety, regional environmental stewardship, remote monitoring and automation, LFG treatment and combustion innovations, and working with contractors on engineering, procurement, construction, and commissioning.

As Ameren puts it, Maryland Heights takes something no one wants, and converts it into something everyone needs. Surely this is one reason why, according to the utility's Ozzie Lomax, manager of gas turbine and renewable energy, "public perception by most in the area has been very positive."

Lomax

In doing so, the utility continues a four-decade tradition (Sidebar 1). In its first 12 months of operation, it has achieved a capacity factor of 90% and delivered 70,000 MWh credited as "renewable" because LFG is a fuel that regenerates itself as long as trash keeps coming to the landfill. The plant has also been in 100% compliance for emissions in a non-attainment zone, was completed 17% under budget and 108 days ahead of schedule, with only one OSHA recordable injury.

These achievements recognized by CCJ (Sidebar 2) were hard-won, coming with the usual challenges of initial operations, and the unusual challenges of process equipment, notably the gas cleaning systems, not necessarily familiar to powerplant engineers, and a highly variable, heterogeneous fuel gas, at least compared to the pipeline natural gas that most gas turbine/generators burn.

1. Maryland Heights Renewable Energy Center generates approximately 14 MW with gas reclaimed from a St. Louis landfill and delivers it to Ameren Missouri's distribution grid at 34.5 kV

1. A history of burning opportunity fuels

In the mid-1970s, Ameren modified a 125-MW coal-fired unit at the Meramec plant to co-combust refuse derived fuel (RDF) at 10% to 20% of the fuel heat input, adding shredders, conveyors, storage bins, feeders to prepare, handle, transport, and inject the RDF into the furnace.

Since then, Ameren has co-fired other difficult waste materials in its coal-fired plants, like waste paint chips from a nearby auto assembly plant (and Meramec station) and shredded tires. According to records, for example, Ameren's Sioux plant burned 19-million tires in the early 1990s, avoiding landfill disposal of a troublesome waste material. "We strive to be a good environmental neighbor on many fronts," says Lomax.

Latest Mercury 50

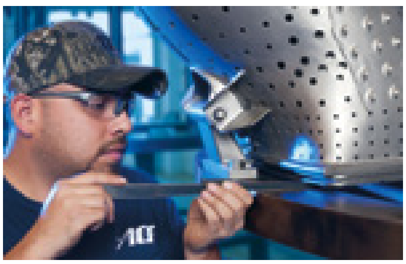
Ameren isn't the first to employ the Solar Turbines Inc Mercury 50 recuperated turbine (Figs 2, 3) for LFG, but it is one of only a few such units deployed globally for LFG. This 38.5%

ACT™

INDEPENDENT TURBO SERVICES

Great products and services, backed by great people.

Gas & Steam Turbine Repair

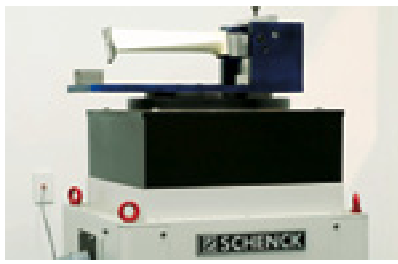


When it comes to repairing your critical equipment, ACT has the technical expertise and repair know how to get it done right. Our experienced personnel can help overcome some of our customers' most challenging equipment repairs. Precision fixtures, state-of-the-art heat treating, rigorous quality standards and experienced "best in class" personnel make ACT the perfect fit for all of your Gas & Steam Turbine repair needs.

Services & Capabilities

ACT 's specialized craftsmen repair the most sophisticated and cutting edge technology parts. Equipped with some of the newest and highly advanced tooling and equipment in the industry, our 24 hour service facility stands ready to help with your most complex repair needs.

Built for Success



A solid foundation starts with great people, years of experience and some of the best tooling and equipment available on the market today. At ACT, we base our culture on service and quality. Our mantra is "get it right, get it on time and provide excellent service". Give us the opportunity to show you the ACT difference.

8525 Freeland St, Houston, TX 77061 | Ph: 713-364-7500 | Fax: 713-364-7450 | sale@act-texas.com | www.act-texas.com

Young & Franklin Inc.

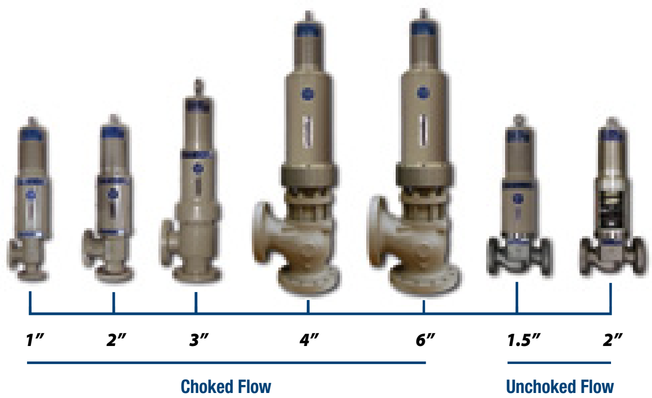
Founded in 1918 and headquartered in Liverpool, New York USA, Young & Franklin Inc. (Y&F) designs, manufactures and services turbine controls for the energy and oil & gas markets. Original equipment manufacturers and asset owners from across the globe look to Young & Franklin for fluid control solutions with the highest quality, reliability and maximum durability.

Y&F provides valves, actuators and controls to premier manufacturers of industrial turbines including General Electric Energy, Solar Turbines, Pratt & Whitney and GE Oil & Gas. With an installed base of products running on more than 10,000 industrial turbines, we have built a reputation based on technical expertise and product excellence.

Industrial turbines require precise control of the combustion process to drive efficiency, reduce emissions and increase availability. Young & Franklin air and gas control assemblies provide that accuracy with a complete range of electromechanically or hydraulically actuated products. From choked and unchoked valves to double block and bleed isolation valves to inlet guide vane actuators, Y&F offers a vast range of solutions for the most demanding industrial turbine applications.

Fuel Control Applications

Young & Franklin delivers proven electromechanical actuation (EMA) for electric fail-safe and non-fail-safe fuel control applications as well as traditional hydraulic solutions. Our patented compact, linear electromechanical actuators are the basis for a complete ship-set of electric Combustion Turbine controls.



3010 Series EMA Gas Fuel Control Assemblies ~
A family of electrically actuated single seat precision gas fuel control valves available in a variety of sizes of choked and unchoked flow configurations. Driven by the Y&F 1100 Series Digital Actuator Controller, the 3010 Series features balanced valve design, fail-safe spring closure for added safety and reliability, and feedback obtained through a resolver or optional LVDT.

IGV Actuation Technologies

Isolation Valve

Isolation Valve in Double Block & Bleed Format

9200 Series Isolation Valves ~ A single stage, solenoid operated, pilot controlled, drop-in replacement isolation valve. This high temperature shutoff valve closes in less than 100ms and has a Cv of 72. A double block and bleed configuration is also available.

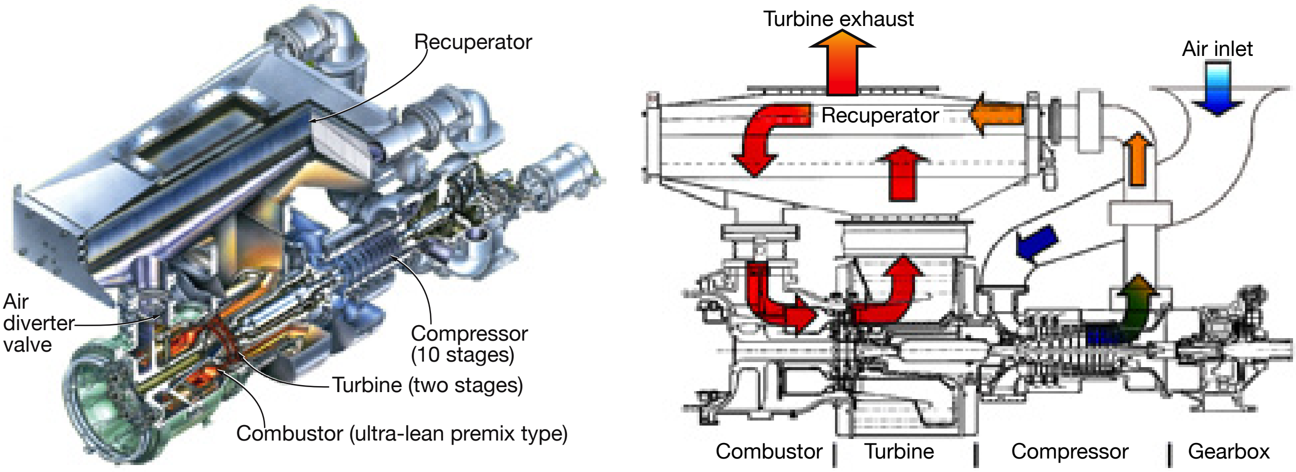
8641 Series Natural Gas Fuel Valve Assembly ~ A balanced double-poppet, all electric valve for gas turbine fuel/flow control. Operated by a Y&F 1100 Series Digital Motor Controller, the 8641 is a retrofit replacement for the Y&F 7-5078 Hydraulic Actuator/ Butterfly Valve and OEM Loader fuel control system on Solar Gas Turbines. The 8641 is designed for use on small turbines (1-20MW).

Currently in development is the **8650 Series All-Electric Inlet Guide Vane Actuator**, which is the first and only all electric IGV actuator to be introduced to the market. Scheduled for release in late 2013, the 8650 eliminates the oil leaks and varnish issues associated with hydraulic actuators, is scalable with forces up to 40,000 lbf, and has a drop-in footprint for easy replacement of many earlier hydraulic units.

For hydraulic applications, the **8277 Series IGV Actuator** is the most robust product available. Designed for use on large turbines, this dither resistant actuator operates from 1200 psi to 1700 psi of hydraulic pressure and is modularly designed for different cylinder sizes. To further improve the actuator's life span, shut dither feature off on MK controls.

Our deep technical competency in hydraulically actuated controls has enabled the company to develop a line of electromechanically actuated (EMA) valves and guide vane actuators. By eliminating the use of turbine lubrication oil, our EMA solutions upgrade the precision, control, performance and reliability of industrial turbines while reducing emissions, improving safety and resolving varnish issues. Y&F possesses impressive in-house design and manufacturing capabilities including an experienced dedicated engineering staff and wide range of advanced CNC machine work centers. We have achieved ISO 9001:2008 certification due to our strict adherence to quality management standards and a culture based on continuous improvement. Global field support is available 24/ 7 through our network of Young & Franklin Authorized Repair & Overhaul partners.

To learn more about Young & Franklin, please call 315.457.3110 to speak with an applications specialist or visit our web site at www.yf.com



2, 3. Mercury 50 is a single-shaft recuperated engine with a rated output of 4.6 MW. Design simple-cycle heat rate is 8865 Btu/kWh. The gas turbine's 10-stage axial compressor has variable inlet guide vanes and stators; compression ratio is 9.9:1; its ultra-lean premix combustion system is equipped with eight fuel injectors and a single-torch ignition system. Turbine is of the two-stage reaction type

efficient turbine, developed under a generous DOE R&D program, has been available since the late 1990s, but was only declared commercial in 2003. At least three other LFG sites are using this unit. As CCJ readers know, new gas turbine designs require extensive feedback loops based on model years of actual field experience. About 100 Mercury 50s are in service around the world.

Ameren evaluated several options, including engine/generators and other smaller gas turbines, but three Mercury 50s (each rated 4.6 MW) proved to have an unbeatable combination of performance, environmental, and life-cycle advantages. Among other things, the GT exhibits the lowest emissions profile (5 ppm NO_x, 10 ppm CO), critical for a non-attainment zone; it offers the highest efficiency, which increased the renewable energy credits (RECs) the facility could obtain; and it provides greater turndown and fuel flexibility.

Engines are popular in LFG applications but typically require several additional units as spares because of their maintenance (oil changes) and rebuild requirements. Although engines can be more efficient, they discharge higher NO_x emissions. The Mercury 50 was the only option that could meet BACT (best available control technology) without downstream emissions controls. One tradeoff is that auxiliary power is high, at 16-18% of output, because of gas processing needs.

All of the options, however, are impacted by a fuel contaminant peculiar to LFG, siloxanes, an ingredient in many consumer products that end up in landfills. When burned, siloxanes are converted into silicon oxide, which can wreak havoc on gas turbine internals. Therefore, siloxanes have to be removed prior to combustion, in addition to other contaminants like moisture and hydrogen sulfide (H_2S).

A pilot and his dog

Automation experts like to joke that in 20 years, plants like Maryland Heights will be run by one operator and a dog, and the dog's function will be to make sure the operator keeps his/her hands off the controls. Of course, they've been joking about that for at least two decades. Still, the industry makes incremental strides in remote operation. Maryland Heights, while small by powerplant standards, is leading the industry in this direction.

The facility is manned only 40 hours a week. For the remaining 128 hours, it is remotely monitored, started, stopped, cycled, and dispatched from a central facility at Ameren headquarters in downtown St. Louis. What's more, Ameren engineers went with Rockwell Automation's Plant APX PLC (programmable logic controller) architecture to accomplish this, rather than a more traditional DCS.

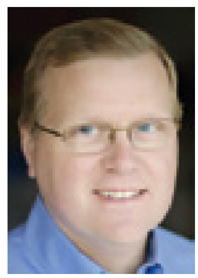
2. Small for a powerplant, large for the power industry

CCJ recognizes Ameren's Maryland Heights Renewable Energy Center with its 2013 Powerplant Award for the following achievements:

- Preparation and combustion of difficult fuels in advanced gas turbines.
- Integration of automation, monitoring, remote capability, and digital intelligence within PLC architecture.
- Community relations.
- Use of renewable fuels for carbon management.

In each of these areas, Maryland Heights has advanced the state-of-the-art for the electric power industry.

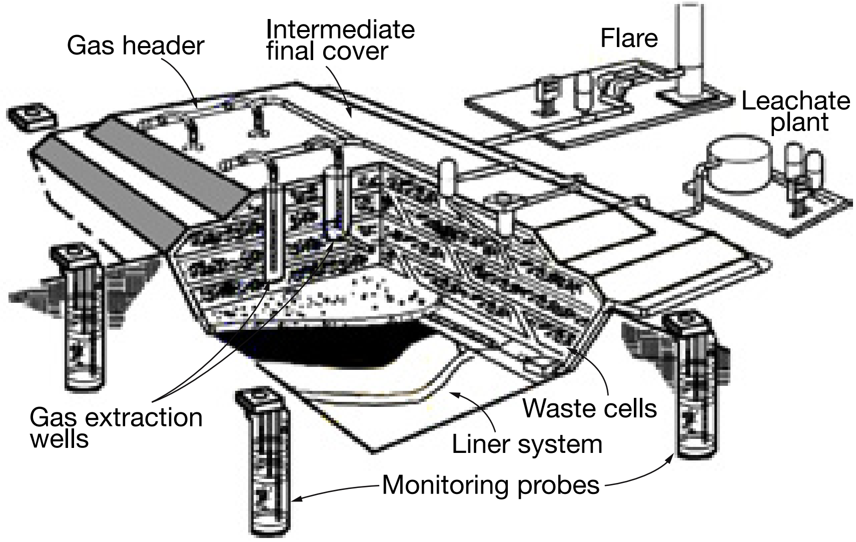
4. Plant Superintendent Mike Whitmore (foreground) traces elements of the "brain" that monitors and controls the "brawn" (hardware) installed at Maryland Heights with Ozzie Lomax, manager of power operations, Gas Turbine and Renewable Generation



Whitmore

Plant Superintendent Mike Whitmore, notes "PLCs were lower-cost, provided flexibility, and can be programmed by plant staff." The objectives in selecting an automation system were to minimize changes to pre-engineered equipment packages, maximize integration flexibility and speed, and have a common graphical user interface to control everything.

However, to achieve these goals, especially the last, Plant APX and its Plant Talk network had to interface with many different equipment devices (motor control and protection, switchgear, process gas analyzers, turbine



5. Landfill is arranged for optimal collection of gas produced in so-called waste cells

controls, gas treatment skid controls, etc), communications protocols (serial, Modbus, TCP, OPC, Ethernet), and corporate networks and data repositories (Ameren central control via RTU, local and remote historians).

In fact, there is direct evidence of the importance of automation, monitoring, control, and digital knowledge management at Maryland Heights. Many powerplants proudly display a large process flow diagram on the wall somewhere in the office. This was the first time the editors had seen, adjacent to the process flow diagram, an even more elaborate depiction of the automation, control, and data and knowledge networks for the plant (Fig 4). This wasn't a P&ID per se, but more like a picture of the plant's brain, nervous system, sensing and response mechanisms, and communications capabilities.

Safety is king

Given the location, Ameren paid close attention to additional layers of monitoring and protection for safe operation. From the controls perspective, engineers added a layer of safety relay circuits so trips don't have to rely on the network. All plant shutdown circuits are hard-wired, in other words. The other safety aspects include:

- First out-of-ground valve—redundant LFG shutoff.
- Fire control panel with multiple sensors and auto-dialers.
- Methane detection systems for warnings and trips.
- High-volume ventilation for pre-trip interlocks.
- Refrigerant leak detection.

Lomax said "we put many hours into designing a robust methane detection and protection system, including infrared heat detectors, passive gas detectors, and fans with backup power supplies that reach maximum speed when methane is detected." The volume of air in the facility "can be evacuated in a matter of minutes." Maryland Heights meets standards for a Class I, Div 2 rating. Two separate fire stations are within a few miles of the plant.

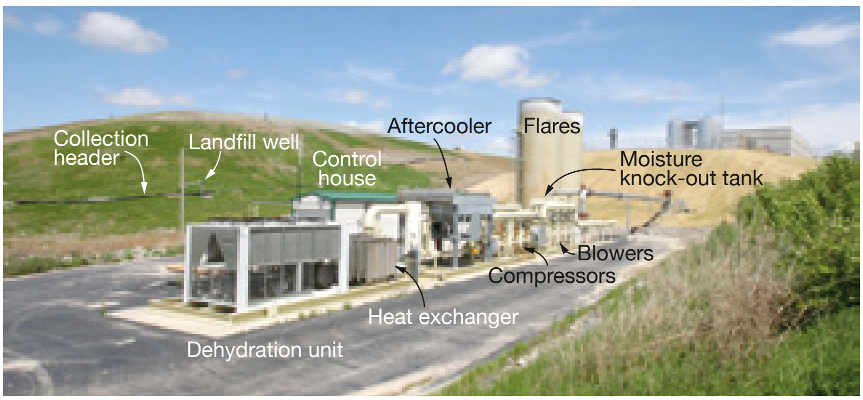
Additional safety and "good neighbor" provisions include reinforced concrete walls, low stack heights, and noise attenuation on all equipment—including silencers on gas turbine exhausts. Cooling equipment and associated fans are located on the north side of the plant, away from the school and homes. Overall, the facility meets a 50-db sound limit. On the "soft" side, Ameren created a partnership with the school and the school board and "adopted" the school as an academic partner. Ameren engaged the students repeatedly through science, technology, engineering, and math (STEM) educational initiatives. "We even supported the school's capital campaign," adds Lomax.

Shared EPC

In a unique arrangement, Ameren engineers and procurement specialists shared procurement of major equipment with the prime contractor, H R Green Co. For certain components, like the gas turbine, compressors, and refrigeration systems, Ameren procured the equipment, avoiding contractor markups.

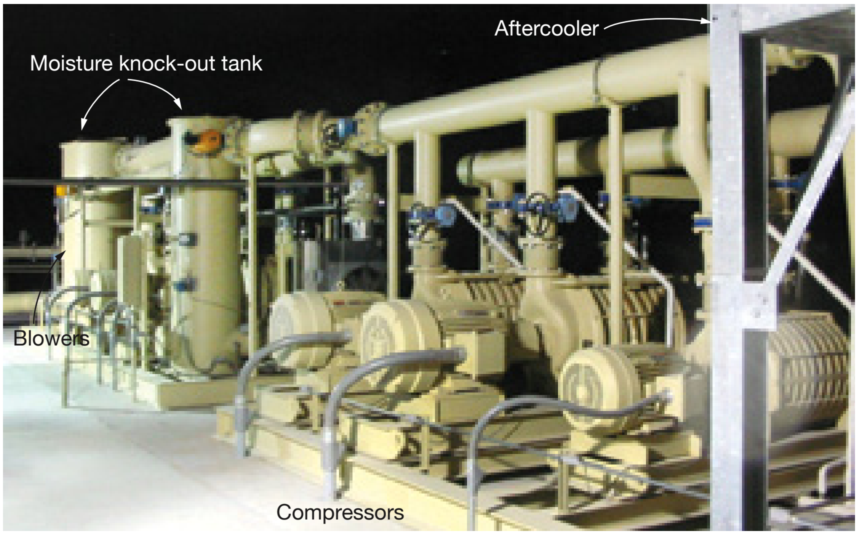
Green, however, retained contractual responsibility for overall performance. All procured equipment was reviewed in detail by both Green and Ameren technical experts, with resultant cost savings along the way. The teamwork continued through manufacturing and factory acceptance testing (FAT). Representatives from one or both companies conducted these visits to request improvements, make corrections, etc, all to avoid field rework issues.

Ameren also took a staged approach to pay for the project. First, $1.5 million was approved by senior management for design. After 90% design was complete, the project team then requested and was approved for $5 million, which was required for down payments on major equipment. Each

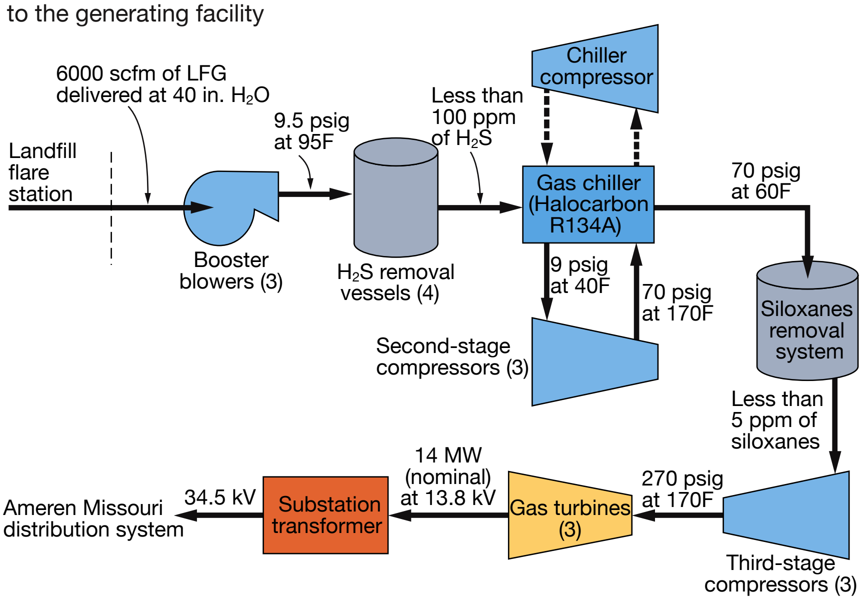


6. Landfill collection skid boosts gas pressure, knocks out moisture, and sends LFG to the Maryland Heights Renewable Energy Center for processing and delivery to the Mercury 50s

7. Wells, 120 in all, reach down into the landfill to collect methane and inject into the collection header



8. Back end of the collection skid shows components that deliver spec LFG to the generating facility



9. LFG received by the Renewable Energy Center is processed to remove hydrogen sulfide and siloxanes, and then compressed to meet the Mercury 50's combustion system requirements. Note that all compressors are of the flooded screw type and are equipped with aftercoolers. The positive-displacement booster blowers also have aftercoolers. Power produced by the gas turbines at 13.8 kV is transformed to 34.5 kV and delivered to Ameren Missouri's distribution system

10. Second- and third-stage compressors boost LFG pressure to that required by the Mercury 50s

procurement contract included exit ramps if Ameren decided not to proceed. Next, the design team prepared a 5000-page construction specification, with direction to solicit bids and negotiate contracts for subcontractor packages. The final result was a firm-price construction package with a 6% contingency.

The project was atypical for Ameren. Projects with 10 times the output of Maryland Heights are still on the tiny side for the utility. Additionally, utilities are used to having consistent quality fuel supplied by large, established suppliers of natural gas and coal. Many internal processes, procedures, and standards had to be adjusted for a project of this scale. Redundancy considerations are just one example. Keeping a 1500-MW plant online requires a different mindset from keeping a 15-MW facility online.

Challenges here were compounded by major organizational changes as well. Landfill ownership changed hands during the project. Ameren also had to effect a transition of the project from the fuels group, which initially led the project, to the central engineering group for engineering, procurement, and construction.

Teething issues

As any experienced powerplant engineer would expect, teething issues are legion with a plant like Maryland Heights. In the process of working through them, Ameren is advancing the state-of-the-art for the rest of the industry and stands ready to exchange technical experience. Given CCJ's deep connections with user groups, first thing to mention is that Ameren is forming a Mercury 50 Users Group, in part, notes Lomax, "because of the benefits we've seen accrue from participation in other user groups, such as CTOTF™."

Most operational issues have two root causes: (1) the powerplant/landfill interface and (2) upsets that typically cascade through the system. For one thing, fuel quality can be highly variable and the objective of the landfill (Figs 5-8), maximizing waste oxidation can be at odds with maximum-megawatts production. For another, as Lomax puts it, "you can't shut down a landfill." When the powerplant trips, the system must revert to flaring gas quickly and safely. "It has to work," stresses Lomax.

Sometimes landfills flow more air through the soil/dirt to control odor, but increasing suction through the air ducts also pulls air into the LFG. Decomposition processes speed up or

slow down depending on rain fall and moisture levels. Although the turbines exhibit flexibility, the combustors are sensitive to temperature and pressure, so changes to the percentage of methane in the LFG, and fuel line pressure, have to be accommodated. "Landfill issues trip the turbine," Whitmore says, "and we have to clear out the gas processing system after sucking air."

An early issue that CCJ loyalists will appreciate involves the turbine fuel nozzles. After a few thousand operating hours, the turbine exhaust temperature readings were out of whack, causing trips and potential flameouts. During a 4000-hr maintenance outage, fuel nozzles were pulled and staff discovered the tips were burnt off. Solar began a process to develop repairs for the nozzles. Although nozzle pilot fuel flow settings, clogging, and siloxanes carryover were suspected initially, failure analysis identified oil carryover from the gas processing equipment as the root cause.

Oil apparently was getting into the LFG lines (Figs 9, 10) because the coalescing filters serving the flooded screw compressors were not installed correctly. Plant technicians discovered that the nuts on six of the seven filters had vibrated off. Thus, there was oil carryover with the LFG but no indication of such.

11. Siloxanes removal is a critical step in the fuel preparation process. Inset photos at the top compare the clean recuperator surface required for top efficiency (left) with surface fouled by performance-robbing siloxanes (right)

The recuperators, a relative novelty for gas-turbine plant operators, have presented no problems "*so far,*" stresses Whitmore, "however, we are aware of problems at other Mercury 50-equipped LFG sites." The turbine is not a quick start unit—about 10 minutes of the 30-min startup period involves heating the recuperators. Plant staff has to be very attentive to this component: "There's no way to clean the recuperators online once they are clogged," added Whitmore.

Lomax stresses that recuperator design involves a basic tradeoff : tighter passages for better heat transfer or looser passages to avoid pluggage by contaminants. Ameren is contemplating additional monitors and analytics to anticipate fouling. Whitmore elaborated: "We have lagging indicators, like pressure loss and thermal effectiveness, but we need leading indicators." The plant has also documented with borescope inspection, after 6000 operating hours, a siloxanes "veneer" on the recuperator's tubes and plates.

It is clear that siloxanes removal (Fig 11), listening to Whitmore, is a primary on-going operating concern. When siloxane levels at the GT inlet are too high, the contaminant plates out on the recuperator surfaces, raising turbine backpressure and robbing efficiency. "The original fuel specification for siloxanes removal and entry into the turbine was modified while we were building the plant," Whitmore notes.

The specification required that the siloxanes removal unit achieve an outlet concentration below 5 mg/m^3. The LFG contains from 18 to 27 mg/m^3. One-quarter of that is knocked out after the chillers, but experience showed that wasn't sufficient to prevent siloxanes buildup (Fig 11, inset). The siloxanes removal unit reduces it below 5 mg/m^3. The new fuel specification now requires a polishing unit to reduce siloxanes below 1 mg/m^3.

In addition, the siloxanes removal unit requires LFG feed less than 100 ppm of H_2S. During initial operation, the H_2S removal media was not working adequately. It was supposed to reduce H_2S from 300 ppm to below 4 ppm, but it could not even meet the 100 ppm inlet level for the siloxanes unit. High H_2S levels hamper siloxanes removal. Another aggravation is that the sulfur gets into the lubricating oil for the flooded screw compressors, which dictates frequent replacement of oil and gaskets.

Ameren is in the throes of a siloxanes removal optimization program and an H_2S removal upgrade program. The plant is testing more efficient methods of siloxanes removal and conducting a pilot for a new kind of polishing bed. The challenge is complicated by the lack of a commercially proven on-line siloxanes monitor. The plant has to take grab samples send to an outside lab for analysis. For H_2S, the plant is testing a new media and adding a misting nozzle system to hydrate the H_2S media.

Best practices

A key lesson learned with the flooded screw compressors is the impact of siloxanes removal on oil temperature. There are four siloxanes vessels holding the storage media. Each is cycled off for media cleaning. When it comes back on, there can be a 20- to 50-deg-F rise in temperature. The plant had to add insulation on some of the lines and experiment with new set points to minimize this impact.

In addition, there's not much wiggle room. "The vendor sized the coolers so tight, we have to watch oil temperature very closely through the summer." Some of these problems will naturally resolve themselves when the contaminant removal units are optimized.

Another lesson learned is that some of the safety gear is too sensitive. For one, the infrared heat sensors were picking up heat from the glow of the turbine casing. This caused unnecessary turbine trips. Imagine your home smoke detector going off because you had a stove burner turned up high. The programming of the sensors was changed to avoid that part of the infrared spectrum.

Other recommendations based on Ameren's experience:

- Consider two Wobbe meters of different models with calibration bypass.
- Add all-welding piping in the construction specification.
- Develop standards for all control system graphical interfaces.
- Schedule regular control system team meetings to coordinate with the OEMs.
- Keep process control algorithms as simple as possible.
- Opt for fast processors in the controllers—faster is always better—and distribute the processing capability when possible. CCJ

The leading edge in managing plant digital assets

Control, automation, and asset management systems, often referred to as digital assets, occupy a peculiar place today. Like many other systems at combined-cycle plants, the DCS and software vendors take on more of the responsibility for making sure that the equipment works. Data and knowledge propagation, proliferating network connections, and cybersecurity, have created a growing interface to the corporate IT folks, outsource services vendors, and even regulators (through emissions monitoring) and safety/Hazop systems.

Many large owner/operators have added centralized fleet monitoring and performance centers and also rely on vendor remote monitoring for key subsystems—such as the gas turbine/generator. Plants continue to add additional digital software and hardware to (1) make use of the available data; (2) obtain advanced diagnostic capability; (3) allow remote work access, share knowledge, and rationalize staff, processes, and procedures; and/or (4) fix unintended consequences of the main digital systems—such as data fog, alarm management, cybersecurity, and operator graphical interfaces on the screens.

In one sense, the physical assets remain fixed but the digital assets reside in places too numerous to count—PCs, laptops, cell phones, iPads, personal digital assistants (PDAs), and other devices. Integrating and managing a plant's digital assets has become one of the most vexing challenges facing today's owner/operators. Jason Makansi, president, Pearl Street Inc, St. Louis, Mo, calls the digital assets the "brain" to distinguish it from the "brawn" of the iron and steel of the boiler, turbine, pumps, piping, valves, heat exchangers, etc. The "gray matter" is scattered far and wide these days, he says.

At the first EUCI-Pearl Street Inc Power Generation Summit, "Managing the Digitally Integrated Power Plant," 75 experts gathered in New Orleans, February 27-March 1, to discuss these and other facets of digital assets. Many of the speakers were the leading practitioners of digital asset integration and pioneers in specific areas. CCJ was a media sponsor for the event, which was so well-received, it will be held again next year (sidebar). Material presented and discussed of value to combined-cycle owner/operators is summarized below.

The big picture

Here are the major themes that emerged from the conference:

Configuration management is coming to your plant. In the previous chapter of the continuing saga of NERC's cybersecurity standards, it appeared as if many plants, if not most powerplants, would be considered non-critical assets and therefore escape the most onerous compliance actions. However, one of the latest revisions, published in January, apply a low-, medium-, or high-criticality definition. The upshot, say NERC compliance experts, is that configuration management is becoming a necessary feature of plant automation and knowledge systems.

Defining configuration management is not straightforward. In this context, it refers to the ability of a plant to document its last current "state," such as before or during a grid incident, and therefore be able to recover from a cyber-event. If you have nuclear plants in your fleet, ask your nuke colleagues; they've been dealing with configuration management for years.

Get to know prognostics. Monitoring and diagnostics is like your father's Oldsmobile. The next logical step is prognostics. Wordsmiths will note it's the root of prognosticate, as in predicting the future, interpreting the tarot cards, calling your astrologer or your stock broker. In this case, it makes a world of sense. By recording and storing large amounts of data, correlating data points, and identifying and comparing patterns under different operating conditions using sophisticated algorithms, software really can indicate, if not predict, the near future, like the next five minutes, or an hour.

Advanced prognostics are being

EUCI/Pearl Street/CCJ collaboration carries forward a rich tradition

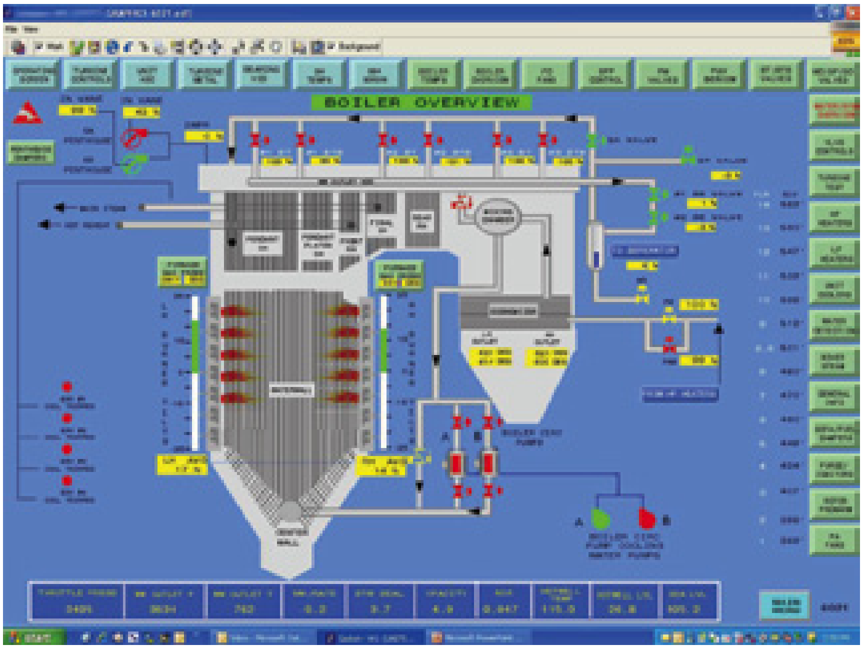
Fifteen years ago, when Pearl Street Inc president Jason Makansi was editor-in-chief of Power magazine, and CCJ's editor Bob Schwieger was its publisher, they launched an industry conference entitled "Power Plant IT," a follow-on editorial product from a special report Makansi researched and authored, "Information Technology for Power Plant Management," published in June 1996. Power held that conference three years in a row.

Makansi

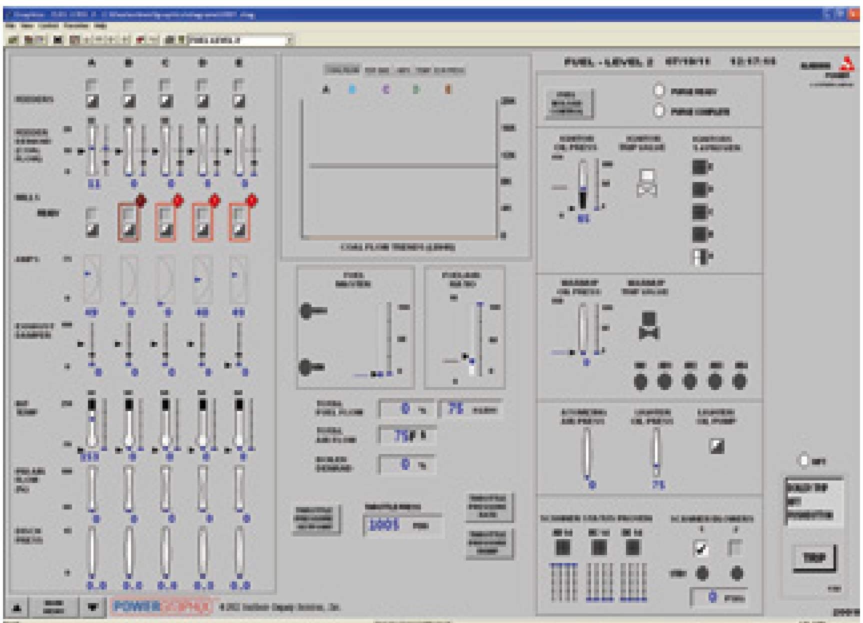
After Makansi left the magazine, he continued to work and do research in this area through Pearl Street's client engagements, organizing sessions at other industry conferences, and playing a leadership role in the annual ISA Power Industry Symposium.

The EUCI Power Generation Summit: "Managing the Digitally Integrated Power Plant," carries on this tradition. Mark your calendar for next year's event, to be held in Dallas, Feb 26-28, 2014. Access www.euci.com/pdf/0213-digital-power.pdf for details.

Emerson Process Management's Power and Water Solutions, served as the overall sponsor of this year's event in New Orleans. This is significant because its president, Bob Yeager, was one of the early and initial supporters of Power Plant IT. PAS Inc and AlertEnterprise also were sponsors of the 2013 EUCI event.



1. Is this boiler operating properly? The typical DCS screen does not reflect how plant operators intuitively think and react



2. Engineers at The Southern Company embarked on a fleet-wide program to overhaul the operator interface so that an operator can answer the question, "Is the plant operating properly?"

embedded in today's control and automation systems, or are available as outsourced services from specialist firms or OEMs. These systems provide early warnings and alerts of serious problems. At the conference, owner/operators reported significant savings by avoiding catastrophic events.

Wireless applications are growing. Some experts are still not comfortable with wireless in the plant environment. First, there are the potential interferences with other communication protocols. Second, they present a separate and potentially higher cyber-security risk than hardwired systems. Owner/operators at the conference with deep wireless experience insist that these challenges are being met; it's the *perception* of wireless among those with no experience that challenges the industry.

Because hard-wiring is costly, wireless systems allow plants to deploy advanced sensors, instruments, and M&D strategies that simply could not be justified otherwise. Some researchers still think cell phones impair brain function, yet the vast majority of Americans seem to use them without incident. The benefits of wireless deployments are simply too compelling to be held hostage by the challenges of perception, noted several presenters.

Plants are rethinking operator interfaces. One presenter showed a screen shot from the typical powerplant DCS and asked, "Can you tell if this boiler is operating properly?" Of course, the rhetorical answer was unanimous: "No!" Data fog is an unintended consequence of digital systems. The challenge is magnified because some owner/operators have standardized on plant control systems and no one thinks to ask real live plant operators for their input during the design phase.

How plant data, trends, and graphics are presented to the operator is being overhauled. This activity started with alarms—too many, too often, too disorganized—from the latest DCS. Now, alarm management has become a function in its own right at many plants.

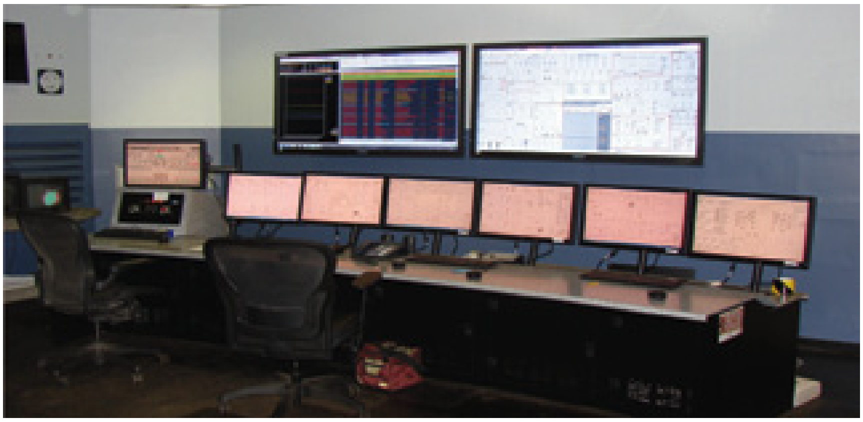
Virtualization is making computer hardware more productive. You probably have to be a real IT geek to comprehend this one. Suffice it to say that virtualization is a way to apply software that makes your computer hardware—servers, PCs, controllers, PLCs—more efficient.

From the plant's perspective, think of it as being able to run multiple operating systems on one hardware platform. One plant manager reported that they converted three *physical* servers to run 16 *virtual* servers. Another way to view it is that virtualization helps you deal with the fact that control system hardware has a 12- to 18-yr obsolescence cycle, while IT equipment typically has a 3- to 5-yr cycle.

One practical example presented is that you can now have your plant simulator running with the same models as the DCS. In other words, you can train at a plant simulator that is running in parallel with the plant's DCS using real-time or recent historical plant operating data.

The real plant and the digital plant are converging. This is where the brain analogy really stands out. Parallel-running simulators are just one example. With today's diagnostics and prognostics, you can replay and analyze plant transients the next day (or anytime in the future, theoretically) and peer into the future and run "what if" scenarios using actual plant operating data.

Plants become self-aware, or self-actualized. Other process industries are employing 3-D visualization technologies to organize and manage all plant data and information. These screen graphics are developed from



3. Control rooms are more streamlined with two 70-in. overview wall-mounted screens for displaying Level-1 information and six desktop screens for Level-2 and Level-3 information

laser-scans of the actual plant equipment in the *as-built state*. Operators soon will be looking into a virtual reality world, a faithful representation of the actual plant, rather than crude diagrams or computer-generated graphics. As the plant moves forward from its initial design state after startup, operations, maintenance, and management will be based on the real-time, current state of the physical plant, captured digitally.

The lexicon is hard to digest—virtualization, self-actualization, prognostics, configuration management. It's enough to make an academic out of a practicing powerplant engineer. But behind these words are powerful techniques and technologies that are helping owner/operators with the perennial goals of faster, better, cheaper. And safer. The following summaries of presentations from plant managers attest to that.

Rethink operator interface

One of the most thought-provoking presentations was given by Harvey Ivey, manager of I&C systems and field support for The Southern Company. He showed a screen shot from the typical powerplant DCS (Fig 1) and asked, rhetorically, "Is this boiler operating properly?" Ivey is leading a program at Southern to rethink how operators receive and respond to information at dozens of the utility's power stations and provide a level standardization for new facilities and retrofits to existing units across the Southern fleet.

Called PowerGraphiX™, it incorporates these core principles: arrange hierarchy, navigation, and graphics based on how operators think and tasks that they perform, not on a typical piping and instrumentation diagram (P&ID); limit use of color to enhance communication, not hinder it; assist the operator's natural ability to detect trends and recognize patterns; provide navigation from overview/big picture, important sub-systems (for example, fuel, water), specific pieces of equipment, and interlocks and diagnostics; convey information, not just data; and apply ergonomic principles.

The result is that operators will view screens that look like Fig 2, not like Fig 1. The control rooms at Southern power stations will look more streamlined, with two 70-in overview wall-mounted screens for Level 1 information, and six desktop screens for Level 2 (system) and Level 3 (equipment) information (Fig 3). Level 4 information includes interlocks and diagnostics.

Standardizing in this way, said Ivey, doesn't just improve operator performance, but reduces the total number of purchased screens, and engineering, licensing, and cybersecurity costs. The total number of operator screens will be reduced from 300 to 600 to around 75. Ivey noted that there's no additional cost to build graphics this way. It costs at least as much to build a poor graphic as a good one, he said.

Rationalizing alarms is another aspect of operator interfaces getting much attention these days. Dan Martian, senior production engineer at Minnkota Power Cooperative Inc, showed how the Milton R Young coal-fired plant managed to control alarm flooding, disable nuisance alarms, and make it practical for operators to respond with adequate time to the most important alarms.

Essentially, the plant follows the guidelines, which apply regardless of the type of station, outlined in the flow chart and table (Figs 4, 5). The principles are derived from "Alarm Management: A Comprehensive Guide," second edition, by Bill Hollifield and Eddie Habibe, published by ISA. The authors are executives with PAS Inc, Houston. One of the guiding principles is to distinguish between an event, something that does not require an operator action, and an alarm, something that does.

Martian reports that, for one plant subsystem, the selective non-catalytic reduction (SNCR) NO_x emissions control, the plant has reduced alarms by 96%. In one week before rationalizing alarms, operators had to consider 5615 alarms! In a week afterwards, that number was reduced to 214. Plant personnel are now able to focus on the 20 most-frequent alarms.

Think prognostics

Diagnostics can tell you what's wrong. Prognostics anticipate what will go wrong, so that you can take actions to prevent significant events. One way to think about prognostics is that they give you an early alert *before* an alarm is triggered.

Moh Saleh, an engineering O&M manager at Salt River Project, described multi-level monitoring systems used at the Desert Basin combined-cycle plant near Phoenix. They include two "foundational" systems—the OSI PI data infrastructure which ties together the DCS, the Mark V gas turbine/generator controls, vibration monitoring systems, and others, and the SmartSignal (now GE Intelligent Systems) EPI Center which pulls data from PI and analyzes patterns based on plant models built by SmartSignal and verified by the plant.

