the conduit

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INSIDE THIS ISSUE:

Risk – What Does It Mean To Me?

By Mark Tanner, P.E.
Senior Principal Engineer

We have all heard the term "Risk." It is used frequently in the media. They mention the risk of a heart attack or cancer if you smoke or maybe the risk of being killed if you do not wear a seat belt or a bike helmet. We hear financial commentators talk about the risk of investing in stocks or bonds or precious metal. Banks talk about whether a person or company is a good credit risk. We hear news stories about the person who risked their life to save their pet. In fact there is so much risk around that we have entire companies that do business based on risk. Insurance companies are in business to protect companies or an individual against some type of risk: health, life, auto, home, economic, etc. So what is risk actually and how can I use it to help my company?

First, what is risk? The Oxford dictionary states that risk is the possibility that something unpleasant or unwelcome will happen. Ok, that is a pretty broad brush, but helps us now understand why the term risk is used so much. So how do we quantify risk and can we use it at our company? Well, it is already being used at most companies. Any large company has a risk management department. However, they are looking at the overall risk to the company. How can I use risk to help me? How about using risk to help with maintenance planning?

The possibility that something unpleasant or unwelcome will happen.

The following equation is used to calculate risk

Risk = the probability of an event x the consequence of the event

Sometimes the term likelihood is used by people instead of probability. There are differences in the statistics world, but for all practical purposes they are interchangeable by most people. With that said, this article will use them as they are often used by non-statisticians.

The probability of an event is based on many engineering factors and preset conditions. The design, operation, and maintenance all play a role in the probability of failure. Continuous monitoring and inspection along with miscellaneous tests and spares can help with probability as well as consequence of failure. For example, a plant manager may ask the maintenance engineer or rotating equipment engineer what is the likelihood this piece of equipment will fail if we delay its overhaul another three years or what type of risk will we be taking if we delay the overhaul. The manager explains this will help the company with budget cuts in maintenance this year. The engineer cannot just provide a number because the likelihood and consequence will be based on many factors.

This is where a risk assessment (i.e., risk-based) approach to maintenance planning can help. Most machines (steam turbines, generators, compressors, pumps, etc.) are capable of being run longer between outages, but there have not been consistent and objective means of quantifying that capability. Equivalent operating hours

(Continued from page 1)

(EOH), fixed time intervals, OEM and consultant estimates alone have been subjective and not cost effective for scheduling outages. Risk assessment models can quantify that capability because they inherently are concerned with probabilities of failure, consequences of those failures, and the factors that may increase or decrease the failure probabilities and/or consequences. Risk models combine technical and reliability factors with financial consequences to arrive at the best possible decision. These models provide guidance on what and where are the steam turbine generator risks, how the time between major outages can be extended with minimal changes in risk, how the risk levels for potential lost revenue can be reduced, and how to prioritize maintenance, upgrades, and spares decisions so that company resources can be cost effectively justified and applied to equipment with the most need.

M&M Engineering Associates along with The Hartford Steam Boiler Inspection and Insurance Company and multiple rotating equipment experts in various industries helped develop the risk assessment models. The reliability and risk factors were developed by leading members of the power generation, process (refinery, petrochemical, chemical products), forest products, manufacturing, and repair industries, drawing on their skills and experience together with M&M Engineering Associates' failure analysis and risk assessment experience along with HSB's decades of experience as an insurer of these machines. These programs consist of algorithms that calculate risk (risk = probability of failure x consequence) for the steam turbine generator from the probabilities of failures, failure consequences, and engineering modifying factors. These factors are applied and the risks calculated based on answering questions related to the specific turbine or generator. These questions range from operations and maintenance, construction and design, monitoring, steam chemistry, upgrades and spares, etc. M&M Engineering, HSB, and industry team experience was leveraged to establish what attributes are important and necessary for a unit to achieve a longer time between major outages and corresponding lower risk levels. These attributes were converted into risk modifying factors to view turbine and generator risks on a holistic basis -design and construction, operation, maintenance, monitoring, and condition at past outages. The factors were calibrated with analyses of units of all kinds. The models and associated risk levels were then validated with units that have run longer intervals.

The risk models were developed based on ASME's Risk Based Inspection Guideline methodologies. The models have been the subject of technical papers or presentations at ASME, API, EPRI, NUSIS, PowerGen, SAE, TAPPI, and Turbomachinery conferences as well as for three different insurance companies and one OEM. Analyses have been completed for over 331 steam turbines and 121 generators. These results reflect 21 different turbine OEM's and 12 generator OEM's. The sizes ranged from 600 HP to 890 MW, operating hours from 8,000 to 340,000, or years of operation from new to 62 years. The turbines had 471 failures (a failure is an event that caused lost production). These failures ranged from fatigue cracked blades to cracked disk steeples from caustic stress corrosion cracking. They ranged from wiped seals to eroded stationary diaphragms.

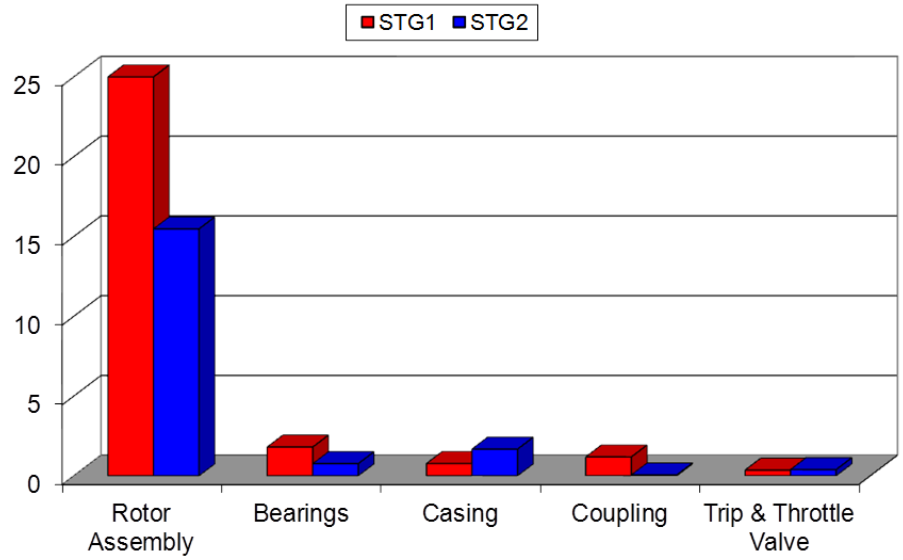

Figure 1. STG1 has higher risk of a rotor assembly failure as compared to STG2.