SmartSignal detects deviations well below control-system alarm levels, Saleh noted. Plant personnel access this prognostic capability 24/7 while SmartSignal specialists monitor the plant remotely during normal business hours. Monitored parameters are compared (at 10-min intervals) to what is "normal," based on correlations among parameters using historical data and learned system behavior.

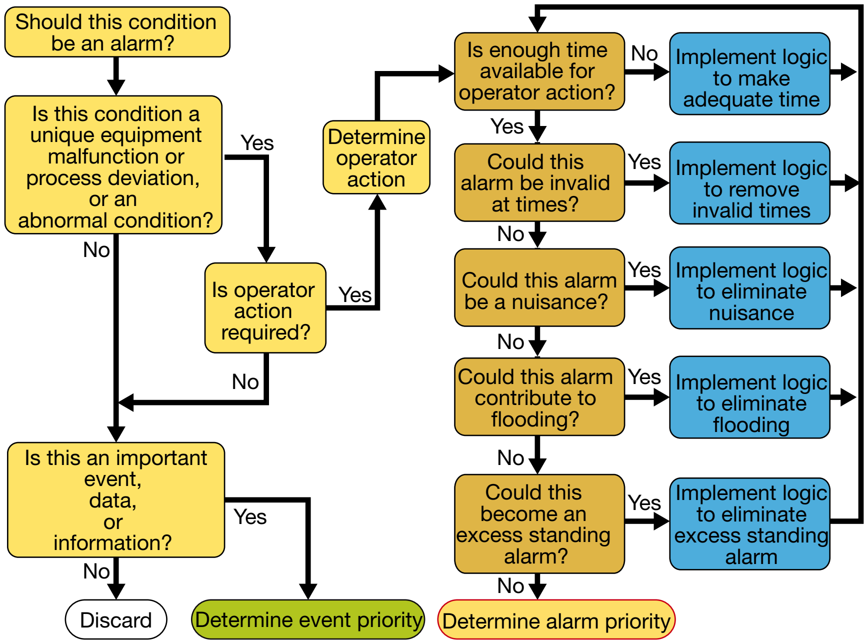
Other monitoring systems used regularly include:

- The combustion turbine OEM's remote diagnostic center which, among other things, compares data to other units in the model-number fleet to analyze patterns and deviations, and is linked back to parts inventory.
- GP Strategies Corp's EtaPro™ performance monitoring system which tracks heat-rate losses and quantifies the impact of failures on plant efficiency and outages.
- Chromalloy Gas Turbine LLC's Tiger®, a knowledge-based turbine condition monitoring system, which allows data replay.
- SmartSignal's Cycle Watch, which tracks the gas turbine's startup "signature" by correlating vibration, bearing temperatures, combustion

parameters, blade path and exhaust temperatures, valve positions, and auxiliary systems.

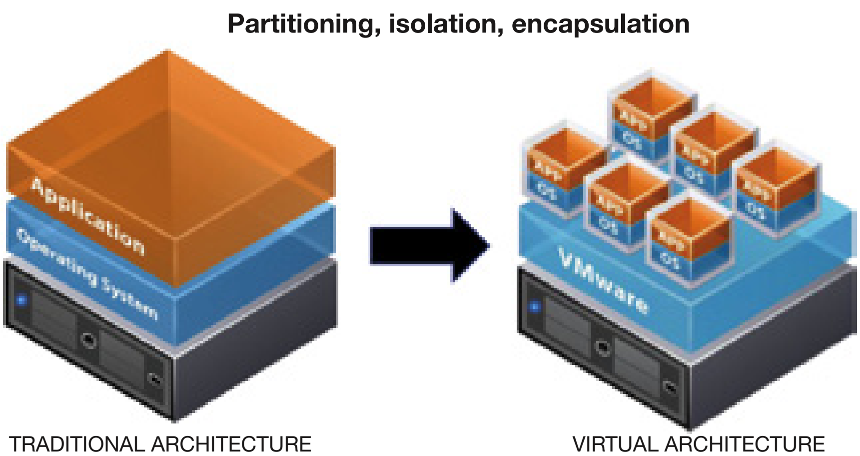
Saleh notes that these systems are particularly useful because Desert Basin "cycles all over the place" but was designed for base-load operation. Each GT experiences 250-300 starts per year. One of the many benefits of monitoring is that it provides informed support for a need to shut down units.

Juan Ontiveros, plant manager of the University of Texas at Austin's Carl J Eckhardt Heating and Power Complex, whose facility was profiled in the 3Q/2012 CCJ, indicated that they are demonstrating a plant health index



4, 5. Minnkota Power Co-op Inc's Milton R Young Generating Station uses flow chart (right) to segregate alarms, then determine their priority using the chart below

Determine alarm priority						
		Severity of consequences for failing to act				
Priority	Severity	Safety	Environmental	Operational impact	Maintenance impact	Time available to act, min
1	Critical	Minor to extreme injury	Catastrophic, uncontained, and reportable	Unit runback and trip	Severe equipment damage, load curtailment, and cost	Less than 3
2	High	Minor injury	Serious but contained and reportable	Unit runback	High equipment damage, load curtailment, and cost	3 to 15
3	Medium	—	Contained and reportable	Unit runback imminent	Moderate equipment damage, load curtailment, and cost	15 to 60
4	Low	—	Minor contained and not reportable	Unit load reduction imminent	Minor equipment damage, load curtailment, and cost	More than 60
5	Later use	—	—	—	—	—
Determine event priority						
6	High	Event of high importance to plant group or personnel other than operator				
7	Medium	Event of medium importance to plant group or personnel other than operator				
8	Low	Event of low importance to plant group or personnel other than operator				



6. Virtualization, used successfully at Basin Electric Power Co-op's Leland Olds Generating Station, involves adding a layer of software in between the physical PC or server and its operating system to create a virtual server with the ability to run multiple applications and operating systems. The technique helps consolidate hardware and makes it more productive

from BNF Technology Inc, a Korean firm. It is described as a sensor-less CBM system for plant equipment using statistical modeling techniques.

Virtualize!

Regardless of what plant you run, you have computer hardware that can probably be rationalized for better performance. Mark Thompson from Basin Electric Power Co-op's Leland Olds Generating Station, discussed a powerplant application of virtualization, essentially using software that mimics hardware to replace physical computing hardware (Fig 6).

The big dichotomy with modern control systems is that the control-system hardware—the stuff out in the plant—is on a 12- to 18-yr replacement cycle while the computer hardware

replacement cycle is 3 to 5 years. Virtualization allows you to consolidate computers and make them more productive. By inserting a "virtual machine" (software) in between the physical machine (PC or server) and its operating system, that physical machine can run multiple applications and multiple operating systems. VMWare Inc, Palo Alto, Calif, is the company that supplied the virtual machine layer to Leland Olds; the product, in IT parlance called a "thin client," is called a hypervisor.

In late 2009, the plant experienced failures of physical servers in the Rockwell Automation PLC platform, raising reliability concerns. The servers were installed in the 2003-2006 timeframe as part of an overhaul of the system and move to a client/server architecture. The system originally included 13 servers. Hypervisor allowed the plant to consolidate into three physical servers running 16 virtual servers. Two of the servers are used to actually run the plant, the third is to back-up and maintain the system.

Basin Electric had never done anything like this before. Based on the success of this initial project, according to Thompson, the plant is going further. It has deployed virtualization for the plant simulators and next plans to consolidate the plant control consoles.

Significant cost savings can be obtained, especially for older plant assets, Thompson said, in addition to the following benefits: running fewer servers reduces power consumption and conserves space, different operating systems can be run on the same platform, virtual servers are easier to rebuild than physical ones, and the plant can better leverage internal IT and computer resources. CCJ

Reduce risk: Expand scope of 7EA compressor inspections

GE's Technical Information Letter (TIL) 1854, released Aug 27, 2012, attributes tip losses on R2 and R3 compressor blades suffered by a few machines in the 7EA fleet to heavy rubs and/or corrosion pitting (Figs 1-3). The OEM considers the phenomenon low risk to unit operation and reliability. However, at least a couple of compressors reportedly have been badly damaged in the last 18 months. Insurers might be less inclined to rate the level of risk as "low."

TIL 1854 says fleet experience and engineering analysis have concluded that compressor rubs can be caused by casing distortion that progresses over time, and by hot restarts initiated between one and eight hours after shutdown. The latter causes critical clearances to decrease. Corrosion pitting, on the other hand, creates a local stress concentration that may result in a tip loss via high-cycle fatigue.

The editors called Rod Shidler, president, and Mike Hoogsteden, field service manager, Advanced Turbine Support LLC, Gainesville, Fla, which inspects more than 2000 gas turbines annually, to get their perspective on the 7EA issue. They provided the photos shown here to illustrate the level of damage Advanced Turbine Support has found, and offered their thoughts on corrective action.

TIL 1854 recommends that if heavy tip rubs or tip loss occurs, tip grinding and/or blending to increase clearances can be performed at a major inspection or when the mid compressor case is removed. Considering that at least two compressors already have been wrecked, Shidler and Hoogsteden suggest a more proactive approach.

They recommend in-situ dye penetrant inspections of all compressor R1 and R2 blades (R3 blades are difficult to access without lifting the casing) where tip rubbing or pitting is in evidence during the next inspection cycle. The R2 blade crack in Fig 4, likely initiated by tip rubbing, is highlighted with dye penetrant. This machine had only 309 starts/1900 hours (and 25 trips) when the crack was found. In-situ blending by technicians from Advanced Turbine Support eliminated the crack without lifting the casing. CCJ


1, 2. 7EA R2 tip liberation occurred in 2010 (left); torn S1 stator vane was collateral damage

3. This 7EA R2 tip liberation happened in 2013. Note that the compressor case already had been removed to facilitate repairs

4. R2 blade crack was later blended out in-situ by technicians from Advanced Turbine Support

Replication can verify metallurgy after restoration heat treatment

By John P Molloy, PE, M&M Engineering Associates Inc

To achieve the creep rupture life expected from a gas-turbine bucket/blade, and to ensure reasonable mechanical properties, the airfoil's microstructure must have the ideal shape and distribution of its constituent phases. The primary beneficial phases of interest are the gamma-prime and carbide constituents. The first probably is the most scrutinized phase during microstructural evaluation, and often is used to determine if a blade requires refurbishment. Carbide shape and distribution is similarly important, but often takes a back seat to the gamma prime in condition assessment.

Ideally, the gamma-prime morphology should be cuboidal, which essentially implies that the microstructure, in cross section, would look like an array of squares (Fig 1). As the square shape of the gamma prime becomes more rounded, or "coarsened" the mechanical properties of the blades are compromised, particularly with regard to remaining creep life. This is the reason most GT buckets/blades are limited to approximately 24,000 fired hours between refurbishment cycles (Fig 2).

Carbide morphology (shape) also influences mechanical behavior. Carbides, like gamma prime, also will change shape and coarsen as operating hours accumulate. They may dissolve in the matrix and coalesce at the grain boundaries as well. If the carbide distribution in the grain boundaries becomes a continuous film over time, the mechanical properties can become severely degraded.

Other phases are also of concern—such as sigma, laves, and mu. Several of these are known as topologically close-packed (TCP), and have a detrimental effect on the mechanical properties if present in any form. By contrast, carbides can be beneficial or detrimental depending on their shape and distribution. TCP phases are often needle-like and are readily discernible in a microstructural analysis.

Having established the *need* for microstructural evaluation of turbine buckets/blades, the next decision is *how*. The most common method for assessing the microstructure of a turbine airfoil is to perform a destructive analysis, where a bucket or blade is sacrificed. This normally entails sectioning the airfoil in three locations (at 10%, 50% and 90% of span) as well as the root. These cross sectional areas are metallographically evaluated for many of the features discussed above.

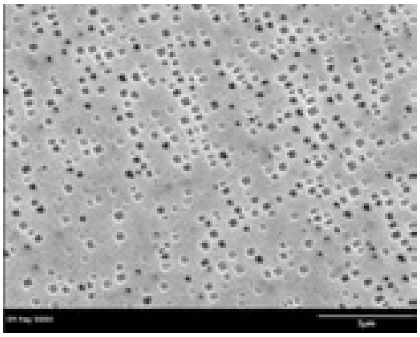
However, today's turbine buckets and blades are engineered to ensure they will retain enough of their properties to survive the typical service cycle. It is during the hot gas path (HGP) refurbishment that the blades receive critical solution annealing and age-hardening heat treatments to ensure that the appropriate microstructure has been restored.

Some service centers also utilize hot isostatic pressing (HIP) to reduce void contents, but this is normally an optional process. Depending on the service center performing the refurbishment, the bucket/blade set may or may not have a destructive analysis to verify the proper restoration of microstructure. Not everyone is willing to destroy a $30,000 turbine airfoil.

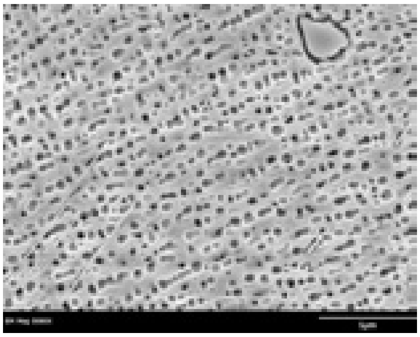
If your goal is simply to ensure that the heat treatment has been effective, the bucket or blade need not be destroyed. Metallographic replication can be performed near the tip of the airfoil, where stress is low and weld repairs often are performed. Such replications can be evaluated at a magnification of 5000X to establish the gamma-prime and carbide morphologies (Fig 3). Ideally, such a replication would be performed after the ageing heat treatment, and before any other processing—such as coating.

The bottom line: Bucket or blade microstructure can be confirmed without sacrificing an airfoil. Moreover, once a bucket or blade is received by a qualified laboratory, a typical replication and evaluation can be done in a day's time. Alternatively, a fully equipped metallurgist can visit to the location of the blades to perform the replications onsite.

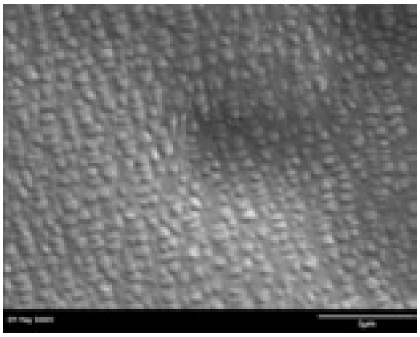
Once the replications have been obtained, the samples must be coated for electrical conduction and evaluated using a scanning electron microscope (SEM) at high magnification (5000X) to establish the gamma-prime and carbide conditions. The replications can be archived indefinitely for future reference as needed. CCJ



1. Gamma prime after typical ageing heat treatment



2. Gamma prime following a complete hot-gas-path cycle



3. Gamma prime morphology is interpretable after a field replication

Engine vibration continues as a major concern of users

The 501D5-D5A Users can be characterized as an intimate group, historically attracting about two-score attendees to its annual conferences and vendor fairs, fewer at the "mid-year" meetings in January. Most attendees have been repeat participants, several from far-away places like Korea and Indonesia, with the typical user knowing perhaps half of the owner/operators in the room.


Fleck

The chairman, Gabe Fleck, recently promoted to manager of gas plant operations at Associated Electric Cooperative Inc, has been at the front of the room for a decade, supported by Vice Chair Barry Mayhew, maintenance manager at Cardinal Power, and Director Lonnie Grote, compliance coordinator for NAES Corp.

Fleck's low-key demeanor and unflinching dedication to the group is critical to the organization's success. He works diligently at technical program development, and with sponsors to provide users new experiences in terms of meeting locations and social events. This June's conference was in Louisville, affording visits to Churchill Downs, the Louisville Slugger Museum, and a local brewing company—plus bourbon tasting on a private yacht. The Seelbach Hilton Hotel was an apropos conference location for a mature group, dating back to 1905 and listed in the National Register of Historic Places.

That time always seems to stand still at D5-D5A meetings is not surprising because of the continuity of attendees and discussion threads. Technical topics are linked from meeting to meeting by interactive messaging via the group's robust online forum (use the QR code to connect to the group's website). Over time, conclusions are drawn and solutions developed—with help from the OEM, Siemens Energy Inc, and participating third-party equipment and services providers, of course.

Fleet characteristics contributing to the group's stability include the following:

- Both engines served are no longer in production (although there are three new D5As in storage), the two fleets holding steady with a total of 150 units worldwide.
- The service factors (operating hours divided by period hours) for engines not in cogeneration service are relatively low, based on information shared by asset owners. One reason for this undoubtedly is the increased use of more-efficient F-class engines in peaking service.

Scan to access D5-D5A website

Given the foregoing perspective, why these "surprises" at the 2013 annual meeting:

- Record attendance, breaking the 50 mark for the first time in the 17-year history of the group.
- Most first-timers ever, 22; plus a dozen who had participated in only one other meeting previously.

The only logical answer may be that the retirements of many senior plant professionals, predicted for several years, is now occurring and that their replacements have little or no experience in operating and maintaining D5s or D5As. Participating in this and other user groups is the only practical way new O&M personnel can come up to speed on what they have to know, and whom they should know to get the help needed going forward.

The technical program began after breakfast on Tuesday, June 4, with presentations by Mitsubishi Power Systems Americas Inc and a few suppliers that would participate in the vendor fair later that afternoon. Four hours of closed user discussion rounded out the day. The second and third days of the meeting were divided between Siemens technical presentations and closed user discussions.

Engine vibration

Engine vibration occupied a considerable amount of discussion time. Identifying and correcting sources of vibration has been a major initiative between the users group and the OEM for the last two years. The collaborative Vibration Improvement Program is guided by an executive committee consisting of user representatives and Siemens management.

Work packages were developed and teams formed to perform root-cause investigations, testing, rotor-dynamics modeling, and data analysis, and to make operational recommendations. Creative Power Solutions, an independent turbomachinery consultant based in the Phoenix area (find out more by scanning the QR code), was retained by Siemens to assist in the effort.

Creative Power Solutions website

A user started the discussion by saying his D5A trips on high vibration about once every 10 starts, with

1. Coke buildup in bearing exhaust line has been implicated in operational problems

2. Over-the-road transport is not without risks. Heights of tunnels and intersecting highways on the chosen route must be checked and rechecked. Allowable bridge loadings also must be verified

the trip setting at 10 mils. It takes two hours for the vibration to build to that point. He thought the turbine blades might be locking-up on startup, so root springs were installed in the gaps between the R4 blade roots and the discs to make rotor vibration levels more repeatable and to facilitate balancing.

The low-cost consumable part was developed to minimize disc wear by preventing blade rock during turning-gear operation. However, springs were not the answer to this user's issue. Where springs do provide benefit, a recommendation was made to replace them at each hot-gas-path (HGP) inspection. More information on blade-root springs is available in the presentation Mitsubishi engineers made to the group. It is posted on the D5-D5A website in an area accessible only by registered users. The steering committee urges qualified owner/operators to register today.

Another attendee said vibration on his machine was traced to coke buildup on the bearing exhaust line; when coke broke off (Fig 1), the balance would shift. He learned that running unbalanced—example: x=2, y=5—contributed to more stable operation. Each time technicians tried to do a proper balance, vibration increased and the unit tripped. Someone suggested that a successful vibration analysis demands that you know what you're looking for.

Yet another user got into the passionate exchange, suggesting that overtightening of bolts on the marriage coupling to adjust run-out can cause vibration when the bolts relax. He said this happened on his unit.

Someone else asked if everyone with a vibration issue is sure their bearing probes are properly located. Here's why: Installing exhaust-bearing vibration pickups on the bearing housing rather than outboard can reduce readings by up to one-half during startup, full speed/no load, and at base load. This location, which is consistent with ISO standards, is said to minimize the contribution of bearing-housing motion to the vibration signal. Redundant probes were suggested when making this modification, to improve serviceability.

The discussion continued with an attendee who was puzzled as to why vibration on his machine was at 4 to 5 mils—until plant personnel really dug into the matter. Turns out the stack was pushing down on the end of the machine and causing the unbalance. The solution was to lift the stack by about an inch.

The air separator also was mentioned as a possible source of vibration. One of the Mitsubishi speakers had addressed that at the beginning of the meeting. He said the original air separator uses spring force to maintain contact with the R1 disc and that relative movement at the R1 disc face can cause fretting. Retrofit with a bolted air separator was said to reduce R1 disc fretting potential and increase the through-bolt compressive load on turbine discs—effectively decoupling the air separator. This mod, developed for the M501F gas turbine, is applicable for the D5 and D5A turbines as well. A drawing is provided in the Mitsubishi presentation cited earlier.

You could sense the frustration of a user who told that group that the vibration gremlin has resided in his D5A since 2001, tripping the unit every dozen starts or so. It seems that rust/dirt accumulated and then released, upsetting the engine's balance. His experience suggested that balance weights aren't necessarily the solution. The unit had so many weights it was ridiculous, he said. Every service technician believed he had the solution, the user continued, and added weights. All were wrong.

Maintenance outages

The closed user discussion shifted to engine maintenance outages, experience with conventional and extended-life parts, repairs and coatings, etc—a cornucopia of subject matter. One attendee with a pending major inspection polled the group for experiences in using contractors for this work.

Standard practice at his facility has been to perform maintenance outages with plant personnel under the direction of an OEM technical advisor. This has worked well over the years, but a multitude of projects would prevent staff from doing the work on the upcoming major. He was leaning toward hiring the OEM or Mitsubishi to perform the outage. What was the group's experience?

Hands shot up in all directions. The majority of attendees had opinions, as you might imagine. Difficult to draw objective conclusions from such an exchange: The experience base of the commenters varied widely, plus the crew from Company X that did a good (or bad) job for you likely was not the same crew that did the bad (or good) job for the colleague disagreeing with your assessment.

Also obvious from the discussion: Performance may vary widely among repair shops, depending on the owner and key personnel at the time the work is scheduled to be done. Thorough due diligence of candidate shops was strongly suggested. A couple of participants stressed very objective evaluation of low-cost providers.

They said some service providers may not have the specific experience, or even qualified in-house procedures, for your work. Those shops may look to you to provide repair procedure. In sum, the users were in general agreement that there is no "right" answer on which way to go regarding repairs. You have to make decisions based on what "fits" at the time.

Good discussion. However, the value of the exchange definitely was positive. For those in the room who had experiences they wanted to forget, it was a welcome opportunity to vent; for those with good experiences, an opportunity to pass on to colleagues their good fortune with the hope that others might benefit as well. There seemed to be unanimity of opinion on two points:

CleaverBrooks®

DO YOU MANUFACTURE  OR PROCESS  OR REFINE 

OR PRODUCE  OR PROVIDE  ?

WE MAKE A BOILER FOR THAT.

With a full line of complete Cleaver-Brooks boiler systems – from burner to stack – available in any size and any capacity, there's a boiler that will fulfill your needs and exceed your expectations. Industrial watertubes, HRSGs, waste heat boilers – we do it all. Whether you need 10,000 lb/h or 1 million lb/h, we offer the only single-sourced, boiler/burner system in the world.

Visit cleaverbrooks.com/engineered or call 1.402.434.2000

3. Crane collapsed while moving a very large generator. This accident involved a fatality

4. Hail storm flattened the top fins on this rotor air cooler

- Leading aftermarket repair shops typically will scrap fewer parts, cost less, and have better turn times than an OEM.
- Owner/operators must have a shop presence to assure proper conduct of repair jobs, assess repair quality, evaluate parts the contractor wants to scrap, etc. If there's no direct employee with the capability to perform these functions, use of a third-party expert was highly recommended. Two oversights mentioned: Repaired transition pieces provided without cooling holes; a new vane row that included a *refurbished* vane.

As the discussion of overhaul experience continued, one user mentioned that his plant had essentially completed its major when the rotor being lifted for reinstallation in the casing was dropped. The lengthy exchange following this revelation left one with the impression that the owner must remain involved in transportation (Fig 2), rigging, lifting (Fig 3), and other such tasks contracted to others. It's your unit that won't be producing power when the unthinkable happens.

There have been several reported "drops" in the last year or so. This particularly disturbing fact might well point in the direction of inexperienced riggers. Rigging is both engineering and art and one must assume that some of the more talented people have retired—riggers get old, too—and that their replacements may not have been properly trained.

Another thread related to annual maintenance outages was started when the subject of contingency was brought to the floor. The question that stimulated the discussion went something like this: For a base-load D5A, how much contingency would you allow for a combustion inspection? First reply: "We aim for 8000 hours but will go to 10,000 or 10,500 if necessary."

Next question: How far can you stretch out an inspection without incurring problems? A different user replied: You should not put off an HGP or major, although some believe 10% in hours is acceptable. It's all about risk assessment, he said. The ductility of R1 and R2 turbine blades is the variable that should drive decision-making. For a base-load unit, material degradation is not as much of a concern as it would be for a peaking machine.

The user continued, saying it's important to get critical hot parts into the shop for thermal rejuvenation. The life cycle of components comes into play here, he added. Is this the first cycle, the second, the third? The younger the component, and the fewer the thermal cycles, the more flexibility you have in scheduling—generally speaking.

Service agreements had a brief run in the open discussion session. Renegotiation and what should be included in the new arrangement were key talking points. A parts agreement was suggested in place of a service agreement. If you go that route, the group was told by a colleague that they have to consider who handles and stores the parts. In addition to tax implications, how will you confirm that all parts are of the quality level you believe they are? Recall the earlier comment on the reconditioned vane segment that was included in the new vane row.

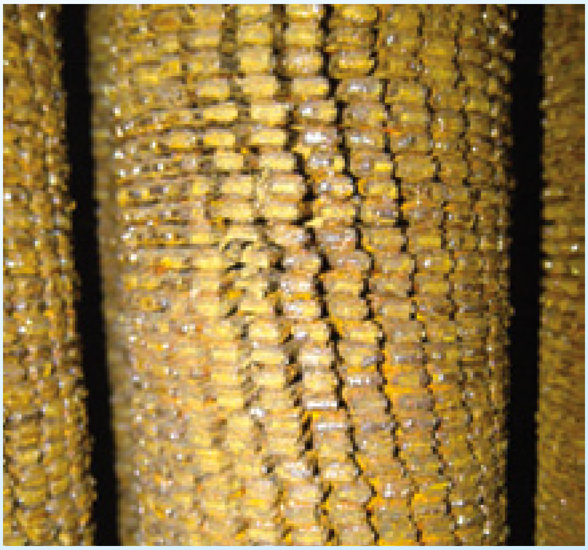
One more thing the experienced user suggested: Specify in the contract that the customer has the right to have the service provider's program manager replaced at its discretion. This is important in situations where the original manager approved by the customer is changed by the contractor or leaves its employ and the replacement is not to the customer's liking.

Finned-tube heat exchangers used for rotor air cooling (RAC) were introduced by a user who wanted to know how to clean fins to improve heat transfer. Pressure washing is not effective he was told and there's the possibility that a high-pressure water jet will tear fins off the tubes. Flooding the housing with a suitable solution was suggested as the best method. But if you go this route, don't forget to put plastic over the motor underneath the unit.

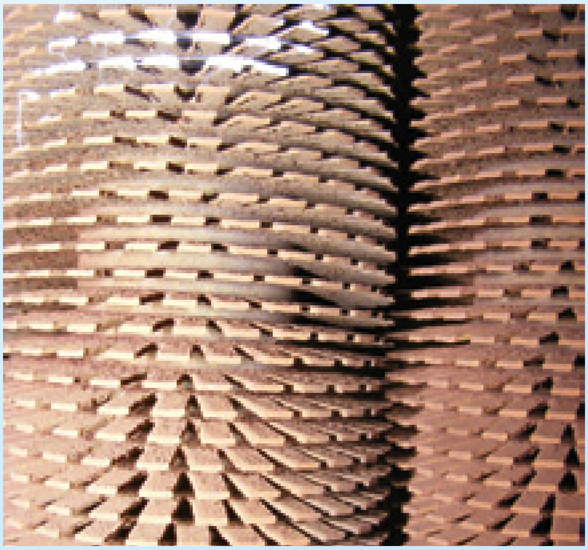
Several attendees were interested in how you might fix flattened-over fins on this and other types of air-cooled heat exchangers (lube-oil coolers, for example). A hail storm really can squash down the fins, one person said (Fig 4). But he was told that this condition had relatively minimal effect on the unit's cooling performance compared to the separation of the fin strips from the tubes. The only practical corrective action for fin/tube separation is to replace the tube bundle, which can cost about a quarter of a million dollars for D5A air-to-air RAC. An infrared scan of the unit can provide an indication of heat-transfer efficiency, someone said.

Two discussion topics linked up when someone asked what type of rotor balancing should be done during a major—high- or low-speed? One attendee said a low-speed balance was fine but another disagreed considering the rotor vibration issues many owner/operators are experiencing with these engines. A user said R1 and R2 blades were changed in the field; the new sets were moment-weighed and properly installed. No balancing was done. This rotor suffered balance problems. Another attendee said they did a high-speed balance during a major with a fully bladed compressor and no blades in the turbine. There no balance issues following the installation of moment-weighed blade rows with no additional balancing.

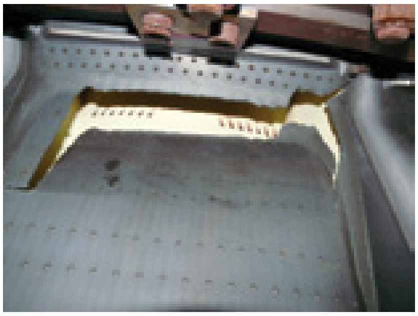
Transition pieces always get air time at GT user-group meetings.



Before



After



5. Failure occurred in the upper panel of the transition piece near the exit mouth (above)

6. Spray nozzles, well distributed and designed to produce small droplets, are critical to success in wet compression (right)

In Louisville, the owner of two D5A peakers commissioned in mid-1999 with water-injected DF42 combustion systems reported transition failures, which occurred in the upper panel near the exit mouth (Fig 5). Temperatures in this region were said to be higher for DF42 systems than they are for DLN. Longer run times and higher outputs probably contributed to the cracking, the user said.

Discussion threads that didn't extend very far included generator issues such as corona damage, partial discharge, and vibration; plus, wet compression (Fig 6) and shaft grounding (Fig 7). Disc cavity No. 3 temperature excursion on startup received brief mention. It is conducive to a turbine trip, which can be avoided by slower ramping. It was said that if operators don't catch the increasing temperature and slow down the ramp, the engine will run back. A user said he avoided run-backs by restricting the ramp to 3.5 MW/min. He added that, in his case, the issue was seasonal, but didn't elaborate.

Air filters. No user-group meeting would be complete without discussion of the filter house. One attendee questioned something he had heard regarding the placement of an evaporative cooler in front of the filters. He mentioned Donaldson Company Inc as the supplier (scan QR code to access website). There were lots of shoulder shrugs with some users thinking they might have heard of this but not sure. An email from the meeting room to Donaldson's GT aftermarket manager, Barry Link, got this response within a couple of minutes:

Donaldson website

Donaldson manufactured several two-stage static inlet filter systems for Siemens V-series machines that were located behind the evaporative cooler. These filtration systems used conical/cylindrical element pairs with a panel-style prefilter. He thought the arrangement probably was specified by the OEM and believed there probably were fewer than a dozen such inlet systems operating in North America.

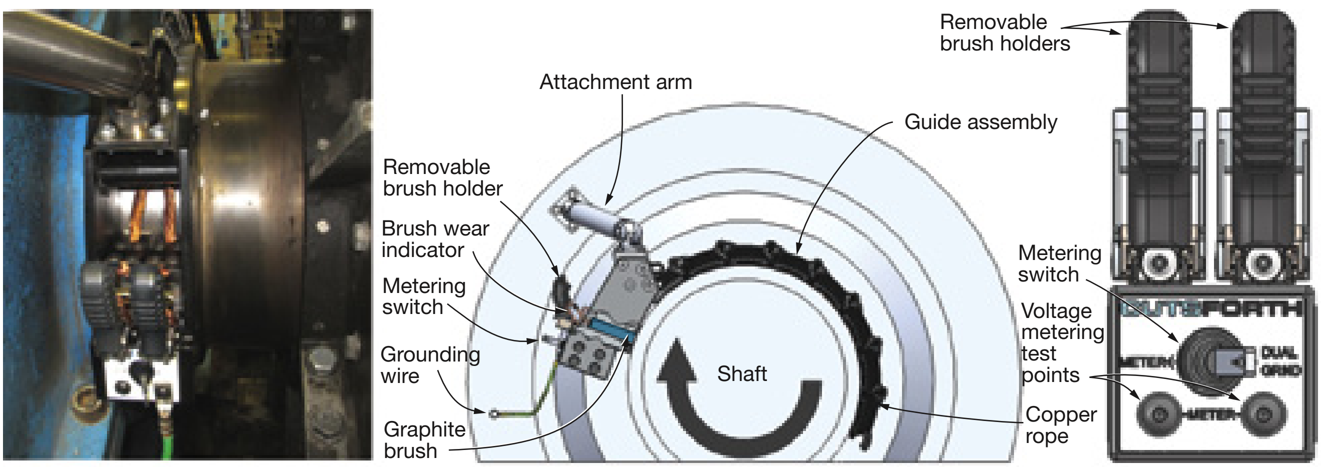
Generally speaking, Link continued, Donaldson prefers not to put evaporative coolers upfront in *first-fit* applications based on the following factors, among others:

- Shorter filter life.
- Shorter evap-media life.
- Increased water consumption because additional blowdown is required.
- Additional inlet-system maintenance.

However, in some retrofit cases, he thought upfront evap coolers could be a viable option based on the lower cost of the turnkey project to procure and install.

Bearings. A user asked the group how often others change out journal bearings. One person said "each major." Several attendees suggested simply rebabbitting pads and resetting clearances. This was discussed in detail last year during the tour of the Pioneer Motor Bearing shop in Charlotte. By show of hands, owner/operators experience more babbitt cracking than loss, probably because of vibration.

User presentations are always instructive, enabling other attendees to see what their colleagues are doing to improve performance and safety. One utility engineer reviewed the capital/O&M projects recently implemented at his plant. Given today's focus on physical and electronic security, and the plant's location in a tornado-prone area, control-room "hardening" was given top priority. This involved adding reinforced cinder-block walls, a hurricane-rated door, and bullet-proof windows. Electronic security upgrades also were implemented. Ethernet outlets were installed and electrical outlets increased in number.



7. Shaft grounding alternative to a carbon brush system, installed at left, is described in center cutaway and brush-section detail at right. Note that the copper rope terminates about halfway inside the last section of the guide assembly. A video on the Cutsforth Inc website (www.cutsforth.com) illustrates the ease with which the copper rope is installed and removed

Generator upgrades included installation of a bus coupler on generator phases to monitor stator-winding partial discharge and the generator pole crossover mod. Safety enhancements: Installation of access ladders, platforms, and steps, and addition of a safety fence around the turbine roof. The handwheels for onsite gas supply valves were painted red so first responders know what valves must be closed.

Lube-oil coolers were modified to provide an additional 5 deg F of cooling and a dam was built around the coolers to catch any leakage. Building HVAC equipment was replaced and upgraded to reduce the headaches and maintenance costs associated with overheating of the electrical package. Turbine insulation was replaced as were station batteries. A turning-gear economizer was installed and the control system upgraded.

Siemens plans its eight hours of presentation/Q&A time at D5-D5A meetings based in large part on topics the users would like the OEM to address. The group's steering committee maintains a collaborative and productive relationship with the Siemens legacy team headed by Mark Kamphaus and Jeff Kain, both of whom have worked closely with Fleck and Mayhew for years. Topics for this year's presentations included the following:

- Axial rubbing program.
- Blade-ring face rope seals.
- Exhaust-bearing extension cover.
- Bently update.
- Exhaust baffle seal.
- Vibration.
- Controls.
- Exhaust cylinder.
- Generators.

If you are an owner/operator of a D5 or D5A and were unable to attend the Louisville meeting, you can access the presentations on these subjects on Siemens' Customer Extranet Portal (CEP). Don't know how to do this? Either solicit help from fellow users via the group's forum or call your Siemens representative.

In their introduction to the specific technical presentations, the Siemens engineers noted that the top reliability detractors in the D5 fleet in the last year were compressor blade rubs, heavy tip rubs in the turbine section, and impact damage on turbine blades. Performance of the D5A fleet has been a solid "A" for the last decade, with reliability, availability, and starting reliability all above 98%.

Technical advisories have been issued in the last year on the following:

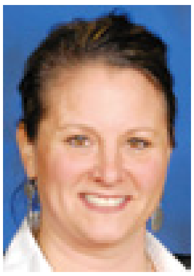
- Tip shroud wear on R4 turbine blades. Users also are seeing wear on the new material, IN738.
- Turbine R2, R3, and R4 potential rubbing issue and recommendations.
- Relocation of vibration probes and addition of additional probes, as noted earlier.
- Inspection of compressor-blade closing and locking keys.
- Urgent product bulletin: Modify the exhaust-bearing-cover removal tool before next use.

Looking ahead, work is ongoing on developing an upgrade for the exhaust baffle seal. The prototype for the 501F is being adapted for the D5.

The Mitsubishi presentation covered a lot of territory in only two hours. It began with a company update that discussed shipment of the company's first air-cooled M501GAC, the acquisition of Pratt & Whitney Power Systems, status manufacturing and repair facilities, etc. Safety performance came next, followed by a review of the various service offerings and engineering solutions for the D5 and D5A fleets. Perhaps of greatest immediate value to attendees was the presentation on planning generator inspections—simplified, robotic, and major. The checklists presented on components to inspect when and by what means are a worthwhile addition to your outage planning library. Access the paper on the user group's website; registered 501D5 and D5A owner/operators only. CCJ

Prioritization of issues improves reliability, performance

That some F-class HRSGs designed for base-load service and installed during the boom are facing extraordinary maintenance projects after 10 to 15 years of cycling, fast starts, and spin cooling should not surprise, Amy Sieben, PE, principal, ALS Consulting LLC, told the more than 100 attendees at the Combined Cycle Users Group's (CCUG) 2013 Annual Conference in Phoenix, in early September.


Sieben

Session Chair Phyllis Gassert, a member of the CCUG's steering committee and plant engineer at Dynegy Power LLC's Ontelaunee Energy Center agreed, citing her facility's experience with failed pressure parts (access article by scanning QR code) as well as its positive experience in using an acoustic monitoring system to warn of tube leaks before they result in catastrophic failures (see following article).

Ontelaunee article

Sieben, who provides engineering services to Chanute Manufacturing Co, has seen more than her share of damage to HRSGs caused by poor operating practices, leaking attemperator valves, poor water chemistry, etc. Recently, she noted, Chanute supplied 24 harps to replace the entire HP evaporator section in a G-Class HRSG.

Sieben said many combined-cycle plants are in dire need of a long-term HRSG maintenance plan. In addition to unforeseen issues causing forced outages and gobbling up unbudgeted maintenance dollars, she finds many plant staffs are so overwhelmed by condition-assessment initiatives for high-energy piping (HEP), flow-accelerated corrosion (FAC), and P91 components that they suffer analysis paralysis—a condition conducive to reactive maintenance.

Critical to moving forward, Sieben said, is prioritization of HRSG issues according to their unique characteristics and unit operating history. The end result is a weighted-risk matrix incorporating such factors as safety, access, cost, loss exposure, etc.

Step 1: Gather information

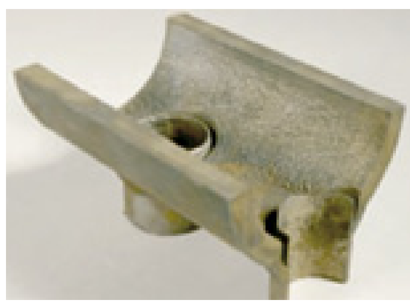
This task should not be underestimated in terms of the time involved—especially if your facility is one of many that has had more than one owner over the years, and the current plant manager, operations manager, maintenance manager, or plant engineer has not been onsite since commercial start. Here's a list of the information she recommended that you compile:

- Historical operating profile—including starts (hot/warm/cold), hours, trips (full load/part load), spin cooling. This information is required for estimating remaining fatigue life should that be necessary.
- Planned operating profile going forward. This should consider external factors—including the shutdown of nearby coal-fired and nuclear units, fuel prices, new generating facilities powered by intermittent renewables, grid requirements (such as ancillary services), etc.
- Issues currently causing outages—such as tube leaks—and operational "work-arounds."
- Failure history—of pressure parts, in particular. Important to enter details in an official record, after validation. Examples: Have tube failures occurred in a specific area of the HRSG? Have any root cause analyses (RCAs) been conducted? Metallurgical analyses? Gather all the data available, making note of missing information—perhaps field weld reports on P91 components.
- History of inspection findings. Are superheater and reheater tubes bent out of position? Is the position/bow changing or growing?
- Maintenance history. Have pressure parts been replaced? Are seals problematic? Are baffles in the correct position? How quickly do finned-tube surfaces foul? How often are tube surfaces cleaned? What is the typical performance gain after tube cleaning?
- Cycle chemistry. Important to know how this has changed over the years. Was AVT(R) ever used? Phosphate?
- Operator training. Is there an active re-certification program for operators?

Step 2: Identify the issues

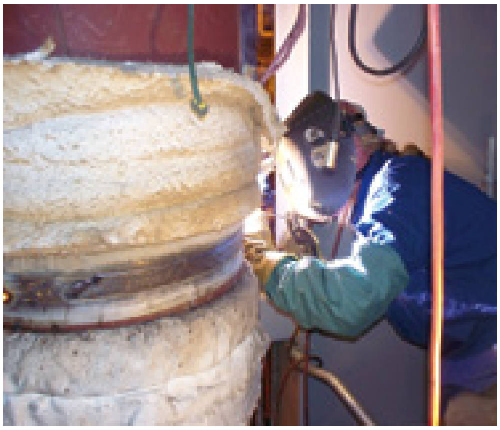
Sieben said that answers to the following questions are important for identifying areas of concern that should be addressed in the strategic plan. This is not a comprehensive list for all plants, she added, but a specific (fictional) plant example:

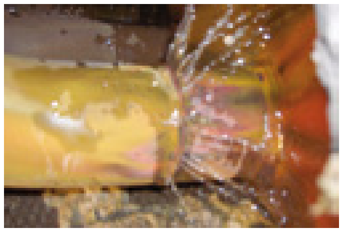
- FAC. There has been evidence of tube- and header-wall thinning in the LP evaporator and feedwater heater (Fig 1). Has a risk analysis been done? Are areas being monitored for progressive thinning? Is the situation well defined/under control?
- HEP. There has been cracking and significant fatigue-life expenditure in piping downstream of desuperheaters (Fig 2). Is a program in place to evaluate the condition of all HEP?
- IP economizers. There have been multiple tube-to-header leaks (Fig


1. Flow-accelerated corrosion must be identified and monitored to avoid in-service failures of pressure parts

3). Does the plant continue to operate until water inventory can no longer be maintained? Has a proper RCA been conducted?

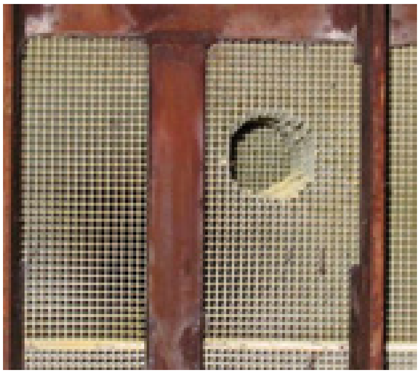
- Liner and ductwork. There is insulation in the catalyst and finned surfaces (Fig 4). Are hot spots, possibly even cracking, in evidence on the exterior casing in the area of the inlet and/or firing ducts?





2. New section of reheat piping is welded in place. Original suffered cracking caused by a leaking attemperator (left)

3. Tube-to-header leaks in any panel (harp) can quickly force a unit out of service (below)



4. Catalyst blockage by fugitive insulation can adversely impact SCR performance (above)

5. Sample and trend catalyst activity regularly (right)

6. Inspect bottom penetration seals for leaking exhaust gas (left)

7. Corroded drain piping should be replaced in timely fashion (above)

- Catalyst. Has the catalyst been tested? Replacement of SCR catalyst is based on reactivity, which should be trended to allow proper planning and budgeting (Fig 5). Catalyst in bubble-period HRSGs is rapidly approaching end of effective life.
- Penetration seals. They don't last forever. Visually check for leaking rainwater from the roof onto pressure parts, and resultant corrosion. Inspect bottom penetration seals for leaking hot gas and overheating of casing, conduit, and wiring at the front end of the unit (Fig 6).
- Drain-line corrosion. There have been leaks in the HRSG which have flooded the lower penetration seals. The pipes look terribly swollen and corroded (Fig 7). Clean and check the extent of drain-pipe thinning at penetrations and outside the casing for the first 10-15 ft (and further as needed) near the back end of the HRSG. If metal thinning is in evidence, consider replacement before a leak requires an outage. These pipes are located upstream of isolation valves so leaks may take a unit offline.
- Outage schedule. All plants should have one. Develop an outage maintenance schedule based on starts or operating hours that is specific to the HRSG—including frequency and budget costs. Enter this information in your enterprise system for tracking work-order generation. Intent here is to cover all items that are outage-related, not capital projects.

Step 3: Rank the issues

Final step is to develop a one-page matrix to prioritize, communicate, and track the problems identified.