To try and describe the process, we will use an analogy that we all should be familiar with. Basically, this risk assessment process is like the medical process. When you visit a doctor's office, a nurse gathers basic details about your health. They check your temperature, blood pressure, pulse, and ask questions about what is

bothering you. They write down the symptoms (location of aches and pains, level of pain, blurry vision, heart racing, etc.) Based on this, the doctor can start his "risk" assessment. He may need additional tests performed or may already be able to diagnose and treat you. If your blood pressure was 180 over 120 and you complained about headaches and chest pains, he is going to send you to the emergency room. He doesn't need to run an EKG to know you are in danger. On the other hand, if your blood pressure is 140 over 85 and you have just complained about headaches, he may review your previous medical records, and ask additional questions which could lead to a diagnosis or requests for additional tests like an MRI or cat scan or blood test. If you are well and just go in for a physical, you will answer questions and the doctor will check the basic vitals along with lungs, hearing, eyes, reflexes and finally a urine and blood test. Based on the results, the doctor may suggest a diet change or increased exercise or possibly a colonoscopy or some medication. The doctor will then say when you need to come in again for another checkup or test.

Equipment risk assessment is a very similar process. You can look at how the unit is being operating based on monitoring information, data from operators, maintenance personnel, electrical personnel, historical records like previous outage reports, etc. Based on the answers, probabilities of various failure mechanisms can be increased or decreased. For example, if a turbine has been experiencing intermittent vibration problems you know that the likelihood of fatigue is higher for blades and disks as well as rubbing damage for blades, diaphragms, seals, and casing. If the blades were previously pitted from old damage, the likelihood of fatigue is even greater. If failure of this piece of equipment will shut the plant down then the consequence of failure is great. If there is a spare, then this consequence is greatly reduced. If there is no affect on the company production, then the consequence is low.

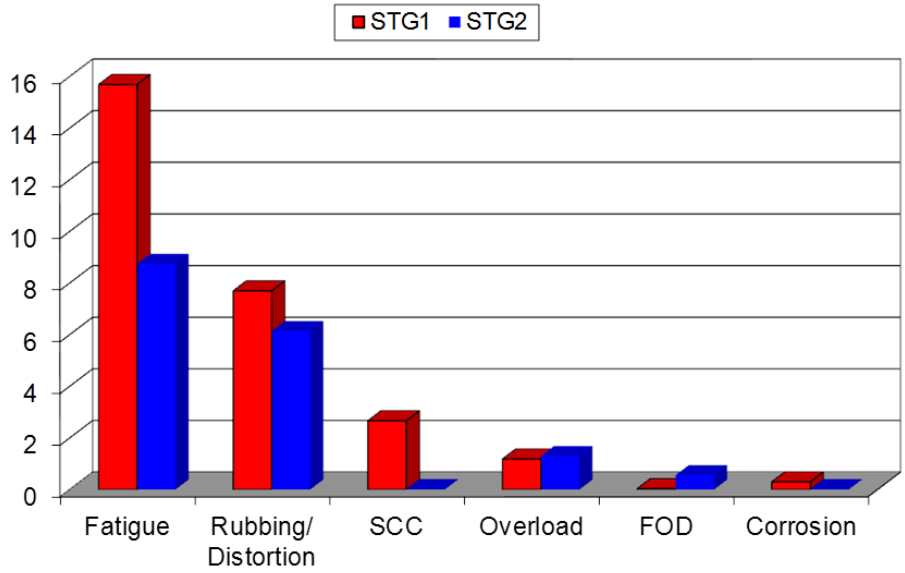

Figure 2. The highest risk failure mode for both STG1 and STG2 is fatigue.

This risk assessment process looks at many factors affecting the risk: equipment design conditions versus actual, equipment construction, operation, maintenance, monitoring and protection, upgrades, spares, past failures, near misses, test and inspection results, process variables (e.g., steam chemistry for a steam turbine).

After the data has been collected and reviewed, risk calculations can are performed. These calculations provide:

- Risk Ranking/Benchmarking the equipment with industry and other company equipment
- Risk contribution ranked by equipment subcomponents
- Risk ranked by failure modes
- Risk ranked by operating modes
- Risk ranked by extended operation beyond past overhaul intervals
- Risk mitigation recommendations

The following charts show the risk results for two steam turbines at the same plant. As can be seen they have different risk and potential failure mechanisms driving the risk.

The following are two examples of recommendations in various categories that came out of the steam turbine risk assessments. These came from multiple risk assessments, but show the range of what is driving the risk and needs to be mitigated or reduced.

Steam Chemistry Related Recommendations

1. The unit does not have any monitoring for sodium in the steam cycle. With an air cooled condenser, the most likely route of contamination would be

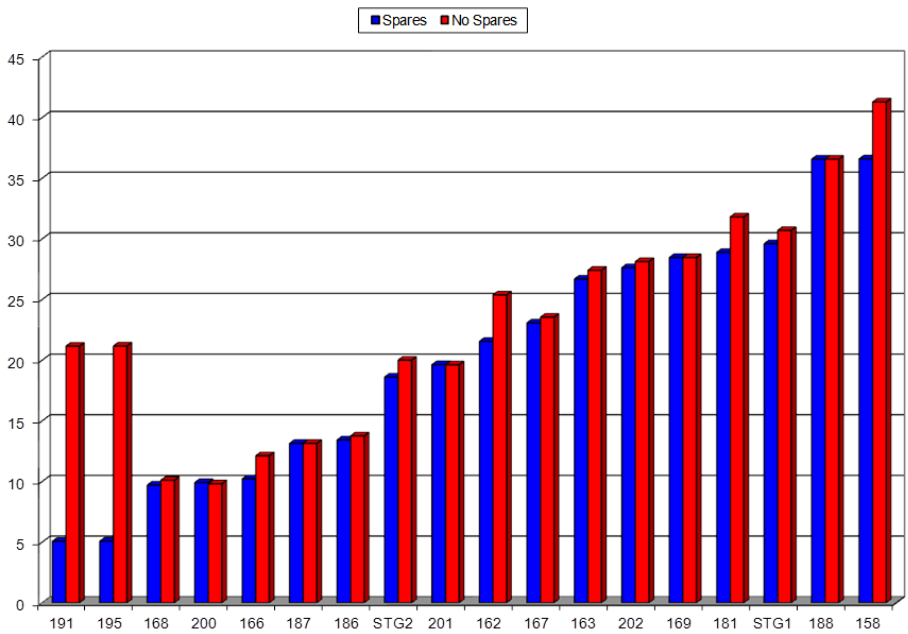

Figure 3. STG1 is a higher risk unit as compared to STG2.

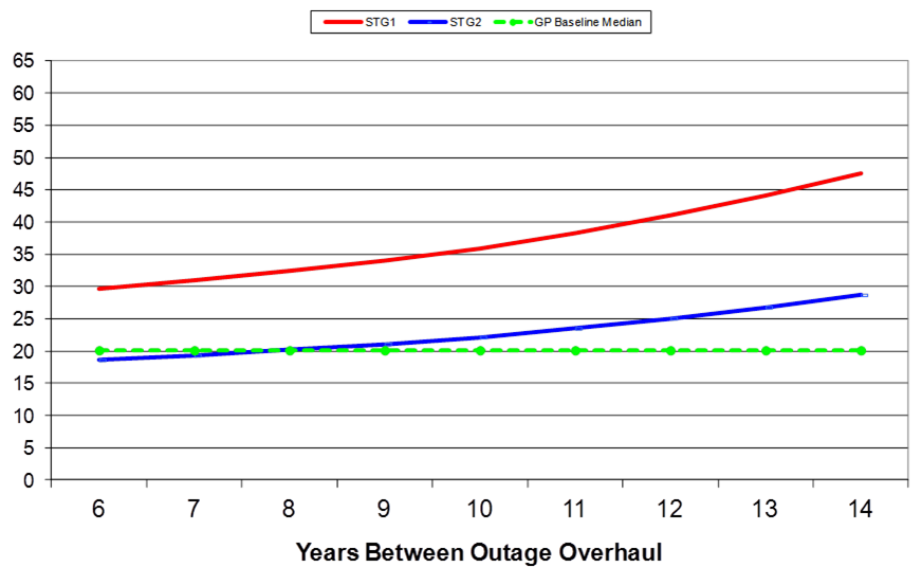

Figure 4. The risk for both STG1 and STG2 increases as the time between overhauls increases.

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through the demineralizer system. The plant has an anion and mixed bed, both of which are regenerated with caustic. Sodium monitoring will ensure that the plant is notified if there is some sodium hydroxide contamination from problems during or after regeneration. Cation conductivity will not detect sodium hydroxide contamination.

2. Direct and continuous monitoring of the steam chemistry is critical to minimizing corrosion and preventing steam turbine failures. Steam purity concerns are even more critical as the overhaul time is lengthened. Most critical is the continuous monitoring of cation (acid) conductivity and sodium in the boiler feedwater and main steam samples. It appears from the information provided that sodium is being monitored in the steam. The normal sodium limit should be < 2 ppb. However, the week's worth of winter and summer data provided by the plant has shown multiple excursions per day with average reading greater than 8 ppb. Thus, excursions greater than four times the EPRI recommended operating limit. The cause for the excursions needs to be identified and action taken to eliminate the sodium excursions, which can lead to caustic stress corrosion cracking of blades and disks.

Operating Conditions

1. The heavy oxidation observed on the shaft seal areas on the HP turbine indicates some very excessive sealing steam temperatures exceeding 538°C (1000°F). The sealing steam temperatures are reportedly on the order of 365°C for the HP. They need to reviewed, evaluated and properly controlled. Very short term temperature spikes on the order of 600+°C (1100+°F) would be required to oxidize the shaft seals as were observed. Depending on when the spikes occurred, the rotor can also be warped by the temperature spikes. A warped rotor shaft may be the cause of the vibration problems this unit has experienced. It also maybe the cause or contributor to past seal rubs and blade cover rubs. The sealing steam must be properly controlled.

2. It is abnormal to break the vacuum at such a high rpm (1200 rpm) after a trip of the turbine. When this is done the L-0 and L-1 buckets are being used to slow the

(Continued from page 4)

turbine/generator assembly down quicker. The additional load on the L-0 and L-1 buckets, in their present eroded condition, may result in a premature failure of these buckets. It is recommended that, based on the information provide, the vacuum not be broken until the turbine is below 300 rpm or preferably on turning gear.

Turbine Construction/Design

1. If seal rubs are discovered in the HP during the next outage, consideration to replacing the seals with a retractable design should be considered. They would be beneficial and alleviate the rubs that can occur during startups because of potential high vibration issues, resulting because of the susceptibility of the HP rotor to steam whirl.
2. If corrosion and it's by products, such as rust and scale, in the lube and control oil piping systems becomes an issue, the supply piping downstream of the oil filters should be changed to 316 SS per API 612 as a minimum. Typically, since the early 1970's, the entire lube and control oil systems including the oil reservoir are 316 SS, the return piping to the oil reservoir varies between 316 SS and carbon steel based on a particular companies internal standards. It is recommended that the emergency stop valve be tested at least once a year, which can be implemented as part of a planned shutdown.