Ranking of HRSG issues critical for ensuring reliability, safety

Issue	Description	Rank	Owner	Access issues	Cost	Impacts: Safety	Impacts: Reliability	Impacts: Performance
1	FAC risk assessment	High	Plant engineer	None	$15k, firm price proposal	Yes	Yes	No
2	HEP risk assessment	High	Plant engineer	None	$50k, guesstimate	Yes	Yes	No
3	IP econ leaks, RCA	Medium	Plant engineer	None	$10k, budget proposal	No	Yes	Yes
4	Duct/liner failure	Low	Maintenance manager	Scaffolding needed	$75k, budget proposal	No	No	Yes
5	Catalyst life	Low	Operations manager	Crane needed	$350k, firm price	No	Yes	No
6	Penetration seals	Low	Maintenance manager	None	$25k, guesstimate	No	No	Yes
7	Drain-line corrosion	Medium	Maintenance manager	None	$10k/yr, budget	Yes	Yes	No
8	Outage maintenance	High	Planner	N/A	$15k, budget	Yes	Yes	Yes

It allows a common understanding at the plant and the corporate levels of the issues, their priority, and the responsible parties. The elements used to rate the strategic issues are the following:

- Access. Is the area accessible for maintenance/monitoring? Online versus offline? Is a lift, scaffold, or crane required—or not? Is insulation removal required—or not?
- Cost/benefit. What are the budgeted costs for repair and replacement? Is the budgeted cost supported by a quote? Will this be a capital project or maintenance? Is a cost/benefit analysis required? Important to identify the expected cost as a firm-price proposal, budget proposal, or guesstimate.
- Safety. Is there a potential for energy release in an area open to personnel? Evaluation should result in a no, possible, or yes.
- Reliability. Does a failure of this part have the potential to cause an outage? Yes or no.
- Performance. Does the issue affect HRSG performance? Yes or no.

The completed matrix (table) ranks as "high" issues that should be evaluated at the earliest possible date, "medium" recommends planning and scheduling an evaluation, "low" suggests oversight and evaluation as time allows. Issues identified in the matrix are priorities for the plant within the next outage cycle.

In sum, the issues matrix is intended to capture and focus the plant team's discussions and decisions on the important issues affecting HRSG long-term reliability and safety. The issues and their rankings are determined at the plant level. The matrix establishes a framework for specific evaluations and program implementation (FAC and HEP, for example), which provide input for capital and expense budgeting. It is not intended to take the place of an enterprise system but to provide input to it.

Benefits of the comprehensive long-term maintenance plan include the following:

- Higher degree of safety.
- Improved reliability (over the alternative of reactive maintenance).
- Reduced insurance premiums (possible).
- Increased ownership.
- Improved documentation and communication.
- Implementation of best practices.
- More effective planning and budgeting.
- Cost savings attributed to planning for replacement parts versus emergency procurement. CCJ

Operators alerted to HRSG tube leaks in real time

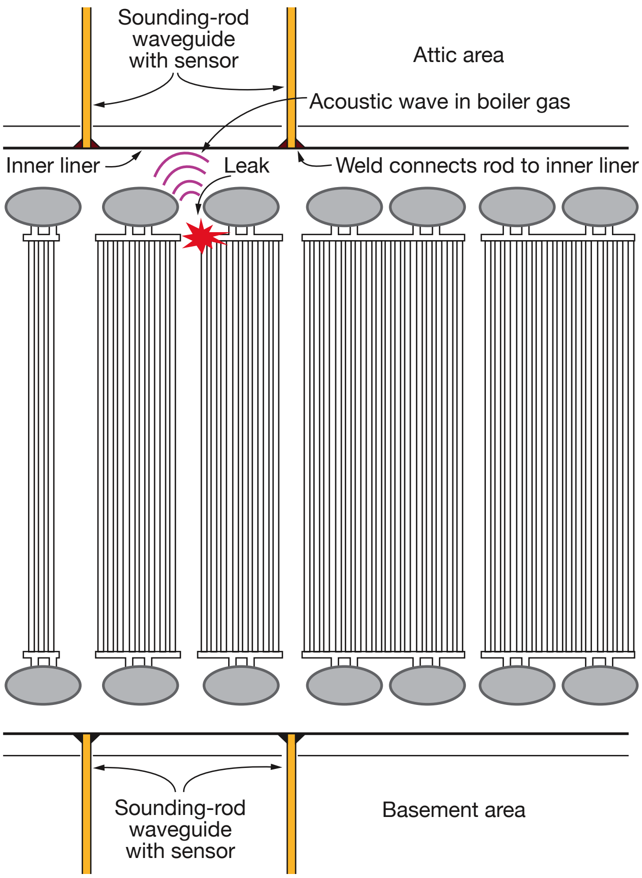
The use of acoustic monitoring to detect tube leaks in steam generators is not new. The technology has been applied successfully for years in boilers serving conventional steam plants, as well as in recovery boilers for the pulp-and-paper industry and in feedwater heaters. Now, thanks to what EPRI calls a "tailored collaboration project" involving the research organization, Dynegy Power LLC's Ontelaunee Energy Center, and Mistras/Triple 5 Industries, acoustic monitoring has been adapted for use in some heat-recovery steam generators.

Application of acoustic technology to HRSGs has been slow to develop, said EPRI's Project Manager Bill Carson, a former plant executive, given their uniqueness of design and, until recently, a service paradigm often characterized by relatively few operating hours and starts. Background noise from gas combustion, turbulent flow of gas-turbine exhaust gas, and the high temperature of the inner liner contributed to the reluctance of plant personnel to embrace acoustic technology. But, as HRSGs have aged and accumulated operating hours and cycles, tube leaks have become a concern and interest has grown in identifying a better method of detection.

The value proposition for HRSG owner/operators is detection and location of leaks early enough, in general, to avoid forced outages by enabling operating decisions that slow the progression of damage and allow more flexible scheduling of repairs. Heretofore, plant O&M personnel were forced to rely on such lagging leak indicators as steam in the stack plume, wet spots at the bottom of the HRSG, high rate of makeup flow, high levels of moisture in CEMS samples, etc.

In simple terms, acoustic monitoring of a boiler involves continuous measurement of sounds from within the unit, signaling an alarm when the sounds of interest exceed a preset threshold for a predetermined amount of time (see following article on ultrasound).

Mistras/Triple 5 provided the acoustic monitoring system (AMS™) used in the Ontelaunee demonstration. Acoustic sensors were installed near areas of historic leak concerns—specifically, reheater and superheater tube-to-header joints. The sensors were connected to dual-frequency-band amplifiers (Figs 1, 2) and the signals routed from the amplifiers to data loggers for trending.

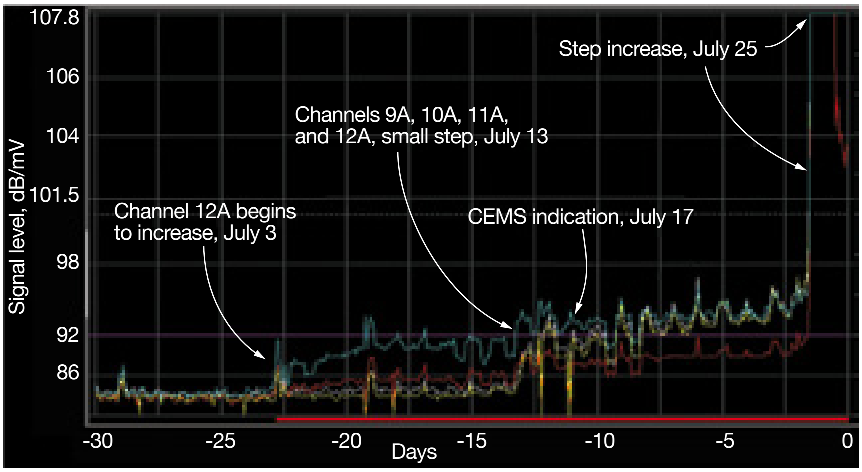


1. Acoustic sensors are located near areas of historic industry concern—reheater and superheater tube-to-header joints, for example (left)

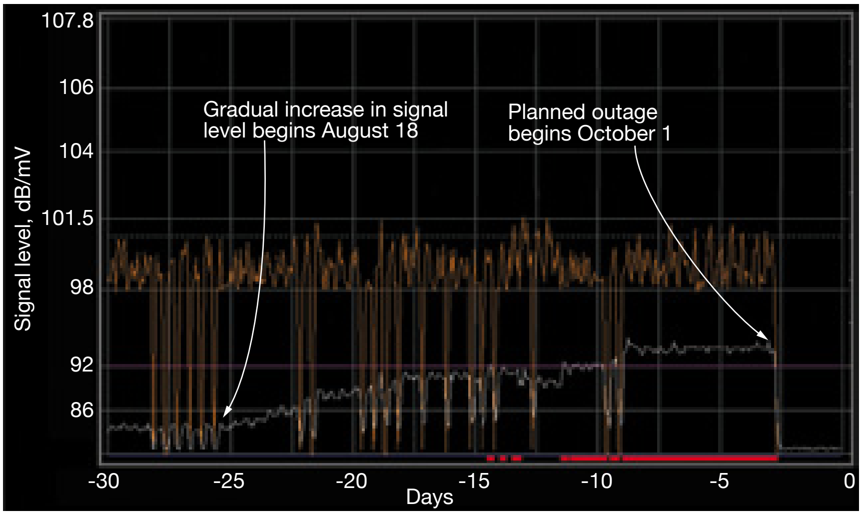
2. Non-invasive sounding rods are welded to the inner liner; sensor, protected by the sensor box, is mounted on the other end (below)

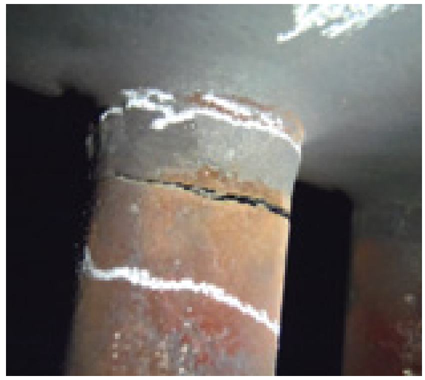
The AMS was installed on Ontelaunee's Unit 2 HRSG for the demonstration project because its operating history suggested it was more susceptible to tube leaks than the Unit 1 boiler. Unit 2 had experienced a tube leak before the AMS was installed. To date, the diagnostic system has detected five tube leaks (the fifth after the demonstration program ended)—all in reheater and superheater panels (harps) close to where the affected tubes enter the upper headers.

Tom Buelter, director of engineering for Dynegy in the Midwest, and Ontelaunee's Production Manager John Goodman and Plant Engineer Phyllis Gassert, told the editors that the AMS system was successful in identifying leaks earlier than other methods used previously, thereby allowing plant management to avoid the technical and economic consequences of tube failures that some others have experienced.



3, 4. First superheater leak, catastrophic in nature (photo), is characterized by the step increase in signal level shown at the right in the chart





5, 6. Gradual increase in sound level begins August 18. Limited cycling allows cracked tube (photo) to continue operating until the planned maintenance outage on October 1

Acoustic monitoring was not new to Dynegy engineers, the company having years of AMS experience on its coal-fired boilers. After tube leaks forced several HRSG shutdowns, the opportunity to participate in the EPRI program was viewed positively. Plant-level goals included identifying the optimal location for the acoustic rods and developing the sound profile for the unit with respect to load. Knowing the unit's healthy acoustic signature is a prerequisite for leak identification.

The value of acoustic monitoring is evident by comparing the acoustic profiles of two tube leaks experienced on Ontelaunee Unit 2 after the AMS was installed. Figs 3 and 4 profile the so-called Superheater Leak 1, which resulted in the catastrophic failure shown in the photo. The chart points to crack initiation with an uptick in signal level on Channel 12A on July 3. Crack progression is indicated by a small-step increase on Channels 9A, 10A, 11A, and 12A 10 days later.

First detection of the leak by an alternative means came on July 17, when a technician noted increased moisture in CEMS (continuous emissions monitoring system) results. The step increase in signal level on July 25 revealed that the crack had propagated to complete failure. Important to note was that the unit continued to cycle after the tube crack was first identified; it took fewer than two dozen starts to go from crack initiation to tube separation.

Superheater Leak 2 was identified by the gradual increase in signal level on August 18 as shown in Fig 5. With the experience from Superheater Leak 1 fresh in their minds, Dynegy's marketing and generation teams collaborated on an operations plan that kept the unit running at low load in the evening rather than shutting it down. This enabled the HRSG to operate until October 1 with a crack that went halfway around the tube (Fig 6). This crack was not identified by any other means during the six weeks of operation prior to the maintenance shutdown.

When a third tube leak was identified by AMS in December 2011, marketing and operations again collaborated on a plan to minimize starts and stops. This time, HRSG 2 remained in service until a planned outage at the end of April 2012.

How AMS works. Pam Grigas, GM of Mistras Group's Triple 5 Products & Systems Div, explained how acoustic monitoring works. She said that tube leaks create noise that travels through the hot gas passing through the HRSG until it "hits" the inner liner. This noise causes the inner liner, sounding rod, and sensor to vibrate. The sensor converts vibration to electrical energy, which is trended and alarmed in the monitoring system. Sensors are effective in identifying leaks within a circular area having a radius of from 20 to 30 ft. Signal amplifiers used in the Triple 5 system can accept inputs from two sensors, minimizing cable runs.

A 12-sensor system such as that at Onetlaunee can be installed in about a week—with sounding rods possibly welded in place during a long-weekend outage. The number of sensors required depends on boiler design. Note that installation requires access to the roof and basement areas because the sounding rods must be welded to the cold side of the inner liner as shown in the first two figures. I&C hook-ups and tuning can be done later, when the unit is back in operation.

For budgeting purposes, figure the cost to equip and install on one F-class HRSG an eight-sensor acoustic monitoring system typically would be in the low six figures; two units would be less than double the cost of one because the electronics cabinet can serve both.

Grigas said AMS is installed on over 300 power boilers—the first, 25 years ago—and on eight HRSGs at three plants. These installations are in addition to the more than 400 systems on feedwater heaters and recovery boilers. AMS's effectiveness is validated by the more than 700 confirmed leaks identified since the beginning of 2005. Grigas told the editors that there have been very few "missed" leaks reported over the last five years—perhaps a dozen at most.

In keeping with today's trend to outsourcing of M&D (monitoring and diagnostic) services, Mistras/Triple 5 has more than 200 boilers under surveillance contracts. The company's database of leak histories enables its technicians identify and access indications quickly and accurately, Grigas said.

For more information on the EPRI-sponsored leak-detection project at Ontelaunee and possible follow-on work to study the acoustic baseline response to duct-burner operation and to correlate load cycles and time-to-leak propagation, contact Program Manager Bill Carson at bcarson@epri.com. The Ontelaunee results are described in "Early Tube Leak Detection in an HRSG Application Using Acoustic Monitoring Technology" (1026653). CCJ

Ultrasound warns of mechanical, electrical problems before failures occur

By Mark A Goodman, UE Systems Inc

One of the main reasons for the advances in condition monitoring programs has been the development and use of technologies such as ultrasound, oil analysis, vibration, and infrared evaluations. This article examines one of these technologies, airborne/structure-borne ultrasound.

Lightweight and portable, ultrasonic translators are often used to inspect a wide variety of equipment. Typical applications include mechanical testing of bearing and gearboxes; electrical testing for corona, tracking, and arcing; and leak detection on pressurized and vacuum systems.

Ultrasound is effective because all operating equipment and most leakage problems produce a broad range of sounds. The high-frequency ultrasonic components of these sounds are extremely short-wave in nature and, therefore, fairly directional. It is relatively easy to detect the source's exact location by separating the signals from background plant and operating equipment noises.

In addition, as changes occur in mechanical equipment, the sound they make changes. The subtle nature of ultrasound allows these potential warning signals to be detected early, before an actual failure occurs and often before the problem can be detected by vibration or infrared scans.

Ultrasound instruments, often referred to as ultrasonic translators, provide information in three ways:

- **Qualitative** with the ability to "hear" ultrasounds through a noise-isolating headphone.
- **Quantitative** via intensity (dB) readings on a meter or display panel.
- **Analytical** with the use of spectral-analysis software to review recorded sound samples.

Although the ability to gauge intensity and view sonic patterns is important, it is equally important to be able to hear the ultrasounds. That is precisely what makes these instruments so popular. They allow inspectors to confirm a diagnosis, on the spot, by being able to clearly discriminate among various equipment sounds. This is accomplished in most ultrasonic instruments by an electronic process, called heterodyning, that accurately translates the ultrasounds into the audible range, so users can hear and recognize them through headphones.

Ultrasound translators are relatively simple to use. They consist of a basic handheld unit with headphones, a display panel, a sensitivity adjustment, and (most often) interchangeable modules that are used in either a scanning (airborne) mode or a contact (structure-borne) mode. Some instruments have the ability to adjust the frequency response between 20 and 100 kHz. Ultrasound instruments may be analog or digital.

Digital instruments indicate intensities as decibels and generally have onboard data-logging with data management software to provide trending information and to create alarm groups for equipment needing special attention. Some of the digital instruments also have onboard sound recording (either in MP3 format or a tape recording) capabilities, which let a user to grab sound samples and review them with spectral-analysis software.

Applications

Applications for ultrasonic translators fall into three, generic categories: mechanical inspection, leak detection, and electrical inspection.

Mechanical equipment produces a "normal" sound signature, while operating effectively, but a change in the original sonic signature occurs as components begin to fail. This change can be noted as a shift in intensity on a display panel and/or as a qualitative sound change that can be heard through headphones. An ultrasonic translator may be connected to a vibration analyzer or the sound samples may be reviewed through spectral-analysis software on a laptop.

Mechanical: bearings

One valuable application of mechanical inspections is bearing testing. According to NASA, ultrasonic monitoring of bearings provides the earliest warning of bearing failure. The agency notes that an increase in the amplitude of a monitored ultrasonic frequency of 12 dB, over baseline, would indicate the initial (incipient) stages of bearing failure. This change is detected ultrasonically, long before it can be detected by changes in vibration or temperature.

Ultrasound translators can also be used to aid in diagnosis. The high-frequency, short-wave characteristic of ultrasound allows the signal to be isolated, so a user can hear and determine if, in fact, a bearing has been correctly diagnosed as failed.

Ultrasound detectors work well on slow-speed bearings. In some extreme cases, just being able to hear some movement of a bearing through a well-greased casing can provide information about potential failure. The sound might not have enough energy to stimulate classic vibration accelerometers, but will be heard with ultrasonic translators, especially those with frequency tuning.

In addition, most slow-speed bearings take a long time to analyze with typical vibration equipment, but by connecting an ultrasonic translator to the vibration analyzer, the resolution improves and the time to grab a sample drops dramatically.

Mechanical: gearbox

To illustrate how valuable ultrasonic evaluations can be, consider the following case study. A tube manufacturing plant had six gearboxes coupled together. Each was driving tools that

MISTRAS | TRIPLE 5 INDUSTRIES

Combined Cycle ASSET PROTECTION

ACTMS™ On-line Stator Vane Crack Detection

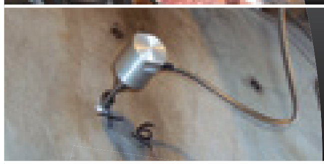
AMS™ HRSG Leak Detection

PROBLEM

ACTMS:
- Cracking/liberating vane through turbine
- Stationary airfoil cracking
- Rubbing, loosening and blade clash
- $7 to 10 million per incident

AMS:
- Tube stub weld leaks at the SH & RH headers
- Tube leaks at the SH and RH Drains
- Inability to locate area of the leak

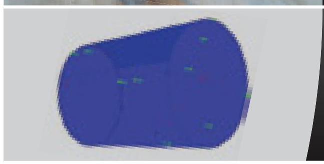
IN SERVICE



ACTMS:
- Non-intrusive sensors
- After-market install
- Complete forward compressor coverage

AMS:
- Non-intrusive sensors
- After-market install
- 24-7 real time monitoring
- Total HRSG coverage or in areas of most concern

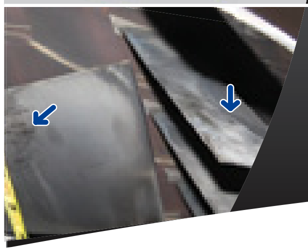
REAL TIME



ACTMS:
- Defect source location
- Graphical displays
- Local and network alarming

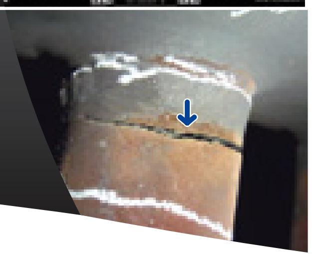
AMS:
- Trend severity and progression of leak
- Locate area of leak before unit removed from service
- Local and network alarming

RESULTS



ACTMS:
- On-line detection of vane cracking
- Insight to unknown condition
- Optimize remaining life
- Early warning to prevent failure

AMS:
- On-line tube leak detection
- Early warning to prevent failure
- Manage market exposure and risk
- Tube leak repair during planned outage or period of low demand



www.mistrasgroup.com

Systems | Software | Monitoring | Services | Instrumentation bent steel to form tubing. An inspector was collecting data from the gearboxes with an accelerometer for vibration analysis and an Ultraprobe® ultrasonic translator.

When listening to the gearboxes with the Ultraprobe, five made a hissing-type sound, one a ticking sound. A time waveform was captured using the accelerometer and then using the ultrasonic translator for both the questionable gearbox and the one next to it. The waveforms from the accelerometer are shown in Figs 1 and 2.

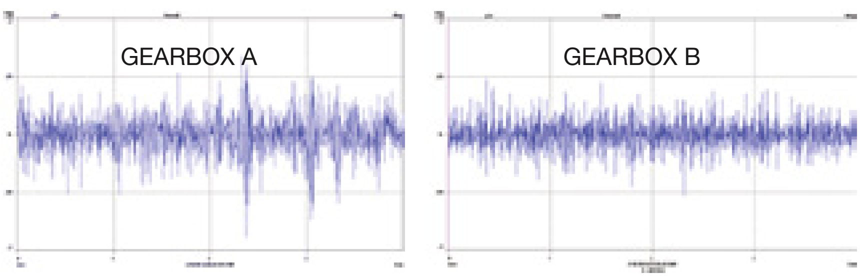
By comparing the two time waveforms, you can see that there is a slight difference between the two gearboxes. When you look at the ultrasonic waveforms, the problem becomes more defined, indicating that there is a broken tooth (or teeth) in gearbox A (Figs 3 and 4).

An evaluation can also be done with spectral-analysis software. A similar type of Fast Fourier Transform (FFT) diagnosis can be performed on a standard PC, as long as it has a sound card.

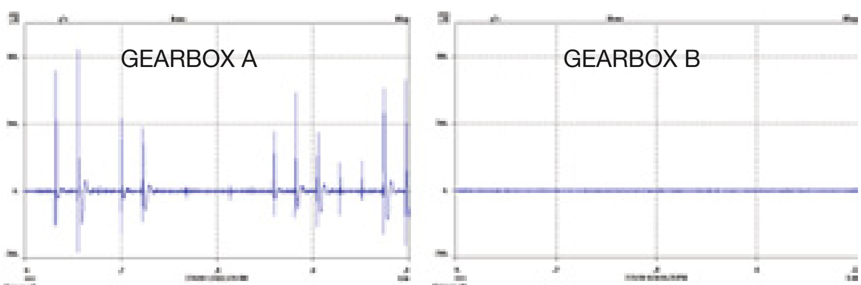
These programs not only provide the spectral and time-series views of sound, but also enable users to hear the sound samples simultaneously, as they are viewing them on the PC monitor. Some ultrasonic instruments make on-board sound recordings, which can then be downloaded to a PC via a compact flash card. When played back in real-time, the acoustic properties can be analyzed and, based on a known-good or normal condition, an anomaly can be quickly identified.

Figs 5 and 6 show the spectral and time-series views of a good bearing. If one were to imagine the sound a good, lubricated bearing makes, it would be a smooth, rushing sound. Note that there are no distinguishing characteristics: This is an example of white-noise. Now, consider a bad bearing (Fig 7). Notice the shift. The bearing is producing a jarring, buzzing noise. Note the fault frequency has been captured as 90-Hz harmonics.

The advantage of ultrasound inspection, aside from providing a finer reso-



1, 2. Waveforms from the accelerometer are similar, masking the damage inside one of the gearboxes



3, 4. Ultrasonic time waveforms clearly show there is a problem. One tooth, perhaps several teeth, are broken in gearbox A lution for viewing the sound image, is that inspections can go beyond what is possible to do with typical vibration or infrared scans.

Mechanical: compressor valves

Ultrasonic evaluations can be very useful for testing valves. For example, reciprocating compressor valves are very noisy and produce a lot of extraneous vibration. By isolating the sound, with the advantage of the short-wave nature of ultrasound, it is possible to listen to and view the sounds of these noisy valves in real-time and to identify a leaking valve.

As a good compressor valve opens and closes, there will be a definite, pronounced clicking. Shown in Fig 8, a good valve will have a definite closed period followed by a distinct open period. A bad valve (Fig 9) has a very long open period because it is leaking. If one listens to these samples, the difference is very obvious.

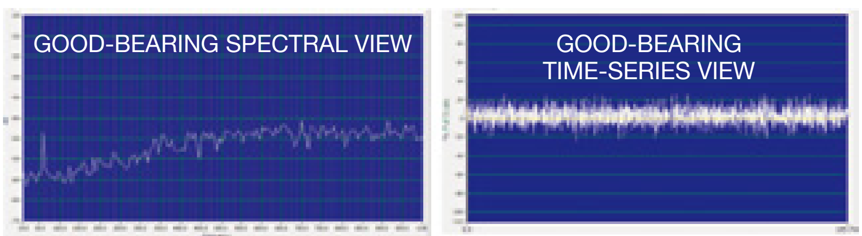
Mechanical: lubrication

In some facilities, equipment is lubricated on a fixed, time-based schedule. Other facilities rely on more effective and efficient predictive models. With routine ultrasonic testing, lubrication technicians can be taught how to effectively apply just enough lubricant to do the job and without over-lubricating.

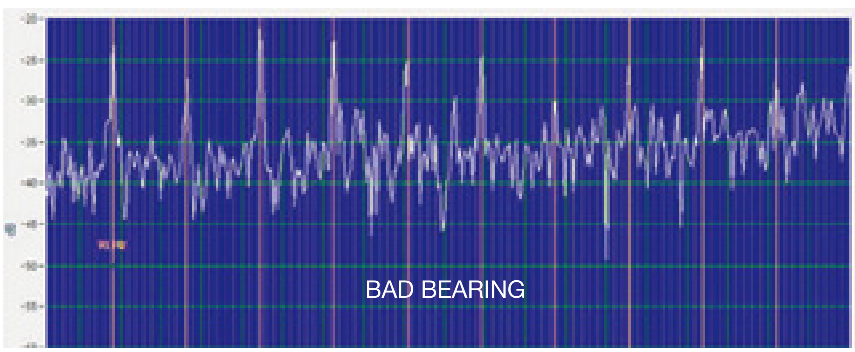
In general, when a bearing has exceeded its baseline by 8 dB, with no change in acoustic quality, the bearing should be lubricated. While applying lubrication, the technician should stop when the sound level has dropped to the pre-determined baseline level.

A way to demonstrate this process is to view a sound image, while noting changes in amplitude and listening to acoustic properties in real time. Fig 10 illustrates a sample spectral view of the sound recorded while a bearing was being lubricated. The top, red overlay is the non-lubricated state. Note how the sound level drops as the lubricant is applied.

When the proper lubrication level is



5, 6. Good bearings produce a smooth, white-noise sound



7. Bad bearings produce a jarring sound reached, the sound level drops by 8 dB with no change in sound quality. There are no distinctive harmonics or spikes, only a representation of the white-noise you would expect to hear, if you were to listen as this sound sample played.

Electrical: corona, tracking, arcing

Now consider the ultrasonic characteristics of electrical emissions. One thing to watch for is the presence of harmonics. Some preliminary experimentation has shown that the main harmonic component of electrical emissions will be most prevalent in corona. As the problem becomes more severe, fewer and fewer 60-Hz harmonics will be observed. Tracking has few 60-Hz components and arcing has very few.

So, when possible, listen to the sound characteristics as they are played in the spectral view and note that the harmonics of 60 Hz diminish as the condition becomes more severe. The frequency content will move up and down in relation to the ionization produced by the particular emission (corona, tracking, or arcing).

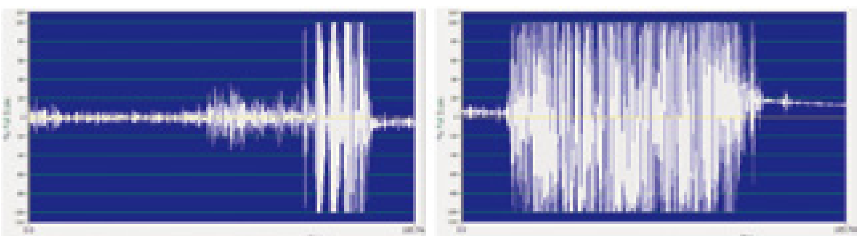
Fig 11 is a view of corona. Note the steady display of 60-Hz harmonics with a lot of frequency content between the spikes. If one listens to corona, it has a distinct buzzing and crackling noise. Listen to corona by scanning the QR code "Corona."

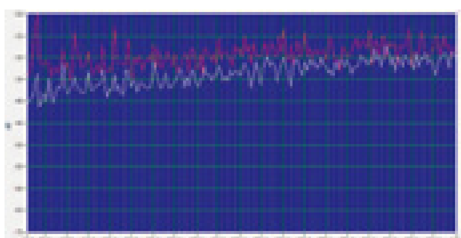
Corona

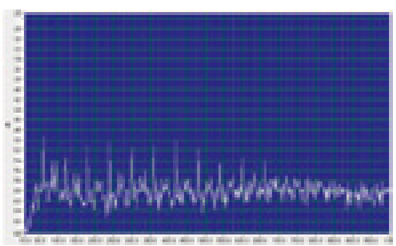
Figs 12 and 13 show tracking. Sometimes referred to as "destructive corona," tracking has a different acoustic property. This type of emission has a rapid build-up and discharge called "baby-arcing." Note that the 60-Hz harmonics have diminished. Listen to tracking by scanning the QR code "Tracking."

Tracking

Arcing is shown in Fig 14; a time-series view is in Fig 15. Note that it has irregular starts and stops and very few 60-Hz


8, 9. Compare a good and bad compressor valve. The good one, on the left, has a definite close and open period. The bad one, on the right, has a very long open period, because it is leaking


10. Ultrasonic guided lubrication allows a facility to apply the correct amount of lubrication, just when it is needed


11. Corona is characterized by 60-Hz harmonics, with lots of frequency content between spikes

harmonics. Arcing primarily contains violent starts and stops. Listen to arcing by scanning the QR code "Arcing."

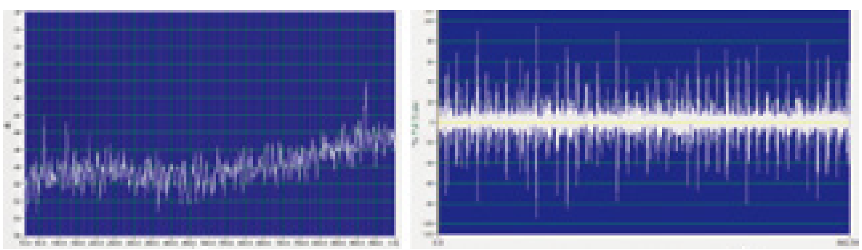
Arcing

Leak detection

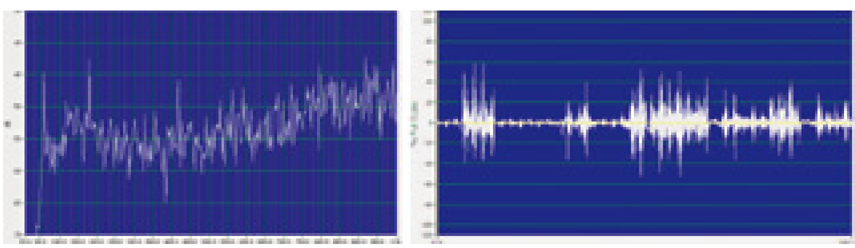
The category of leak detection covers a wide area of plant operations. Some plants include it as part of an energy conservation program, while others use it to reduce fugitive emissions. No matter what it is called, leaks cost money, effect product quality, and wreak havoc on the environment.

Leaks can occur in liquid or gas systems. The greatest advantage of ultrasonic detection is that it can be used in a variety of leak situations, since it is sound sensitive—not gas specific. Therefore, it can be used to find pressure leaks (compressed air), negative pressure leaks (vacuum), and leaks in valves and steam traps.

When a liquid or gas leaks, it moves from the high-pressure side of a leak, through the leak site, to the low-pressure side. Once there, it expands rapidly and produces a turbulent flow, which has a strong ultrasonic component. The ultrasonic intensity of the signal falls off rapidly the further the test equipment gets from the source. For this reason, the exact spot of a leak can be located.



12, 13. Tracking has few 60-Hz components and is characterized by popping sounds



14, 15. Arcing has irregular starts and stops and very few 60-Hz harmonics. A time-series view is at the right

Wrap-up

Airborne ultrasound instruments are becoming an important part of condition monitoring, fugitive emissions and energy conservation programs. Their versatility, ease of use and portability let managers effectively plan, and implement inspection procedures. By locating leaks, detecting high-voltage electrical emissions, and sensing the early warning signs of mechanical failure, these instruments help reduce costs, improve system efficiencies, and reduce downtime. For optimum effectiveness, it is recommended that all major technologies, infrared, vibration, and ultrasound, be used as part of a comprehensive inspection program. CCJ

Hawaiian Electric advances the use of biodiesel as a GT fuel

State-mandated renewable portfolio standards are designed to shift the production of electricity from fossil fuels and nuclear power to wind, solar, biomass, and other green alternatives. The standards differ among the three-dozen states that have established RPSs with regard to the percentage of kilowatt-hours that must be produced from renewables by a given year. Hawaii has the most challenging rules in the nation, requiring its utilities to produce 40% of their net electricity sales from renewable resources by the end of 2030 (25% by the end of 2020).

Hawaiian Electric Co (HECO), the primary electric supplier to homes and businesses on the island of Oahu, is investing heavily in the development of wind and solar generation to meet this requirement. But of greater importance to owner/operators of gas turbines, the utility is believed to be the global leader in the use of biodiesel, burning B100 (100% biodiesel) in a nominal 110-MW, oil-only, simple-cycle peaking W501D5A at its Campbell Industrial Park Generating Station (CIP) to back up intermittent renewables.

The industrial park also is home to the utility's Barbers Point tank farm and adjacent to the Kalaeloa Cogeneration Plant and the HPower waste-to-energy facility, both independent power producers that sell electricity to HECO.

The production and combustion of liquid and gaseous fuels from biomass, refuse, coal, and other solids is not new. In fact, diesel engines had operated on vegetable oils long before the first gas turbine (GT) appeared. According to a report on Wikipedia, August 10 was the 120th anniversary of Rudolf Diesel's prime model, a single-cylinder engine with a flywheel at its base, debuting and running on peanut oil.

Importantly, all biofuels are not equal in the eyes of environmentalists. HECO's work in the field began more than five years ago, Cecily Barnes, the utility's fuels manager told the editors. Some early tests involved the use of palm oil, which is a suitable fuel, but the utility encountered environmental concerns surrounding its use because of the deforestation associated with at least some palm plantations. So, the utility partnered with the Natural Resources Defense Council to develop environmental guidelines for the sustainable production and use of biofuels.

Renewable Energy Group Inc, Ames, Iowa, recently signed its third contract with HECO to supply Campbell Industrial Park between 3- and 7-million gal/yr of high-quality biodiesel processed from used cooking oil (known as yellow grease) and waste animal fats. The contract runs from mid-2012 to mid-2015. REG says its North American processing facilities are capable of producing more than 200-million gal/yr of biodiesel.

HECO's Campbell gas turbine is behind the parking lot now equipped with PV panels that both shade employee vehicles and produce 128 kW for internal use

There is no indigenous natural gas in Hawaii and HECO has relied heavily on fuel oil for power generation, making the state's residential electricity the most expensive in the nation. Three quarters of Oahu's electricity was produced from the combustion of fuel oil in 2012. The premium the company pays for biodiesel shipped from the Lower 48 to Hawaii is partially offset by a tax incentive of up to $1/gal awarded by the Internal Revenue Service to certified blenders of petroleum diesel and biodiesel. The maximum incentive is earned for a mixture containing 99.9% biodiesel and 0.1% petroleum diesel, which is what HECO burns. The fuel is transported to Hawaii by ship in 6340-gal ISO tank containers supplied by Agmark Logistics Inc.

Combustion

The black-start Campbell D5A, equipped with a water-injected DF42 combustion system, was purchased "new" on the grey market. When HECO bought the unit it had not committed to burning biodiesel, but Siemens warranted the engine for operation on that fuel. The OEM modified the gas turbine before shipment to Hawaii, to minimize coking of biodiesel on fuel nozzles during shutdown.

Siemens and HECO collaborated on the testing of biodiesel prior to installation of the D5A to assure operational success. Tests were conducted in October 2008 at ENEL's respected Sesta Laboratory under the OEM's direction. The test rig was arranged in a DF42 configuration and emissions targets were achieved with water injection when firing B100 fuel up to full-power conditions.

One of the findings of the Sesta tests, later confirmed in the field, was that biodiesel cokes at a lower temperature than petroleum diesel. This suggested implementing two changes to the engine before first operation:

- Make the candlesticks and their tips removable. The D5A has one candlestick in each of its 14 combustors.

- Install an effective system to purge fuel from the nozzles on shutdown.

The purge system installed is not 100% effective and nozzles do experience coking, which gradually increases based on starts. Both NO_x and CO levels remain steady until the amount of coking hits a tipping point. Eventually, the candlesticks must be cleaned in an ultrasonic sink; this requires a day-long outage. HECO engineers are exploring alternatives to the ineffective water purge—possibly a long air purge.

Campbell's new peaker was commissioned on No. 2 petroleum distillate and met all of Siemens' performance guarantees, which were based on that fuel. Operation on biodiesel began before the end of 2009 and the unit only has burned the alternative fuel since. Generally speaking, said Robert Isler, PE, manager of generation project development, biodiesel is a "drop-in" fuel for this engine.

Isler added that he would not be overly concerned about the feedstock from a technical standpoint, provided the fuel complies with ASTM D6751, "Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels," as well as the OEM's requirement that the amount of sodium and potassium contained in the fuel not exceed 0.5 ppm. Sodium + potassium content bears watching, at least in HECO's case, because those elements are used in the reaction process to make its biodiesel.

Cloud point is another parameter of concern, but not in Hawaii. Recall that the cloud point of a fluid is the temperature at which dissolved solids (wax, in particular) are no longer completely soluble, giving the fluid a cloudy appearance. This metric indicates the tendency of oil to plug filters or small orifices at cold operating temperatures.

The Campbell site is relatively simple in arrangement. The generating station includes the 501D5A with a 210-ft exhaust stack, three-story control building, water-treatment building, two 1.8-million-gal fuel tanks, and four water tanks. Nonpotable recycled water is used for all plant operations. Project also included an additional 138-kV transmission line of about two miles in length to deliver power from new and existing units to the grid more reliably. Recently, a 128-kW photovoltaic panel system was installed to both shade the parking lot and produce power for internal use (photo). The system includes two chargers for electric vehicles.

Fuel handling, behavoir

Biodiesel is transferred from the ISO shipping containers to the storage tanks as delivery trucks arrive at the site. This relatively simple operation typically takes less than about an hour per container: Truck enters the plant, lines up the transfer system, pumps out the container, and exits. Isler said the composition of the biodiesel is relatively consistent, even when switching from one feedstock to another.

Stored biodiesel remains in good condition, he added. While published information suggests this fuel should not be in stagnant storage for more than six months, HECO has not experienced any problems associated with fuel degradation at Campbell. The plant always is mixing new fuel with old, so some fuel in the tanks is really old by oil standards.

No fuel recirculation system is installed, Isler continued. But the tanks, designed for naphtha and ethanol, have floating roofs and they limit the amount of oxygen that comes in contact with the biofuel. The tanks were cleaned when the unit was switched from petroleum diesel to biodiesel, but not since. The fuel forwarding skid has pumps and filters (no heater); a second set of dual filters protects the primary fuel pumps.

There is only one liquid fuel system, but it can be used to burn both biodiesel and No. 2, as demonstrated during the switch from petroleum distillate to biodiesel following commissioning activities. The two fuels could be blended as well, in any combination, and that mixture burned. However, any fuel change requires, at a minimum, re-tuning of the combustion system and adjustment of water flow for NO_x control. Note that about 10% less water is required for biodiesel than for petroleum distillate to meet the plant's 42-ppm NO_x limit. Also, the practical maximum output is lower when firing biodiesel than conventional No. 2.

The 501D5A typically operates as spinning reserve at minimum load (40 to 50 MW) to protect against a trip of the largest unit in service. This is the most cost-effective way to operate the system, but not the unit. Fuel consumption at minimum load is about one ISO container an hour.

In peaking service, Campbell averages about 100 starts annually and operates a total of about 500 hours. It's important to check combustion dynamics at full load when burning biodiesel.

Isler said the use of biodiesel has been a positive experience. Compared to alternative biofuels, such as ethanol, it has a higher heat content and is less volatile. This means more power can be produced by a given engine, biodiesel is safer to handle than ethanol, lubricity is better, etc. Results of a preliminary inspection prior to the first combustion inspection were satisfactory, as expected. Opacity is a fact of life during starts and the regulations reflect that need. Initiation of water injection and a clear stack must be accomplished during the allowed startup period of one hour.

Experience of others

Others are adding to the biofuels experience base, although not in the Lower 48 at this time because of the very favorable gas prices. Here are briefs on their experience:

Kalealoa Cogeneration Plant, Campbell's neighbor, which burns low-sulfur fuel oil from an adjacent refinery, conducted a test of about four hours on one of its two gas turbines, burning roughly 17,000 gal of palm biodiesel in place of the LSFO. Automatic changeover from one fuel to the other worked flawlessly. Results: "Overall, the biodiesel test burn. . .successfully demonstrated the plant's ability to burn biodiesel as an alternative fuel. The units produced about 1% more power with 0.4% increased efficiency (compared to burning LSFO).

"Preliminary data suggest that increased fuel flow due to the lower heating value of biodiesel contributed to the increase in the output of the unit. . . .Overall pulsations level did not change with biodiesel. NO_x, SO_x, and particulate emissions significantly decreased. It is believed that the sulfur content in the residual diesel fuel left in the storage tank contributed to the SO_x emissions. CO emissions did not show any significant change."

Aero engines. In a paper at the 2010 triennial World Energy Congress in Montreal, three GE experts had this to say about the challenges presented by the use of biofuels in aeroderivative gas turbines: "All of the current liquid biofuels used or being considered for the GE aeroderivative product line exhibit a lower heating value less than standard diesel No. 2; thereby requiring a step increase in fuel flow of from 10% to 50% to deliver the same power output.

"Other characteristics of liquid biofuels present challenges in terms of fuel handling that are not an issue for standard diesel No. 2—such as low lubricity, affinity for water, and being an effective solvent. As a result, in some instances the material composition of sealants and gaskets and valve types in the fuel system must be altered to be compatible with the fuel." CCJ

Your direct connection to CCJ's Online Buyers Guide

at www.ccj-online.com/bg

Products and services from 90 companies support new unit construction, retrofit and maintenance activities at existing facilities, and plant operations. Solutions span gas and steam turbines, HRSGs, pumps, valves, piping, cooling towers, condensers, etc

AAF International

Global leader in the field of air filtration, meeting the most demanding conditions and the toughest environmental challenges. The company's filtration, noise abatement, and other turbine products are effective, durable, and crucial to greater efficiency and performance.

ABB

Leading power and automation technologies that enable utility and industry customers to improve performance while lowering environmental impact. Turbine-automation control systems are based on ABB's field-proven control platforms that deliver safe and reliable control.

Advanced Filtration Concepts

Offers new and innovative filtration products for the GT/CC power industry. Invest to save with inlet air filters that are high efficiency, low backpressure, and long lasting. As the largest stocking distributor of industrial air filters in the West, AFC is equipped to meet your most urgent GT inlet filtration needs. Turnkey installation available.

Advanced Turbine Support

Has delivered unbiased fleet experience and superior customer service for more than a decade. Company provides users high-resolution borescope inspections, cutting edge ultrasonic and eddy-current inspections, and magnetic-particle and liquid dye-penetrant inspections in accordance with OEM Technical Information Letters and Service Bulletins.

Aeroderivative Gas Turbine Support

AGTSI offers a full range of gas-turbine and off-engine parts from the most basic to the most critical. The company is strategically located in Boca Raton, Fla, near three major airports—including Miami. AGTSI is available to its customers 24/7/365, maintaining "on call" service capability.

AGTServices

Over 200 years of combined, proven OEM engineering, design, and hands-on experience; known in the industry for its schedule-conscious, cost-effective solutions with respect to generator testing and repairs.

Allied Power Group

Earned a reputation for high-quality repairs of IGT and steam turbine components. APG specializes in hot-gas-path and combustion components from GE, Siemens/Westinghouse, and other leading OEMs. Shop staff includes engineers and expert technicians who work together to determine the best method of repair.

American Chemical Technologies

Provides state-of-the-art synthetic lubricants to the power generation industry. Founded more than 30 years ago in the US, ACT has grown to become an international supplier of value-added lubricants that provide superior benefits to equipment, the environment, and are worker-friendly.

ap+m

Largest worldwide independent stocking distributor of both aeroderivative and heavy industrial gas-turbine engine parts. As a stocking distributor of over 17,000 parts, ap+m provides internal and external engine parts as well as package parts to operators, end users, and depots worldwide.

ARNOLD Group

With more than 550 installed insulation systems on heavy-duty gas and steam turbines, company is the global leader in designing, manufacturing, and installing the most efficient and reliable single-layer turbine insulation systems.

ATCO Emissions Management

With a full line of noise control products and the company's Balanced Design Approach™ to reducing installed cost, ATCO is a single-source pro-

ABOUT QR CODES

A wealth of data in the palm of your hand. Visit your App Store and download one of our suggested QR readers for your smartphone or tablet to access enhanced digital content and information.

Recommended, free, and easy-to-use apps:

- AT&T Code Scanner
- QR Reader for iPhone
- QR Reader for Android

vider of complete, cost-effective noise, emissions control, and heat-recovery solutions.

Bibb EAC

Multi-discipline consulting engineering firm with a focus in the power industry, Bibb has participated in a variety of projects ranging from repowering existing plants to renewable energy.

Braden Manufacturing

Braden designs and manufactures air filtration systems and filters, inlet cooling/heating, silencing, exhaust and inlet ductwork, diverter dampers, simple cycle SCRs, expansion joints, bypass stacks, and diffusers and plenums.

Bremco

Full-service industrial maintenance contractor since 1976. Company experience in combined-cycle projects includes header, tube, and complete panel/harp replacements. We also have significant experience in liner repairs/upgrades, duct-burner repairs, penetration seals, and stack-damper installations.

C C Jensen Oil Maintenance

Manufactures CJC™ kidney-loop fine filters and filter separators for the conditioning of lube oil, hydraulic oil, and control fluids. Our extensive know-how ensures optimal maintenance of oil systems and equipment reliability.

Camfil Farr Power Systems

A world leader in the development, manufacture, and supply of clean air and noise reducing systems for gas turbines. A correctly designed system minimizes engine degradation, leading to lower operating costs, optimum efficiency, and less environmental impact.

Chanute Manufacturing

Contract fabricator of HRSG products—including finned tubes, pressure-part modules, headers, ducting, casing, and steam drums.

Cleaver-Brooks

Complete boiler-room solutions provider that helps businesses run better every day. It develops hot-water and steam generation products aimed at integrating and optimizing the total boiler, burner, controls system to maximize energy efficiency and reliability while minimizing emissions.

Creative Power Solutions

CPS is a group of engineering companies in the power generation and energy utilization sector. Its mission is to provide advanced, efficient, and customized technology solutions to clients ranging from OEMs to plant operators and energy consumers.

Conval

Designs and manufactures high-performance valves for the world's most demanding applications, including power generation. Company has a series of power generation case studies that demonstrate the unique features and benefits of forged valves.

Cormetech

The world's leading developer, manufacturer, and supplier of catalysts for selective catalytic reduction (SCR) systems to control emissions of nitrogen oxides from stationary sources. Cormetech SCR catalysts are highly efficient and cost-effective where systems must be capable of reducing NO_x by more than 90%.

CSE Engineering

Specializes in gas, steam, and hydro turbine control system upgrades, <ITC>® HMI replacement for GE Speedtronic™ MK IV and V, gas and steam turbine field services, Woodward parts and repairs. CSE is a *Woodward Recognized Turbine Retrofit Partner.*

Cust-O-Fab Specialty Services

Provides the latest technology in exhaust plenums, exhaust ductwork, and exhaust interior liner upgrades that will drastically reduce external heat transfer, making the unit safer and more efficient and easier to operate and maintain.

Cutsforth

Our experience and innovative designs have brought best-in-class brush holders, collector rings, shaft grounding, and onsite field services for generators and exciters to some of the world's largest power companies.

DeepSouth Hardware Solutions

Spent the last seven years stockpiling surplus Westinghouse WDPF, WEStation, and Emerson Ovation control systems. Many of the items we carry are cost-prohibitive or obsolete from the OEM. Our reputation is built on fast service, low prices, and quality hardware.

DEKOMTE de Temple

Manufactures fabric and metal expansion joints which compensate for changes in length caused by changes in ductwork temperature. Axial, lateral, or angular movements can be compensated for. Company has gained a global reputation for ingenuity of design and quality of products.

Donaldson Company

Leading worldwide provider of filtration systems that improve people's lives, enhance equipment performance, and protect the environment. Donaldson is committed to satisfying customer needs for filtration solutions through innovative research and development, application expertise, and global presence.

DRB Industries

Leading supplier of gas-turbine inlet air filtration and cooling products along with turnkey installation. DRB also supplies cooling-tower parts and retrofits and evaporative media, and offers plant audits and inspections.

Dresser-Rand Turbine Technology Services

Specializes in the service and repair of heavy industrial gas and steam turbines. D-R provides aftermarket solutions for combustion, hot-gas-path and stationary and rotating components for most major gas-turbine models and frame sizes.

Dry Ice Blasting of Atlanta

Offers professional dry-ice contract cleaning services performed at your facility. Company provides a full range of dry ice blasting machines and capabilities to accommodate any size job by its team of trained, certified, and experienced operators.

EagleBurgmann Expansion Joint Solutions

Leading global organization in the development of expansion-joint technology; working to meet the challenges of today's ever-changing environmental, quality, and productivity demands. Company's flexible products are installed on equipment where reliability and safety are key factors for operating success.

ECT

Offers R-MC and PowerBack gas turbine and compressor cleaners to eliminate compressor fouling. Additionally, ECT designs specialty nozzle assemblies and custom pump skids for the proper injection of chemicals and water for cleaning, power augmentation, and fogging.

Emerson Process Management

Ovation™ control system offers fully coordinated boiler and turbine control, integrated generator exciter control, automated startup and shutdown sequencing, fault tolerance for failsafe operation, extensive cyber security features, and embedded advanced control applications that can dramatically improve plant reliability and efficiency.


Find a vendor, fix a plant ...online
Gas turbine/generators
Steam turbine/generators
Heat-recovery steam generators
Controls, instrumentation, diagnostics
Auxiliaries
CCJ ONline
Buyers Guide

FIND A VENDOR, FIX A PLANT

Environmental Alternatives

The first company to utilize CO_2 for cleaning HRSGs, having introduced this technology to the combined-cycle power market back in the early 1990s. EAI offers the most experience in the industry for this type of work.

Eta Technologies

Consulting services for all types of GTs, especially in the areas of component manufacture, repair, RCA, component remaining life assessment and metallurgical evaluations, with extensive and unique experience on Siemens V engines. Eta also provides replacement aftermarket parts for V engines.

Falcon Crest Aviation

Distributor of ZOK27 and ZOKmx gas-turbine compressor cleaning detergents. ZOK27 is a single cleaner and inhibitor in one that cleans and protects the engine—and also inhibits its corrosion. ZOKmx is a power cleaner formulated to replace solvents providing exceptional cleaning without the health and environmental risks associated with solvents.

Flow Systems

Specializes in repair and overhaul of gas-turbine accessories and steam-turbine equipment, as well as rotating equipment, utilizing modern techniques, highly skilled personnel and a state-of-the-art service facility to deliver superior quality, feasibility, and delivery to meet customer demands.

Frenzelit North America

Specializes in providing long-term expansion-joint solutions for gas-turbine exhaust applications. In addition to manufacturing superior quality expansion joints, Frenzelit also makes HRSG penetration seals, insulating materials, and acoustic pillows for silencers.

Freudenberg Filtration

Global technology leaders in the field of air and liquid filtration. The company's Viledon and micronAir brands are synonymous with high-quality filtration systems for industrial applications. Additionally, Freudenberg offers a wide-ranging service portfolio to ensure that its filter systems provide optimum benefit.

Fulmer Company

Provider of brush holders, machined components, and assemblies for the OEM, power-generation, and industrial markets. Fulmer is the largest North American manufacturer of brush-holder assemblies, offering single- and multiple-brush units for power generation OEMs and aftermarket customers.

Gas Turbine Controls

World's largest stock of GE Speedtronic circuit boards and components for the OEM's gas and steam turbines. GTC stocks thousands of genuine GE-manufactured cards for the MKI, MKII, MKIII, MKIV, MKV, MKVI, and LCI controls, as well as EX2000, Alterrex and Generrex excitation.

Gas Turbine Efficiency

Provides solutions involving the application of electrical, mechanical, and process-related equipment and components for optimizing system performance. GTE's experienced team of engineers and designers has solid industrial process backgrounds with expertise in fluid systems, instrumentation, and system controls.

GEA Heat Exchangers

From design to construction, replacement towers to spare parts, GEA has built, repaired, replaced and upgraded field-erected cooling towers for over 40 years for the power and process industries.

W L Gore & Associates

Focuses on optimizing gas-turbine performance via the application of hydrophobic, membrane-based, HEPA inlet air filters, which eliminate the need for off-line washes while dramatically reducing or eliminating the power-output and heat-rate degradations that result from turbine fouling.

GP Strategies

Works with utilities and independent power producers worldwide to increase profitability by maximizing plant availability and generating capacity, while minimizing risk. Company developed EtaPRO™ performance and condition-monitoring technology and GPiLEARN™ web-based training technology.

Groome Industrial Service Group

Offers a variety of SCR and CO catalyst cleaning and maintenance services nationwide and has formed strategic alliances with industry experts and catalyst manufacturers to ensure that Groome offers the most widely supported, comprehensive, turnkey service available.

GTC Services

Field engineering company offers gas-turbine owners and operators worldwide "Total Speedtronic Support." Engineers have decades of experience servicing and troubleshooting all GE Speedtronic systems.

Haldor Topsoe

Our air pollution technology includes a series of unique catalysts for Selective Catalytic Reduction (SCR) systems for the control of nitrogen oxides (NO_X), and the reduction of carbon monoxide (CO) and volatile organic compounds (VOCs), from stationary and mobile sources.

Hilliard

The HILCO® Division cost-effectively brings fluid-contamination problems under control and engineers a full-range of filters, cartridges, vessels, vent mist eliminators, transfer valves, reclaimers, coolant recyclers and systems, and membrane filtration systems.

HRST

Provides HRSG, conventional boiler, and powerplant technical services and products. Company specializes in HRSGs and waste-heat boilers. HRST engineers, technicians, and designers perform inspection, analysis, and design upgrades to help clients avoid and solve boiler problems.

Hydro

Engineered solutions enable combined-cycle plants to achieve pump reliability and reduced O&M costs. As the largest independent pump rebuilder, Hydro works hand-in-hand with pump users to optimize the performance and reliability of their pumping systems.

Hy-Pro Filtration

Provides innovative products, support, and solutions to solve hydraulic, lubrication, and diesel contamination problems. Company's global distribution and technical-support networks enable customers to get the most out of their diesel, hydraulic, and lube-oil assets. ISO 9001 certified.

JASC

Engineers and manufactures actuators and fluid-control components for power generation, aerospace, defense, and research applications to improve operational capability and performance.

Johnson Matthey

Worldwide leader in the development and manufacture of catalysts for the reduction of NO_x, CO, VOC, NH_3, and particulate emissions from gas turbines, boilers, stationary reciprocating IC engines, and industrial processes.

KnechtionRepair Tools

Manufactures tools designed to make thread repairs to both the female and male ends of cross-threaded compression fittings. In most cases, the repair will be accomplished without removing the tube from the system. This saves the O&M tech time and avoids additional downtime.

Kobelco Compressors America

Provides robust, high-efficiency fuel-gas compressors for use with all major types of gas turbines—including GE, Mitsubishi, Alstom, Siemens, Rolls-Royce, and Solar. Over 300 of the company's screw-type compressors have been supplied for gas turbines.

Liburdi Turbine Services

Advanced repairs employ the latest technologies and are proven to extend the life of components for all engine types. Company specializes in high-reliability component repairs and upgrades for blades, vanes, nozzles, shrouds, combustors, and transitions.

M & M Engineering

Provides failure analyses and related services to industrial and insurance-company clients. M&M's expertise includes corrosion in boilers, steam turbines, generators, combustion turbines, deaerators, feedwater heaters, and water and steam piping.

Mechanical Dynamics & Analysis

One of the largest turbine/generator engineering and outage-services companies in the US. MD&A provides complete project management, overhaul, and reconditioning of heavy rotating equipment worldwide.

Membrana, a Polypore company

Market-leading producer of microporous membranes and membrane devices used in healthcare and industrial degassing applications. The Industrial & Specialty Filtration Group manufactures Liqui-Flux® ultrafiltration and microfiltration modules as well as Liqui-Cel® membrane contactors.

Moran Iron Works

Global fabrication company committed to providing efficient processes, flexibility, and adaptability to ensure projects are completed on schedule. Moran specializes in one-of-a-kind fabrication and replacement of critical turbine components.

NAES

The energy industry's largest independent provider of operations, construction, and maintenance services—including equipment retrofit and repair, onsite turbine inspection/overhauls, and staffing solutions.

National Electric Coil

Leading independent manufacturer of high-voltage generator stator windings with expertise in design and manufacturing of stator windings for any size, make, or type of generator. This includes diamond coils, Roebel bars—including direct cooled, inner-gas, and inner-liquid cooled bars—and wave windings.

Natole Turbine Enterprises

Provides gas-turbine consulting to the utility, cogeneration, IPP, and pipeline gas-turbine markets. These services are directed toward component repair, rotor refurbishment, overhaul, upgrading, and reapplication.

NEM Energy

A leading engineering company operating globally in the field of steam generating equipment. NEM supplies custom-made solutions regarding industrial, utility, and heat-recovery steam generators for power generation and industrial applications.

Nooter/Eriksen

World's leading independent supplier of natural circulation HRSGs behind gas turbines and a single-source supplier of custom-designed heat-recovery systems. NE's annual sales volume includes HRSGs for combined-cycle powerplants whose output exceeds 8 MW.

On-Site Equipment Maintenance

Solid reputation in the power industry for decades as the industry leader in rebuilding critical and severe service control valves, AOVs, MOVs, and turbine valves. Company also specializes in boiler feed pumps, circ-water pumps, condensate pumps, fuel pumps, and rotating equipment.

Pneumafil

Major air-inlet filter-house supplier to all major turbine manufacturers for over 45 years. Company manufactures certified, high-efficiency filtration products for all brands, pulse style or static style inlet housings, to ensure maximum turbine output and efficiency.

Powergenics

Leading supplier of industrial electronic circuit-card and power-supply repairs to industrial and power generation customers. Company provides a very high-quality repair at a substantial cost savings from the OEM and other competitors while maintaining a warranty service second to none.

Praxair Surface Technologies

Leading global supplier of surface-enhancing processes and materials, as well as an innovator in thermal spray, composite electroplating, diffusion, and high-performance slurry coatings processes. Company produces and applies metallic and ceramic coatings that protect critical metal components.

Precision Iceblast

World leader in HRSG tube cleaning. PIC cleans more HRSGs than any other ice blasting company in the world. It ensures that HRSGs operate efficiently by providing the cleanest boiler tubes possible.

Proco Products

Supplies rubber expansion joints to the power industry in sizes ranging from 1 to 120 in. ID. Proco keeps joints up to 72 in. ID in stock at its Stockton (CA) warehouse and works through an agent/distributor network to supply products to combined-cycle plants.

PW Power Systems

Provides competitive, efficient, and flexible gas-turbine packages rated from 25 to 120 MW. PWPS offers a full range of maintenance, overhaul, repair and spare parts for other manufacturers' GTs with specific concentration on the high-temperature F-class industrial machines.

Rentech Boiler Systems

International provider of high-quality, engineered industrial boiler systems. Rentech is a market leader in providing HRSGs for cogeneration and CHP plants. It is in its second decade of designing and manufacturing high-quality custom boilers—including HRSGs, waste-heat boilers, fired packaged boilers, specialty boilers, and emissions control systems.

Sargent & Lundy

Provides complete engineering and design, project services, and energy business consulting for power projects and system-wide planning. The firm has been dedicated exclusively to serving electric power and energy-intensive clients for more than 120 years.

Sentry Equipment

Engineers, manufactures, and services components for collecting representative samples of steam, water, gas, liquid, slurry, and bulk solids. This enables analytical and operational professionals to gain samples safely and simply, and with repeatable results.

Sound Technologies

Provides engineered silencers and systems for new and replacement gas-turbine applications—including turbine inlet silencing, turbine enclosures, bypass systems, and HRSG inlet shrouds and stack and vent silencers.

SSS Clutch Company

Clutches enable operators to disconnect generators from simple-cycle turbines for synchronous-condenser service. Clutches also find application in CHP plants and in single-shaft combined-cycle facilities where operating flexibility is beneficial.

Strategic Power Systems

Provides products and services focused on capturing powerplant operational and maintenance data to develop reliability metrics and benchmarks for end users—including some of the most recognized organizations in the global energy market.

Sulzer Turbo Services

The leading independent and most technically advanced and innovative services provider for all brands of mechanical and electromechanical rotating equipment. The company also manufactures and sells replacement parts for gas turbines, steam turbines, compressors, motors, and generators.

Thor Precision

Value-added service center provides reverse-engineered rotor bolting for the gas-turbine aftermarket—specifically for Frame 3, 5-1, 5-2, 6B, 7E, 9E engines—including compressor, turbine, marriage, and load-coupling hardware.

Turbine Controls & Excitation

TC&E is an engineering consultation firm focused on turbine and generator controls services. Services include emergency troubleshooting, maintenance support, and equipment upgrades on GE MKxx controls, exciters, and LCIs.

Turbine Diagnostic Services

Conducts all aspects of steam turbine, gas turbine, and generator mechanical maintenance, plus vibration analysis and balancing, generator inspection and electrical testing, controls/excitation troubleshooting and upgrade support, turbine/generator instrumentation calibration, and I&E outage support.

Turbine Generator Maintenance

Provides turnkey field service maintenance for all turbine/generator components. TGM services the turbine, generator, exciter, control systems, and auxiliaries either individually or in any combination. Its service area includes the US, Caribbean, and South America.

TurboCare

Comprehensive product and service solutions for rotating equipment manufactured by all major OEMs—including component repair, equipment refurbishment, system retrofits, engineering, and replacement parts.

Universal Plant Services

Specializes in the maintenance, repair, and overhaul of gas and steam turbines, centrifugal and reciprocating compressors, as well as all rotating equipment, with qualified millwright and field machining specialists.

URS

Leading provider of engineering, construction, and technical services offers a full range of (1) program-management; (2) planning, design and engineering, (3) systems engineering and technical assistance, (4) construction and construction management, (5) O&M; and (6) decommissioning and closure services.

Victory Energy

Offers all types of industrial boilers: watertube, HRSG, firetube, and solar-powered units. Company provides unprecedented support with its rental boilers, spare parts, field service, and auxiliary equipment—including water-level devices, economizers, stacks, expansion joints, and ductwork.

Wabash Power Equipment

Full range of power equipment and services including: packaged boilers, rental boilers, and electric generators; diesel/generators and gas and steam turbine/generators; pulverizers and accessories; auxiliary equipment; spare parts.

Wood Group GTS

Leading independent provider of services and solutions for the power and oil and gas markets. These services include powerplant engineering, procurement and construction, facility O&M, repair and overhaul of gas and steam turbines, pumps, compressors, and other high-speed rotating equipment.

Young & Franklin

Premier fuel control supplier for combustion turbines for both long-term hydraulic solutions and, more recently, innovative all-electric controls solutions. Product scope supports natural gas, liquid, syngas, and alternative fuels as well as providing air controls to provide proper fuel to air mixtures.

Zokman Products

Distributor of ZOK27 and ZOKmx gas-turbine compressor cleaning detergents. ZOK27 is a single cleaner and inhibitor in one that cleans and protects the engine—and also inhibits its corrosion. ZOKmx is a power cleaner formulated to replace solvents providing exceptional cleaning without the health and environmental risks associated with solvents.

Evaluate the regulatory impacts of upgrades *before* you buy

These are tough times for electric utilities. Many people seem to believe they know more about the business of producing and delivering electricity than company executives, who are challenged daily by demanding questions and opinions from regulators, politicians, customers, special-interest groups, and others about everything from species displaced by new infrastructure to the unfair price of electricity produced "free" from solar and wind resources.

Having both viable and politically correct answers to questions yet not thought of is part of the job. For the generation side of the business, this requires a living plan for producing power five, 10, and 15 or more years from now at competitive prices and consistent with unspecified regulatory requirements. Variables and unknowns should be evaluated independently and often to provide the most accurate and current information to executives on the front lines and for inclusion into integrated resource plans required by state authorities.

One ongoing study at NV Energy, and probably many other generators as well, involves identifying possible upgrades for existing assets capable of satisfying near-term increases in demand and delaying the need for new resources.

Staff Engineer Susan Hill provided users attending the respected *Regulatory and Compliance Roundtable* at CTOTF's™ 38th annual Spring Turbine Users Conference (April 2013) a valuable methodology for doing this. Generation strategy is one of Hill's responsibilities at NV Energy. The Georgia Tech chemical engineer has more than 15 years of experience in power-generation operations and process optimization in the utility, pulp-and-paper, and pharmaceutical industries.

Upgrade options now being considered by NV Energy include these:

- Cooling of compressor inlet air using absorption or mechanical chillers, or inlet fogging. Each of these enhancements boosts compressor mass flow, which increases power production. Adding thermal-storage capability to a chiller package can further improve performance by reducing chiller size and shifting power consumption to off-peak hours. The latter provides more power for sale during peak periods.
- Engine performance improvements offered by OEMs and third-party providers. Examples include:
  1. A Siemens FD3 upgrade for the utility's four 501FD2 gas turbines.
  2. Replacing hot-gas-path (HGP) parts in NV Energy's eight 7FAs to those provided in GE's Dot-04 package.
  3. Upgrading HGP parts on all F-class frames with a third-party supplier's latest offerings.
  4. Adding GE's OpFlex to improve the operating flexibility and performance of the company's 7FAs.
- Using TurboPHASE™ to boost peak output and respond quickly to grid requirements.
- Power augmentation by injection of steam or water to increase compressor mass flow.
- Addition of PV capability where switchyard capacity is available.
- Replacement of seals and hardware on steam turbines to return the machines to as-new condition.
- Addition of wet cooling capability to plants served exclusively by air-cooled condensers, to reduce backpressure and increase generation when ambient temperatures are highest.
- Installation of a packaged boiler to take advantage of unused steam-turbine capacity.

Key steps in the process outlined by Hill and co-presenter Jonathon Bader, PE, of Sega Inc, an engineering firm based in Overland Park, Kans, were the following:

- Identify possible upgrades.
- Identify any plant limitations.
- Perform high-level design of upgrades for applicable units.
- Determine potential capacity increase for each upgrade.
- Assess upgrades for complexity.
- Estimate lead times for projects.
- Evaluate environmental/permitting limitations.
- Determine controls upgrades required, if any.

The next level of investigation involved these tasks, among others:

- Evaluate the candidate facility's balance-of-plant infrastructure for supporting the proposed upgrade.
- Use thermal engineering software to gauge performance.
- Estimate capital cost and the incremental increase in plant variable costs.
- Conduct an environmental assessment that evaluates the possible impacts of the following environmental statutes: PSD (Prevention of Significant Deterioration)/BACT (Best Available Control Technology), NSR (New Source Review), NSPS (New Source Performance Standards).

The environmental assessment portion of Hill's presentation was of particular interest to attendees who had never participated in PSD, NSR, and/or NSPS evaluations. What quickly became apparent was that no particular upgrade could be applied across the utility's fleet with equal success.

One reason for this is the many locations of the company's generation assets and the different rules that can apply to each. To illustrate: About three-quarters of NV Energy's capacity is in southern Nevada, specifically Clark County; most of the remainder is in northern Nevada, relatively close to Reno. Some Clark County assets are in PM10 non-attainment areas; plus, ozone rules are not well defined for the county going forward. Northern plants are in an attainment area.

PSD analysis needed? One of the first questions you should ask when evaluating upgrade options is, "Will it trigger PSD analysis?" PSD rules, Hill pointed out, apply to both attainment and non-attainment areas and analysis is required if your project results in a significant increase in emissions.

The next question likely is, "What is significant?" To determine that, compare the potential increases in emissions of criteria pollutants attributed to the upgrade with the "significant emission rate" (SER) in tons per year for each pollutant as specified in the PSD rules. These numbers are as follows: PM10, 15 tons/yr; PM2.5, 10; NO_x, 40; VOC, 40; CO, 100; CO_2e, 75,000.

In case you read through the list quickly, take note of the last entry. Greenhouse gases (GHG)—including CO_2, CH4, N_2O, SF_6, and certain fluorocarbons—became regulated under the federal Clean Air Act in 2011. The CO_2e designation stands for carbon-dioxide equivalency or the amount of CO_2 that has the same global warming potential as the mixture of greenhouse gases.

The bottom line: If the emissions after the upgrade exceed the pre-upgrade emissions by more than the SER, PSD analysis is necessary, Hill said. The next question probably is, "What does PSD analysis involve?" According to Hill, it means (1) air dispersion modeling for NAAQS (National Ambient Air Quality Standards) and PSD, and possibly ambient-air modeling as well, and (2) BACT review and possibly installation. Even if the upgraded facility satisfies BACT, she said, the process adds time and expense to the project.

In sum, Hill stressed that if PSD analysis is required for upgrading a relatively new unit the best outcome is a longer permitting process, later project implementation, and higher cost; the worst, modification of existing controls. For older units, expect that you'll have to install BACT, which probably means a sizable investment.

NSR is another hurdle that must be cleared. It is applicable to construction or modification of a major stationary source. The obvious question from anyone considering an upgrade is, "What is meant by modification?" Colin Campbell of RTP Environmental Associates Inc, who presented on the challenges of NSR during the same session as Hill, said that "modification" as defined by Congress was, "Any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously."

EPA's "major modification" definition in NSR rules is narrower and more specific, he continued. Specifically, it (1) allows for exclusions for some types of changes—for example, routine maintenance/repair/replacement, (2) establishes *de minimis* exemption levels for emissions, and (3) clarifies that emissions increases are determined based on actual annual emissions.

But that's not all. Campbell said that after much litigation, the current status is that (1) exclusions must be interpreted narrowly, consistent with Congressional intent, and (2) whether maintenance/repair/replacement is routine or not may be based on the nature, extent, purpose, frequency, and cost of the project. Apparently, upgraded replacement components—such as HGP parts—could be considered a "major modification," in at least some cases. However, the deal breaker for many upgrade projects might well be GHG.

Next steps. Hill began wrapping up by asking, "Now we know the 'triggers' for additional permitting and possibly capital, how do we estimate without a full detailed emissions analysis?" The answer, she said, it to make some simplifying assumptions and calculations, such as these:

- Assume emissions in pounds per million Btu of heat input will not change.
- Calculate the fuel increase required by upgrade under consideration.
- Assume a number of operating hours at the higher rate of fuel input.
- Calculate the increase in pollutant emissions and compare them with the SER and other "triggers."
- Highlight those projects that come within 50% and 100% of SER.

Then rank projects based on cost and risk and decide which ones to take to the next level of evaluation, which involves the following:

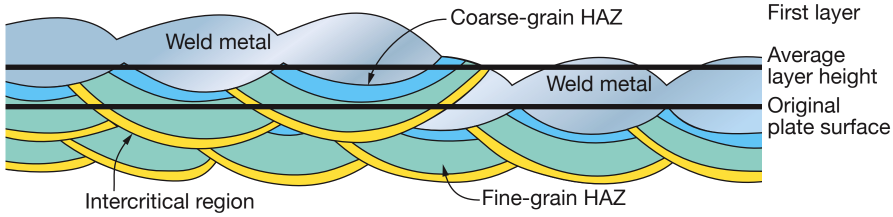
- Detailed engineering.
- Detailed review of permitting implications—including potential changes in SCR performance.
- Develop performance curves for use in production cost modeling to quantify the benefit of each proposed project in the dispatch model. CCJ

The science and art of quality weld repairs

Proper selection and application of weld technologies for the repair of high-temperature components in heat-recovery steam generators and high-energy piping systems is critical to maintaining the high availability and reliability demanded of combined-cycle plants. European Technology Development's Chief Metallurgist Dr David Robertson and Director Dr Ahmed Shibli discussed with the editors the industry experience ETD has compiled in a comprehensive report that the research organization believes is of great value to owner/operators of generating plants.

"Guidelines for high-temperature weld repairs: Review of worldwide plant and R&D experience," published last fall, is a 300-page treatise focusing on 2.5CrMo, 0.5CrMoV, CrMoV, P91, and AISI 316 steels. The document provides comprehensive guidelines on weld repair procedures and integrity/life assessment of weld-repaired high-temperature components. For details and information on how to order, contact ashibli@edt-consulting.com.

Robertson and Shibli said that, for better decision-making, industry personnel responsible for weld repair of high-temperature components should come up to speed on (1) typical features of welds, (2) damage that may affect welds in service and the consequent need for repair, (3) the excavation design and geometry of full and partial weld repair, (4) welding processes, (5) welding and post-weld heat treatment (PWHT) requirements of the construction codes, (6) performance assessment of weld repairs, (7) principles of microstructural control within weldments—among many other things also covered in the report.



The temper-bead method of cold-weld repair. Coarse grain size is defined as equal to or greater than 50 micrometers; fine grain, less than 50. Grains can be measured only by metallographic examination of a weld section

Cold welds. One of the document's 13 chapters is devoted to cold-weld repairs—defined here as weld repair where preheat may be applied, but PWHT is excluded. The technique can help users mitigate the financial impact of lost production by allowing units to return to operation sooner than they would if PWHT were required.

Cold-weld repair technology was pioneered in Russia in the 1960s and later advanced in the UK. The US National Board Inspection Code in 1977 allowed weld repairs without PWHT for several materials provided specific buttering techniques were used. In 1995, the NBIC accepted that certain welds were impractical to PWHT and allowed cold-weld repair provided the owner/operator could demonstrate properties equal to those for the original construction.

Several controlled weld-metal deposition techniques were developed to enable cold-weld repairs. They use the thermal fields, generated by successive weld beads, to provide both the grain refinement necessary to assure success as well as some local tempering of the structure of the heat-affected zone (HAZ). The so called half-bead, temper-bead, and heat-input control techniques all are based on controlled overlap of the adjacent weld bead segments and the use of several buttered layers. The temper-bead technique some prefer for cold-weld repairs on P11 and P22 is illustrated in the figure.

Cold-weld repairs are not as simple as they might sound. Decisions on excavation configuration, filler-metal specifications, heat input at various stages of the repair, etc, are critical. Plus special training is required for welders performing the work. The ETD report is valuable for its perspective and recommendations on the process to avoid missteps.

Keep in mind that toughness of the HAZ and weld strength depends significantly on use of a welding technique that minimizes the coarse region from the parent metal. Bill Kitterman, GM, Bremco Inc, oft noted by users for the quality of its weld repairs, extracted relevant material on the art from the company's files that has been collected over the years. A passage published on www.gowelding.com suggested the following:

"The first layer of weld should consist of small beads, deposited using low heat input to ensure minimum penetration into the parent metal. This can be achieved by using small electrodes, welding in the horizontal position, and adjusting the angle of the electrode to minimize penetration. Great care must be taken to avoid hydrogen cracking and lack-of-fusion defects. A 50/50 bead overlap will reduce the course-grained area, but not necessarily remove it altogether.

"Depositing a bigger weld bead on top of the smaller ones, such that its refined zone overlaps the coarse areas created by the original runs, is the preferred technique. Sometimes the first beads are ground down slightly to enable the refined zones of the next beads to line up correctly. The final bead of any welding sequence should be deposited in the middle of the cap, away from the parent metal."

One of the takeaways from the investigations by Robertson and Shibli is that cold-weld repairs of thermal fatigue cracks using Inconel-type weld metal normally are considered temporary, possibly providing up to five years of service before another crack is caused by thermal cycling. However, the two experts point out that such temporary repairs are sufficient to reach the next scheduled outage when a more permanent repair can be made.

Amy Sieben, PE, principal, ALS Consulting LLC, Forest Lake, Minn, a firm specializing in HRSG inspections, repairs, and upgrades, said temporary repairs concern her because the need to make repairs permanent often is quickly forgotten by plant personnel, or deferred until it is forgotten.

Kitterman said the preparations for cold weld repairs—welder training, test welds, and metallographic examinations to confirm quality work—should not be underestimated. Plus approval by applicable authorities (insurance company, state regulators, etc) is required. He believes it's generally easier to follow standard procedures with PWHT except in situations where PWHT may be impractical—which Kitterman believes are rare.

In wrapping up their exchange with the editors, Robertson and Shibli reminded that for a given repair situation, both the operating conditions and type of defect must be considered. Cold welding with nickel-based filler should be suitable for repair of manufacturing defects in castings, such as turbine casings, they said, or for repairs to previous weld repairs made at the manufacturing stage—because they generally experience low stress levels. Subject to periodic inspection, the repairs could be considered permanent. By contrast, in-service defects generally are caused by more severe loadings, so cold-weld repairs with nickel-based filler should be regarded temporary, as noted earlier. CCJ

How to design, retrofit drum-type HRSGs to cycle, start faster

Vogt Power's HRSG University came to Las Vegas June 27 for a full day of presentations and collaborative discussion conducted by Chief Thermal Engineer Kelly Flannery and two members of the boiler manufacturer's aftermarket and field services team, Peter Allison and Deron Johnston.

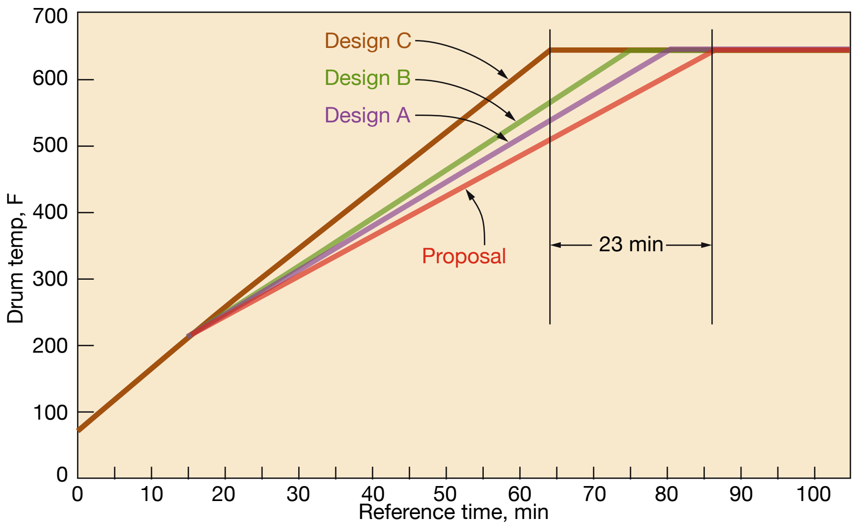
The informative program, presented without commercials beyond a 10-min review of who Vogt Power International is and what it does, appeared well-received by two dozen or more "locals" from NV Energy and other power producers in the area. The same program had been presented in Phoenix earlier in the week.

With budgets tight, and air travel and hotels at premium prices these days, Vogt saw an opportunity for its serious outreach program and was rewarded with support from power producers hungry for structured training on subject matter often overlooked in a time-constrained work environment.

The meeting began with a two-hour session on HRSG design delivered clearly, quickly, and succinctly by Allison. It was a particularly valuable presentation for someone new to combined cycles and cogeneration plants powered by gas turbines and for those who needed a refresher.

Presentations on SCR catalyst and lessons learned in retrofit and upgrade activities to improve performance, and a primer on HRSG inspections, flanked a tutorial by Flannery on design ideas for improving the operating flexibility of conventional heat-recovery steam generators to meet emerging grid requirements. Flannery's certainly was a timely topic considering the attention fast-start plants with Benson-type once-through HP sections are now receiving.

The chief engineer began by reviewing why combined cycles should be designed, or retrofitted, to cycle and start and ramp fast: There's money to be made providing grid ancillary services. Example: Rapid start/ramp to back up must-take renewables when the wind stops and clouds appear. Fast starts/fast ramps also reduce the total emissions during a start, cut startup costs, and enable the plant to achieve full-load revenues faster.



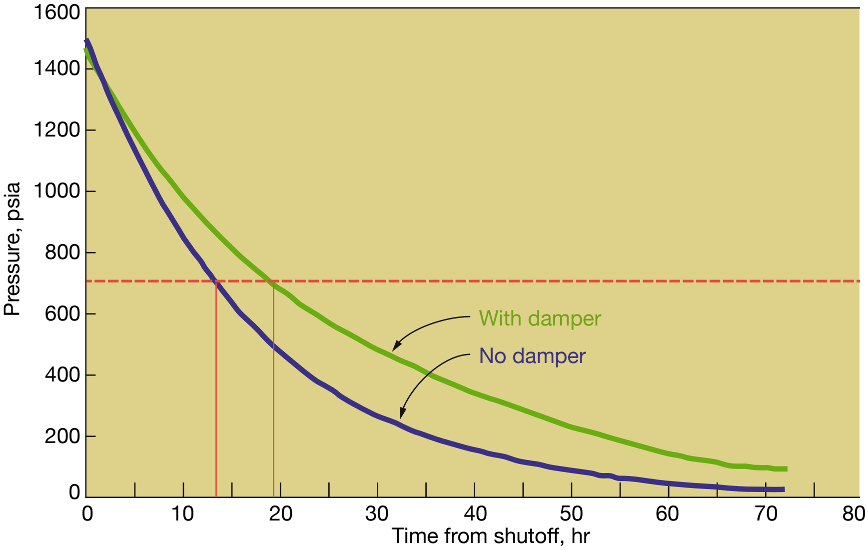
1. Smaller-diameter steam drum made from higher alloy steel reduces shell thickness and enables a faster startup ramp rate. Alternative drum designs all are set for 15 minutes for initial steam generation

Drum design options

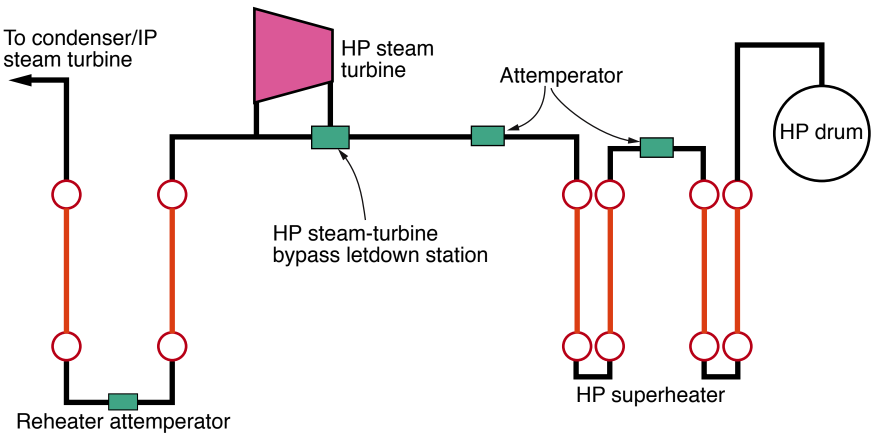
Parameter	Proposal	Design A	Design B	Design C
Drum ID, in.	72	72	66	66
Drum material	516 Gr 70	SA 299	516 Gr 70	SA 299
Shell thickness, in.	5.25	5.0	5.125	4.625
Storage time, min	3.0	3.0	2.2	2.2
Startup ramp rate, deg F/min	6.0	7.2	6.6	8.75
Total life usage	0.854	0.852	0.854	0.852

Flannery then suggested several things users might consider incorporating into their specifications to enable fast starts and ramps, including the following:

- HRSGs and condenser designed for 100% steam-dump capability. Water-cooled condensers, he noted, are more conducive to fast starts than air-cooled condensers.
- Wet reheater. Flannery recommended putting steam into the reheater as soon as possible after the gas turbine is started. Running the reheater dry shortens its life, he said.
- Provide a final-stage attemperator to accommodate the steam-turbine roll. Some owner/operators view this as a risk. While it certainly is more risky than having no final-stage attemperator, the risk can be managed by good engineering and conservative design—that is, an adequate run of straight piping downstream of the attemperator, quality valves, effective drains, and



2. Stack damper has a significant impact on the rate of drum pressure decay. Note that for shutdowns of 24 to 40 hours, drum pressure for units with a stack damper is about double that for units without



3. HP to cold-reheat steam bypass avoids dry reheater operation during startup

good instrumentation.

- Effective design and tuning of the BOP control system.
- Online, real-time monitoring of HRSG life consumption.

Flannery spent about 10 minutes on pressure-part design considerations to accommodate fast starts and cycling. He began with a review of the all-important HP drum, made of carbon steel, which is used for steam/water separation and to maintain adequate storage volume. The ability to reduce drum size (read shell thickness), he said, contributes to faster starts and ramps, as the table confirms. Today's tools for finite element analysis help engineers design for minimum thermal soak time.

The table shows how drum design parameters impact the ramp rate of a typical F-class combined cycle. The standard offering described in the first column would be a 6-ft-diam drum made of 516 Gr 70 steel and having a shell thickness of 5.25 in. Storage time is the industry norm of 3 minutes, the allowable startup ramp rate 6 deg F/min.

Fast forward to Design C: With a startup ramp rate of 8.75 deg F/min it can reach rated output faster than the other options. It employs a higher grade of steel for a relatively small financial penalty. SA 299 typically costs less than 5% more than the baseline 516 Gr 70. The smaller drum is made possible by taking exception to the 3-min storage rule, the speaker suggested. The rapid-response capability of modern control systems is said to allow the reduction in storage volume to 2.2 minutes, possibly less, without compromising plant reliability. Fig 1 illustrates the advantages of Design C well. It comes up to the desired drum temperature in 64 minutes, compared to 87 minutes for the reference case.

Looking ahead, Flannery sees other possible changes to standard design practices for drum-type units to enable cycling and faster starts. These include:

- Drums with still less storage capacity, perhaps as low as 1.25 minutes.
- Thicker nozzle connections than required by the *ASME Boiler and Pressure Vessel Code*, to increase service life.
- A method for keeping the HP drum and HP evaporator warm during shutdowns, to avoid cold starts. A rule of thumb: A cold start consumes seven-fold more drum life than a warm start and the latter uses up four times more drum life than a hot start. Maintaining the drum at about 400F significantly increases its design life, the speaker said.

One way to keep the HRSG warm during shutdown periods is to install a stack damper and make sure no valves are leaking. The upper curve in Fig 2 shows drum pressure decay for a HRSG equipped with tight valves and a stack damper. Note that drum temperature is held at or above the recommended 400F through a weekend shutdown. Flannery also recommended insulating the stack to minimize condensation in the back end of the unit.

Fig 3 illustrates the wet-reheater arrangement mentioned earlier to extend the life of that tube bundle by avoiding dry operation during startups. For success, this scheme requires the condenser to handle full-load steam flow, which usually is not possible at an existing plant. For a new plant the condenser obviously can be sized appropriately.

Other design considerations to support cycling include these:

- Automated vents and drains and the use of condensate drain pots for positive verification that all condensate has been removed from the reheater and HP superheater. Recommendation: Install quarter-turn ball valves on all drains.
- Motorized blowdown valves for drum chemistry control.
- Leak-proof valves in attemperator systems to avoid piping damage from water impingement, to prevent water from entering the superheater panels, and to minimize pressure decay during shutdowns.
- Steam sparging to keep the boiler warm during shutdowns and assure proper freeze protection. Flannery suggested that owners get an auxiliary boiler into the plant environmental permit.
- Drum-wall thermocouples to provide the best information available for decision-making.
- Avoid complicated piping arrangements to accommodate expansion and contraction with minimum stress. CCJ

Safety, thorough planning critical to outage success

That's certainly not news, but when outages don't go smoothly the reason often involves a violation of safety procedures and/or a failure to plan work packages rigorously. As you sit through open discussions and presentations on these subjects at user-group meetings there's a tendency to "tune out" because you think you've heard it all several times before.

Fact is, plant personnel with five or more years of experience and several user meetings under their belts may be familiar with as much as 90% of the ideas/experiences being discussed, but that still leaves 10% to learn. With regard to safety, an "A" is not good enough; perfection should be your goal. And let's not forget that a primary objective of user groups is sharing information. It's impossible to bring people new to the industry up to speed on the collective knowledge if you're not engaged in the discussion. Your active participation is important.

Safety was the first open-discussion forum on the agenda of the 2013 Frame 6 Users Group meeting in League City, Tex (Houston area), June 17-20. BASF (Geismar)'s J C Rawls, a member of the steering committee, was the session leader. One of the first topics brought to the floor was fire-watch experience. A couple of users opined that having more people on fire watch is not necessarily better; they can get in the way and could have a negative effect on job safety.

Listening to the experiences of others in the industry you hear more and more about the negatives of excessive regulatory involvement in the business of power generation. Supervisory personnel are increasingly tied up with paperwork leaving them less time to manage and observe. The thought that paperwork improves safety or mitigates pollution is ludicrous. Rather, it can create the false impression that personnel are doing all that's necessary because a generating facility's paperwork has passed official muster with a history major who never worked in a powerplant.

Second topic: confined space. Define "confined space" before the outage, urged a few of the seasoned plant supervisory personnel in attendance. One user said he considers as "confined" any space that presents a unique rescue concern, any place not normally designed to have people in it, and/or any area where inert gases can accumulate. Example: Underneath the turbine compartment. An assessment of confined spaces was suggested; reclassify by re-evaluation where appropriate.

A consensus formed on the belief today that too many safety measures have been implemented to protect against phantom hazards. Also, the thought that "more is better" regarding safety precautions is flawed. "You can do too much," someone said. One user recalled an incident where fall protection caused a back injury. Another: Fall protection prevented workers from escaping a fire. Suggestion: Focus on planning for safety; have contractors provide safety supervisors depending on the type of job and number of

Frame 6 Presentation

Frame 6 Users Group

2014 Annual Conference

June 23-26

Sanibel Harbour Marriott Resort & Spa

Ft Myers, Fla

www.Frame6 UsersGroup.org

2013 Steering Committee

Co-chairs:

Jeff Gillis, *ExxonMobil Chemical*
Sam Moots, *Colorado Energy*

Members:

Geoffrey Kret, *Total Petrochemicals USA*
J C Rawls, *BASF (Geismar)*
John Vermillion, *Atlantic Power Corp*
Brian Walker, *Foster Wheeler Martinez Inc*
Zahi Youwakim, *Huntsman Corp*


Gillis


Moots


Kret


Vermillion


Walker


Youwakim

people involved.