Turbine Maintenance

1. With the longer time intervals between outages, it is important to continue a formal valve inspection program between major outages for the trip and throttle (main stop) valve, control valves, non-return valves, and actuators for the various valves. The valve internals should continue to be inspected every 3 years for fouling, FOD debris, wear, dimensional discrepancies, and seat leakage. The inlet strainer to the valves should also be opened and inspected for debris at this same time. On an annual basis, the valve actuators and servomotors should be inspected visually and internally for functionality, leakage and wear. Failure, sticking, or slow closing of any of these valves or actuators may result in major damage (overspeed or overload) to the steam turbine.
2. Because of indications of significant silica contamination and some caustic contamination, a borescope inspection should be performed as soon as practical to look for erosion, corrosion, FOD, cracking, and fouling/deposits. Any significant findings or observations should be addressed proactively up to and possibly including and early full dismantle inspection.

Properly applied risk assessments can assist in minimizing the probability of failure and/or the consequences of failure. Methodical evaluation of operating conditions, maintenance actions, inspection frequencies and other factors that affect aging equipment will result in better decision making regarding use of equipment assets, manpower, and dollars.

Dew Point Corrosion: A Case Study

By Oscar Quintero
Mechanical Engineer

and

Catherine A. Noble, P.E.
Senior Engineer

Dew point corrosion (also called low temperature corrosion) results from the attack of acidic vapors that condense over the surface of the material due to cooling down of the acidic gases. One of the more common situations involving dew point corrosion is in coal fired electric utility flue gas or air pre-heaters. This happens when the temperatures fall below the acid dew point, and in most industrial scenarios, sulfuric acid forms. Other moisture along with sulfurous ash deposits can form "acidic vapors" and attack a susceptible metal.

Some reasons why dew point corrosion occurs are:

Air leaking from inlet to outlet - This cooling is partly caused by cold air leaking in and decreasing the gas temperature, such that it drops below the dew point temperature. This allows the formation of acidic vapors condensing over the surface of the material.

Idle periods - As the boiler cools, the temperature of the external surface drops below the dew point, allowing moisture to form on the surfaces of the tubes.

One failed air heater tube made from CorTen B steel was received for corrosion analysis and examination.

Figure 1. The air heater tube section in the as-received. condition.

The tube came from a boiler that burns bark, tire-derived fuel, and gas fuels. It has a flue gas temperature between 480 and 500° F during normal operating conditions. The as-received tube section is shown in Figure 1.

The air heater tube section exhibited corrosion on the external surface of the tube. The ends of the tube were badly damaged. In addition, the wall thickness was extremely low. A perforation was noted over most of the length of tube. Cross sections from the air heater tube were removed at the failed area and at an area remote to the failure. The cross sections were prepared using standard metallographic techniques of mounting, grinding, polishing, and etching. Severe wall thinning of the air heater tube was observed in the perforated area (Figure 3). The cross section opposite from the perforation revealed deposit accumulation as well as severe wall thinning. The typical microstructure for all the air heater tube sections consisted of pearlite and carbides in a ferrite matrix. There was no heat damage observed in the microstructure of the air heater tube. In addition, no material defects were noted that contributed to the failure.

The deposits collected from the internal surface of the tube were analyzed in-situ using the scanning electron microscope (SEM), where elemental analysis was performed using energy dispersive X-ray spectroscopy (EDS) to determine their composition. The EDS spectrum of the chemical composition of the internal deposits is shown in Figure 2, and the results are summarized in Table 1.

The deposits consist mostly of iron and oxygen. Lesser amounts of carbon, aluminum, silicon, sodium, calcium, and zinc were present. In addition, trace amounts of sodium, magnesium, phosphorus, chlorine, potassium, and chromium were present. In this case of dew point corrosion, elements such as sulfur and