Package entry is considered a concern where a CO_2 system protects against fire. Several thoughts on this topic, some obviously in conflict, including the following:

- When the unit is operating and the package must be entered, keep the doors open, go in, get the required job done, and get out.
- Lock out the fire protection system before you send anyone inside the package when the CO_2 system is active. This user's plant had a simple switch to lock out CO_2.
- Install windows in compartment walls to protect against opening a door into a hazard.
- When opening a compartment door, do so slowly from behind the door and with your foot on the bottom of the door to guard against getting hit by a blast of hot air or steam.
- Call the control room before entering the package.
- A problem with opening the package door is how to tell if it is properly sealed after it is closed.

Bad things can happen to a well-planned outage was the subject of a case history presented by an experienced user. It illustrates the challenges plant management personnel face all too often. The 60-day project was carefully planned to accommodate rotor work and lifetime assessment, internal alignment, and generator work. New parts were ordered, received, and identified onsite.

Problems surfaced soon after the outage began. First, the rotor was shipped to a different shop than planned because the OEM was reconfiguring its repair network; the job paperwork did not transfer along with the engine. The next wrinkle had to do with personnel: It seemed like there was a new job foreman weekly. Then the outage from hell suffered the following, among other things:

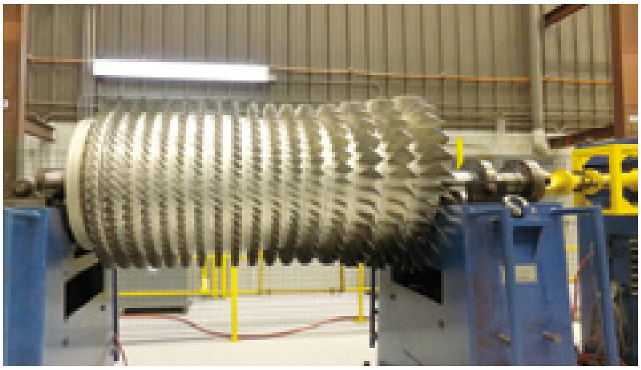
- Forklift ran into the 17^{th} stage compressor wheel (Fig 1).
- A five-day delay for a coating decision.
- Another five-day delay because new second-stage buckets would not balance.
- A new shop work schedule (two 10-hr shifts versus two 12-hr shifts) added four days to the schedule.
- Quality of craft skills was called to into question; millwrights crushed liners adding yet another four days to the outage (Fig 2).

1. A careless forklift operator damaged this 17^{th} stage compressor wheel (above)

2. Careless millwrights crushed combustion liners, which will be replaced during an upcoming outage

3. New 16th stage wheel was required based on findings of the rotor life assessment investigation

4. Compressor section of a 6B gas turbine is balanced after being refurbished (below)



The speaker suggested to his colleagues that they check everything again and again, and once more for good measure. He inferred that you can't review enough things often enough. Does the shop have the scope of work you provided? What's the status of documentation: incoming and final reports? Verify compressor wheel run-outs, review and sign off on inspection forms, verify completeness and quality of repairs, check rabbet fits are to spec, etc. You undoubtedly will learn a lot. Example: This user was surprised to find that 12 of the 17 compressor wheels had a patch ring from Day One; the owner never knew.

Investigations of work done revealed questionable craftsmanship. On restart, the owner found the unit running to the right—rather than in the center—and up. Follow-on checks revealed many measurements pertaining to shroud blocks, honeycomb seals, turbine roundness, etc, did not fall with the OEM's specifications. Report quality was disappointing too. The speaker said the detail promised in the final report and the actual document were "miles apart." The final report, as first submitted, was just four pages of pictures. The speaker concluded that lack of ownership probably was the biggest problem with the shop.

The rotor life assessment revealed the need to replace the 16^{th} stage compressor wheel (Fig 3). Soundness of the turbine-section components—wheels and spacers—was confirmed by magnetic-particle, ultrasonic, and hardness inspections. No defects were found and the rotor was certified to run until 300,000 hours.

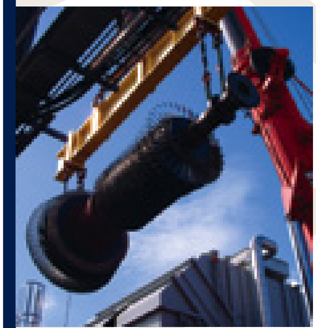
Following corrections and adjustments, restoration of the engine to "as-original" confirmed a 20-psig increase in compressor discharge pressure and a power increase of 6 MW—5 MW from compressor work, 1 MW from closing gaps in the turbine section. Within one year, the OEM is supposed to replace the damaged liners and share investigation results on the reasons the new second-stage buckets did not balance. The owner is already compiling its task list for the next hot-gas-path and major inspections.

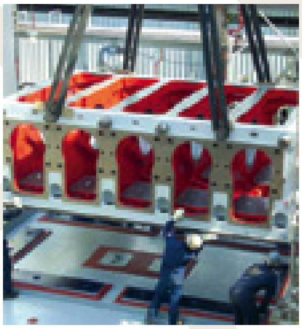
The bottom line: It's not just planning, it's also execution.

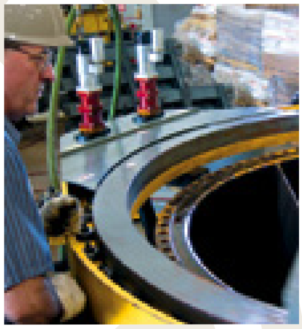
Compressor

The compressor discussion, led by Geoff Krett of Total Petrochemicals USA, a member of the Frame 6 steering committee, touched on several topics (Fig 4). They included:

- No water. Keeping water out of the machine is beneficial in all respects, one attendee said, reflecting on the HEPA







Condensing economizer gives fast return on investment

Most user-group meetings allow substantial time during refreshment breaks and meals to share experiences individually and in small groups. You can learn a great deal. One of the attendees at this year's meeting of the Frame 6 Users Group told the editors during a coffee break about an energy-saving idea that has provided a meaningful return for both his plant and its host, a finishing steel mill: A condensing heat exchanger in the flue-gas circuit.

Condensing economizers are not new but there hasn't been much mention of them in the power-generation sector, at least, since the "energy conservation days" of the mid-1970s. Credit Primary Energy Recycling Corp, Oak Brook, Ill, for finding a fast-payback application for the technology at its Portside Energy LLC combined heat and power (CHP) facility in Portage, Ind. Primary Energy supplies its customer electricity, steam, and hot softened water.

The 6B-powered 1 × 1 combined cycle, built inside the host's fence (photo) went commercial in June 1996 equipped with steam power-augmentation capability. An IST once-through steam generator (OTSG) sits behind the engine and is capable of producing 150,000 lb/hr of 1500-psig HP steam. A backpressure steam turbine generates up to 20 MW, bringing total plant capability to 63 MW when operating at maximum output. The ST's fourth-stage extraction provides IP steam to the offtaker at 225 psig for process use while exhausting LP steam to the mill at 25 psig for producing hot water.

Two fired boilers, each capable of generating 175,000 lb/hr, bring the plant's total capability to 500,000 lb/hr of HP steam. The three steam generators are arranged in a header system. One of the fired boilers is equipped with a 26:1 low-NO_x turndown package enabling its operation at a minimum setting of 3% rated output. The deep turndown capability was installed in fall 2012 along with the condensing heat exchanger as part of the energy conservation upgrade.

Addition of a condensing heat exchanger (right of stack) to the 6B-powered CHP system at Portside Energy significantly improved plant's bottom line

The condensing economizer receives exhaust gas from the OTSG at 280F by way of an induced-draft fan powered by a variable-speed drive. The heat exchanger consists of two independent over/under finned-tube bundles. The upper one preheats cycle water flowing to the deaerator, the lower coil raises the temperature of makeup for the 2000-gpm once-through hot-water system. Flue gas may exit the economizer at less than 100F.

Hot-water makeup, sourced from the lake, may be as low as 44F in winter. The raw water is passed through a multimedia filter and softener before being heated in the economizer. Typically, 30 to 40 gpm of water condenses out of the stack gas flowing through the heat exchanger. It is sent to a cation exchanger and then directed to the demin water system. The balance of the plant's cycle makeup comes from lake water that is filtered, run through cation and anion exchangers, and then a mixed-bed polishing unit.

Energy savings are said to have exceeded expectations. In wintertime, LP steam demand has been reduced by as much as 70,000 lb/hr depending on mill output and ambient temperature.

presentation summarized later in this report. For example, the OEM suggests firing after a crankwash to eliminate moisture. This means that if you wash the compressor before a borescope inspection you'll have to heat up the unit and then cool it down again—an unnecessary stop/start cycle. Or is it? If you don't wash the unit you'll reduce the visibility for the borescope inspection.

- More on filtration strategies. Don't be lulled to sleep by just changing prefilters and wraps, the user opined, because the final filter is deteriorating and when that happens pieces of filters can go downstream.
- Pressure-drop limits. You can allow the differential pressure across a filter to increase to 4 in. H_2O, someone said. But severe fouling from a dust storm or fire, or horizontal rain, can cause the delta p to spike in a relatively short time. Bursting of filters occurred at one plant when the pressure drop hit 6 in. H_2O.
- BASF's J C Rawls described a simple, back-of-the-envelope calculational procedure that can be used on the deck plates to track compressor efficiency. Scan the QR code on p 77 with your smartphone or tablet to access Rawls' presentation.

The question plant personnel should ask themselves, he said: "Am I making the megawatts I should be at this ambient temperature?" A 1% loss in 6B compressor efficiency, Rawls continued, can cost you half a megawatt in output—in round numbers.

The speaker cautioned attendees to use absolute temperatures in the equations he presented. He also said that while the specific heat of air is not constant, the suggested 0.24 Btu/lb-deg F is a good approximation.

- A pitfall of selecting galvanized steel over stainless for an air inlet system equipped with fogging for evaporative cooling is that demin water breaks down the coating and releases zinc. A user reported that zinc-plugged cooling holes in first-stage buckets, causing life-limiting wear and tear. While galvanized steel is less expensive than stainless, which tolerates the fogging environment well, there is no free lunch.
- Soap normally is not used for washing compressors online. But one user suggested keeping an open mind on the subject because an oil leak on the No. 1 bearing will require it.

Combustion section

Discussion on the combustion section was scattered, most likely because of the wide variety of engines in the fleet—some steam-injected units, some water-injected, some DLN. Inspection intervals varied from one user sticking with 8K CIs based on starts, to a few running 12K CIs, to the majority with 24K HGPs. General consensus was major inspections at 48K, although a few users were considering extending that interval. Other topics included the value proposition of fiberoptic flame detectors over water-cooled ones and experiences with TBC coatings on first-stage nozzles.

Rawls, who has the skills of a polished instructor, offered another valuable technical presentation for O&M personnel during this part of the program, chaired by John Vermillion of Atlantic Power. "Estimating exhaust 'swirl'" offers guidance on how to trace the source of a high-temperature spread back to a specific location in the combustion chamber. This presentation also can be accessed using the QR code referenced earlier.

Three basic steps are involved, he said:

- Identify the high and low spots in the exhaust-temperature profile.
- Back-trace the exhaust-temperature anomaly through the gas swirl angle to its location in the combustion chamber.
- Identify the hardware capable of producing a variation in the com-

bustion pattern.

The speaker then explained "swirl angle" to those unfamiliar with the term. He said it is the angle between the measured representative exhaust-gas temperature, at varying loads, and the known combustor source location. Rawls went on to say that the swirl angle is not a rigidly controlled parameter and could vary among units. It should be treated only as a tool for O&M personnel, he stressed.

Mitigation of operational risk was a discussion highlight on the last day of the meeting. One user got things moving by sharing that Hurricane Rita opened the eyes of his plant's management to what specifically was needed to minimize the adverse operational impacts of severe weather events. Action taken at this chemical plant was to install a new substation exclusively for utilities which provides a black-start hook-up to a truck-mounted 4-MW generator.

All electrical needs for the onsite power system are available via the new substation—from the makeup water inlet through the stack. This arrangement greatly simplifies restart, the user said, because utilities are now independent of process. Previously, "endless" coordination with process personnel was required and only certain systems on the power side could be returned to service at any one time.

Others talked about bootstrapping the power system back into service with small units—using them to get larger units in service, etc. Their budgets obviously did not support the installation of a black-start system like that described above. The electrical discussion during this part of the program was robust. A point was made that just having a diesel doesn't mean you have black-start capability. It takes considerable effort to understand your system and the process plant's immediate needs (power or steam) to configure an effective, reliable, and rapid restart.

Control system upgrade or complete replacement was a topic of limited discussion this year. Consensus view was that a leave alone/upgrade or replace decision depends on the product. Electricity is not as critical or profitable as gasoline, for example (the vast majority of attendees were at plants not regulated by NERC/FERC).

Thus it's most likely a complete control-system retrofit would be done where a high-value product is involved and operational reliability is very important. The others would be most inclined to retain original control systems and rely on the industry's robust third-party network for parts and service. A point made to anyone planning a control-system replacement was to pull all new wire between the control system and turbine. Old wiring likely would be a weak link in a new system.

Odds and ends

- Lube-oil coolers. An attendee spoke about opening 20-year-old lube-oil coolers for maintenance during an HGP to find tube wall thickness in some areas was cause for concern. Tube bundles were replaced. The sharing party recommended that others with plants beyond perhaps 15 years old should take tube-wall measurements if they have not yet done so.
- Shaft grounding was brought to the floor by someone disenchanted with his plant's standard carbon-brush system. An alternative suggested is profiled on p 46. One attendee seemed puzzled by the idea that his 6B's shaft might be magnetized. One possible reason offered by others in attendance: Rotor was mag-particle tested on a shop visit and never demagnetized.

This started a whole new thread on the need for carefully monitoring shop activities affecting your equipment. A point noted was that mag-particle was not the only NDE test with possible "side effects." The group was informed of the flammability of dye-penetrant fluid by another user. He learned that when one of his components caught fire during inspection.

Vendor presentations

There's a risk associated with integrating vendor presentations into user group programs focused on sharing experiences among owner/operators: A technically weak presentation can cost the attention of your audience until the next coffee or meal break. Steering committees mitigate this risk by providing the candidate speaker well-defined guidance on subject matter of value to the group, having first-hand knowledge of the speaker's experience, and conducting a critical review of the presentation before the meeting.

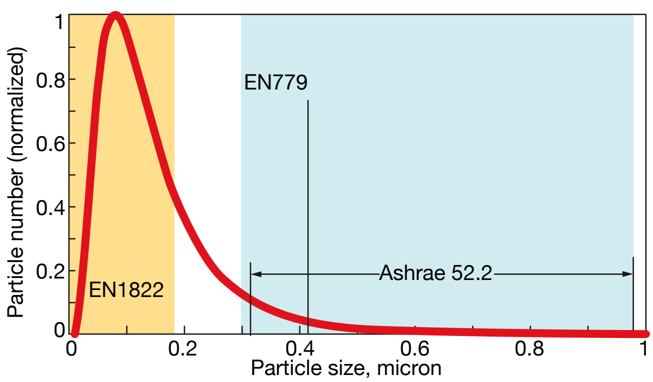
The committee's job is especially challenging when the presentation concerns what many would believe is pedestrian subject matter—air filters and lube oil, for example. The Frame 6 Users Group exceeded expectations at the 2013 Conference with three outstanding presentations by technical experts on air filters, lube oil maintenance, and shroud-block mods to assure top engine performance.

Latest performance data on HEPA filters

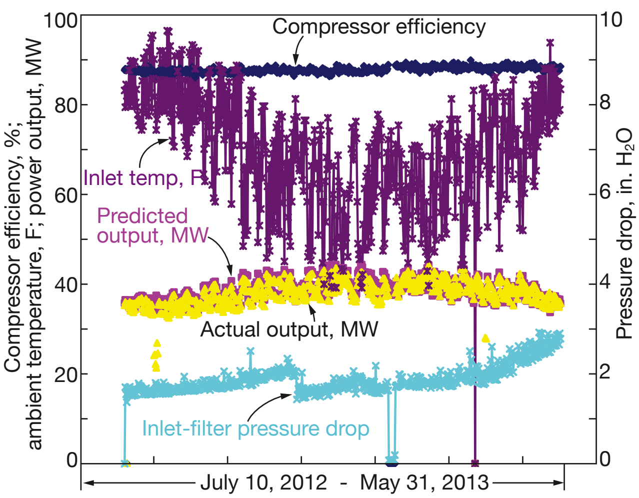
Absent a scientific hands-up poll, it's reasonable to assume many attendees believed they knew pretty much all there was to know about air filters, a frequent discussion topic at this and other user meetings—that is, until Tom Kelmartin, PE, W L Gore & Associates Inc, began speaking.

For those new to the industry, Gore has championed the virtues of HEPA gas-turbine inlet filters for the last five years or so. HEPAs are expensive compared to conventional filters and there had been limited field experience and data to cost-justify their use until Kelmartin reviewed the product's performance on Frame 6 turbines. No smoke and mirrors here, three users with two or more years of experience on Gore HEPAs were in the room and confirmed what the speaker had to say.

Kelmartin began by reminding the users that GTs ingest enormous amounts of air for combustion. A base-load Model 6B, he said, may compress more than 100 billion ft^3/yr of ambient air containing dirt, salt, moisture sand, soot, insects, corrosive gases, etc, depending on location. These contaminants can foul the compressor, block cooling passages, and cause



5. Distribution of submicron particles in urban air reveals there are 100 times as many 0.1-micron particles than 0.5. The standards most familiar to users, Ashrae 52.2 and EN779, do not address the particles that dominate in numbers—those below 0.3 micron. Note that particles smaller than 40 microns are invisible

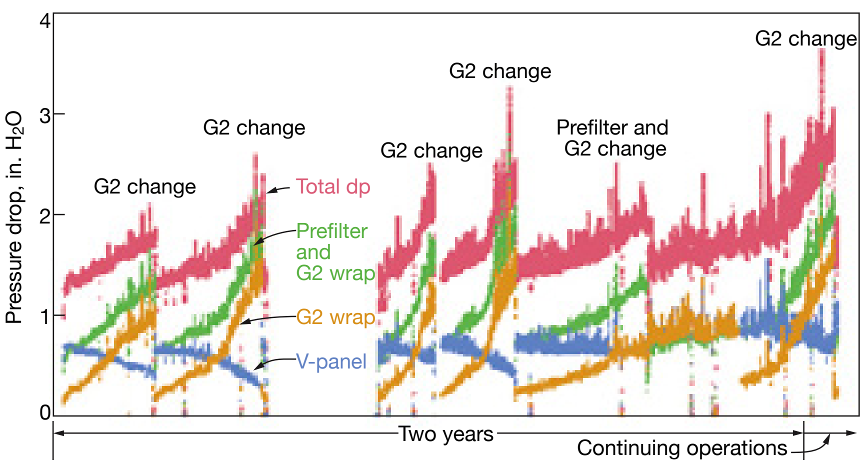


6. Unit performance is graphed between July 10, 2012 and the end of May 2013. Note the relatively constant compressor efficiency and power output (left)

7. Changing G2 and prefilters over the two-year period from May 20, 2011 to May 20, 2013 has maintained V-panel filters at near-new performance (below)

blade erosion and corrosion and possibly foreign object damage.

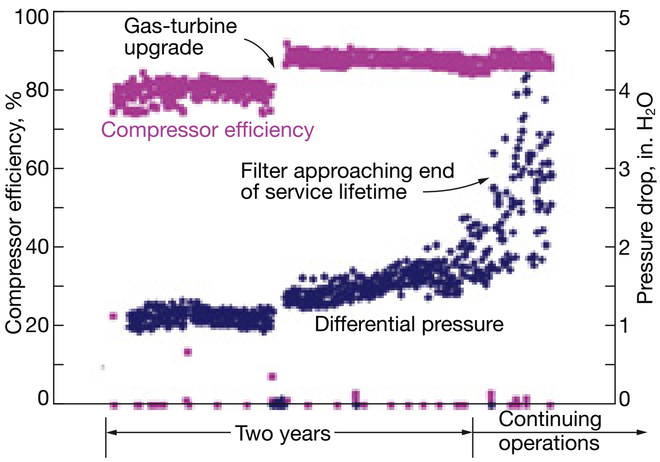
Conventional filters are very good at capturing large particles, he continued, but depending on the media, often inefficient at removing sub-micron particles, liquids, and dissolved contaminants. By contrast, HEPA filters are designed to capture submicron particles—of which there are many (Fig 5). The speaker acknowledged that the knock on HEPA had been relatively high pressure drop and limited life, but advancements have virtually eliminated these as concerns as data gathered from Frame 6 users would confirm.



To put the particle capture capability of HEPA filters in perspective, Kelmartin said that Merv 15 filters often specified for GT service would allow about 25 lb/yr of pollutants into a 25-MW unit, a Merv 16 would allow 12.3 lb, and an E12 Gore filter less than 0.1 lb. HEPA filter ratings, which were "H" and are now "E," are based on the minimum capture rate of the most penetrating particle size (MPPS)—typically about 0.1 micron. The minimum required particle removal efficiency to qualify for an E12 rating is 99.5%, Gore says its E12 does 99.85%.

Case history 1. The objective of this chemical plant, located in a heavy industrial and agricultural area near a major river, was to determine the effectiveness and service lifetime of an E12 HEPA inlet system. Its 120 V-panel filters, equipped with Merv 12 prefilters and a disposable G2 coarse pad, were installed in May 2011 along with instrumentation for online collection of air-flow and differential-pressure data.

As Figs 6 and 7 show, the HEPA system has succeeded in keeping the compressor efficiency and power output relatively constant. Also evident from the information collected is that optimal change-out of prefilters protects the V-panels, extending their lifetimes. Other benefits: Regularly scheduled offline washes are no longer required and online washing has been eliminated; filters are replaced less frequently.



8. High delta-p spikes during fog events (right side of chart) indicate remaining filter life is limited

Case history 2. The objective of this refinery, located in a heavy industrial and urban area near an ocean, also was to determine the effectiveness and service lifetime of an E12 HEPA filtration system. Each of its 448 cylindrical cartridge filters was outfitted with a coalescing wrap. Data captured over more than two years of operation are shown in Fig 8. Compressor efficiency was relatively flat over time, as was power output (not shown here). The need for offline washes was reduced significantly and the goal of a two-year lifetime for the filters was achieved.

Of particular interest, the impact of moisture/fog on filter differential pressure was relatively minor during the first two years of operation. Frequent delta-p spikes during later fog events (right side chart) indicated that filter life was ending. However, the accelerated failure path unlikely was caused by moisture alone. A plant representative at the meeting said that there was a construction project only a few yards from the refinery that significantly increased the ambient dust loading. When you get construction dust in the filters and mix it with fog, he said, you get filter plugging.

Based on all of the test data gathered to date, Kelmartin said his company believes that the final HEPA filter could last 3.5 years or longer. It does not degrade over time like cellulose, he added; the support structure could degrade first.

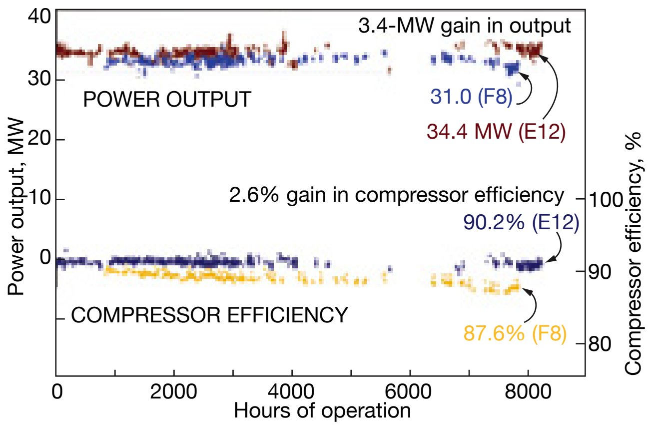
Case history 3. Another coastal petrochemicals plant compared gas-turbine performance when using Gore E12 HEPA cylindrical filters wrapped with coalescers to that when running F8 filters. Each test was conducted for one year. Results, summarized in Fig 9, were dramatic: There was a 3.4-MW gain in output and a 2.6% improvement in compressor efficiency when operating with HEPA filters.

Proof positive, the question is: Would switching to HEPA filters benefit your plant as it did the three facilities described above? Kelmartin recommended this five-step analysis to get the necessary answers for management:

- Would a relatively flat power-output curve eliminate the need to purchase power at certain times of the year? If so, how much could the plant expect to save?
- How much would be saved by elimi-

nating offline washes? This calculation should include availability improvement and the loss of generation when the unit is offline if washing cannot be done during a planned outage.

- What is the value of the improved heat rate in terms of fuel savings?
- How much would the plant save by not having to clean the compressor during major maintenance?
- What credit can you take for virtually eliminating corrosion and erosion of compressor parts?



9. Comparing one-year plots of power output and compressor efficiency using E12 and F8 filters illustrates the value proposition of HEPA filters

Lubricant analysis, maintenance

If you have been on the deck plates of a combined-cycle plant for five years or so, you've probably heard at least three or four presentations on lube oil. One might have been by a consultant who believes your oil's additive package is depleted, one from a lube oil supplier who explains the details on his company's latest oil designed specifically for your gas turbine's demanding high-temperature stop/start service, one from the supplier of a mineral-oil alternative lubricant who suggests eliminating varnish problems forever with a different fluid, one from a provider of lab services to keep you informed about potential problems, one from the provider of filtration equipment that will remove varnish and stop the sticking of your servo valves, etc.

Snippets of information, most factually correct and logically presented, but only part of the picture. How would you approach a specific lube-oil issue that threatens plant availability and reliability? No chemistry pros at the overwhelming majority of sites—mostly mechanics and E/I&C techs to whom chemistry is as understandable as a foreign language. Many fleet owners have one chemist at headquarters, but that person's time often is consumed by water treatment challenges—makeup, cycle water, cooling water, waste water, etc.

What basis would you use to select from among the alternative solutions presented by services providers? Plant decision-makers left on their own might roll the dice on the low-cost solution because of budgetary constraints. Perhaps they'll be lucky and the choice will be the correct one; however, there's a better than even chance it will not be the solution and might even make matters worse.

What to do? Begin by learning the basics, and the language, of lube-oil maintenance so you have a knowledge platform from which to ask better questions of all those who claim to know exactly what your problem is and how to solve it. This certainly is a good start and probably was on the minds of the Frame 6 Users Group's steering committee when they invited Richard Trent of Hy-Pro Filtration and Peter Dufresne of EPT to speak.

The comprehensive presentation—a more accurate descriptor might be "workshop"—was divided into two main parts: (1) condition monitoring of gas and steam turbine oil, and (2) varnish—its physical and chemical characteristics, monitoring, and treatment/elimination. The first part provided attendees a valuable checklist of standards and tests to become familiar with. Trent and Dufresne began by identifying two important standards to consult before establishing or updating an oil analysis program:

- ASTM 4378-03, "In-service monitoring of mineral turbine oils for steam and gas turbines."
- ASTM D6224-02, "In-service monitoring of lubricating oil for auxiliary powerplant equipment."

How often to conduct analyses was the next subject addressed. The two experts said testing frequency depends on the following:

- Unit criticality: Critical systems should be tested more often than non-critical systems.
- Unit age: New units should be tested more frequently than those older than six months.
- Fluid age: Fluids should tested more frequently as they approach end of life (when RPVOT is less than 50% of the value of new oil).

Three important definitions regarding frequency:

- Regular turbine-oil analyses are conducted every one to three months.
- Periodic analyses are conducted every three to 12 months.
- As-required analyses are conducted when issues are under investigation.

Regular analyses:

Appearance, should be checked visually by a plant employee at least weekly. You want "clean and bright" oil, the speakers said. Haziness indicates more than 100 ppm of water. Turbine oils often darken slowly over the years. Rapid changes in color should be investigated for contaminated or accelerated degradation.

Viscosity at 100F (ASTM D445) is very sensitive to contamination or severe oil degradation. An increase in viscosity suggests incorrect oil or the formation of an oil/water emulsion; a decrease, incorrect oil or contamination with a solvent.

Total acid number (TAN, ASTM D664) is a measure of oxidative degradation. An increase may indicate a depletion of anti-oxidants. The speakers suggested comparing TAN results with those of RULER or RPVOT (see below) to evaluate anti-oxidant levels. Trent and Dufresne noted that hot spots/elevated operating temperatures accelerate degradation and that elevated acid levels cause corrosion.

ISO particle count (ISO 11500 and 4406) quantifies particles produced by wear or contamination. When the analysis results are worse (higher) than 18/16/13 (between 1300 and 2500 particles per milliliter larger than 4 microns/between 320 and 640 larger than 6 microns/between 40 and 80 larger than 14 microns) your attention is required. Remember that the more particles in your oil, the faster equipment components wear. An increase of two ISO numbers from one analysis to the next is cause for concern.

Varnish potential (ASTM D7843). Fluid degradation leads to the formation of compounds that are precursors to insoluble varnishes. A fluid's potential to form varnishes is measured on a scale of 0 to 100. Numbers in the 16 to 30 range indicate possible varnishing; 31-40, probable varnishing; more than 41, varnish formation assured with unit trips likely.

Moisture (ASTM D6304/D7546) reduces the lubricating ability of the turbine fluid. It also accelerates fluid degradation and is conducive to equipment corrosion. A quick check of fluid appearance is a useful screening test. Action is suggested if the moisture level of GT lubricant reaches 100 ppm; 200 ppm for steam turbines.

Metals (ASTM D5185) may indicate equipment wear or fluid contamination. Identify the specific metals present to determine the source.

Periodic analyses:

RULER (Remaining Useful Life Evaluation Routine, ASTM D6971) determines levels of antioxidants (generally phenols and amines) remaining in the oil. Remedial action is suggested if the amine content drops to 50% of the new-oil amount. Oxidation is the primary cause of turbine-oil degradation and antioxidants mitigate that process. When antioxidants are depleted, rapid degradation can occur.

RPVOT (Rotating Pressure Vessel Oxidation Test, ASTM D2272) determines the lubricant's resistance to oxidation and sludge formation using accelerated test conditions. Test more frequently than every six to 12 months if the RPVOT value falls below 50% of new oil, replace at 25%.

Rust test (ASTM D665) should be conducted annually for a steam turbine, as required for a GT. Turbine oils contain rust inhibitors to protect metal surfaces and any indication of rust is a warning of potential problems. It may mean severe water ingress has depleted the rust inhibitors.

As-needed analyses:

FTIR (Fourier Transform Infrared, ASTM E2412) is used to monitor oxidative degradation of oils. Results are complimentary to those obtained from TAN, MPC (Membrane Patch Colorimetry), and RULER tests.

Foam test (ASTM D892) should be used when foaming is excessive, which can lead to rapid fluid degradation by micro-dieseling.

Air release (ASTM D3427) test determines if oil has sufficient residence time in the reservoir to release entrained air, which otherwise might contribute to poor lubrication, wear from cavitation, degradation caused by micro-dieseling, etc.

Demulsibility/water separability (ASTM D1401) test is used to assure that the fluid will not support the formation of a stable emulsion.

Insolubles by ultra-centrifuge (ASTM D2273) removes finely suspended insolubles for analysis. Results are complimentary to those obtained from ISO particle count and MPC.

Flash point (ASTM D92) test can identify oil contamination by low-boiling-point solvents which can decrease oil viscosity and impede the lubricating ability of the fluid.

Varnishing

Varnishing of lubrication systems is analogous to scaling of water systems: There are many reasons for it, many operating problems caused by it, and many strategies for mitigating its effects. Critical to preventing/controlling varnish is knowledge of how it is formed, and that's where Trent and Dufresne began their presentation.

Oxidation, they said, was the primary cause of lubricant breakdown by water, entrained air, and heat. It causes soluble byproducts to form and if they are not removed, the saturation point for these byproducts in oil ultimately is reached and insoluble suspensions are created. Insolubles agglomerate into larger soft particles. They attach to metal surfaces—in particular, surfaces cooler than the lubricant in areas of low flow—and cure to form a lacquer-type coating which reduces tolerances in critical components, such as servo valves.

Monitoring the potential for varnish formation is very important. Patch tests—such as MPC introduced earlier and QSA (Quantitative Spectro Analysis)—are helpful in this regard, as is RULER (see above). Systems offered by the presenters for removal of soluble varnish, as well as non-spark-discharge filter elements, were part of the presentation.

For more detail, access Trent's presentation from last spring's CTOTF™'s CT-Tech workshop on the subject, "Contamination control solutions for GE 7E and legacy turbines." CTOTF's Presentation Library is open to all GT owners and operators at no cost. If you don't already have a "library card," register now at www.ctoff.org.

Additionally, visit www.cleanoil.com and view the video on varnish formation using the home-page link and access https://www.hyprofiltration.com to order at no cost the company's "Hydraulic and Lube Oil Contamination Reference Chart." It's a helpful reminder on the information presented here.

Another resource is CCJ's coverage of lube-oil issues and varnish mitigation ideas; use the search feature at www.ccj-online.com. To begin, here are a few articles to consider reading:

- "Options for preventing, eliminating varnish in hydraulic, lube-oil systems," 3Q/2007, p 46.
- "PAG gets good reviews from two top generating companies," 3Q/2009, p 18.
- "CRV Plate helps protect servo-valve components against varnish," 1Q/2010, p 96.
- "Vanquish varnish to improve gas-turbine reliability," 2011 Outage Handbook, p 90.
- "User group gets an assist on fan gearbox lube-oil solution," 4Q/2009, p 42.

Shroud-block mod boosts output

Doug Nagy, manager of component repairs for Liburdi Turbine Services, told the users that at least some of them could boost the output of their 6B engines by minimizing the leakage of hot gas between rotating and stationary turbine components.

With most gas turbines represented by attendees relatively old, Nagy said there's an opportunity to squeeze 0.25 MW, possibly more, from the typical machine. The calculation is based on 0.040 inches of excessive clearance in a 50-MW gas turbine. This translates to a loss of as much as $240,000 per service interval with power at 4 cents/kWh. However, the metallurgical engineer reminded the users that while excessive tip clearances are responsible for losses in efficiency and power output, insufficient tip clearance is conducive to tip rub/damage.

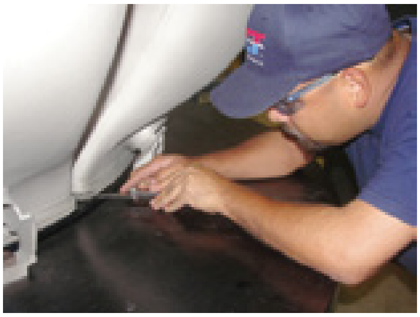
Mind the gap. Nagy suggested several alternatives for reducing tip losses, including the following:

- Optimizing R1 blade tip clearance by doing the final tip-height grind with blades in the rotor to achieve consistency.
- Apply an engineered blade tip offering superior oxidation resistance during R1 bucket manufacture or repair to protect against burning at the top of the airfoil. The tip might also contain embedded abrasive particles to "grind" into abradable shroud blocks to create an optimum clearance.
- Reblade the turbine first stage, when appropriate, with airfoils made of single-crystal or directionally solidified alloy for high-temperature strength.
- For minimizing leakage by the second and third turbine stages, the speaker presented the details on the company's seal mod for outer shroud blocks and the advanced cutter teeth it welds to buckets.

Details on the Liburdi solution were published in 4Q/2012 as part of the 7EA Users Group report. Turn to p 74 in that issue and read, "Metallurgy that translates to a stronger bottom line."

Shop tour

The 2013 Frame 6 Users Group meeting went into OT with a well-executed and informative tour of ACT Independent Turbo Services' shops after the official end of the conference with lunch on June 20. Owner/operators spent nearly three hours with VP Engineering Glenn Turner, VP Operations Matt Lau, and other ACT team members learning/reviewing how to repair combustion components, nozzles and vanes, blades and buckets, etc.



10. ACT's Hugo Parra measures distance between the transition piece and the nozzle face

11. Transition piece is held in place by the bullhorn and aft bracket

12. Diameter of the TP is measured in several places to assure roundness

13. Moment-weigh area is high-tech

The last time this group toured ACT, located in the shadows of Houston's William P Hobby Airport, was in August 2005. Back then, virtually all of ACT's business was conducted out of one building with several repair booths, fixtures, and vacuum furnace. Today there are multiple buildings, each buzzing with activity.

ACT was purchased by Platt River Equity a few years ago. Large investments in facilities and personnel were made in 2010 through 2012 to expand ACT's capabilities—including the addition of a rotor shop equipped to repair both gas and steam turbines. The rotor shop, which opened in 2012, was not on the tour because of new construction—it already was being expanded. Everyone was invited to spend another night in hot, humid Houston to see that facility the next day, but there were no takers.

The afternoon began with a 40-plus slide presentation by Turner describing capabilities, tooling, fixtures, etc, that the visitors would see on the shop floor. Most of the material covered is available on the company's website.

First stop on the tour was a full nozzle replication jig to verify proper fit-up of transition pieces (TPs). You've probably seen one several times and might give it a "ho-hum." But this tour was different. Rather than just have someone standing by to answer specific questions as most shops conducting tours do, Combustion Area Foreman Hugo Parra was on hand to show the group how to make critical measurements and what to look for (Fig 10).

A user volunteer then was requested, to take the same measurements and compare his results to Parra's. With repair maven John F D Peterson, one of the founders of the Frame 6 Users Group, on the tour, everyone knew who that volunteer would be. Peterson has an unquenchable thirst for knowledge and is a person who can't seem to spend enough time on the shop floor. Equipped with Parra's feeler gage (a wedge gage is a more typical), Peterson measured the critical distance between the TP picture frame and the nozzle face. There was no doubt that his measurements would be very close to the ones that Parra took.

Later, Peterson told the editors that the TP, held in place by the bullhorn and aft bracket, grows towards the first-stage nozzle (Fig 11). The nozzle ring grows in the opposite direction, he said. Goal is to assure a gap that would accommodate the thermal expansion in both directions yet minimize leakage of combustion gases between the picture frame and the turbine inlet flange.

The visitors were told that the TPs in the jig were sent to ACT by a turbine owner that had purchased them from a third-party supplier and wanted their fit-up dimensionally verified before they were sent to the plant. Good thing: "H" blocks in the bullhorn brackets (refer back to Fig 11) were out of alignment on one of the TPs and required correction. Such alignment is critical: Any distortion of the bracket or TP can shorten a part's life.

Roundness of the TP at the combustor end also is critical and multiple dimensional checks were made for each to verify acceptability (Fig 12). Another measurement checked was the spacing between adjacent TPs.

Next stop on the tour was the moment-weigh area and a briefing on the relatively new Shenck system, said to be the most advanced on the market

14. Inert-gas welding chambers are used for critical welds (left)

15. Digital vernier caliper takes precise measurements to calculate nozzle flow area (below)

16. Ipsen vacuum furnace maintains tight control of temperature and vacuum to assure proper heat treatment today (Fig 13). Top accuracy, repeatability, and optimization sequencing are among its attributes, according to ACT personnel.

Steve Baasen, blade area supervisor, demonstrated how to position a bucket on the scale and Curtis Jennings of Suncor Energy repeated the process.

Baasen told the group that the scale is so sensitive—units are gram-inches—that the body heat associated with having several observers in the room would affect results. Adjacent to the moment weigh area is ACT's high-capacity flow-test system for turbine components. Its sonic nozzle design and precision instrumentation allow for accurate and repeatable flow measurements on critical flow components—such as F-class buckets, all of which are checked before shipment.

The group migrated to a demonstration at the inert-gas welding chambers shown in Fig 14. They are equipped with micro-plasma welding machines for use where weld quality is critical and the heat-affected zone (HAZ) must be minimized—as, for example, on high-stress parts. The users were not invited to show off their welding skills in this area.

A user question, "Why manual welding?" was answered this way: It's difficult to use an automatic welding process on repaired parts because service life creates minute distortions that require set-up and qualifications of the welding process for each component. New parts are very consistent and it's not necessary to reset the welding process after each piece.

On the way to the mockup of a Frame 6 nozzle ring, the visitors were introduced to sophisticated machines recently added—including a seven-axis CNC rapid-hole EDM machine for use in restoring the cooling schemes of F-class and other new-technology parts. Also, a CDC sinker EDM for precision machining of F-class parts prior to welding.

At the R1 nozzle ring, more measurements were in order—this time to ensure the correct flow area between adjacent repaired nozzles tack-welded into position. Lau noted that flow area must provide for addition of thermal barrier coating after welding is complete. Even a slight reduction in the OEM's design flow area would increase compressor discharge pressure and adversely impact machine performance.

After the demonstration on how to measure/calculate flow area (Fig 15), Peterson took the digital vernier caliper to see how well his skills stacked up against those of the shop craftsmen. Once again Peterson's measurements were close to the official numbers. Note that calculating flow area involves measuring the distance between adjacent vanes in three places: the top of the vane, at the bottom, and in the middle, where two independent measurements are made. The numbers are added and divided by four; the result is multiplied by the distance between the inner and outer side wall of the vane.

Heat treat. The loading of ACT's new Ipsen vacuum furnace (6000-lb capacity, 2400F rating, 10^{-4} to 10^{-5} torr vacuum range, and temperature uniformity across the furnace of better than plus/minus 10 deg F) with F-class first stage buckets came next (Fig 16). Shawn Zafar, process engineer, supervised the activity. The Ipsen replaced a smaller furnace seen during the 2005 tour.

Final stop was the NDE area where the users observed fluorescent particle examination of original R2 501FD2 turbine blades. Long cracks were in evidence across two airfoils, proving once again this was not an "arranged" showcase tour. CCJ

Tight control of cycle chemistry, rigorous operating procedures

Don't delay. Make plans now to attend the fifth annual Australasian HRSG Users Group (AHUG) meeting, December 3 to 5, in Brisbane, Australia. This conference and its associated workshops are acknowledged by some industry observers as the leading public forum, in terms of content, for owner/operators of heat-recovery steam generators worldwide. The 2012 meeting, also held in Brisbane, had 80 attendees—about half first-timers—from seven countries.

O&M personnel representing utilities as well as independent generating companies, consulting firms, and equipment/services providers participated last year, with many staying for the two half-day workshops on the third day that focused on technical and management aspects of cycle-chemistry optimization and next generation HRSGs. Bullish members of the steering committee, chaired by Barry Dooley of Structural Integrity Associates Inc, think the upcoming conference could draw more than 100 participants.

A benefit of traveling West in December (summer in that part of the world) is to learn how your colleagues on the other side of the International Date Line deal with many of the same problems you face. In some cases, their solutions are different; in others, they come up with the same answers, thereby reinforcing your decisions. The lineup of speakers is world class and the subject matter "spot on" in terms of what users need for keeping their plants at top performance.

The information exchange at AHUG is vibrant and generally more meaningful than at the HRSG meeting held annually in the US. A smaller audience and high percentage of subject-matter experts enables participation by all as well as in-depth answers to questions. Knowledge is transferred in these four ways during the conference:

- Questions submitted by users prior to or during the meeting. In a few cases, the questions come from colleagues who can't attend the formal meeting and they receive their replies from a member of the steering committee after the event. AHUG is very proactive in the sharing of information among owner/operators of generating plants powered by gas turbines.
- Formal presentations by consultants, equipment/services providers, and users; nearly two dozen of these in 2012.
- Short case histories by owner/operators; eight of these in 2012.
- Workshops addressing timely topics in detail.

Open discussion

Pressure parts

The punctual Dooley welcomed attendees promptly at 8 am, introduced the steering committee, thanked the sponsors, offered a few tips on how to extract maximum value from content-rich program, and passed the microphone to Bob Anderson of Competitive Power Resources (US), who led the first open discussion session.

A few minutes were devoted to NFPA standards before hardware took center stage. The group was told by an attendee that the NFPA code essentially is followed in Australia; in some instances these rules may be modified by local gas codes (each state has its own regulator).

The subject of purge credit was introduced. Recall that NFPA required a pre-start purge prior to 2011, but changed that to allow a purge on shutdown provided a triple block/double bleed arrangement was provided on gas lines to the gas turbine and duct burners (if installed). If this is "news" to you, come up to speed by using the search function at www.ccj-online.com; simply enter "purge credit."

The discussion leader asked the group what would be required to implement the shutdown purge in Australia? A power producer replied that it likely would be possible if gas valving were upgraded in accordance with the latest NFPA standards and the procedure received local approval. Anderson explained that elimination of condensate formed during a prestart purge lessens the severity of thermal transients, thereby reducing the wear and tear on pressure parts.

Ligament cracking. A user in the UK who was unable to make the meeting seemed surprised at finding very little evidence of ligament cracking at tube stubs, despite rigorous borescope inspections. He asked via email if any OEMs or owner/operators had experience to the contrary. A consultant, expert in the inspection of boiler pressure parts, said his firm had only found one small indication in a P91 superheater header in all of its work and classified that as an "isolated finding."

A representative of a global firm with deep experience in advanced inspection techniques and pressure-part engineering assessments said he associates ligament cracking with the thicker headers and thermal imbalances characteristic of conventional boilers. He viewed the condition as less likely in the thinner-wall P91 headers typically used in HRSGs.

A very experienced boiler inspector reported no ligament cracks to date. However, he said, his company regularly finds cracks in drums, downcomer nozzles, and riser nozzles—typically in HRSGs that cycle. A user added that cycling was thought the cause of a crack in the HP drum of his plant's F-class HRSG. That crack, located near where the downcomer is attached, was ground out. Another user reported a similar experience with a downcomer-nozzle crack that could not be dressed out. Finding the crack was easy, he said, but it was difficult to determine crack depth, which is very important information.