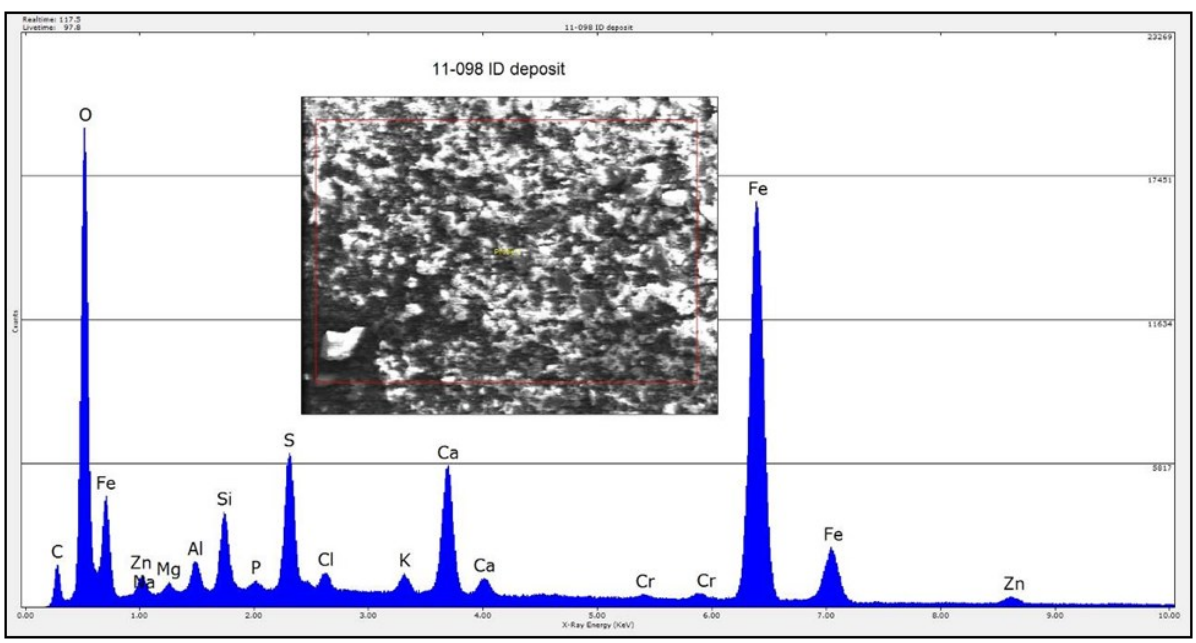
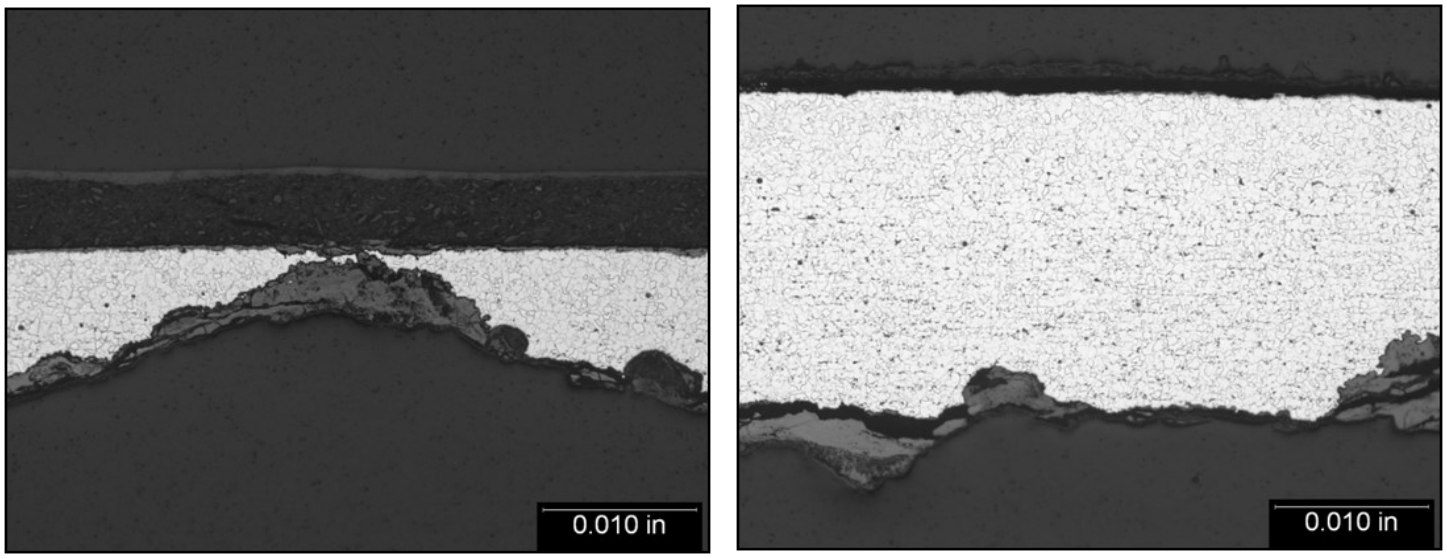


Figure 2. EDS spectrum of the chemical composition of the deposits collected from the internal surface of the heater tube.

Perforated Area



Opposite from Perforated Area

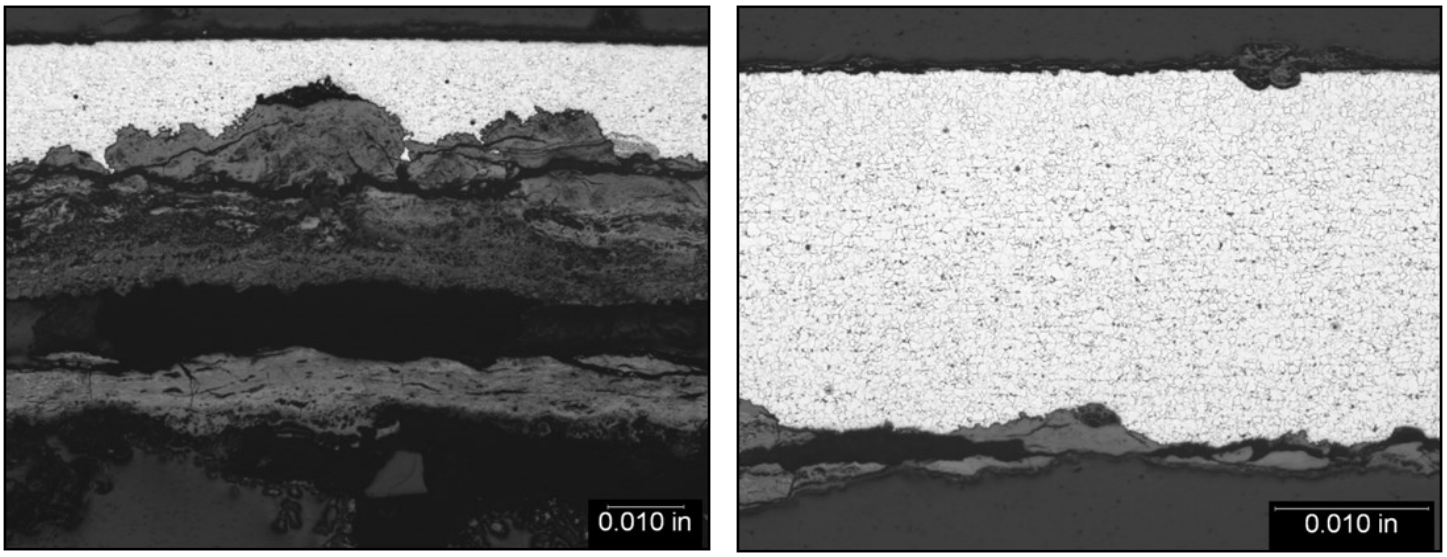


Figure 3. **Micrographs show the typical view of the perforated area (top images) and remote from the failure (bottom image) of the primary heater tube.**

chlorine in a wet environment can react with the cooled vapors to form acidic compounds such as a low concentration of sulfuric acid, which is very corrosive to carbon and low alloy steels, such as CorTen.