A materials expert reported that his company's inspectors find many cracks in the oxide layer on pressure parts—most attributed to corrosion fatigue (CF) and most in boilers serving conventional steam plants. He said it was important to quickly deal with these findings by dressing out cracks and stress risers and adjusting chemistry. If a crack is left too long, the consultant continued, then CF becomes a far more difficult problem to address.

Another consultant long on operating experience noted that the root cause of cracking often is rapid pressure ramps (up and down). Owners sometimes don't have allowable ramp rates to guide operators. This is a serious oversight, he said. In other instances, the ramp rates in place exceed OEM recommendations. Final-

proper layups, probing inspections, critical to high availability

ly, the consultant stressed frequent inspections.

How frequent? a user asked. As a general rule, an HRSG expert said, one good visual inspection annually should be conducted of gas paths and steam drums, plus downcomer and riser nozzles. Follow up with mag particle or other appropriate nondestructive examination (NDE) method of any cracks found. Results should be analyzed by an expert and steps taken in timely fashion to dress out stress concentrators to maximize fatigue life and prevent other issues.

A local consultant reminded the group that AS3788, "Pressure Equipment Inservice Inspection," is the inspection code of record in Australia and New Zealand. If you want to extend your inspection interval beyond one year you need strong justification. An owner/operator said it is possible to extend the interval to four years if you have long-term history (a decade is a rule of thumb) of no problems. A user said his plant was pulling together such evidence to meet management demands of increasing inspection intervals to the maximum as fast as possible.

Another owner reported having extended a plant's inspection interval to four years (for one of its coal-fired units), but described the approval process as long and demanding. It took nearly 18 months to assess the results from previous outages, he said. Company's philosophy is to focus its inspection efforts on high-risk areas.

How to do this was offered by another user. Develop an inspection manual for all of the HRSG's pressurized components—including external pipework—he said. This involves identifying the failure mode of each component, determining its probability of failure, etc. Inspection frequency is based on this analysis. It's a big job to launch such a project, the user stressed. And it must be kept up to date by the continual addition of meaningful data—such as load ramp rates—and reassessment of inspection needs over time.

AHUG V

December 3 – 5, 2013
Brisbane Convention & Exhibition Centre

Register today: www.ahug.co.nz

The annual meeting of the Australasian HRSG Users Group (AHUG) provides a forum for sharing knowledge and experiences among owners, operators, manufacturers, service providers, consultants, and others with an interest in heat-recovery steam generators and associated plant processes and equipment.

The group's steering committee, chaired by Barry Dooley of Structural Integrity Associates Inc, has the following members:

John Blake, *Stanwell Corp.*
Andy Sibley, *Contact Energy.*
Lester Stanley, HRST Inc.
David Addison, *Thermal Chemistry Ltd.*
Bob Anderson, *Competitive Power Resources.*
Des McInnes, *consultant.*

Conference program

The 2013 meeting focuses on the water-treatment, mechanical, and nondestructive examination (NDE) aspects of HRSG design, construction, commissioning, operation, and maintenance. It begins with two days of presentations and discussion on the following subjects, among others:

- Heat-transfer components and pressure parts.
- Tube failure mechanisms, including FAC and thermal fatigue.
- Water treatment/cycle chemistry, including treatment options with internal deposits, chemical cleaning, and shutdown/layup/storage.
- Piping systems.
- Hands-on and remote inspection.
- Welding.
- Valves.
- Balance of plant.

Presentations on this year's program, which may make this the top HRSG meeting ever in terms of content value, include:

- Prioritized inspection experience at a 118-MW refinery cogeneration plant that burns both process and natural gases.
- Analysis of superheater and reheater drain performance at a nominal 400-MW combined-cycle plant.
- Impact of HRSG tube cleaning on plant efficiency and emissions.
- HRSG standby and layup considerations to minimize back-end corrosion.
- Overcoming issues with corrosion-product monitoring at a 320-MW 1 × 1 combined cycle installed in late 2008.
- P91 experience at a 435-MW 1 × 1 combined cycle installed in 2009.
- Preservation strategy for critical equipment.
- HRSG borescope inspection strategies and results.
- Remaining-life assessment of HRSGs.
- Wet storage chemistry experience at a major combined cycle.
- HP bypass valve assessment.
- Steam cation conductivity in the HRSG plant.
- Case histories of major repairs to and retrofits on HRSGs.
- Impact of steam-flow timing on reheater thermal transients.
- Remote digital video inspection of HRSGs.
- Inspection findings on P91/304H dissimilar metal welds.
- Update on the latest IAPWS guidance documents for steam-purity and iron monitoring at combined-cycle plants.

Two four-hour workshops are scheduled for the third day, December 5:

- "Managing deposits in HP evaporators," conducted by Barry Dooley of Structural Integrity Inc and Colin Gwynne of Aurecon Group.
- "Inspecting HRSGs," conducted by Scott Wambeke, Structural Integrity Inc.

A small exhibition rounds out the program.

A suggestion was made that inspection tasks for the HRSG be aligned with planned gas-turbine outages. Example given by a GT26 owner was that during a three-day Alstom A inspection, HRSG inspections focus on chemistry and the gas pass. The HP drum usually is too hot for entry so it is inspected from the door. It generally is possible to get in the IP and LP drums for close-up visual inspections. Inspection results are reviewed after each outage and a "living document" is maintained.

The idea of video-based inspections was tabled because of a variety of issues, including camera positioning, image quality, etc. An inspection expert touted the advantages of borescopes for fast review of large areas of the HRSG, especially when searching for locations of FAC attack. However, access can be a problem, he said, and sometimes ports must be added, such as in upper headers, to reach into individual tubes.

Is thermal fatigue (TF) a higher-profile damage mechanism because of increased cycling? Person submitting the question, who was not in attendance, also wanted to know how often tubes are plugged in service and what impact plugging has on HRSG efficiency. One participant recalled a failure where a T91 tube connected to a P22 header. The defect in the HP manifold was thought related to thermal fatigue, but this was not confirmed. The header was replaced with a P91 header.

Another offered that thermal fatigue often is the direct result of something else having gone wrong first. The example given was a vertical gas pass where finned tubes were hung up on tube supports. One of the industry's top consultants said that, in his opinion, attemperator problems cause the most TF failures.

Plugging is a good option in many cases where access is difficult, a member of the steering committee said. Have plugs available, he added, as well as repair procedures for going through headers, etc. Someone asked: Do you leave the tube attached? Answer: best to partially cut the tube to relieve future stresses. Another repair expert jumped into the conversation. General philosophy is to cut the tube free so it is hanging, he said, this to prevent hang-ups.

The second expert added that you have to be sure the tooling is available to achieve your goals. He also reminded that patches on P91 headers are very difficult to install. The first expert contributed a second reminder: Make sure you know where economizer division plates are before you cut a hole in the header.

Chemistry

Prepared presentations followed the open discussion on pressure parts. Q&A stimulated some audience exchange on a few of the first day's papers, but not all. Chemistry was the focus of the open discussion that jump-started the program on the second morning when Dooley rang the bell at 8 am. One participant wanted to get some perspective on sizes, temperatures, and engines for combined cycles in Australia and New Zealand. Here's some of the information shared by the group:

- Engines. Mentioned were Alstom GT 26, GE Frame 9, Alstom 13E2, and Siemens SGT-800.
- Configuration. Combined cycles have from one to three engines and range in capacity from about 200 to 650 MW with most under 450 MW.
- Steam temperature. GT26s have high exhaust temperatures at part load, a consultant said. Steam to the turbine is about 1085F, he added; a user said at his plant steam to the desuperheater was 1160F.

Next question put to the AHUG attendees: What is the group's two-shifting experience (shutdowns of four to six hours) and what return-to-service/standby chemistry issues are you facing, if any? One user said his 175-MW plant was designed for base-load service but had been two-shifting/peak-chasing the last five years. The 2 × 1 station has only one HRSG and it is of the once-through design manufactured by IST. Thus its optimal cycle chemistry is different from that used in drum-type boilers. However, this plant was dealing with chemistry issues and had suffered stress corrosion cracking in the steamer.

One of the world's leading power-plant chemists reminded the group of the two basic rules for two-shifting:

1. Don't allow the redox potential to change.
2. If on an oxidizing cycle, don't change pH—this to minimize the amount of corrosion-product transport. It's all about the interfacial science, he said, wanting to keep the oxide in a stable condition.

Another chemist suggested holding vacuum between the operating cycles if possible and to run makeup water through a membrane degasser to minimize its oxygen content. The first chemist added that users should not worry about CO_2 ingress.

AVT(O). An attendee wanting a better understanding of how AVT(O) works asked: Do you just run with no reducing agent and rely on air ingress (which may be very minimal) or should you have oxygen injection?

One of the world's top chemists responded. It does not matter, he said; the original concept for AVT(O) was to make it different compared to AVT(R)—specifically, eliminate the use of a destructive reducing agent. However, experience with AVT(O) has shown that very low oxygen levels—that is, less than 5 ppb at the condensate pump discharge (CEP)—is not optimal.

Ideally, the consultant continued, you want about 10 ppb at the CEP, from air or oxygen. He also suggested that users monitor system health by checking drum oxide color (red is good) and ensuring that all surfaces touched by water are passivated—this to obtain a hematite dominated film.

Another chemist in the room said it was his experience that some plants admit air on the vacuum side of the condensate pump, others inject oxygen manually or via automatic control. He suggested that some valve tweakers may pose risks if manual adjustment of oxygen content is employed; an automatic injection system is better.

There was considerable give-and-take on the subject. One user offered that in switching coal-fired units from AVT(R) to oxygenated treatment in the early 1990s, plant personnel found there was insufficient oxidizing power with AVT(O) and air was added. No issues.

An OEM representative remarked that for units with an LP-drum feedwater tank system, CO_2 ingress will give high cation conductivity (CACE) in LP steam and that this causes confusion as to whether carryover is occurring or not. The chemists responded. One said CO_2 is not an issue; you have to understand what is causing the elevated CACE. Another suggested testing carryover using ion chromatography (IC) to get at the root cause of the problem. But if you do this, he said, be sure you know if you're sampling saturated or superheated steam.

A user then commented that OEMs give chemistry specifications for steam, but IC analysis conducted to determine the reason for high readings of cation conductivity at his plant showed no issues with sulfate or chloride so they continued to operate.

Another user in the audience held up the caution flag regarding operation outside of OEM limits. A recent steam-turbine failure, he said, illustrated the importance of documenting such operational decisions. You need to put in an official record the justification for not running within OEM limits in case a legal issue develops in the future.

Mention was made of ongoing work by the International Association for the Properties of Water and Steam (IAPWS) that would soon provide users validated

guidance on issues discussed during the foregoing exchange. Stay tuned to www.iapws.org for developments.

Chemical cleaning is a subject about which relatively little has been written regarding HRSGs. An attendee asked: What's the best chemical for cleaning the steam/water side of HRSGs—inorganic (such as HCL and HF) or organic (citric or formic acid)? Are boil-out, flushing, and steam/air blowing alternatives?

There was no clarification as to whether the question pertained to a pre-commissioning chemical clean or one required by poor operating practices over the years. Most in the group offering an opinion assumed the former, judging from their comments. An OEM engineer said the choice of cleaning solvent often depends on environmental disposal options and cost, adding that a degrease stage might not be so necessary today. That almost certainly would be the case for a unit that had a service history.

A user said it was necessary to do a full clean rather than just a degrease, which most respondents apparently agreed with. Another OEM engineer said decisions on chemical cleaning normally are made by the EPC contractor. That likely would be the case in the US, but not necessarily the way things are done elsewhere.

A chemist with deep knowledge said solvent selection is site- and project-specific, the former impacting accessibility of chemicals and waste disposal. Experience in Australia and New Zealand, he said, has been with citric acid, HF, and HCl. Of great importance, the chemist added, is a detailed specification that defines the scope (full steam path included?), various steps in the process—such as flushing, iron removal stage, passivation stage, flush, and storage—and the metrics for determining when the unit is considered "clean."

The discussion dug deeper with an OEM engineer mentioning that superheater cleaning often is avoided in the US because of chromium disposal concerns. Regarding the waste stream from the cleaning of evaporator panels made of steel containing small amounts of chromium, he was unaware of any issues. Yet another HRSG supplier was said to have identified no issues associated with the cleaning of T91 superheaters.

A second chemist joined the information exchange noting there may be risks associated with cleaning the superheaters of future plants because of unknowns associated with the effects of solvents and inhibitors on advanced materials.

While the conversation seemed to support the notion that less might be more with regard to chemical cleaning, a naysayer took the floor citing under-deposit corrosion failures in the preheater sections of one unit that was not cleaned after construction 10 years earlier. One of the two most vocal chemists said it's not unusual to find heavy deposits in preheaters and he didn't see that as a general problem—unless the deposits were "super heavy," as no boiling should occur in the preheater. This is unlike the condition in an evaporator, where concentration mechanisms allow for under-deposit corrosion with heavy tube deposits and poor water chemistry.

The subject of air blows versus steam was next. A user said he preferred steam because of the poor performance experienced with air blows. An OEM reported good experience with air blows, with no operational issues identified after commissioning. There are many different variations of steam blows, a consultant noted: continuous blow, intermittent blasts, low pressure, high velocity, etc. However, no advice was offered on what was most effective and under what conditions.

When planning for boiler cleaning, the group was told, be sure to have plenty of makeup water available in temporary tankage onsite. Supply often is the limiting factor for steam blows.

To sample tubes, or not? Practical questions and insightful discussion are a hallmark of AHUG. What are people doing in regards to HP evaporator tubes: sample or borescope inspection? "Very difficult to justify engineering to allow for tube sampling" was the first reply, from a user. Another owner/operator said his company has taken HP evaporator tube samples from all units in its fleet. First time was in 2010 after a base-load plant had operated for 10 years. Samples were taken high up and to the sides; duct burners are in the center of the tube bundle.

A consultant said that discussion of the subject at another user group meeting suggested that the heaviest deposits might not be found high up in the tube. Another user apparently agreed. It sampled two tubes in one unit, the first tube center and top, second tube sample center and side. No issues were identified.

Yet another owner experienced several evaporator-tube failures and its consultant reported "lots of variability in tube condition." It was moving towards use of a borescope to identify areas of concern. A chemist questioned this looming decision. He considered it "risky," saying you typically find during a proper analysis that which you see bears no relationship to the results from a scanning electron microscope—information needed to determine when to clean a boiler.

Acronyms

The global community of powerplant water chemists uses acronyms and terms that may be unfamiliar to some deck-plates personnel. Here are several you should be aware of:

AVT(O), all-volatile treatment (oxidizing).
AVT(R), all-volatile treatment (reducing).
CACE, conductivity after cation exchange; more simply, cation conductivity.
CEP, condensate extraction pump; more simply, condensate pump discharge.
IAPWS, International Association for the Properties of Water and Steam (www.iapws.org).
PTZ, phase transition zone in a steam turbine.
Redox potential—or oxidation reduction potential (ORP)—is a reliable measurement, in millivolts, indicating whether cycle water contains an oxidizing agent (positive voltage) or reducing agent (negative voltage).

Presentations

Total iron corrosion-product testing

Thermal Chemistry Ltd's David Addison, a globally recognized water consultant with years of experience in powerplant operations, told AHUG attendees that accurate measurement of total iron in a combined cycle's steam/water circuit is critical to understanding the degree of effectiveness of the cycle chemistry program formulated to protect against corrosion and deposition.

He reminded that 99.9% of the materials contacting steam and/or water are ferrous-based—including the carbon steel used in HRSG feedwater, economizer, and evaporator circuits; the P/T11, P/T22, P/T91, and other alloys specified for superheaters, reheaters, and main steam piping; and the stainless steels used in condensers, sample lines, etc.

Addison's goal was to convince those not currently monitoring iron levels to do so and those using the incorrect monitoring techniques to change their approach.

Next step was a crash course on the different forms of iron found in an HRSG (bullets immediately below).

The first two combined are referred to as particulate iron and account for 99% of the total iron collected at sample points.

- Metal.
- Surface oxide. This includes FeO (mill scale), Fe_3O_4 (in-situ formed magnetite), transported and deposited magnetite, Fe_2O_3 (in-situ formed hematite), and hydrated iron oxides.
- Soluble iron, Fe^{2+}. Once in solution it precipitates as a solid oxide particle.

The challenges presented by iron monitoring, the chemist said, include the following:

- Once corrosion occurs, the iron forms a solid oxide in the liquid phase—normally magnetite.
- Feedwater must be considered a two-phase fluid: water and iron oxide.
- Saturated steam/early condensate must be considered a three-phase fluid: steam, water, and iron oxide.

Total iron (soluble + particulate iron) should not exceed 2 ppb in condensate and feedwater systems and 5 ppb in the HRSG evaporator circuits, according to limits recommended by the IAPWS. These quantities may seem relatively insignificant, but given the high flow rates in an F-class HRSG, they translate to a large amount of iron transport over time.

Again stressing the need for an accurate and repeatable measurement of iron transport, Addison identified several grab-sampling and analysis methods in use that have best-reported detection limits *above* the IAPWS 2-ppb limit. They are UV-Vis (Ferrozine method), ICP-AES, and Graphite Furnace AA. Please excuse the jargon, but there's no meaningful way to simplify the terminology. The chemist added that a technical guidance document for total iron sampling and testing is under development by the IAPWS and expected soon.

What works? Addison endorsed the Corrosion Products Sampler as the best method today for measuring total iron. The system he showed during the AHUG presentation is offered by Sentry Equipment Corp but there are other models on the market and in-house constructed systems often are seen in the field. Sentry's passes a measured flow of sample through a 0.45-micron particulate filter (a 0.1-micron filter may be preferable). Filters are removed at the end of the collection period and the captured species analyzed. This

1. Standby corrosion is clearly in evidence on this two-year-old HRSG

2. Heavy oxide deposits can block drum-level transmitter ports, causing incorrect readings and possibly unit trips (above)

3. Dehumidification system typical of the type used to maintain the HRSG water/steam side at less than 30% relative humidity (right)

involves acid digestion of the filter and analysis for Fe^{2+}. Total iron on the filter divided by total sample flow gives the average concentration of iron in the system at the sampling point during the collection period.

Note that dissolved products are collected on ion-exchange membrane filters or, in some cases, ion-exchange resin. However, studies have shown that the dissolved species have very low concentrations.

An alternative, considered by Addison as the second-best system available today for measuring total iron, is grab sampling with ultra-pure nitric acid preserved bottles followed by constant volume digestion (all particulates are dissolved) and analysis using inductively coupled plasma mass spectrometry. Best reported detection limit for this method is 1 ppb.

Standby corrosion

You can just hear someone on the plant staff saying to an HRSG inspector regarding unexpected waterside corrosion damage, "But we didn't do anything to cause this condition." Precisely the point: It was important to do *something*.

Thermal Chemistry Ltd's David Addison was back at the front of the room speaking to AHUG 2012 attendees about shutdown and layup practices that would assure a flexible return to service for combined-cycle plants. He asked the first question, "What is HRSG standby corrosion?

And then answered it: Standby corrosion is the unwanted formation of non-protective iron oxides from Rankine Cycle materials—bluntly, rust. It occurs under stagnant, low-pH, and oxygen-saturated water and when high-humidity (more than 30% RH) conditions exist. The condition

4. Material oxidation on the hot gas side of the HRSG can be minimized by use of a dehumidification system

is often ignored. Plants in reserve, two-shifting, and frequent start/stop service are most prone to standby corrosion damage (Fig 1).

Addison said there are several risks associated with standby corrosion, including these:

- Decreases plant material thicknesses over time, creating an opportunity for failure and/or leakage.
- Causes pitting (galvanic corrosion), a condition conducive to leaks and stress corrosion cracking and corrosion fatigue failures.
- Transport of corrosion products to areas of high heat flux—such as HP evaporators—where they increase the risk of under-deposit corrosion.
- Blockage of drum-level transmitter and sample lines with possible loss of unit control and the risk of unit trips (Fig 2).

When you place an HRSG in wet storage, Addison continued, it is critical to protect the in-service generated protective oxides—that is, hematite and magnetite. This requires maintaining the operating pH and redox conditions in storage. Specifically, maintain: (1) pH at about 9.8 by dosing prior to shutdown and during drum-level top-offs, and (2) dissolved oxygen in boiler water at 5 to 10 ppb by capping the drum with nitrogen prior to pressure collapse.

Also important is to circulate boiler water periodically during shutdown (every few days) to avoid a stagnant (no flow) condition conducive to pitting attack. Very few HRSGs are designed with this capability but a retrofit may be beneficial if your shutdowns can extend more than a couple of weeks.

Periodic topping-off of drums likely will be required during wet storage to account for leakage and water shrinkage as the boiler cools. Important to assure that the chemistry of water added matches the boiler's water inventory in terms of pH (by dosing with ammonia or amine) and redox potential (by controlling the level of dissolved oxygen).

If your station has multiple units, top off from an operating unit with matched water chemistry. If not, best practice suggests having a standby vacuum deaerator or membrane degassser to match the oxygen content of makeup to that in HRSG water.

Successful dry storage requires the removal of all moisture to achieve a relative humidity of less than 30%. This means blowing down the HRSG while metal surfaces are hot, to assure residual moisture is evaporated from metal surfaces. The procedure can be challenging in the preheater and LP

sections where metal temperature is relatively low.

Immediately after the blowdown step has been completed, circulate dry air throughout the unit and maintain continuous flow throughout the layup period (Fig 3). Nitrogen is an alternative to dry air, but its use inhibits maintenance access. Addison suggested that the steam turbine be protected during layups in a like manner.

Storage pros, cons. The chemist then reviewed the pros and cons of both wet and dry storage to assist owner/operators in decision-making. The big benefit of wet storage, he said, is that it's easy and effective for short outages and assures the plant's fast return to service. However, it's not free. Here are some of the expenses associated with wet storage:

- Installation of a nitrogen capping system and the cost of the inert gas. Note that if the nitrogen cap is lost, boiler water will quickly become oxygen-saturated.
- Installation of a pump skid to allow periodic circulation of boiler water during extended outages.
- Deaerated water is required for drum top-offs during the storage period.

Low-humidity dry storage is highly effective for protecting against corrosion of both the HRSG (steam/water circuitry and gas side, Fig 4) and steam turbine. A big plus is that dry storage doesn't inhibit offline maintenance and plant access. However, the cost of a dehumidification system is significant and continuous monitoring is necessary to ensure moisture levels throughout the protected areas are not conducive to corrosion. Caution: If dehumidification is done incorrectly, standby corrosion rates can be high.

What not to do when laying up an HRSG wet:

- Don't use a reducing agent/oxygen scavenger for storage solutions, or any other treatment chemicals not normally employed during plant operation.
- Don't partially drain the HRSG and later reapply a nitrogen cap, or refill under air.

Dry storage should not be attempted after the HRSG cools and the water is drained. It simply doesn't work, Addison warned users. Another caution: Don't circulate air with a relative humidity above 30%.

The chemist encouraged owner/operators to have clearly defined guidelines and procedures in place no matter what path—wet or dry—is taken. Risk assessments that involve the chemistry, operations, and engineering departments should be factored into the development of such guidelines and procedures to maximize the probability of success. Operator training is an essential part of the program.

When returning to service from storage, wet or dry, Addison recommends heavy HRSG blowdown to establish stable chemistry conditions as soon as possible. Where wet storage has been employed, remember to (1) isolate the nitrogen system, (2) set drum levels in the startup position, and (3) fire the gas turbine as soon as possible. After a dry layup, be sure to (1) line up auxiliary systems, (2) isolate the dehumidification system, (3) purge the HRSG with nitrogen to displace air, (4) fill the boiler with pH-corrected deoxygenated water to the correct drum levels for startup, and (5) fire the gas turbine as soon as possible. If solid-alkali dosing of drums is a normal procedure, include that in Step 4.

Workshop

Next-generation HRSGs

The shuttering of nuclear and coal-fired generation in the name of the environment has encouraged manufacturers of gas turbines and heat-recovery steam generators to push the designs of their equipment to limits unexpected a decade ago. Today, for example, you can buy a single-shaft combined cycle for 60-Hz service with an output of nearly 500 MW (about double the rating of a late-1990s unit) and an efficiency of more than 60%. The 50-Hz version of the same system is rated 680 MW. The engineering achievement is even more remarkable given renewables-era demands that these behemoths be able to start and ramp up and down quickly.

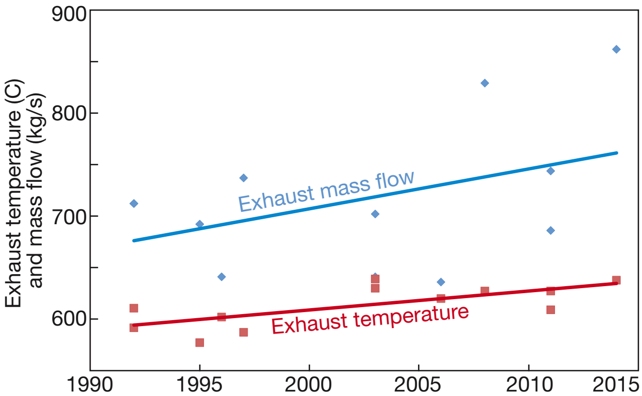
A "high five" is due the AHUG steering committee for hosting a workshop that gave attendees a close-up view of the engineering and decision-making that underpins the development of the next generation of HRSGs. The special session was chaired by Ian Perrin of Structural Integrity Associates Inc and included presentations from representatives of Alstom, NEM, and Nooter/Eriksen.

Overview. Perrin outlined some of the challenges facing designers of advanced HRSGs, and by extension, engineers responsible for high-energy piping and bypass systems, to focus the attention of participants on the workshop's agenda. The challenges, he said, include the following:

- Larger HRSGs to accommodate the higher exhaust-gas mass flows from G-, H-, and J-class gas turbines.
- Higher GT exhaust-gas temperatures and velocities.
- Larger-diameter and thicker-wall pressure parts.
- Increased use of creep-strength-enhanced ferritic steels and advanced stainless steels.

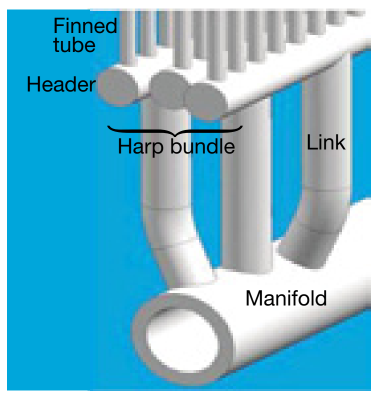
The higher operating pressures, temperatures, and flows characteristic of advanced HRSGs have a significant impact on boiler and piping design. Perrin offered the following comparison as evidence:

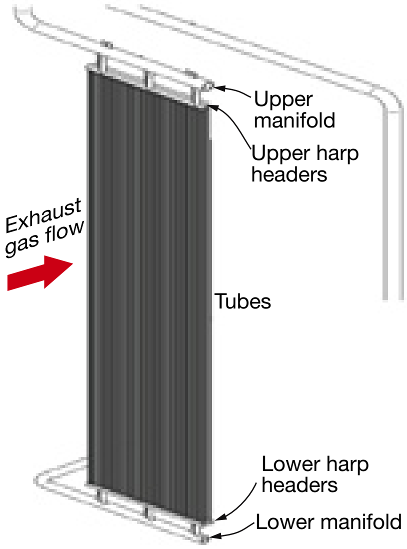
- Case 1: Relatively conventional HRSG by today's standards, designed to produce 800,000 lb/hr of 2200 psig/1050F HP steam; Grade 92 components.
- Case 2: HRSG for a more advanced turbine, designed to produce



5. Exhaust temperature and mass flow continue to increase over time as indicated by these data for large 50-Hz engines. Multiply flow in kg/s by 7920 to obtain units of lb/hr; to get temperature in F, multiply C by 1.8 and add 32 (left)

6. Alstom's harps are characterized by headers with a single row of finned tubes (right)





7. Stresses on mechanical assemblies are thermal fatigue, from cycling, and creep, caused by elevated temperatures and pressures

950,000 lb/hr of 2600 psig/1100F HP steam; Grade 92 components.

For the same flow velocity (pressure drop), pipe diameter increases from 12 to 16 in. in going from Case 1 to Case 2 conditions. In addition, pipe wall thickness doubles from 1 to 2 in. and pipe weight increases by 2.4 times.

Changing the material in Case 2 to Super 304H austenitic stainless steel, which is designed for high-temperature service (creep-strength-enhanced ferritic steels generally are restricted to applications where steam temperatures are below 1175F), pipe diameter can be held to 14 in. and the weight increase to only 1.3 times that for Case 1. Pipe wall thickness remains about the same as Case 1.

Perrin pointed to the increased use of advanced ferritic and stainless steels today to limit the wall thickness of pressure parts. However, he cautioned that material selection requires careful consideration. Example: Super 304H, while attractive because of its high-temperature strength, has a larger coefficient of thermal expansion and a lower thermal diffusivity than some alternatives. Also, the use of stainless steel introduces the need for dissimilar metal welds (DMWs).

With higher exhaust and steam temperatures, he continued, consideration must be given to oxidation resistance of pressure parts and structural supports (such as tube restraints), etc. For temperatures above 1175F, perhaps coatings will enable use of ferritic steels. Austenitic stainless steels have better oxidation resistance, to about 1400F, but they are prone to exfoliation. Shot peening might help there.

The high exhaust-gas mass flows associated with large gas turbines impact superheater and reheater designs as well as the design of the inlet duct. Gas velocity is of concern because of its possible effects on tube vibration and heat absorption.

Codes and standards require scrutiny, Perrin advised. New designs will operate at conditions that may be outside of previous experience. Section I of the *ASME Boiler and Pressure Vessel Code* still does not consider cycling, but the EN Code does. However, it is lacking in other areas. And neither code addresses creep-fatigue interaction.

Alstom was first to present among the boiler OEMs. The speaker divided trends influencing design into two groups: operational and steam/water cycle (Fig 5). The latter essentially duplicated what Perrin had said earlier. Operational trends/challenges included an increased number of on/off cycles, high ramp rates, and low-load operation. A concern expressed was that on cold starts, HP and reheat manifolds are subjected to high-temperature gradients. Tubes heat up quickly before steam flow from the drum is established; manifolds are cooler.

As steam-flow requirements increase, the speaker said, the options are to increase HRSG width or height. If width is increased, more tubes are added to maintain velocity and pressure drop; if tube length is increased, velocity and pressure drop increase as well. Steam-drum length is extended as output increases to maintain the same shell diameter and wall thickness.

Next Generation GT exhaust temperatures are within the current experience range, the speaker said. He added that steam temperatures may increase above current levels to boost cycle efficiency; also that peak steam temperatures may occur at part load or during duct firing.

Alstom attributes some of its HRSG's operational flexibility to the use of multiple desuperheaters—one between the final two stages of superheating and one between the HP outlet and the steam turbine. Also to an integrated plant design that allows owners to manage fast-start GT exhaust conditions to meet steam-turbine ramp-rate limits.

Each OEM's boiler has one or more design features to satisfy market demands. Alstom's HRSG is characterized by what it calls the OCC™ (Optimized for Cycling and Constructability) design. Its finned tubes have no bends and harps have only a single row of tubes as shown in Figs 6 and 7. Shop content is maximized to minimize field labor. An enhanced drum-nozzle configuration contributes to lower stress concentrations where nozzles connect to the drum.

Fast-start capabilities of the OCC design are the following: 30 min for a hot start (maximum shutdown of about eight hours); 100 min for a warm start (maximum shutdown of about 60 hours); 150 min for a cold start (shutdown of more than 120 hours). The speaker said the HP and reheater manifolds are the limiting components in terms of fatigue life, not the steam drum. The OEM's calculations show that fast hot starts will consume the most component life because of the high number of such starts. For example, a cycling HRSG might expect to have 4000 hot starts

8, 9. Tube modules for HRSGs serving late-model gas turbines are much larger and more robust than most people in the industry are familiar with over its lifetime, 1000 warm starts, and 200 cold starts.

NEM's presentation covered much the same material as the other OEMs with two significant exceptions: mention of VM12, a new material for pressure parts in demanding service, and DrumPlus™, the company's solution for fast start/fast ramp at high steam pressures and temperatures.

VM12 (for Vallourec and Mannesmann), a 12%-chromium steel containing cobalt, tungsten, and boron, was developed for advanced HRSGs and other applications. It is said to combine good creep resistance and high steam-side oxidation resistance. V&M says it has successfully demonstrated production of the material in several laboratory and industrial heats, and several sizes of tubes and pipes have been fabricated using different rolling processes. Extensive testing suggests the material is ready for prime time and the NEM speaker seemed positive about VM12's promise for the EN market in the near term. However, there's no commercial experience to date and ASME has not yet blessed the material.

NEM's way for accommodating fast starts and ramps at today's challenging steam pressures and temperatures is DrumPlus, which combines the advantages of drum-type and once-through HRSGs. Design is largely in accordance with a conventional drum-type HRSG but with the advantages of a once-through unit.

In brief, the conventional HP drum, which would be susceptible to fatigue damage in a fast-start application, is replaced by a knock-out vessel and external separator bottles. This smaller drum has a relatively thin wall to accommodate thermal stresses. Because of the reduced volumes of both steel and water, DrumPlus has the dynamic capabilities of a once-through unit; however, it has considerably more water inventory to provide a higher degree of operational flexibility. Also, DrumPlus does not require the condensate polishing system recommended for a once-through boiler.

The Nooter/Eriksen presentation began with a review of the following impacts gas-turbine size has on the design of a conventional triple-pressure HRSG with reheat:

- HP and reheat design temperatures are going higher and higher. An HRSG on the back of a late-model, 60-Hz, F-Class gas turbine might be designed for an HP steam temperature of 1115F, for a G-Class turbine that might go to 1150F, and for a J-Class unit, 1215F. Recall that back in the 1990s, HP steam conditions for an F-Class turbine were in the neighborhood of 1820 psig/1055F; in the mid 2000s, 2425 psig/1085F.
- HP steam piping diameter and wall thickness.
- Structural members.
- Basic module/casing configuration.
- Stack diameter/height.

The speaker showed photos of several plants with today's largest HRSGs and presented thumbnail sketches of the projects. Figs 8 and 9 offer eye-popping perspective.

Next, the following design features conducive to cycling were suggested:

- Tube stubs for HP and reheat panels.
- Reliable drains system.
- Reheater steam bypass.
- Stack damper.
- External stack insulation.
- Economizers with return bends between tube rows, no tube bends at the inlet header, no pass partition plates, and tube-to-tube expansion flexibility.
- Desuperheaters of the nozzle ring design equipped with separate control valves, piping liners, and drain pots downstream. The latest control logic should be employed for operating block and control valves.
- Instrumentation to enable duct-burner heat release across the entire unit.
- Advanced monitoring and control techniques for water chemistry, drum level, and duct burners.
- HP and reheat sections designed to accommodate expansion, such as by use of flexible coil arrangements.
- Spring hanger header support.
- Use of higher strength steel for steam drums—such as SA-302 Gr B—can have a dramatic impact on the life of a drum in cycling service. The speaker provided the following comparison between a standard SA-516 Gr 70 shell material and SA-302 Gr B for a drum designed for 2625 psig/685F with a 64 in. ID. Shell thickness for the 302 material is a nominal 4 in., about an inch thinner than for the 516 steel.

For a 30-yr projected life, the assumption is that the HRSG will make 300 cold starts (from 60F), 1800 warm starts (from 212F), and 6000 hot starts (from 500F). For the 302 material, the 300 cold starts would consume 17% of the drum's fatigue life and the 1800 warm starts, 15%. By contrast, 300 cold starts with 516 steel uses 63% of the drum's fatigue life; the 1800 warm starts, a whopping 115%. The hot starts have virtually no impact on fatigue life with either material. The bottom line: The 302 drum consumes less than one-third of its fatigue life in 30 years while the 516 drum is at end of life in less than 17 years of its expected 30-yr life. CCJ

What price (value) six minutes?

One-tenth of an hour doesn't seem like much, but in the scheme of electricity grid operations, it can save tens, even hundreds of thousands of dollars. Associated Electric Cooperative Inc (AECI), Springfield, Mo, shaved six minutes off the start times of three V84.2 simple-cycle gas turbine/generators at its Holden Power Plant, for a small fraction of the cost of installing new fast-start generation.

This is particularly significant given today's competitive electric-power generation business, the reduction in start time having substantially improved Holden's market position. "Six minutes buys us time to ride out a disturbance, avoid more costly spinning reserves, comply with NERC disturbance and control performance standards, and balance intermittent wind resources," explains Mark Treat, principal engineer. As most of the industry realizes now, intermittent "must take" wind capacity poses challenges to utilities and grid operators.

AECI's territory is experiencing wind penetration twice the national average. "Between the beginning of 2012 and 2013, our system wind capacity doubled, to 600 MW," Treat told the editors. Associated Electric, like many utilities these days, is long on generation capacity, but short on flexibility. The cooperative needed assets that could get to full load in less than 10 minutes.

"In addition to putting up to 300 MW on line that quickly (if we lose a coal unit, for example) we also have six extra minutes to make better decisions about which units to load next, or simply to ride out a disturbance—like a storm passing through, or a sharp decrease in wind output," Treat emphasizes.

In other words, it's about minutes as much as megawatts. The NERC Standard for Disturbance Control requires AECI to provide reserves within 15 minutes of a disturbance event. Holden is often counted as non-spinning contingency reserves. Faster starts allow for better compliance with this standard. Similarly, a recent revision to NERC Control Performance Standards requires correction of negative automatic control error (ACE), or under-generation, during periods of low frequency within 30 minutes. This allows more time before Holden units have to start. "We potentially avoid thousands of dollars in fines," adds Treat.

You can see how fast those minutes can add up by charting the escalating number of starts the Holden units have been through—150 in 2008, 180 in 2009, and 329 start attempts (319 successful) in 2012. The number of starts has more than doubled in five years! To shave six minutes off the normal V84.2 start-to-full-load period of 15 minutes, Siemens, which was responsible for the upgrade work, made no physical changes to plant hardware. It only modified the control system logic and tuning, including the following:

- Air dampers and fuel-gas isolation valve open earlier in startup sequence.
- Proper opening and closing of fuel-gas isolation valve in event of a trip on startup.
- Optimize ignition-gas valve sequencing and operation.
- Provide operator selection for fast- or normal-start sequence.
- Allow operator to select starting load gradient from 10 to 27 MW/min.
- Allow fast start to be selected remotely through a remote terminal unit (RTU) interface.
- Modify inlet-guide-vane (IGV) logic to achieve adequate premix through a faster transfer time.
- Modify pilot gas valve to enhance flame stability.
- Allow fast-start load gradient to kick out once load set point is reached or when outlet temperature control is achieved.
- Adjust startup parameters so that startup curve is more linear between 150 and 3600 rpm.

Control system logic and tuning changes allow V84.2 simple-cycle gas turbines at AECI's Holden Power Plant, which began commercial operation in 2002, to achieve full load in nine minutes, six minutes faster than the original design

In practice, achieving faster starts and doubling the number of starts on the unit also has doubled the tile fallout from the GT's silo combustors. "We see in six months the tile fallout we used to see in a year," observes AECI's David Shirley, senior combustion turbine specialist. Tile fallout is a prevalent maintenance issue with GTs equipped with silo combustors (which Siemens no longer supplies in the US). Holden personnel monitor the situation every six months now instead of annually.

"We knew there would be condition issues like this," concedes Treat, "we're also monitoring the impact on the turbine blades over time." But, as Treat notes, maintaining rolling or spinning reserves isn't cheap either. Fast-start mods to Holden clearly was the better option. "It's all a matter of trade-offs."

Although Holden maintains a 1.5-million-gal fuel-oil reserve at the site, the fast-start capability only applies to gas firing. "The only oil we've burned in the last seven years has been for testing purposes only," says Shirley.

According to AECI, these are the first 60-Hz simple-cycle units of this design to undergo the fast-start modifications. "Siemens built the capability into the equipment, we just decided to take advantage of it," says Treat. Prior to this project, the Holden units were AECI's fastest loading machines. The utility has no aero GTs in its fleet, which are typically more nimble.

The mods were completed near the end of September 2012, with testing complete by the first week in October. Within a few seconds of each other (start times), all three units met the 27-MW/min loading rate and achieved start to full load (103 MW) in around nine minutes. Within 24 hours of project completion, a fast start was called for by dispatch and Holden responded as expected. In late January 2013, all three units successfully went through fast-start sequences to respond to the trip of a coal unit. CCJ

2014 BEST PRACTICES Awards

Combined-cycle, cogeneration, and simple-cycle generating units powered by gas turbines

Deadline for entry: December 31, 2013

The editors of the COMBINED CYCLE Journal have tweaked the categories for the magazine's annual Best Practices Awards program, focusing them on industry issues to maximize the value of the solutions presented in the entries. Some general categories for years past, like design and management, have not attracted much interest of late and Senior Editor Scott Schwieger, who manages the program, and the CTOTF Leadership Committee, which provides the judges, collaborated on the changes.

At virtually all of this year's user group meetings, the concerns of owner/operators with grid requirements for fast-start assets, right-staffing and skills development, performance improvement, among others, took center stage. The entry categories listed below enable users to share ideas on these timely subjects for the benefit of all.

The bullet points that accompany each category are "grey-matter triggers" to stimulate thinking on possible subjects for your entries. They are not meant to be specific subjects for entries, although they might be in a few cases. The administrative rules for the awards program essentially remain the same, the most important being the deadline for entries: December 31, 2013.

ENTRY CATEGORIES

1. FAST STARTS

- Engine/fuel system/controls/emissions uprates/improvements/enhancements to enable fast starting of existing gas turbines in both simple- and combined-cycle service.
- Improvements/enhancements to enable other grid ancillary services—such as black start, synchronous condenser, etc.

2. NEW SKILLS/WORKFORCE DEVELOPMENT

- O&M staffing plan (permanent employees) for the next 10 years in terms of numbers, skills development required, etc, for peaking and combined-cycle facilities.
- Training program for single plant or fleet (rotating staff).
- Multi-skills training—e.g., operator/mechanic.
- Specialized training—e.g. controls, cycle chemistry, etc.
- Capturing intelligence.
- Training for simple-cycle facilities running more.
- Finding time for combined-cycle training at high capacity factors.
- Scenario training—e.g., what-if problem solving, how to respond to off-normal and emergency conditions.
- Retraining programs.
- Qualifying employees for advancement.
- Repurposing coal-plant personnel for peaker and combined-cycle duty.

3. WATER MANAGEMENT

Water-use restrictions and higher prices, plus bans in many areas on plant liquid discharges, have placed additional burdens on owner/operators. What are your best practices for such things as:

- Water-use survey and ongoing monitoring.
- Demand reduction—for example, reducing boiler blowdown, raising cycles of concentration.
- Onsite treatment of drains for reuse.
- Treatment and use of municipal and industrial wastewaters for plant makeup.
- Alternative uses for plant wastewater streams.
- Sampling and pretreatment of ground and surface waters.

4. PERFORMANCE IMPROVEMENTS

- Starting reliability.
- Availability.
- Emissions reduction.
- Thermal performance monitoring program.
- Benchmarking.
- Data retention and analysis.
- On-staff or contract service for monitoring.
- Program for identifying/correcting deficiencies; trigger points for action.
- Staff awareness/training.
- Condition-based maintenance program.

5. PLANT SAFETY PROCEDURES

Goal is to identify successful equipment/methods/procedures for assuring the safety of plant and contractor personnel, and compliance with critical standards developed by such industry organizations and professional societies as:

- NFPA (56, 70E, 85, 850, etc).
- ASME Boiler & Pressure Vessel Code.
- IEEE.

6. OUTAGE MANAGEMENT

- Planning process.
- Outage safety programs.
- Pitfalls to avoid from previous outages.

- Personnel responsibilities—plant staff, fleet specialists, contractors.
- Improving upon past performance—e.g., reducing outage cost, shortening the schedule.
- Planned-outage strategy—e.g., shut down or run 1 × 1 while working on one GT and HRSG.
- Forced-outage strategy.
- Pre-outage inspection program to fine-tune outage scope.
- Review process for OEM alerts.

7. O&M—GENERATORS, TRANSFORMERS, HIGH-VOLTAGE ELECTRICAL GEAR

Best practices for:

- Inspection.
- Maintenance.
- Repair.
- Upgrade.
- Safety.

8. O&M—MECHANICAL: MAJOR EQUIPMENT, BALANCE-OF-PLANT

BOP includes condensers, cooling towers, high-energy piping systems, major valves and pumps, water treatment, fuel handling and treatment, plant auxiliaries, etc.

- Inspection.
- Maintenance.
- Repair.
- Upgrade.

9. PREDICTIVE ANALYTICS/ M&D CENTERS

Shrinking staffs and inexperienced operators demand new solutions to "watch over" plant systems and equipment for impending problems and to maintain desired levels of availability and reliability. Two such solutions are M&D centers and software packages to warn of developing issues. What best practices can you offer in these areas, among others:

- Vulnerability analysis: How do you determine what's most likely to cause a forced outage at your plant?
- How do you decide which software packages best meet plant needs?
- How to evaluate the economic value of software packages.
- Staff capabilities/training necessary to successfully implement a software solution.
- How to evaluate in-house versus contract M&D center
- Capabilities required in an in-house M&D center, staffing, communication, decision-making regarding plant shutdown, etc.
- Alternatives to predictive analytics.

JUDGING/RECOGNITION

All entries will receive industry recognition by way of a profile in a special editorial section on Best Practices published in the Q1/2014 issue of the COMBINED CYCLE Journal. A panel of judges with asset management experience will select for formal recognition at an industry event next spring, the Best Practices they believe offer the greatest benefit to the industry given today's demanding goals of improving performance, reliability/availability, and safety, and reducing costs, while satisfying the requirements of ever more challenging regulations promulgated by EPA, NERC, OSHA, regional grids, etc.