In this particular case, the dew point corrosion occurred in an air heater tube. Dew point corrosion can occur in other areas of the system, such as air heaters, feed water heaters, and boilers. This section below discusses some mitigation measures to prevent dew point corrosion.

Mitigation

The following items are measures that can be used to prevent or minimize dew point corrosion are:

Using a steam preheater to heat incoming air before it enters the preheater.

Addition of neutralizing fuel additives like calcium or magnesium oxide/ hydroxide. Such additives prevent an acidic environment.

Controlling air leakage from perforated cold end tubes.

Using fuels with lower sulfur content.

Injection of ammonia to reduce the acidity of the flue gas.

The drawback in using ammonia is that it forms bisulfate deposits, which can lead to fouling.

Employing a high pressure water spray of deposits on the fire side after boiler shutdown, followed by a lime wash to neutralize acidic substances.

Field Replication of Gas Turbine Blade Microstructure

By John P. Molloy, P.E.
Senior Consulting Engineer

To ensure reasonable mechanical properties and particularly creep rupture life of a gas turbine blade, it is paramount that the blade microstructure has the ideal shape and distribution of the constituent phases. The primary beneficial phases in question are the gamma prime and carbide constituents. The gamma prime constituent is probably the most scrutinized phase during microstructural evaluation, and is often used to determine if a blade is in need of refurbishment or not. The carbide shape and distribution is similarly important, but often takes a back seat to the gamma prime in assigning a condition to a blade.

Ideally, the gamma prime morphology should be cuboidal, which essentially implies that the microstructure, in cross section, should look like an array of squares. As the square shape of the gamma prime becomes more rounded, or "coarsened" the mechanical properties of the blades will be compromised, particularly with regards to remaining creep life. It is primarily for this reason that most gas turbine blades are limited to approximately 24,000 fired hours between refurbishment cycles.

In addition to gamma prime coarsening, the carbide morphology (shape) is also a factor in mechanical behavior. The carbides will change shape and also coarsen over time. Carbides may dissolve in the matrix and coalesce at the grain boundaries. Over time, if the carbide distribution in the grain boundaries becomes a continuous film, 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 (on contrast to carbides, which can be beneficial or detrimental depending on the shape and distribution). These TCP phases are often needle-like and are readily discernible in a microstructural analysis.

Now that we have established the need for microstructural evaluation of turbine blades, it is necessary to discuss the methods. The most common method for assessing the microstructure of a blade is to perform a destructive analysis, where a blade is sacrificed. This normally entails sectioning the airfoil in three locations (10%, 50% and 90% span) as well as the root. These cross sectional areas are metallographically evaluated for many of the features discussed above. However, today's turbines blades a marvelously engineered to ensure that they will maintain enough of their properties and survive their typical service cycle. It is during the hot gas path (HGP) refurbishment that the blades received their critical solution annealing and age hardening heat treatments to ensure that the appropriate microstructure has been restored. Depending on the service center performing the refurbishment, the 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 blade.