RULES

1. Entries accepted only from employees of powerplant owners and third-party firms with direct responsibility for managing the operation and maintenance of gas-turbine-based electric generating facilities in the Western Hemisphere.
2. Maximum of four entries from the same power plant.
3. Entries must be received by midnight December 31, 2013 via regular mail/courier, fax, email, or online submission (http://www.ccj-online.com/best-practices/enter).

TO ENTER

1. Award category (select one):
   - Fast starts.
   - New skills/workforce development.
   - Water management
   - Performance improvements.
   - Plant safety procedures.
   - Outage management.
   - O&M: Generators, transformers, HV electrical.
   - O&M, mechanical: Major equipment, BOP.
   - Predictive analytics/M&D centers
2. Title of Best Practice.
3. Challenge: Description of business or technical challenge motivating the development of a Best Practice.
4. Solution: Description of the Best Practice.
5. Results: Document the benefits gained by implementing the Best Practice. For example, percent improvement in starting reliability or plant availability, dollar or percent saving in annual operating cost or reduction in annual maintenance cost, improvement in man-hours worked without a lost-time accident, etc. Please limit your response for Section 5 to the equivalent of three pages of single-spaced 12-pt. type. Add photos, drawings, tables, etc.,
6. Na me of plant.
7. Plant owner.
8. Plant personnel (and their titles and company affiliation) to be recognized for developing and implementing the Best Practice.
9. Contact for more information (name, title, company, phone, fax, e-mail).

Refer questions/submit entries to:

Scott Schwieger, senior editor, COMBINED CYCLE Journal, 7628 Belmondo Lane, Las Vegas, NV 89128.

Voice: 702-612-9406. Fax: 702-869-6867. E-mail: scott@ccj-online.com

How to reduce catalyst lifecycle cost, improve reliability

By Terry McTernan, PE, Cormetech Inc

Driven by the current regulatory climate and the growing dependency on natural gas for base-load electric generation, the majority of gas-plant fleets have made broad investments in selective catalytic reduction (SCR) systems. The successful operation of these systems requires monitoring, routine preventive-maintenance inspections, and periodic evaluations of the catalyst.

By taking a fleet-wide management approach, owners and operators can reduce catalyst lifecycle costs and insure reliable operation of their SCR systems. Improper management can result in permit violations and associated fines, operating restrictions, and bad publicity for the site. Under the Clean Air Act Amendments, air-permit regulations concerning NO_x emissions are increasingly stringent, with levels as low as 2 ppm required in some locations.

Gas-fired fleets may include both combined- and simple-cycle units. In the former, the SCR modules are housed within the heat-recovery steam generator (HRSG) at an optimal temperature location, typically 600F-800F.

In a simple-cycle gas turbine, the SCR usually is installed in an expanded outlet duct immediately downstream from the turbine. Duct size is optimized to achieve the SCR catalyst reactor performance required. The short transition section from the turbine outlet to the SCR inlet often challenges system design. Turbine exhaust-gas temperature is often too hot to be efficiently treated by the SCR system. Many units rely on tempering air to cool the exhaust gas—typically to 900F or below.

An economic evaluation should be performed to determine if use of tempering air is warranted, or if a high-temperature catalyst would be a better option. Evaluation parameters include the following: capital versus operating costs, operating-time limits, volume of catalyst, duct size and back pressure, purge-fan versus tempering-air-fan costs, distribution equipment (tempering air and ammonia injection grid (AIG)), etc.

Recall that ammonia, a reducing agent, is injected into the SCR catalyst system and thoroughly mixed throughout the flue-gas stream to convert NO_x to nitrogen and water. To accomplish the uniform delivery of ammonia, a piping network—or AIG—is installed upstream of the catalyst (Fig 1). Ammonia flow is regulated across the grid by a series of control valves. It is critical that the ammonia concentration within the exhaust gas be homogenous as it enters the SCR catalyst bed. This prevents the loss of unreacted ammonia—called "slip"—and eliminates areas starved of ammonia, which is conducive to localized, incomplete NO_x reduction.

1. Proper operation of the ammonia injection grid is critical to meeting permit requirements for NO_x emissions

Based on analyses of SCR operating data and catalyst samples, AIG and duct modifications may be warranted.

Maintenance plan. SCR systems require routine oversight and must be maintained. Historically, many gas plants with SCRs operated cyclically, with extended periods between starts. This type of operating profile can accelerate ageing of catalyst system components, increasing the importance of regular inspections and preventive maintenance.

SCR catalyst systems may run with little attention for three to five years and gradually begin to show signs of performance loss and system wear. Several things can trigger a decrease in the NO_x emissions control system's ability to perform adequately. This includes HRSG tube leaks, blinding of the catalyst inlet by dislodged liner insulation, plugged ammonia injection lances, seal degradation, and/or abnormal turbine conditions (Fig 2). It is important to monitor equipment condition and evaluate performance demands against system capabilities to ensure reliable operation and avoid emergency shutdowns.

Catalyst condition should be evaluated regularly. Catalyst is the most expensive part of the SCR and its performance can vary widely over the system's lifetime. Plants where catalyst has been operated and maintained properly typically report long life prior to replacement. Responsible planning and auditing can increase the useful lifetime, thereby effectively reducing SCR operating costs and avoiding the large, unbudgeted expenditures associated with buying new catalyst. For the most effective program, gas-plant owners should focus on the long term and evaluate SCR life-cycle costs.

Fleet-wide lifecycle management

For plant owners and operators, a baseline survey of each SCR unit

2. Insulation blinding of catalyst face is evident at left; same catalyst after cleaning is at right

within the fleet serves as the logical starting point in the development of an overall catalyst management process and strategy. This fleet-wide approach leads to a comprehensive and efficient management plan that will lower costs and make decision-making more efficient. It is superior to managing various SCR systems at different plants individually.

A fleet SCR manager should be chosen. His or her job is to assure the compliance of all environmental air permitting requirements by creating a comprehensive baseline for each site and developing an ongoing, preventive maintenance strategy. Since SCR equipment is custom-manufactured for the unique demands of each plant, the fleet manager must take into account current and future permit conditions and operating demands on each unit.

Balancing the requirements of each SCR system in the fleet can be challenging. A system can reduce NO_x by greater than 95%, but, when the efficiency of the SCR is pushed beyond 85% and—or, if—the outlet emissions are less than 5 ppm, the system becomes much more sensitive to several independent system parameters. These include overall catalytic potential, effective ammonia injection/mixing in the flue-gas stream, flue-gas characteristics for inlet NO_x, velocity, and temperature distributions. Issues can be addressed by high-efficiency SCR designs with system modeling, flow correction devices, enhanced catalyst volumes, and a robust ammonia injection grid design.

As plant equipment is upgraded, repaired, or otherwise modified, the performance environment for reliable emissions control can be affected. Understanding these potential impacts to the SCR system is essential and should be studied. For example, components of the ammonia delivery system may deteriorate over time. The system may reach a point where it can no longer perform adequately with aging catalyst.

Baseline survey. A properly executed baseline survey, conducted by a qualified catalyst management provider, should fully assess the current condition of each SCR in the fleet. Surveys must be site-specific, since each location will have its own unique history and permitting requirements. The survey should begin with each site's air permitting requirements and goals, which can vary significantly based on the age of the unit, geographic location, cost of ammonia, etc. And, it should identify the SCR system supplier and include a review of the site's operating history (Fig 3).

Next, site maintenance records, catalyst test reports, and control-room feedback should be assembled. Finally, a documented physical inspection of the SCR catalyst systems is recommended to help verify the historical records and equipment status.

Management plan

After the data are collected and a physical inspection of the plant is complete, consider diagnostic testing of the catalyst. Laboratory testing is conducted to determine the catalytic potential of the SCR reactor bed and to predict its ability to continue to meet performance requirements.

It is important to verify that testing be conducted under conditions that closely match the actual operating conditions of the SCR system, not under a set of theoretical or standardized design conditions. The sample should represent a typical cross section of the SCR and the operating history should be known. A convenient method for sampling purposes is to incorporate an easily removable sample tray within the catalyst module, as shown in Fig 4.

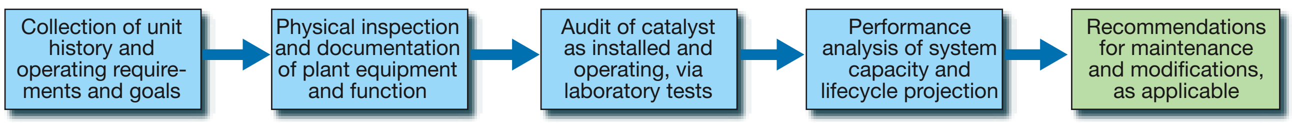
The samples in the tray can be quickly removed when the unit is offline. This way, an operator can avoid drilling into the catalyst to extract core samples. Note that core samples typically are not required for units with homogeneous honeycomb catalysts, but may be recommended for units with alternative-type products and/or ones that have a localized problem—such as a tube leak.

Analyses should be conducted in a controlled laboratory environment using custom-built and validated SCR catalyst test equipment. This will accurately determine how the catalyst is performing. The fleet manager can then compare its performance to previously tested elements.

The assessment of field operating data is important, because it determines the performance requirements of the SCR, operating conditions, test conditions for the laboratory performance test, and the performance threshold. If field data change relative to previous evaluations, the test conditions and/or the performance threshold also may have to change. An analysis of field operating data, together with laboratory test results, can determine if flue-gas bypass and/or an ammonia-to-NO_x imbalance is adversely affecting SCR performance.

In the prediction of remaining life, an analysis of the trends in laboratory test results from a series of audits and field operating data over time is compared with data from similar units and expectations based on unit operating history. From this comparison, a prediction is made of the remaining life where the SCR is expected to meet performance requirements.

If the factors that affect catalyst deactivation do not remain consistent throughout the estimated remaining life, the future rate of deactivation will differ from the current observed trend. For this reason, periodic auditing to measure potential changes in the deactivation trend is recommended to improve the accuracy of remaining-life projections.



3. SCR fleet baseline survey activities

Recommendations going forward

For systems nearing end-of-life (from a performance standpoint), but with meaningful remaining catalytic capacity, equipment system improvements may be possible. For example, a plant may be able to redesign or upgrade the ammonia injection system. The catalyst management organization may employ CFD modeling as part of the optimization process, which can result in a reduction of ammonia usage and improve overall emissions performance.

If survey results and diagnostic testing reveal that remedial measures to the catalyst bed are necessary, or that catalyst must be replaced, the catalyst manager has several options to recommend to the plant. SCR systems that contain catalyst with substantial remaining catalytic activity may be candidates for refurbishment of the catalyst bed. This is a good option for a plant that has deteriorated seals, module wear, and distortion that cannot be repaired by maintenance action.

When SCR catalytic potential has degraded the point where it can no longer meet plant needs, the entire SCR reactor bed must be addressed. Options include: full replacement, partial replacement, integrated reuse with new catalyst, and regeneration.

Each method has its advantages and disadvantages and must be considered within the context of a given unit, plant, and fleet. For example, regeneration uses a special, aqueous-based chemical solution to remove certain types of contaminants. This might be a viable option, if the problem can definitely be solved by regeneration

4. Sample tray for catalyst module facilitates sample removal

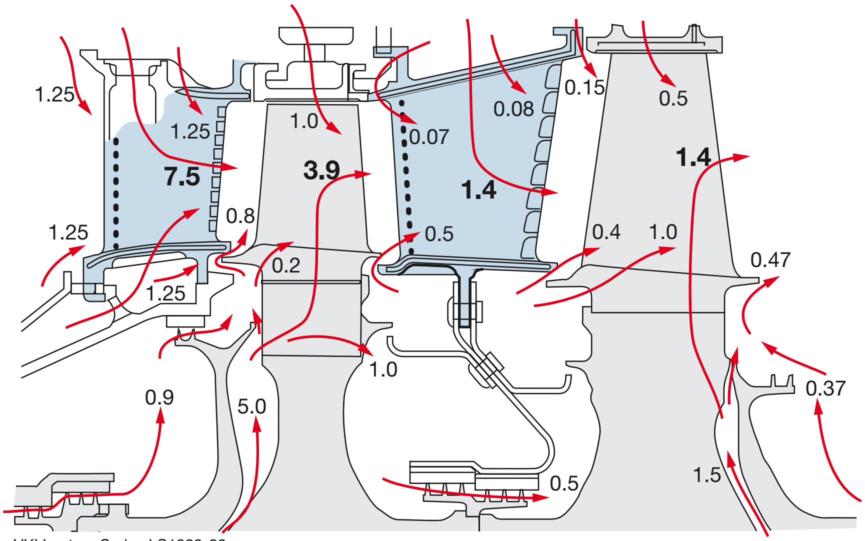
and the long-term performance can be guaranteed. Additionally, any work, including replacement and integration, must be feasible within a given outage period.

Partial reuse is another possibility and may involve the integration of an advanced module design, which can lower total-pressure loss. As with other approaches, site-specific goals and constraints must be considered. Ultimately, the best approach is the one that will result in a robust SCR system with long-term, guaranteed performance.

Final thoughts. To successfully operate an SCR, the fleet manager must monitor the system, perform routine inspections, and periodically evaluate the catalyst. For simple- and combined-cycle gas plants, this effort includes the continual review of operating data, NO_x reduction, ammonia slip, pressure loss, and ammonia usage. By taking a fleet-wide approach to managing these tasks, owners and operators can benefit from reduced SCR lifecycle costs and insure the reliable operation of their SCR catalyst systems. CCJ

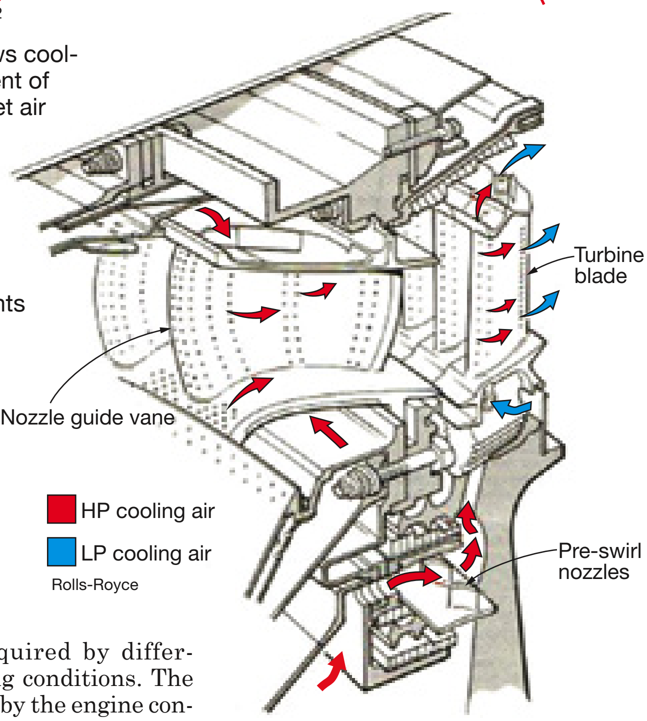
Monitor engine cooling-air flows to enable top performance

By Brent A Gregory and **Oleg Moroz,** Creative Power Solutions (CPS)



VKI Lecture Series LS1999-02

1. Worm chart shows cooling flows, as a percent of total compressor inlet air flow, for the first two stages of a gas turbine (above)



Rolls-Royce

2. Circuit diagram reflects how cooling air is delivered to individual components (right)

In a modern gas turbine, up to about 20% of the main compressor (inlet) flow is bled off to perform cooling and sealing of hot-section components. Cooling flows are necessary for the engine to function. However, too much cooling has a negative impact on performance and output. To optimize performance, one must know what cooling flows to monitor and control

Using a four-stage turbine as an illustration, here's how critical components are cooled (in order of decreasing flow):

- Vane 1. Cooling to first-stage turbine vanes is provided internally to keep materials at a safe temperature.
- Rotor and blade cooling. An external pipe takes air from the engine's compressor, cools it in an external heat exchanger, and directs the cool air to turbine blades and the rotor.
- Vane 2. Two pipes (a main line and a bypass) provide cooling air to second-stage vanes.
- Vane 3. Two pipes (a main line and a bypass) provide cooling air to third-stage vanes.
- Vane 4. Two pipes (a main line and a bypass) provide cooling air to fourth-stage vanes.

Some OEMs rely on coolant delivery systems other than pipes. Example: They may channel cooling flow through the major internal skeletal structure of the engine.

Important to this discussion is that Vane 1 and rotor and blade cooling flows usually cannot be adjusted because they are determined by engine design. When an external pipe delivers cooling air to the turbine rotor and its blades, that flow can be monitored easily. While Vane 1 cooling flow generally is not measured, a thermocouple in the region of the vane "box" helps determine flow using an algorithmic model.

Easiest to measure and control are cooling-air flows to Vanes 2 through 4. The main line carries most of the flow, which is determined by the differences in pressure between the compressor (where the air is extracted) and the turbine (where the cooling air is introduced). Flow is controlled by an orifice in the pipe. The larger the orifice throat area, the more air will pass.

The bypass line, smaller than the main line, has a valve to modulate cooling flow as required by different engine operating conditions. The adjustment is made by the engine control system. Cooling flows for Vanes 2, 3, and 4 are controlled by disc-cavity temperatures. If more cooling flow is need to reduce disc-cavity temperature to the control limit, the valve admits more cooling air. Disc-cavity limits are used to keep turbine parts at a safe operating temperature.

If an engine is having trouble staying within disc-cavity temperature limits, cooling flows can be adjusted by changing orifice plates in the main and/or bypass lines. However, this should be done carefully because changing cooling flows will impact engine life and performance.

One way to monitor cooling flows is to track disc-cavity temperatures and the position of bypass valves. By comparing actual disc-cavity temperatures to control specified temperatures it can be determined if an engine is being overcooled or undercooled.

Another useful exercise is to look at bypass-valve positions for Vanes 2, 3, and 4. If a bypass valve is fully open, it means there's insufficient cooling flow; if fully closed, the engine is being overcooled. Note that some control systems treat 100% as fully open, others fully closed. Check the appropriate manual to learn how your control system is configured.

Trend both the positions of bypass valves and disc-cavity temperatures over a range of ambient temperatures and engine loads to determine if orifice plates in the main lines and bypass lines are sized properly.

Cooling principles. OEMs may identify engine cooling flows in a diagram often referred to as a worm chart (Fig 1). The numbers in the figure are percentages of total compressor inlet air flow. Cooling flows delivered to individual components are illustrated in Fig 2 for a first-stage vane. Actual representation of cooling flows can be modeled using a sophisticated 3-D characterization of the flow as shown in Fig 3.

Effect of cooling on performance. To demonstrate the effect of cooling flow on the performance of a gas turbine typically used in simple- or combined-cycle service, the authors produced a theoretical model in a commercially available code (GasTurb) and varied cooling flows to see their impacts on the operating point. GasTurb allows engineers to change both the amount of the cooling flow and its energy content.

As discussed above, the main purpose of cooling air is to maintain safe vane and blade metal temperatures during gas-turbine operation. Cooling flows have a net positive result on gas-turbine performance. Because cooling air does not go through the combustor, some of the work is lost; however, cooling air permits operation

B&B-AGEMA GmbH

3. CFD model shows cooling flow emerging on the surface of a turbine blade and the main stream flow's impact on it

at a higher firing temperature which leads to a higher net power output and better efficiency.

Engine operation overview. At base load, most GTs are operated on an exhaust-temperature control curve (Fig 4) typically created by running the engine model through a range of ambient temperatures at a given design firing temperature. Based on model output and site-specific conditions, a control curve for base-load operation is created.

The main disadvantage of the curve is that there's no awareness of the engine's actual firing temperature during operation. So, if cooling flow increases, firing temperature increases as well, to maintain the same exhaust temperature for a given shell pressure. Here, firing temperature is defined as the temperature of the gas leaving the combustor—so-called T4.

On the other hand, if the cooling flow decreases, the exhaust temperature increases; this causes a reduction in firing temperature to maintain the exhaust temperature defined by the control curve.

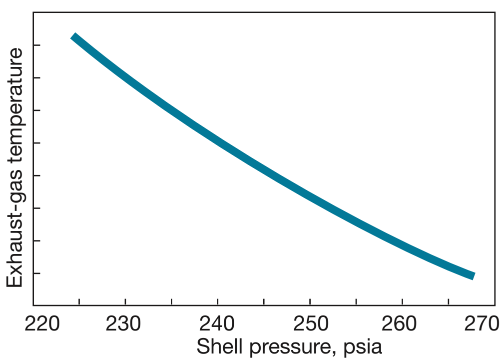
Site-specific GT models are required to predict engine cooling flows. Developing such models usually requires performance software and a significant amount of reliable engine data. Measuring cooling flows is not as complicated. By recording temperature, pressure, and pressure drop across a known orifice, they can be calculated to verify cooling-flow measurements.

One of the primary reasons for tracking cooling flows is to determine how T4 changes with time. Knowing the exact value is not the goal here. With engine variations and the inability to monitor Vane 1 cooling flow, the actual T4 value is difficult to determine. However, knowing how T4 is *trending* helps you assess engine performance and make appropriate O&M decisions.

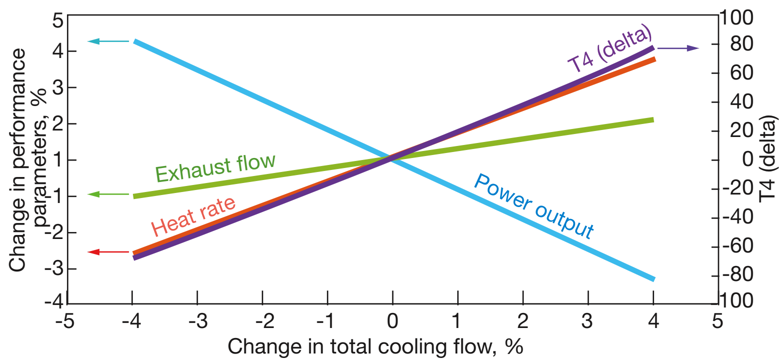
Recall the First Law of Thermodynamics from academic study: Energy is always conserved. Simply put, Energy in=Energy out. T4 can be estimated by creating a heat balance around the combustor. First perform a heat balance around the engine to determine total air flow into the GT, then subtract cooling-air flows to calculate the amount of air entering the combustor. Keep in mind that good data are needed for repeatable and valid performance assessments, and this requires that you install proper plant instrumentation and calibrate it regularly.

Effect of cooling flows on engine operation. The benefit of monitoring engine cooling flows is better assessment of engine performance and operation. Fig 5 was created using the commercial GasTurb software referenced earlier. An F-Class engine was modeled based on data publicly available. GasTurb uses generic compressor and turbine maps available in the public domain.

The plotted data illustrate the impact of changes in the total engine

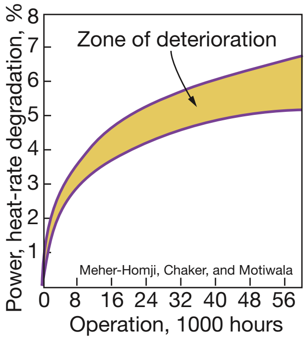


4. Base-load exhaust-temperature control curve, developed using GasTurb software, is typical for an F-Class engine in power-generation service

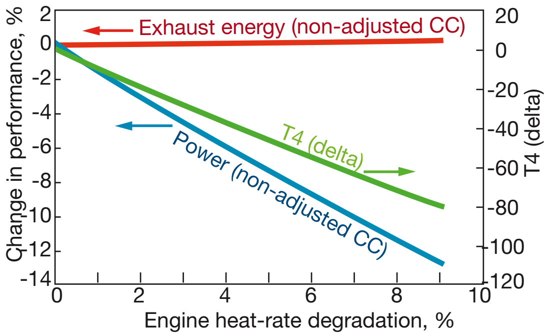


5. Engine cooling flows have a significant impact on engine performance as well as engine firing temperature

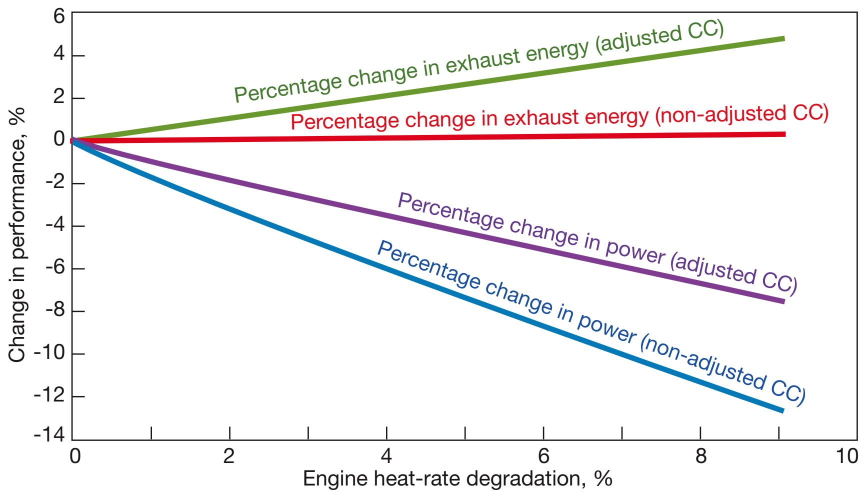

Put a power plant in your pocket!
Make a Power Plant Trading Card™ for your facility.
The first plant cards were published in 1998. Since then, cards have been completed for 115 plants. They are a big hit on station tours, and a user-friendly way to communicate with internal and external stake holders.
Send away for a free sample or request a quote.
OCEAN STATE POWER
PASCO COGEN
SUTTER
SANTAN GENERATING STATION
TNP ONE
Be sure to visit the industcards on-line photograph gallery "Power Plants Around the World"
industcards
5605 Bent Branch Rd
Bethesda MD 20816 USA
www.industcards.com
industcards@aol.com
industcards™



6. Power output and heat rate deteriorate rapidly after commissioning and overhaul; rate of change in degradation slows later



7. Engine degradation has a significant impact on performance



8. Maintaining constant T4 through engine degradation has a significant impact on power output

Sample potential recovery calculation

Engine operation since "as-new" condition, hr	8000
Heat-rate loss over 8000 hr (Fig 6), %	3.2
Engine output at ISO, MW	200
Power loss with non-adjusted control curve (blue line in Fig 8), %	~4.8 (9.6 MW)
Power loss with adjusted control curve (purple line in Fig 8), %	~2.8 (5.6 MW)
Potential recoverable power output, %	~2 (4 MW)

cooling flow from +4% to -4% on firing temperature, power output, heat rate, and exhaust energy. As mentioned earlier, cooling flows can account for up to about 20% of total engine air flow. The curves were created by keeping the engine on the base-load exhaust-temperature control curve generated by GasTurb and reflect what you would expect to see during operation.

The power and heat-rate impacts are significant from a performance point of view; but just as significant is the impact that firing temperature may have on the lifecycle of turbine parts. Based on experience, increasing the firing temperature by 40 deg F may decrease the life of hot-section parts by as much as 50%. If firing temperature is trended, any spikes or falls in T4 can be identified and investigated immediately. This minimizes the opportunity for surprises that could contribute to unplanned outages or to extensions of planned outages.

Maintaining optimal performance. Another benefit of tracking cooling flows and trending T4: Maintain optimal engine performance and output. As mentioned earlier, the base-load exhaust-temperature control curve is created based on design firing temperature. The control curve is not aware of what the actual engine firing temperature is during operation.

Turbine degradation has an inverse exponential profile. Most of the degradation occurs in the first few thousand hours, with wear and tear leveling out as time goes on. A sample degradation curve is presented in Fig 6. An engine completing an outage may have tight blade clearances in the turbine section as well as new components, such as seals. Clearances will open up as the engine goes through several thermal cycles. Seals also will see most degradation during the first few thousand hours of operation.

After the break-in period, the engine is not able to extract as much energy out of the working fluid, causing the exhaust temperature to rise. The control curve "sees" the exhaust temperature increasing and engine controls respond by reducing firing temperature. While parts lives are extended at the lower firing temperature, engine performance suffers.

Fig 7 illustrates how a decrease in firing temperature caused by engine degradation adversely impacts performance. This chart was developed by holding the GasTurb model on the design exhaust-temperature control curve. Thus T4 is dropping as engine heat rate increases. Note that the heat-rate increase is based on turbine degradation only; compressor degradation is not included. To reiterate, because the turbine is not able to extract as much work out of the working fluid, the exhaust temperature increases and T4 must drop to stay on the control curve.

The plot in Fig 8 reflects how engine performance can be optimized by adjusting the base-load control curve, so the engine operates at constant T4. The blue and red curves are the same as in Fig 7. The purple and green curves were developed by keeping the firing temperature at the design level as the engine degrades.

In Fig 8, the purple curve represents the unrecoverable and expected engine degradation. The blue line reflects the power loss attributed to both the unrecoverable engine degradation and the inability of the control curve to self-adjust and maintain a constant T4 value.

The bottom-line benefit of monitoring cooling flows and trending firing temperature is that when firing temperature drops, the control curve can be adjusted and some of the lost performance and capacity generally can be restored. The table offers an example, based on the the GasTurb model, of the potential power recovery that a control-curve adjustment can achieve. In this case, 4 MW can be restored 8000 hours after commissioning or following an overhaul. But, once again, remember this assumes heat-rate deterioration is due only to turbine degradation mechanism. If compressor degradation were included, the recovery would be less.

Wrap up. Cooling-flow monitoring, together with properly calibrated plant instrumentation, allows for trending of engine firing temperature and performance using fundamental thermodynamics. Due to this monitoring, performance issues arising during engine operation can be accurately assessed and corrections executed during scheduled outages.

A quick way to determine if an engine has cooling issues is to trend disc-cavity temperature and bypass-valve positions for a range of ambient conditions and loads. Bypass valves that are fully open or closed are conducive to engine undercooling or overcooling. Low disc-cavity temperatures are indicative of overcooling; high temperatures mean insufficient cooling.

Neglecting to monitor cooling flows and engine health may lead to an under-performing engine, unnecessary forced outages, or premature replacement of engine components. CCJ

Kirn passes the chairman's baton to Borsch

The big news from CTOTF's™ 38th annual Fall Turbine Users Conference and Trade Show in Coeur d' Alene, Idaho, September 8-12, was the announcement by Chairman Robert G (Bob) Kirn that he would be retiring from TVA in early October and that this would be his last CTOTF meeting in an official capacity. He had been chairman since 2008—only the fourth chair in the group's rich history.

Kirn left at the top of his game, so to speak. Under his leadership, CTOTF meetings have expanded to include a vibrant opening-day program consisting of the Industry Issues and O&M and Business Practices Roundtables and the very popular and insightful Regulatory and Compliance Roundtable on Day Two. The technical program remains as strong as it ever has been in the group's four decades of service to the industry—bolstered by recent addition CT-Tech™, which provides expanded instruction and training in plant operations and design theory on user-identified subjects.

The more than 30 subject-matter experts that comprise the CTOTF Leadership Committee organized and conducted four full-day and a dozen half-day technical and regulatory sessions, plus two CT-Tech workshops and a robust equipment/services exhibition, at the Coeur d' Alene Resort.

There were more than five dozen formal presentations, a few panels, and several discussion sessions hammered into a program that began at 7 am with breakfast and ended at 9 pm every evening except on the final day of the meeting. Kirn, who used to play football for the US Merchant Marine Academy (Kings Point), challenged the session chairs and vice chairs to use every second on the clock productively.

1. CTOTF Executive Committee pauses for a moment at the 2013 Spring Turbine Users Conference and Trade Show in Myrtle Beach, SC, where Chairman Robert G Kirn (third from left) announced that he would retire from TVA and CTOTF at the conclusion of the fall meeting in Coeur d' Alene, Idaho, held September 8-12. From the left are Ray DeBerge, Ed Sundheim, Kirn, and Jack Borsch, who was elected to replace Kirn as chairman

2. Rich Evans, Old Dominion Electric Co-op, was elected to the executive committee at the fall meeting; he assumes Jack Borsch's former position as vice chair for turbines

3. Kimberly Williams, of NV Energy and vice chair of CTOTF's Regulatory and Compliance Roundtable, received the Best Presentation Award at the fall meeting for her "Proposed Revisions to Combustion Turbine NSPS" last spring

Jack Borsch, VP of O&M at Colectric Partners and a former plant manager, was elected the all-volunteer organization's fifth chairman (Fig 1). His former position, executive vice chair for turbines, has been filled by Rich Evans of Old Dominion Electric Co-op, a long-term CTOTF committee member and plant manager (Fig 2). Evans' professional experience spans both aero and advanced-frame engines.

The remaining members of the CTOTF executive committee—Ed Sundheim, director of engineering services for Essential Power LLC, and Ray DeBerge, a GT fleet superintendent for Ameren Missouri, continue in their current positions.

A report on the fall meeting will appear in a later issue; this article reflects timeless material presented at the 2013 spring meeting. The next CTOTF meeting, the 39th annual Spring Turbine Users Conference and Trade Show, will be held April 6-10,

2014 at the PGA National Resort & Spa in Palm Beach Gardens, Fla. Mark your calendar to sign up when registration opens Jan 2, 2014 at www.ctotf.org.

CTOTF spring 2013

The 2013 Spring Turbine Users Conference and Trade Show got into the nitty gritty of gas-turbine (GT) operations and maintenance on the second day of the meeting, conducted at the Marriott Grande Dunes in Myrtle Beach, SC, April 7-11. Day One, Monday, April 8, was devoted to presentations and discussion on training, information resources, and best practices, plus a vendor fair in the evening.

Tuesday's program focused on regulatory and compliance issues and GE E-class and legacy engines; the sessions were conducted in parallel. This was the first CTOTF meeting that the Regulatory and Compliance (R&C) Roundtable, chaired by Scott Takinen, director of executive projects for fossil generation at Arizona Public Service Co, ran an entire day.

Judging from the robust content and discussion, it probably could have gone two days without anyone yawning. The morning R&C program addressed environmental regulations, with Vice Chair Kimberly Williams of NV Energy at the front of the room; Vice Chair Alan Bull of NAES Corp, directed the afternoon session on NERC and FERC regulations.

Chairman Pierre Boehler and Vice Chair Ed Wong, both with NRG Energy Inc, divided the GE E-class and legacy program into two segments: OEM presentations in the morning and presentations by third-party equipment and services providers, plus user-only open discussion, in the afternoon.

Proposed changes to NSPS for GTs

That plant managers and supervisors are having a difficult time keeping up with environmental regulations was obvious from the strained facial expressions on many attendees during Williams' opening presentation, "Proposed Revisions to Combustion Turbine NSPS." Don't let the plain-vanilla title fool you.

The presentation's content provided credibility to a message delivered by a user on Monday that went something like this: Don't be lulled to sleep thinking the federal government is just trying to eliminate coal as an energy source for electric generation; it has declared war on all fossil fuels, and natural gas is next.

Williams eased the group into the subject matter, starting with a history of the New Source Performance Standards for GTs, then providing details of the onerous changes proposed to those regulations, and finally, what impacts EPA's suggested changes could have on asset owners if enacted as written. It's fair to say that many of the users participating in the heavily attended session (standing room only) found it difficult to believe what they were hearing.

One example is the proposed change to the definition of "reconstruction," a trigger for NSPS, which may result in more restrictive operating and compliance requirements. Under the current definition, Williams said, "reconstruction" is taken to mean the replacement of components of an existing facility to the extent that the fixed capital cost of the new components exceeds 50% of the fixed capital cost of a comparable *entirely new facility*—including major process equipment, instrumentation, auxiliary facilities, buildings and structures, etc.

The new definition, if EPA has its way, would be to use only 50% of the cost of the compressor, combustor, and turbine sections as the "reconstruction" trigger. In EPA think, this typically means that the third time a turbine is overhauled or refurbished it would be considered "reconstructed." That translates to an NSPS review every 10 years because maintenance costs are cumulative over time.

Curiously, EPA is on the record with the following: "This proposed rule [the proposed revisions in sum] would not result in additional costs or additional reductions of emissions of criteria pollutants." Another of the agency's comments: "We do not intend for these editorial revisions to substantively change any of the technical or administrative requirements of the subpart [that portion of Part 60 of Title 40 of the *Code of Federal Regulations* pertaining to gas turbines] and have concluded that they do not do so."

If you're not familiar with the foregoing and want to come up to speed quickly, access Williams' presentation in CTOTF's online Presentations Library (Sidebar). It earned the NV Energy engineer the user group's award for the best presentation at the spring 2013 meeting (Fig 3).

Background. Williams, who has 15 years of experience in the environ-

How to access CTOTF presentations

CTOTF's library of presentations is arranged in chronological order by meeting (most recent first). If you don't already have a "library card" and you are a GT owner or operator (any make and model), register now at no cost. Simply scan the QR code with your smartphone or tablet to directly access the sign-up form at www.ctotf.org.

Confirmation of your acceptance as a CTOTF member with full IBBCS (Internet Bulletin Board Communications Service) privileges generally will be emailed to you within 72 hours. As a member, access www.ctotf.org and click on the "CTOTF IBBCS" button in the left-hand tool bar on the home page. Scroll down the page to "Presentation Library" and click on that link.

mental aspects of oil production and electric generation, told attendees at the recently concluded CTOTF fall meeting in Coeur d' Alene, Idaho, that her spring presentation was still current. She began her presentation last spring by reminding attendees where NSPS fits in the alphabet soup of EPA regulations.

Simply put, it establishes pollution control standards of performance for new and modified stationary sources in certain categories—such as electric generating units. These standards are separate from, and in addition to, the Best Available Control Technology/Lowest Achievable Emission Rate limits associated with Prevention of Significant Deterioration/New Source Review rules.

NSPS for gas turbines date back to 1979, Williams said, when the standards were presented in 40 CFR 60 Subpart GG and made effective on Oct 3, 1977. More restrictive standards were issued in July 2006 and published in 40 CFR 60 Subpart KKKK—so-called Quad K.

The Utility Air Regulatory Group (UARG), a voluntary, not-for-profit group of electric utilities, other electric generating companies, and national trade associations, filed a petition for reconsideration in September 2006. EPA's proposed revision was published on Aug 29, 2012. This version has not been promulgated—yet. Williams did not discuss the possibility of ongoing appeals and the degree of success they may or may not have, or when the proposed rules could become law.

The Quad K standards in effect today apply to stationary gas turbines that commenced construction, modification, or reconstruction after Feb 18, 2005. EPA's proposed changes to those rules include the following, among many others:

- Modify the test for "reconstruction" as described earlier.
- Include startup and shutdown activities in emissions standards. Today's NO_x limits do not apply to engine starts and stops, or to engine malfunctions. Williams said that EPA is considering designating the first 30 minutes of operation as "part load," subject to a higher NO_x limit. She suggested that this would complicate monitoring.
- More restrictive NO_x averaging periods, now 30 days for gas turbines in combined cycles with a peak-load heat input greater than 850 million Btu/hr (HHV), and four hours (rolling average) for simple-cycle GTs with a peak-load heat input equal to or less than 50 million Btu/hr (HHV). Note that the first example is for a 2008-vintage GE 7FA, the second for a P&W SwiftPac® built in 2008.

To illustrate the level of detail associated with some proposed changes, consider that the 30-day average for large frame engines in combined cycles would be acceptable for any unit using the output-based standard (see next bullet). However, those using the input-based standard would have to comply with a four-hour average. Proposed changes to the NO_x averaging period for simple-cycle turbines are far more complex:

- Change the output-based NO_x standard from gross to net basis with units of lb/MWh.
- Add a new form of input-based NO_x standard with units of lb/million Btu.
- New compliance monitoring requirements. Example: Units using post-combustion NO_x controls to comply with emissions rules can no longer rely on Part 75 CEMS (Continuous Emission Monitoring System) because the specified analyzer span is inconsistent with Part 75.
- New definition for turbine tuning, which would be limited to 30 hours annually: As proposed it means planned maintenance of a lean, premix combustion system involving adjustment of the operating configuration to maintain proper combustion dynamics.

Upgrades versus new capacity. Williams' presentation was the perfect segue for NV Energy Staff Engineer Susan Hill, who provided attendees a methodology for evaluating the regulatory impacts of upgrades that might allow the utility to postpone new capacity additions. Hill's presentation was developed into a separate article and is featured on p 71.

NERC/FERC

NERC/FERC compliance matters dominated the afternoon session of CTOTF's Regulatory and Compliance Roundtable with Vice Chair Bull making formal presentations on the latest version of PRC-005, "Transmission and Generation Protection System Maintenance and Testing," and the key elements of a strong internal compliance program.

Bull, an electrical engineer with more than a decade of industry experience, has NERC compliance responsibility for all of NAES's facilities in North America. Roundtable Chair Takinen chipped in with a case history on APS's audit experience in the WECC (Western Electric Coordinating Council) region.

A considerable amount of equipment is aggregated into "protection system" as defined by PRC-005: protective relays, communications systems, voltage and current sensing devices, station DC supply, and control circuitry. NERC spent five years updating the standard, which includes specific maintenance and testing guidelines. PRC-005-2, adopted by the NERC Board of Trustees on Nov 7, 2012, was awaiting regulatory approval by FERC at the time of the spring conference.

In simple terms, the purpose of PRC-005-2 is to assure that all protection systems affecting the reliability of the bulk electric system are maintained in working order. Since the spring meeting a draft of PRC-005-3 has been circulated for comment. It adds passages on the maintenance and testing of reclosing relays that can affect the reliable operation of the bulk power system.

Violations. Judging from the large number of PRC-005-1 violations self-reported or identified during audits over the last several years, many owner/operators could use a primer on how to avoid citations. And that's what Bull prepared for attendees. The presentation was robust, encompassing nearly 100 slides, the vast majority content-rich.

The failure of users to maintain proper documentation and to do all the maintenance required by the standard accounted for most of the violations, as the summary list below suggests. The violations generally indicate a lack of procedural rigor and/or unfamiliarity with the tasks required. They include:

- No summary of protection-systems maintenance and testing procedures.
- Maintenance and testing intervals not defined.
- Basis for maintenance and testing intervals not documented.
- Protection-system maintenance and testing program did not include all the component types as defined by NERC.
- Missing documents. More specifically, an inability to document implementation of maintenance and testing procedures.
- Failure to complete maintenance and testing procedures within prescribed intervals.

The first part of Bull's presentation helped attendees refresh their knowledge of the types of protection systems used in electric generating facilities. It included a list of more than a dozen generation protection relays you're likely to find in most plants. Bull noted at this point that the existing definition of "protection system" does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required *at this time.*

Bull's review of NERC's changes to PRC-005-1 was comprehensive and especially valuable to those in the group who had difficulty complying with the first version. Details were well organized. There were individual slides for each of the components/systems aggregated into the "protection system," as defined by NERC. They identified the component of concern, the maximum maintenance interval, and the maintenance activities required.

For example, in one slide for communications systems, one entry is for "any communications system with continuous monitoring on periodic automated testing for the presence of the channel function, and alarming for loss of function." The maximum maintenance interval is every 12 calendar years (second major for a base-load combined cycle). One of the maintenance activities specified is to "verify that the communications system meets performance criteria pertinent to the communications technology applied—for example, signal level, reflected power, or data error rate."

Bull then reviewed the proposed timelines for implementation of the various requirements of PRC-005-2, which ranged from 12 months to the 12-yr maximum interval. This was the perfect introduction to well over a dozen slides detailing "appropriate evidence" to assure that you have the required paperwork to verify the results and prove you conducted the necessary maintenance and tests properly. Several slides answering frequently asked questions closed out the presentation. Bull's slides are available at www.ctotf.org in the Presentations Library.

Bull opened this presentation on the culture of compliance with a FERC policy statement: A company should act "aggressively to adopt, foster, and maintain" an effective culture of compliance, and have in place "rigorous procedures and processes that provide effective accountability for compliance."

Interestingly, while there are no FERC requirements for having an Internal Compliance Program (ICP), it is important that your facility's/company's compliance culture be viewed positively by regional auditors. Having a highly rated compliance program could reduce, possibly eliminate, the civil penalty that otherwise would be imposed if a violation were to occur.

Regional auditors, the vice chairman continued, are required to assess and document your company's compliance culture as part of the audit process. Such assessments involve completion of a compliance-culture survey, plus ICP review. Among the variables that auditors factor into their assessments are these:

- Compliance history and repetitive violations.
- Failure to comply with compliance directives.
- Self-disclosure and voluntary corrective action.
- Degree and quality of cooperation during the audit process.
- Concealment of violations.

Thirteen assessment areas are used by the audit team to evaluate your plant's/company's ICP. Here are questions the auditors ask themselves:

- Was the ICP well documented and widely disseminated throughout the entity?
- Has the plant/company named and staffed an ICP oversight position and is that position supervised at a high level? Does the oversight position have independent access to the CEO and/or board of directors?
- Is the ICP operated and managed independently of those responsible for compliance with reliability standards?
- Does the plant/company have sufficient resources for its ICP?
- Is the ICP a living document?
- Does the ICP:
  1. Have the support and participation of officer-level management?
  2. Provide for appropriate and sufficient staff training?
  3. Include formal, internal self-auditing for compliance with all applicable reliability standards on an established periodic basis?
  4. Include disciplinary action for employees involved in violations of the reliability standards, if appropriate?
  5. Have internal controls—including self-assessment and self-enforcement to prevent recurrence of reliability-standard violations?

E-class and legacy GE engines

The GE E-class and Legacy Roundtable never disappoints. Many gas turbines in the multiple fleets served—including Frame 5s, 6Bs, 7B-Es, and 7EAs—are more than 20 years old; relatively few are held captive by long-term service agreements. With owners increasingly parsimonious, the plant-level engineering and maintenance solutions required to keep these machines operating, or ready to run, promote valuable discussion and sharing of ideas, best practices, and lessons learned.