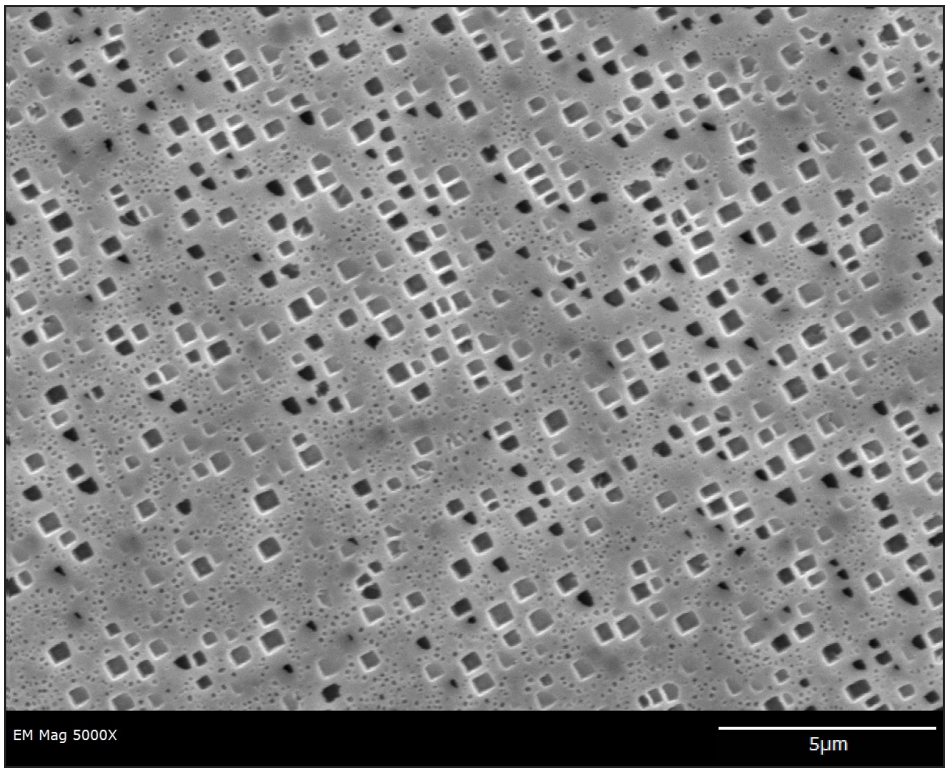


Figure 1. Typical gamma prime after ageing heat treatment

On the other hand, if the goal to ensure that the heat treatment has been effective, the blade need not be destroyed. Metallographic replication can be performed near the blade tip (where stress is low, and weld repairs are often performed). These replications can be evaluated at 5000x to establish the gamma prime and carbide morphologies. Ideally, such a replication would be performed after the ageing heat treatment, but before any other processing, such as coating. The blade microstructure could be "blessed" without sacrificing a blade. Moreover, once a blade is received, a typical replication and evaluation can be done in a day's time. Replications can be done by sending one blade to M&M Engineering's laboratory in Leander, TX. Alternatively, M&M Engineering staff can travel to the location of the blades to perform the replications on-site. Once the replications have been obtained, the samples must be coated (for electrical conduction) and evaluated on a scanning electron microscope (SEM) at high magnification (5000x) to establish the gamma prime and carbide conditions. This may provide additional quality assurance for independent gas turbine service center efforts in an era where fewer fleets are beholden to OEM refurbishment.

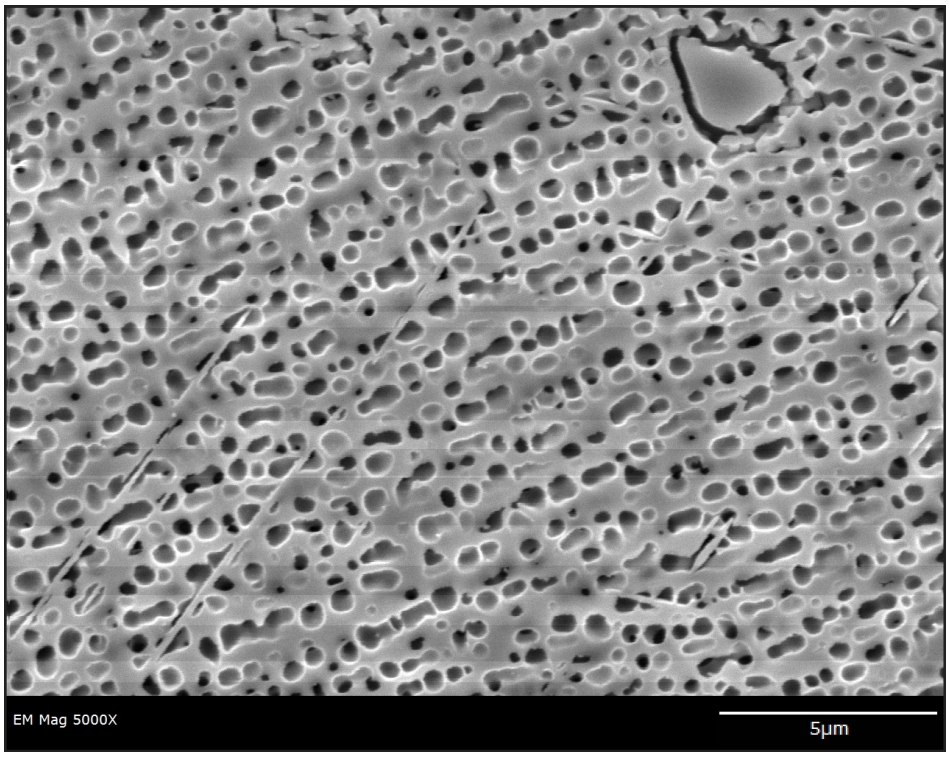


Figure 2. **Typical gamma prime after a complete hot gas path cycle**

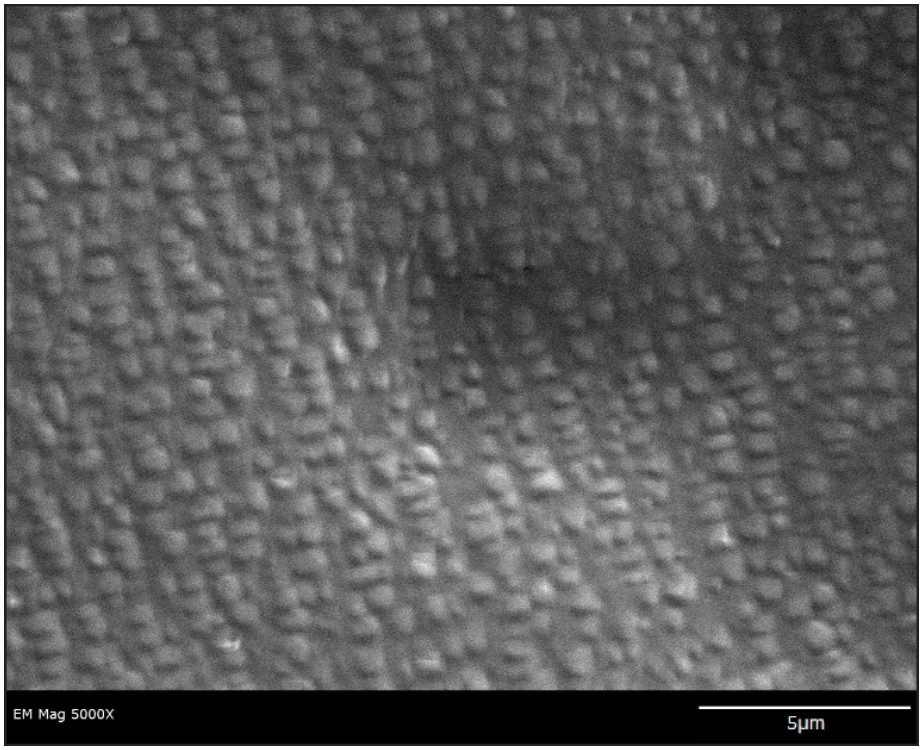


Figure 3. **Typical replica of gamma prime after exposure to hot gas path conditions**

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Seminars & Workshops

Catherine Nobile attended the 21st Annual HRSG User's Group conference & expo on April 29 through May 1, 2013 in Tampa, Florida.