The OEM filled the morning session of the day-long program, covering a wide range of subjects—including the following:

- Technology updates to enable faster starting.
- Repairs and service updates.
- Mitigation of vane rock.
- Casing and exhaust system maintenance.
- Lubrication specifications.
- Rotor lifetime strategies and issues.
- Turning-gear improvements.
- TIL (Technical Information Letter) updates.

The exclusive afternoon program for owner/operators included several of the same subjects, but from a third-party or user perspective. To illustrate:

Hy-Pro Filtration. Richard Trent, manager of technical field services, presented on lubricant improvement and varnish mitigation. The lube-oil expert's refresher on fluid cleanliness, lubricant challenges, varnish mitigation strategies, and related topics crammed material worthy of a two-day seminar into one hour. He touched on ISO codes, patch tests, the impacts of fluid cleanliness on bearing life, types of filter media and testing, beta ratio, filter-element sparking, how varnish forms, varnish potential measurement, etc.

In sum, this presentation, available through CTOTF's Presentation Library, could serve as a "short course" for plant personnel who could benefit from a primer on lube oil. Plus, many of these topics have been covered previously in the CCJ and can be accessed via the keyword search feature at www.ccj-online.com. You can get there from here by simply scanning the QR code with your smartphone or tablet.

PSM's Product Line Manager Ian Summerside reviewed his company's successes in upgrading about four dozen E-class turbines with its sub-5-ppm-NO_x LEC-III® combustion system and refreshed attendee minds on how well buckets and shrouds of its design have performed. PSM, he said, is now working to complete its product-line offering for the entire engine—including nozzles and compressor blades, as well as rotor inspection and overhaul services.

User presentations are particularly valuable and there were several—including a rotor lifetime assessment conducted in a third-party shop and an exhaust-system retrofit. Here's a summary:

Gasket tear. Seasoned users know everyone on the deck plates has something of value to share and many bring a couple of photos on a thumb drive so others might benefit from their experiences. Such informal "presentations" often take only five minutes or so, but the learning is cumulative. One

4. Section of material missing from the rubber expansion joint (top, center) went downstream and into the compressor

5. A portion of the missing expansion-joint material wrapped around an inlet guide vane (near right of center in the photo)

6. Other pieces of rubber damaged R1 airfoils and they required blending

7. Frame 5 rotor, which has a two-stage turbine section, surpassed 5000 fired starts—the trigger for a mandatory end-of-life inspection

8. Inspection of the first-stage wheel, (left) revealed indications in the rabbet fillet area. A new contour was machined (right) with analysis confirming a nominal 70% reduction in peak stress in the area of interest

example from this session involved a piece of 7EA inlet expansion joint that caused compressor damage.

Plant personnel repaired the rubber joint about a year before a portion of it tore loose and went downstream (Fig 4). Note the hole in the expansion joint at the top center of the photo. One piece of liberated rubber wrapped around an inlet guide vane (Fig 5), while other pieces went into the compressor and banged up several R1 blades (Fig 6). Blending was necessary.

First lesson learned: It's virtually impossible to make a high-quality repair on rubber expansion joints of the type used at the engine inlet. One reason is that the material degrades over time. A couple of users attending the session believed it can be difficult to get more than three years of service from such a joint; actual life depends in large part on the operating profile and the ambient environment. Second lesson learned: Rubber isn't "soft" to a delicate compressor blade turning at 3600 rpm.

Rotor inspection, repair, and life assessment are on the minds of managers at most plants with legacy engines. A user with a Frame 5 that in 2012 surpassed 5000 fired starts—a trigger for mandatory rotor end-of-life inspection as specified by the OEM's TIL-1576—discussed his experience during the session (Fig 7). The gas-only summer peaking unit, located in an outdoor package in the Northeast, began commercial operation in 1971. Its only hot-gas-path/major inspection prior to this overhaul was in 1981.

To mitigate fatigue risk, the scope of work included eddy-current inspection of bolt holes, bores, and rim features, and advanced ultrasonic testing of disks, together with materials evaluations. No indications were found during the advanced NDE or metallurgical assessments. Inspections, materials characterization, and shop work were performed at Dresser-Rand Turbine Technology Services' facilities in Houston.

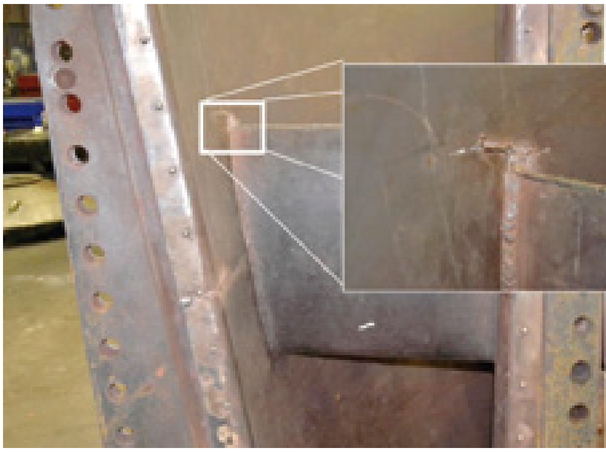
Dye-penetrant and eddy-current inspections identified a substantial number of indications (most very shallow) in the rabbet fillet area of the first-stage wheel. The wheel was repaired and stress analyses were conducted to confirm the viability of the repaired part for continued service (Fig 8). The rotor was reinstalled and the unit recommissioned for service in 2013.

Conclusions drawn from analyses conducted on the rabbet-fillet repairs were these:

- The repaired fillet has much lower stress than the original.
- Steady and high-cycle loadings were considered. In both cases, analysis of the repaired geometry suggests improved fatigue durability.
- Additional surface treatments of the repaired design—such as polishing and shot peening—are expected to further enhance durability relative to the original configuration.
- The repaired configuration is believed superior to the original (in the region of the repair) with respect to allowable number of starts or hours of operation.

Exhaust-frame refurbishment. A user reported that the exhaust system for one of his company's Frame 7Es required refurbishment after suffering years of wear and tear in cycling service. The overhaul was managed by Integrity Power Solutions LLC, an OEM licensee. IPS President David Clarida was on hand during the presentation to answer questions. For a backgrounder on the overhaul of exhaust systems for GE frames, scan the QR code with your smartphone or tablet. Specific issues identified and addressed during the presentation included the following:

- High temperature in the load compartment.
- Cracking at the outer diffuser/airfoil joint (Fig 9) is relatively common in the fully welded design shown because it restricts thermal expansion. An alternative and more forgiving approach is the "floating tail" method of attachment, where a portion of the airfoil's trailing edge is not welded to the diffuser, allowing for thermal growth. Recall that the airfoils surround structural struts, shielding them from direct contact with hot exhaust gas.
- Cracking of the inner diffuser (Fig 10) is rare. In this case, the crack



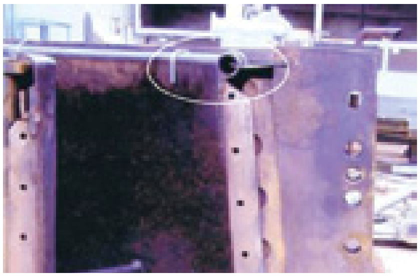
9. Cracking at the outer diffuser/airfoil joint was one of the inspection findings

10. Cracking of the inner diffuser was found at the weld

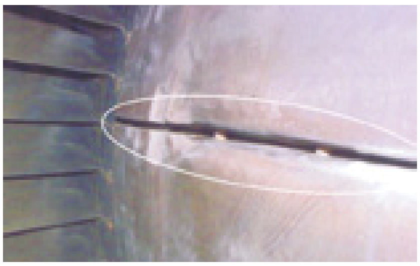
occurred at a weld, which might indicate an improper fabrication procedure.

- Disengagement of the flex seal (Fig 11) is considered a serious issue because it allows air to leak out of the exhaust-frame cooling circuit.
- A gap at the horizontal flange of the inner diffuser (Fig 12) is fairly common, and problematic because it allows cooling air to escape.
- Distortion (Fig 13) has allowed the horizontal flange for the outer diffuser, and the exhaust-frame casing, to move out of alignment.
- Failure of the exhaust frame's outer cover (Fig 14) is quite common. A design upgrade was possible here, but not implemented.

The game plan for this project was relatively simple: Replace outer and inner diffusers, airfoils, and flex seal in-kind (Type-304 stainless steel, Fig 15), along with insulation packs and bolting. A thorough inspection found the existing exhaust-frame horizontal and vertical flanges acceptable for reuse. Recall that the exhaust frame bolts to the turbine casing on one end and the aft diffuser on the other. No reinstallation or re-commissioning issues were mentioned by the speaker.



11. Flex seal was disengaged



12. Gap at the inner-diffuser horizontal flange was somewhat expected

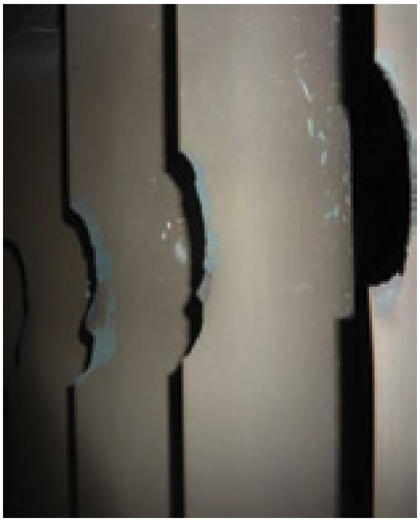
13. Distortion of the diffuser came as no surprise

What took a bite of out of these R3 turbine buckets? President Rod Shidler and Field Service Manager Mike Hoogsteden of Advanced Turbine Support LLC had no sooner finished presenting on the results of recent inspections of Siemens 501FD2s and GE aeros at the spring meeting when one of the company's technicians forwarded photos of significant damage to the trailing edges of 41 third-stage buckets on a GE7FA (Fig 16). It looked as if something took a bite out of the buckets.

What apparently had happened was that a repair weld holding a section of flex-seal ring pipe in place cracked allowing the pipe section to liberate

14. Failure of the exhaust frame's outer cover is relatively common

15. Exhaust frame was refurbished with new outer and inner diffusers, airfoils, and flex seal



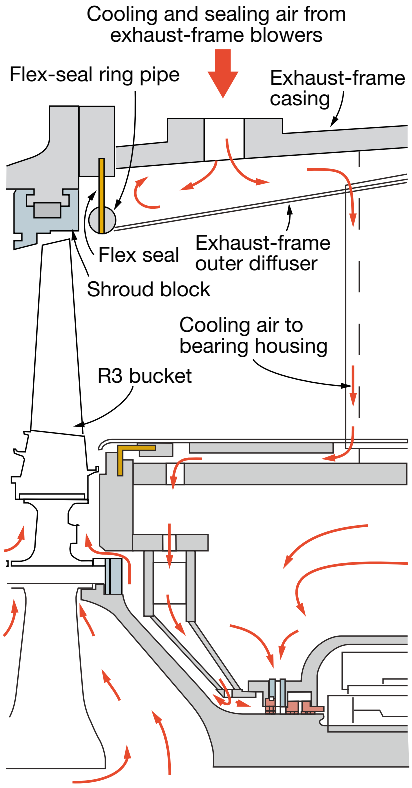
16. Impact damage on trailing edge of R3 bucket

and damage the buckets, located only an inch or two away from the flex seal. Two of the lessons learned: (1) Be sure this part of the engine is on your inspection check list. (2) Repair welds in the exhaust section have an element of risk given the high temperature (nominal 1000F) and very turbulent nature of the gas stream—especially so when the work is done on engines subject to daily thermal cycles.

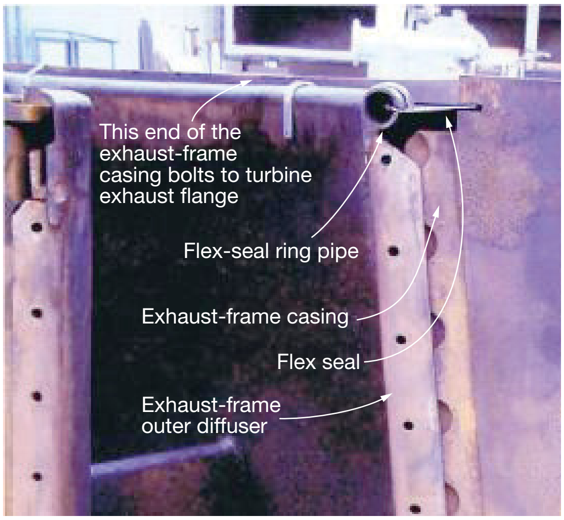
To understand exactly what happened, please read on. A necessary first step is a review of the arrangement and general design of the components involved. For this information, the editors reached out to IPS's Clarida, who had been fielding questions on virtually the same subject at the GE E-class and Legacy Roundtable (see section immediately above). The exhaust systems on most GE E- and F-class units are nearly identical.

Clarida began by pointing out that the same components often are referred to by different names in industry discussions so it's important to look at the diagrams as you read further. Fig 17 shows the arrangement of 7FA components from the R3 bucket row to a point about 6 ft beyond the turbine exhaust flange. Note, in particular, the locations of the flex seal, flex-seal ring pipe, and exhaust-frame outer diffuser, and the proximity of the flex-seal ring pipe to the shroud blocks and the rotating R3 buckets.

The flex seal essentially is formed by a couple of layers of thin-gauge sheet metal that slide into a slit in the flex-seal ring pipe on one side and a slit in the exhaust-frame casing on the other side (Fig 18). Its purpose: Provide a barrier between the hot exhaust gas and cooling air for the bearing housing while allowing the exhaust-frame casing and outer diffuser to expand and contract independently of each other.



17. Exhaust system for a GE 7FA immediately downstream of the turbine section reveals a gap of about 2 in. between the flex-seal ring pipe and the R3 buckets



18. Top half of exhaust-frame casing standing on end that bolts to the exhaust diffuser

By their nature, function, and environment, flex seals are subject to wear and tear conducive to failure. When the barrier between the exhaust and cooling air is breeched, one of two things is likely to happen: Air from the exhaust-frame blowers escapes into the exhaust stream, thereby starving the bearing housing of cooling, or if the backpressure is high enough, exhaust gas would flow into the cooling circuit and possibly overheat the bearing housing. Thus regular inspection by a trained professional is important.

Clarida said that the flex-seal ring pipe is in two sections—one for the upper half of the unit, one for the lower half. They meet at the horizontal joint. The flex seal is divided into several sections. When a flex-seal segment fails, one possible solution (not recommended) is to cut out a section of ring pipe in the affected area, replace the damaged seal segment, and reweld the section of ring pipe in place. The alternative is to remove the upper half of the casing and replace the entire ring pipe and flex seal in the affected half of the unit.

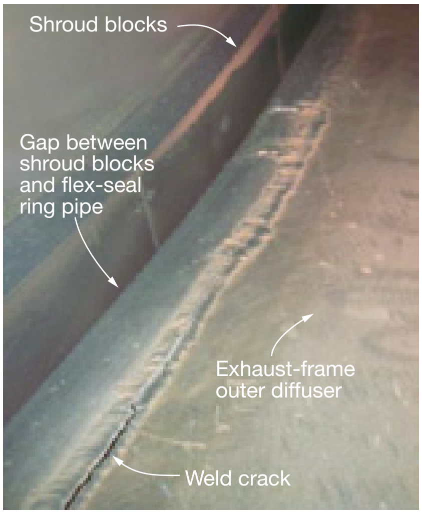
This obviously is the more expensive and time-consuming option, but Clarida said it is the only way to ensure against the weld cracking and ring-pipe segment liberation shown in the photos provided by Advanced Turbine Support (Figs 19-21). It is very difficult to make quality weld repairs of the type required, he continued, because of the tight spacing between the shroud blocks and the ring pipe. The circumferential welds at the ends of the pipe segment being replaced are particularly challenging.

Generators, HV electrical, I&C

No user group serving gas turbine owner/operators covers generators, high-voltage (HV) equipment, and I&C to the degree CTOTF does. The day-long Gen-EI&C Roundtable conducted at the spring conference, chaired by Moh Saleh, Engineering Manager at SRP's Desert Basin Generating Station, offered four presentations with actionable content.

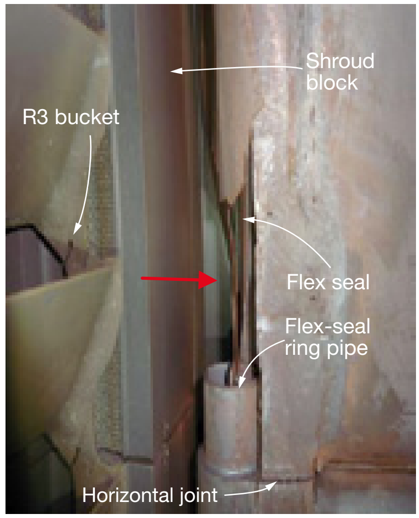
The opening presentation, "7FH2 Generator Noise," by Vice Chair for Generators Craig Courter, maintenance manager at Guadalupe Power Partners LP, was the perfect segue for the second: "Generator Belly Bands," by Bill Dollard, manager of contracts and business development for AGT Services Inc, Amsterdam, NY. The HV portion of the program was anchored by a presentation on "The Use of Ultrasound for Arc Flash and Electrical Failure Detection," by VP Engineering Mark Goodman of UE Systems Inc. Goodman's presentation was developed into a standalone article (turn to p 56).

The final formal presentation,



19. Cracked weld where the flex-seal ring pipe connects to the exhaust-frame outer diffuser

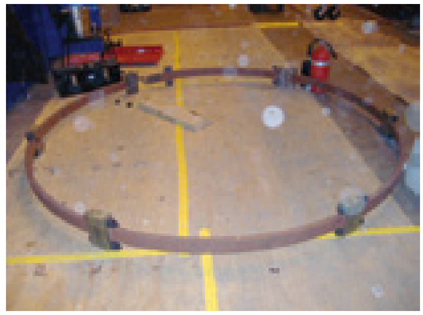
20. Liberated section of flex-seal ring pipe believed to have caused the R3 bucket damage



21. Liberated section of flex-seal ring pipe was immediately above the horizontal joint

22. Slight greasing was found on the belly band and keybar, indicating that the belly band was loose

23. No sign of greasing was in evidence on belly-band bolts, nuts



24. This belly band is comprised of six segments

"Early Warning of Stator-Vane Cracking in Combustion Turbines," by David Sinay, power industry market manager for Mistras Group Inc, Princeton Junction, NJ, was included in the I&C portion of the proceedings, directed by Vice Chair John-Erik Nelson, principal mechanical engineer for Braintree Electric Light Dept's Potter 2 and Watson Generating Stations.

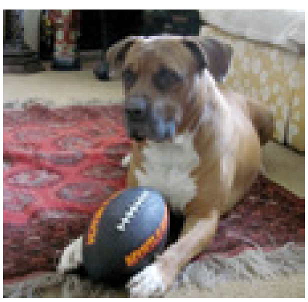
In his opening remarks, Courter noted that generators, particularly those installed during the "bubble" years, continue to report key-bar rattle events. Left uncorrected, the condition is conducive to deterioration of the generator stator. The "rattle" can be detected with the Harmonic Noise Index (HNI), a test proprietary to GE that analyses acoustic data. It is a useful tool, the vice chair said, for identifying, prior to disassembly, what may be happening inside a generator.

Unit operating data indicated a slight uptick in vibration on the collector-end bearing. Operating temperature was normal and the low-frequency noise was heard only at base load. The sound was directional and there were no visual indications. Testing proceeded this way, Courter said:

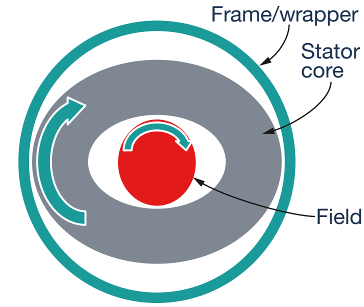
- A generator load test verified that noise attributed to high deck vibration occurred only at base load.
- Onsite vibration analysis, based on a three-point test, identified the exciter end as having higher levels than the opposite end of the unit.
- A third-party vibration analysis confirmed the plant's findings.
- The harmonic content of the acoustic data was analyzed using HNI to determine the extent to which the 2/rev frequency and its harmonics were present in the overall noise level. The HNI level calculated was higher than that of a normally operating hydrogen-cooled generator serving a 7FA gas turbine. It also was within an HNI range that suggested significant core/key-bar interaction (Figs 22 and 23). The average sound pressure level at base load was the highest of all load points examined. Having accurate diagnostics, Courter said, allowed the plant to run until the next planned outage and to plan and obtain competitive bids for repairs with no exploration costs and no surprises.

Dollard began his presentation by explaining exactly what belly bands—a/k/a core compression bands or belts—are and why they may be needed (Fig 24). Simply put, their function is to control radial vibration between the core and stator frame (key bars, building bolts, etc). As the field rotates, he said, it applies a force to the core that makes it slightly egg-shaped (Fig 25). Depending on the OEM, stator-frame design, size (large units are most prone), the distortion may lead to key-bar vibration.

Dollard asked attendees, "How do you know belly



Roscoe, CCJ's sergeant-at-arms, who owns the game ball from the CTOTF spring 2013 meeting at Myrtle Beach, SC, urges users not to miss the spring 2014 conference in West Palm Beach, Fla, at the PGA National Resort & Spa. Visit www.ctotf.org

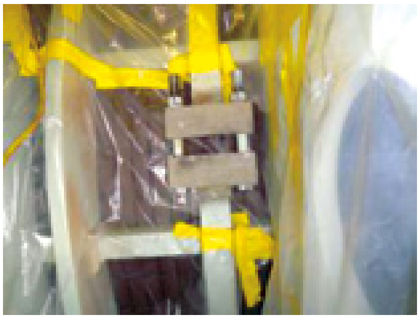


25. Core is slightly egg-shaped during operation

26. Access doors are removed to inspect belly bands

27. Grinding shims and welding usually are necessary to tighten belly bands. Band shown is snug against round key bar; key bars also may be rectangular in cross section

28. Tent prevents rain and airborne debris from getting into outdoor units open for belly-band inspection, installation, etc



29. Plastic sheeting prevents metal filings, dropped bolts, weld spatter, etc, from escaping into the generator

30. Blisters are removed to access the wrapper

31. Access doors are cut into the wrapper

bands are the problem?" He answered that question by offering the following tell-tale signs:

- An increase in stator-frame vibration, usually in the radial direction.
- A step-change or gradual increase in "sound" level.
- Noisier than a sister unit.
- Acoustic survey indicates the unit is more noisy on one end than the other.
- Visual inspection of key bars or building bolts reveal greasing or dusting.

There are three types of belly-band projects, Dollard told the group. They are: (1) inspection and tightening, (2) replacement of existing belly bands, and (3) installation of new belly bands on units that didn't have them originally, or extra belly bands on units that already have one or more.

It is relatively easy to inspect belly bands installed during frame manufacture, because access doors generally have been provided for this purpose (Fig 26). After removing doors, Dollard said, check bolt torque and verify tightness with a "ring" test of the belly band. If tightening is required, grinding of shims and/or buckles and welding inside the outer wrapper likely will be required (Fig 27) and care must be taken to prevent foreign material from entering the generator (Figs 28 and 29).

A user asked, "Why might you replace or add belly bands?" Replacement usually is motivated by improper design, the AGTServices expert said. For example, the band might be of the wrong diameter relative to core OD, or the material might not be quite right for the application. Poor installation or broken bands are other reasons for replacement.

When belly bands must be installed in an operational unit to reduce vibration, it often is necessary to provide one or more access doors. Blisters, where used to facilitate the flow of cooling air, must be removed first (Fig 30). Then doors are cut in the wrapper with grinders (Fig 31), until about 1/32nd of an inch of steel remains.

Chisels are used from this point on to help keep debris from getting inside the unit. FME (foreign material exclusion) considerations contribute to the time-consuming process. It normally takes a couple of weeks to add belly bands on a GE 324 generator (Fig 32). Final welding after installation of belly bands is shown in Fig 33.

Testing after completion of work should include standard outage electrical testing and an EL CID test if the field was removed. You might want to check core torqueing as well, if accessible—in particular if data indicate the possibility of core looseness. Validate your efforts with an acoustical survey on restart and a visual check during the next major outage. Finally, does the generator sound quieter? Does the floor not shake as much?

Dollard's presentation focused on GE generators. Regarding Westinghouse units, he mentioned that they generally should be core-torqued every 10 years or so and that requires removal/replacement of belly bands where installed.

Sinay introduced users to acoustic-emission monitoring technology capable of detecting cracking of compressor stator blades while the unit is operating. Mistras Group's Acoustic Combustion Turbine Monitoring System (ACTMS™) has been installed on six gas turbines to date and is credited with at least one documented "save," having detected and located an S1 vane crack in an F-class gas turbine at a combined-cycle plant owned and operated by Florida Power & Light Co (Fig 34).

He reminded attendees that vane cracking in some engine models is a recognized industry concern. ACTMS's non-intrusive sensors, mounted on the turbine case by magnets or waveguides that transfer the cracking energy to

32. Belly-band installation on a GE 324 generator takes about two weeks

33. Wrapper and blisters are welded back in place and the generator is repainted

the sensor while dissipating heat. A typical installation on a GE 7FA has 12 sensors arranged in a conical array to detect cracking in rows S0 through S5, an area of concern.

The sensors are wired to a monitoring system located outside the turbine enclosure that evaluates sensor signals in real time. Use of multiple sensors enables ACTMS to locate the position of a crack in three dimensions for follow-up verification during a borescope examination. Details on how ACTMS works are in Sinay's presentation, available through CTOTF's Presentations Library along with the other presentations summarized here.

Wet-tower inspection checklist

A highlight of the spring Combined Cycle Roundtable, was an inspection checklist presented by Ken Mortensen, an R&D project manager for SPX Cooling Technologies. The SPX/Marley veteran has managed several engineering and operations departments over his 34-yr career, so he knows wet towers from all angles—including water quality, materials selection, operations, maintenance, makeup treatment, etc.

The MIT-educated chemical engineer suggested that plant personnel pull background information for the inspector before he or she comes onsite—particularly helpful are:

- A tower data sheet and a general arrangement drawing.
- Service records—including details of any reconstruction, maintenance, or upgrades done since COD.

Mortensen's inspection checklist should be a "keeper" for any maintenance manager to build on. Here's an outline of what he suggested:

- Tower casing and partitions. Check for leaks, cracks, holes, brittleness. Verify attachment hardware is intact and that access doors are in good working order and closed during operation.
- Structure. Spot-check tightness of hardware, identify the cause of any cracking found, verify columns are plumb and that diagonal bracing is in place. Girts straight? Compression blocks in place?
- Fan deck. Verify panel integrity, and that perimeter air seals are in place and attached.
- Access systems. Check for (1) loose stair treads, guardrails, and stringers, (2) absence of structural or hardware degradation on ladders and stair tiebacks, (3) weld integrity on metal ladders, (4) no broken or deteriorated members on walkways, and (5) condition of safety cages.
- Cold-water basins. Look for excessive sludge and accumulated debris (remove, of course, if found), check basin seals and joints, ensure anchorage is sound and tight and that concrete basins have no spalling or cracking. Examine surrounding areas for evidence of basin leaks.
- Piping and valves. Verify that fluid handling equipment—including supports—is in good condition and operational, and gaskets, O-rings, and bearing pads are in place. Check flanged connections for proper tightness.
- Nozzles and spray arms. Randomly inspect nozzles for clogging. Check diffusion rings and splash plates, bands and gaskets. Look for splits in spray arms and nozzles.
- Hot-water decks. Inspect for damage or deterioration of splash boxes, leaks in downtakes, deck sagging/support degradation, silt or scale buildup, corrosion or delamination. Ensure deck seals are in place and caulked.
- Fill. Look for clogging, scale, algae, erosion, sagging, torn sheets, ice damage, cracking of fill support members, etc.
- Drift eliminators. Verify cleanliness. Look for gaps between packs or at the structure, sagging, or other damage.
- Fan stacks. Inspect for structural and UV damage, ensure tip clearances are within OEM tolerances.
- Gearboxes and motors. Verify correct oil levels and leak-tightness—especially at the pinion seal and fittings.
- Driveshaft and couplings. Ensure proper alignment; check flex elements for signs of deterioration, cracking, or brittleness.
- Fans. Measure fan pitch to confirm it is within tolerances provided by the OEM. Assure that blades, hubs, clamps, etc, are in satisfactory condition.

34. ACTMS locates a crack in a 7FA S1 vane

Inspection complete, be sure that the plant's SME (subject matter expert) sits down with the inspector for a debriefing on critical findings. Then develop a plan for inspections, maintenance, and upgrades going forward. A thorough inspection report with photos should be the final deliverable.

To learn more about how to extract top performance from wet cooling towers, access CCJ ONscreen's webinar on the subject conducted by David Brumbaugh, president, DRB Industries LLC. Your private viewing is available at no cost. Access using the QR code or from your computer at www.ccj-online.com/onscreen. CCJ

BUSINESS PARTNERS

Repair cross-threaded compression fittings quickly

Compression-type tube connections, such as those manufactured by Swagelok Company, are specified for use in fluid circuits because of their ability to seal leak-tight despite frequent disassembly/reassembly—that is, unless the threads are damaged in the process by debris, misalignment, or inadvertent impact. Cross-threading of the nut on the tube end, which can occur while connecting it to the male end of the fitting, is the most common type of damage.

When the threads are damaged to the point that the connection cannot be remade leak-tight, replacement is required. Change-out of both the male end of the fitting and the captured nut on the tube end may be necessary. The male fitting sometimes can be replaced quickly by unthreading and installing a new fitting. The tube end, with the nut retained by the compression ferrule, has to be replaced.

The standard repair when threads are damaged: Cut back the tube to an acceptable location and add an additional fitting. This also requires adding a piece of tubing with new nuts and ferrules to return the tubing run to its original length. The most common, and preferred, repair option is to replace the complete run of tubing from fitting to fitting.

Ken Knecht, the former maintenance supervisor at a generating plant equipped with gas turbines in simple- and combined-cycle configurations, has developed, and is offering for sale through KnechtionRepair (www.knechtionrepair.com), a new tool capable of repairing damaged threads. He told the editors that in his 35-plus years on the deck plates he was forced to deal with damaged threads more often then he'd like to remember. "They can cause hours of delay in job completion," Knecht said, "costing owner/operators thousands of dollars in lost time, parts, and repairs."

The manual thread-chasing tool Knecht developed is designed to repair both the male end of the fitting and the female captured nut on the tubing at the connection location. It is compact and can be used in space-challenged locations, right at the point of connection, as the video illustrates (access by scanning the QR code). The tool includes a holder to restrain the nut on the tube in concentric alignment with the thread-chasing hollow-bore tap, which is turned manually to repair/clean the damaged threads.

Thread-chasing tool

For the male end, a thread-chasing die with a concentric alignment hole is used in conjunction with an alignment pilot inserted in the fitting. The die, held in alignment by the pilot, is turned manually to repair/clean the damaged threads. After the repair, the pilot is removed and the fitting is ready for assembly.

The repair tool for two-ferrule, tube-type compression fittings currently is available for ⅜ and ½ in. tubing; additional sizes are under development.

Frame 5 upgraded to profitability

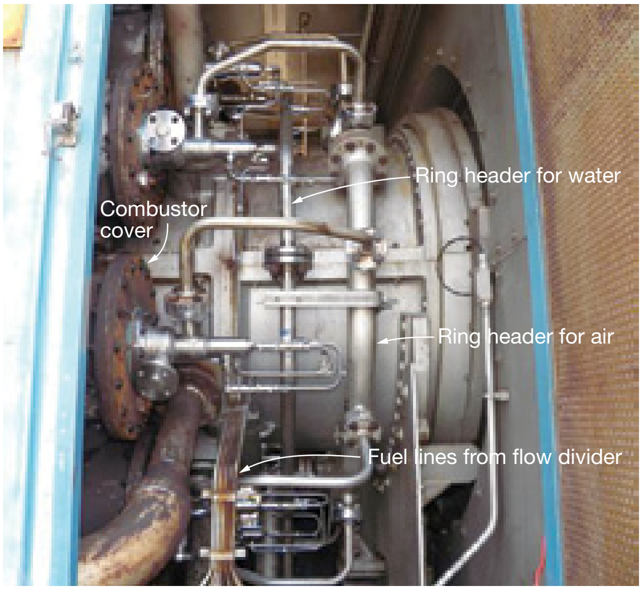
A few years ago, Frame 5s generally were viewed as gas turbines without a future in the generation sector of the US electric power industry. But increasing reliance on intermittent renewables has restored their value in many locations as a reliable resource when the wind stops blowing and/or the sun stops shining. An example was provided by Mike Moore, senior VP for optimization and upgrades in Wood Group GTS's Power Plant Services business unit, who called the CCJ editorial offices to share information on an upgrade project that delivered a rapid return on investment.

The Frame 5P, a nominal 25-MW machine located at an Ohio coal-fired plant, was relegated to black-start service until a recent market opportunity justified investment in the engine to provide grid ancillary services. Wood Group (WG) was awarded a contract to install a water injection system on the distillate-only unit to reduce NO_x emissions from 119 ppm to 65 ppm and satisfy permit requirements for the intended service.

The scope of work included supply and installation of the following new equipment: (1) water injection skid and shed (Fig 1), (2) ring manifold for NO_x water, as well as all the tubing and fittings connecting the ring to individual combustors (Fig 2), (3) WG fuel nozzles and liner caps, (4) flame scanner that does not require water cooling, and (5) electric fuel metering valve to improve starting reliability. The project was completed within a 10-day planned outage.

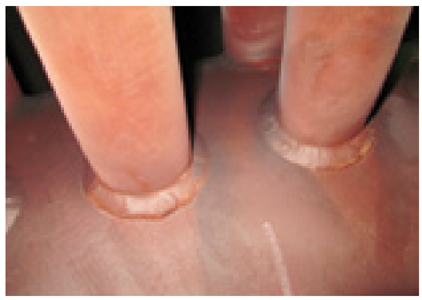
1. NO_x water injection skid is installed in a weather-proof building (above)

2. Ring header for water injection is in the middle of the photo. Fuel is supplied from the flow divider (not in photo) via the tubing bracketed together at the bottom of the photo (right)



The engine's controls also were upgraded. That project involved Emerson Process Management, which replaced the original system with its Ovation DCS. The coal-fired unit onsite was equipped with Ovation controls and the availability of technicians and parts made it a wiser choice in the utility's mind than Wood Group's PLC-based control solution installed on many GE gas turbines.


3. Before ice blasting


4. After ice blasting

NDE identifies birth defects, wear and tear in tube-to-header weld area

Tube leaks are the leading cause of forced outages in coal-fired boilers and EPRI research suggests they also are the major cause of damage to multi-pressure combined-cycle plants. Carryover of water into tube bundles, dewpoint corrosion, offline corrosion, high-temperature oxidation, and metal fatigue from cycling—among other mechanisms—contribute to, or are the direct cause of, tube failures in heat-recovery steam generators.

Owner/operators work diligently to avoid forced outages: An unplanned outage at an inopportune time can put a serious dent in your plant's bottom line. Until recently, finding tube leaks before they caused an outage was a hit or miss proposition. The acoustic monitoring solution presented on p 52 is capable of mitigating risk, but there's more you might consider doing.

Example: Conduct a health assessment of your HRSG's pressure parts and welds. This has been discussed frequently in the **CCJ** as a way to identify cracking in steam-drum nozzle welds, to measure the wall thicknesses of components in areas prone to attack by flow-accelerated corrosion, etc.

The maintenance supervisor at a Mid-Atlantic 2 × 1 F-class combined cycle installed during the bubble, concerned about the number of cracked tube-to-header welds occurring at the bottom of his HRSG panels, took condition assessment to the next level. He had all lower tube-to-header welds in the three rows (total) of reheater and superheater tubes examined by technicians proficient in dye-penetrant, mag-particle, and x-ray techniques. Plus, he had sections of one reheater tube and one superheater tube removed for detailed laboratory analysis. A section of a third tube was removed and replaced in-kind because of damage.

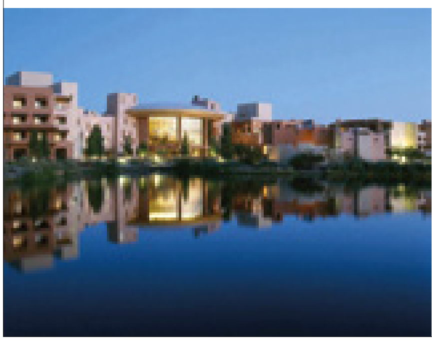
As many plant managers have learned, work done constructing plants during the bubble often was careless. Improper hardness of P91 and the use of wrong materials in piping systems and for welding are two examples. In this case, crack indications were identified in 14 tube-to-header welds; the welds were ground out and joints rewelded.

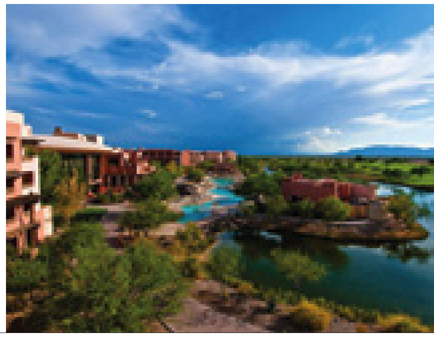
Proper preparation of metal surfaces was critical to success, the maintenance supervisor said. He hired Precision Iceblast Corp for this work because conventional grit blasting might possibly mask surface indications and because use of dry ice eliminated the need for clean-up of debris. PIC's Keith Boye said a three-man crew with one ice gun cleaned the surfaces required on one HRSG in less than 12 hours (Figs 3, 4). Spacing was tight, he said, so the smallest technicians on staff were assigned to this job. Also, the physical layout required the use of nozzles designed and fabricated for the application by company personnel.

Reminder: Clashing occurs in 7FAs as well as 7EAs

Clashing, the term used to describe contact between rotating blades and stationary vanes in Frame 7 compressors, has been a hot topic at meetings of the 7EA User Group for years. In fact, it was a headline item in the State-of-the-Engine report by Advanced Turbine Support LLC, Gainesville, Fla, at the 7EA meeting last fall. Service Manager Mike Hoogsteden stressed the need to borescope regularly and to document clashing findings to minimize the possibility of catastrophic loss. He said field data have revealed increases in clashing damage over time.

Early last April, Hoogsteden called CCJ's editorial offices to say that an Advanced Turbine Support inspection team had just found significant clashing damage in a 7FA. Note that clashing between the trailing edge of rotor blades and the leading of stator



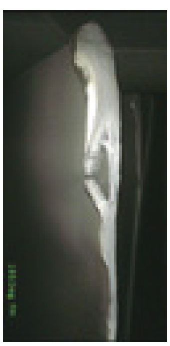


vanes almost always occurs in Stage 1 of 7EA compressors and in Stages 2 and 3 of 7FA compressors.

In this most recent case, the damage was identified in Stage 3 of an unflared 7F compressor and was severe enough to cause a forced outage (Figs 5, 6). Hoogsteden reminded that the probability of clashing is not necessarily related to unit operating history. This type of damage has been found on flared and unflared compressors with as few as 190 total starts and 1465 fired hours.

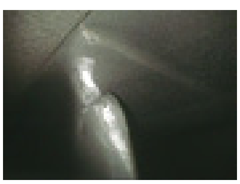
He also said that it is easy to overlook clashing during a standard borescope inspection because of where the damage occurs. It takes an experienced technician with sophisticated NDE tools and techniques to do the proper inspection, he added. For 7EAs, Hoogsteden said, Advanced Turbine Support would likely recommend eddy current testing of rotor blades and stator vanes; however, a dye-penetrant inspection could be done as well. For 7FAs, the company has successfully performed limited eddy-current inspections of stator vanes in both Stages 2 and 3.

If clashing damage is found, Hoogsteden recommended a follow-up clashing-specific inspection, followed by a 25-start inspection interval until repairs can be performed.



5. Torn 7FA third-stage stator-vane tip (left)

6. Torn 7FA R3 rotor blade platform (below)



Eight bells

Steve Lefton, a highly visible and well-respected industry consultant with deep experience in HRSGs and combined-cycle and cogeneration systems, was killed in late July when the plane he was piloting crashed near South Lake Tahoe. Lefton had recently retired; he was 67.

Company news

Wood Group GTS will replace the Mark VI Millennium control system for an LM6000PC (dual fuel, enhanced Sprint™) at Arizona Electric Power Co-op's Apache Generating Station with an open-architecture Rockwell ControlLogix® platform.

In related news, Wood Group GTS completes $2-million worth of major maintenance services for a Frame 6B and Frame 5 gas turbine. Work included a major inspection and the repair of HGP parts—including buckets, nozzles, shrouds, transition pieces, crossfire tubes, fuel nozzles, and flow sleeves.

The company also introduces new NERC CIP conversion and compliance services for owner/operators, which includes integration of the NERC compliance program with plant O&M procedures. A project underway involves reducing the regulatory risk associated with the operation of five LM6000s at a plant in the Northeast by providing a continuous audit-ready compliance program.

Finally, Wood Group GTS announces the signing of a 10-yr service agreement with Papeles y Conversiones de Mexico, Monterrey, for the company's Solar® Taurus™ 60 gas turbines. Contract covers preventive and corrective maintenance, turbine and gearbox overhauls, round-the-clock emergency cover for trouble-shooting, remote support, and conditioning monitoring.

Sulzer Turbo Services launches an update to its iPad app, TS Solutions, giving users access to company information that enables decision-making regarding services and repairs to rotating mechanical and electromechanical equipment.

Structural Integrity Associates Inc acquires TubeTrack, an electronic tracking program for boiler tubes, from Burns & Associates Engineers. Historically, TubeTrack has focused on data management for boiler tubing, but SIA has bigger plans—including its expansion into high-energy piping and BOP systems, with expanded capability for data analytics to facilitate condition assessment and asset management.

Emerson Process Management, Pittsburgh, replaces aging turbine and BOP controls at Exelon Generation's Westport 5 Generating Station with its Ovation™ expert control system. New gas-fuel valve trains were part of the retrofit package. The unique 116-MW peaking facility consists of eight Pratt & Whitney GG4-7 gas generators coupled to four Worthington double-flow expander turbines. The plant provides emergency black-start capability to the Baltimore area.

Calpine Corp reports that its plants generated approximately 23 million MWh in 2Q/2013 and achieved a record-low second-quarter fleet-wide forced-outage factor of 1.6%. Starting reliability for the fleet during the quarter was 99%.

People

Turbine Generator Maintenance Inc, Cape Coral, Fla, expands its generator services unit and hires the respected Paul Heikkinen as director of that group, which includes Ben Irvine, Tim Jones, and Chris Fowler—each with nearly two decades of field experience.

NAES Corp, Issaquah, Wash, names James Couch senior business development manager, based in Sulphur, La. He brings more than 40 years of construction/O&M experience to the company and its customers.

Hamon Deltak Inc, Minneapolis, names Richard Edelen director of quality to strengthen its worldwide team for HRSGs and waste-heat boilers. Edelen has more than 25 years of experience in quality management initiatives and in working with the ASME *Boiler and Pressure Vessel Code.*

Bill Stroman, one of the industry's top water consultants, told the editors that his employer Capital Power has entered an agreement to sell its powerplants in Rumford, Tiverton, and Bridgeport to Emera Inc. The deal is expected to close in 4Q/2013. After the closing, Capital Power's merchant power activities would focus on Alberta and Stroman once again will be offering independent consulting services—effective Dec 2, 2013.

Mike Rutledge resigns from his CTOTF™ position as Siemens chair with his appointment by SRP to the newly created position of generation participation asset manager. In this job, Rutledge focuses on coal-fired assets rather than gas turbines and combined cycles.

Products/services

Conval Inc, Somers, Ct, now offers its high-performance Clampseal® and Camseal® vent and drain valves in sizes from ½ through 4 in. Automated globe valves are available in angle, Y, and T-pattern configurations and allow for remote monitoring and control. Valves are repairable inline, with no welds to remove and replace. Seats may be cut, ground, and lapped; disc can be turned or replaced, and lapped to the seat.

Mitsubishi Power Systems Americas is actively promoting its M501JAC, an air-cooled version of the company's state-of-the-art steam-cooled J-Series GT introduced in 2009. Shipment of the first engine in the air-cooled series is expected in 2015. Simple-cycle output is 310 MW, efficiency tops 41%. In a 1 × 1 single-shaft combined-cycle configuration, the power block delivers 450 MW at an efficiency of more than 61%.

PW Power Systems Inc, Glastonbury, CT, announces the sale of its latest aero power solution—the 120-MW FT4000™ SwiftPac®—to a unit of Exelon Generation in Maryland. Scope of the contract includes BOP equipment, installation, and commissioning.

Clark-Reliance Corp announces a new remote water-level indication system for boilers. Eye-Hye® SmartLevel™ incorporates new technology to intelligently monitor the condition of its probes which require periodic cleaning to maintain accuracy. Smart technology tells operators when probe-column blowdown is necessary.

Swan Analytical USA Inc, Wheeling, Ill, offers the AMI Deltacon Power analyzer for the automatic and continuous measurement of specific and cation conductivity (before and after a cation exchanger). Sample pH value and ammonia concentration are calculated.

Plant news

Lea Power Partners LLC, operated by Consolidated Asset Management Services LLC, reports that its Hobbs (NM) generating facility was found in 100% NERC compliance (no findings) following an audit conducted early this summer. Plant Manager Roger Schnabel told the editors, "CAMS culture of compliance is made evident through the success of this audit." Lea Power was a recipient of three 2013 Best Practices Awards.

Old Dominion Electric Co-op, Glen Allen, Va, selects Mitsubishi Power Systems Americas to supply two gas turbine/generators for its Wildcat Point project in Cecil County, Md.

COMBINED CYCLE Journal 2Q/2013

Index to advertisers