Anna Gentry attended the AWEA WindPower2013 conference and exhibition on May 5 through 8, 2013 in Chicago, Illinois. In addition, Anna also participated in the conference as a volunteer.

David Daniels attended the International Conference Combined Cycles with HRSGs, Heat Recovery in the Industry Chemistry, Related Issues on May 6 through 8, 2013 in Heidelberg, Germany

Please visit us at www.mmengineering.com for additional information regarding conferences and events.

Letter to the Author

The question below was received in response to the article entitled *Water and Steam Chemistry Audits—Taking the Independent View* from our Vol. 13, No. 1 issue of *the Conduit*. It has been answered by David Daniels, the in-house chemist and principle scientist.

Q. *Can you advise if you have come across any corrective measures for treating MIC or scaling within larger diameter piping (8 inch or larger firewater loops)? These are mainly carbon steel or ductile iron. Any chemical treatments or hydro washing you can recommend?*

A. There are a number of things that can be done. First—do nothing—that is to say that once the air has been depleted, the aerobic bugs die. Once the sulfate is depleted, the SRBs die. A completely stagnant system rarely corrodes to failure. The worst cases of firewater piping corrosion are the ones where they are religious about testing the system and therefore are routinely adding new water (oxygen, sulfate) to the system. Every time they add new water the corrosion cycle starts again.

Second, depending on the system, there are non-oxidizing biocides that can be added to the water to minimize MIC in carbon steel and ductile iron piping. Adding bleach doesn't work as it will first try to oxidize the bugs, but will also oxidize the piping as well; and then is gone. The 10 bugs that survive the bleach treatment are 10^6 bugs in no time.

Hydro-lancing is an excellent way to remove existing corrosion and bacteria, if it can be arranged so that all the piping runs can be drained of debris. In large diameter piping, pigs can be used. Either method requires a number of connections on the system. Once it is clean however, if you don't change the conditions, the corrosion and bugs will come right back. So the best sequence is 1) figure out how you are going to prevent MIC in the future, 2) get that ready, 3) work out a cleaning plan that removes the scale and bugs from the piping with no dead legs, 4) clean it, and 5) begin treatment immediately after cleaning.

the Conduit is distributed free of charge by M&M Engineering Associates, Inc.. We welcome your comments, questions, and suggestions, and we encourage you to submit articles for publication.

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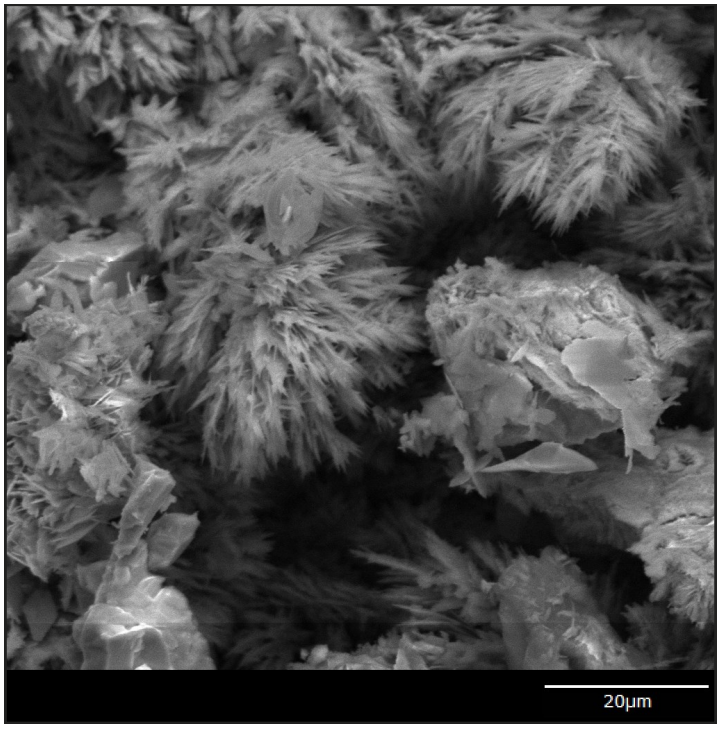
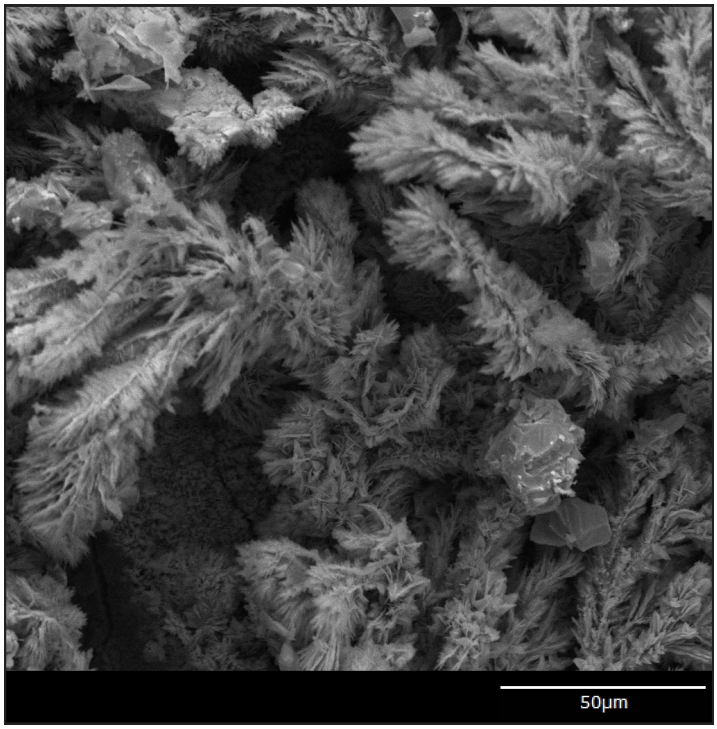
Birds of a feather...





Copper oxide, viewed with a scanning electron microscope

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