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The Current State of Boiler Tube Failures in Fossil Plants

INTRODUCTION

At the last international boiler tube failure conference in 1991 [1], the conference participants ranked the following areas as being of the highest priority to improve the overall area of boiler tube failures (BTF):

- Understanding corrosion fatigue and developing solutions.
- Developing NDE techniques for corrosion fatigue.
- Improvement in fly ash erosion control.
- Better identification of mechanisms.
- Management commitment.

It was also noted that BTF ranked as the number one equipment problem in fossil plants and had remained there for the previous 28 years [2]. However, the situation appeared to be improving: the equivalent unavailability factor due to BTF was about 2.7 % and was decreasing on an annual basis (Figure 1).
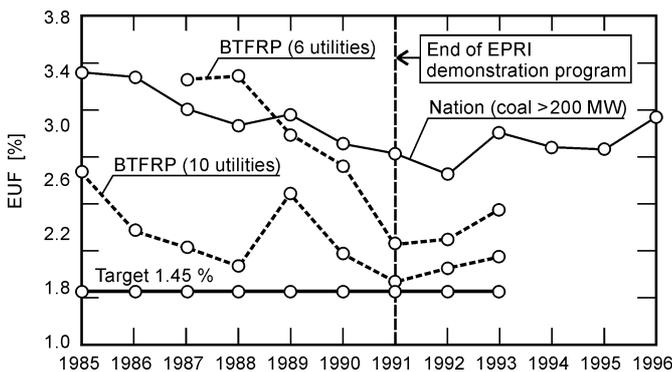
Figure 1:   Equivalent Unavailability Factor Due to BTF: Boiler Tube Failure Reduction Program (BTFRP).

Utilities are shown and compared with the National Average for Coal Fired Units greater than 200 MW. (Data supplied by NERC/GADS)

Six years later it is disappointing to report that the situation in the industry has deteriorated, and that in 1996 the unavailability factor was at about 3.0 % and increasing on an annual basis (Figure 1).

Previous and subsequent analyses have indicated that the disturbing feature of these BTF is that most of them are repeat failures. This is despite the major efforts expended to understand the mechanisms and possible root causes, and to develop permanent solutions. A recent compilation provides the theory and action oriented procedures for each BTF mechanism [3].

A number of possible reasons for this downturn can be suggested:

- Impending deregulation of the utility industry.
- Competition forces the utilities to be more cost sensitive. This means less capital replacement projects. Plant personnel perform more repair or partial replacement.
- Consolidation of utilities. Systems optimization to balance efficiency, capacity, emissions, and reliability in combining utility markets.

Each or all of these trends is leading to less people in plants and, in many cases, to those people previously involved in BTF moving to new responsibilities so any continuity is lost.

This amplifies one of the conclusions from the last conference that the barrier to achieving major availability improvements is not technical, but one of management and economics. It appears that in the current market the adoption of formalized company-wide BTF Reduction Programs is now of paramount importance. This is discussed again later.

BOILER TUBE FAILURE DEMOGRAPHICS

There have been a number of previous EPRI/NERC programs to assess the statistics of BTF [2,4]; these together with the 1991 Conference Survey [1], and on-going assessments of the industry, provide a current ranking of BTF mechanisms (Table 1).

In terms of boiler locations, most comprehensive BTF data compilations worldwide indicate that the order of decreasing failures is waterwalls, superheater, reheater and economizer.

Corrosion Fatigue
Fly Ash Erosion
Under Deposit Mechanisms (Hydrogen Damage and Acid Phosphate Corrosion)
Long Term Overheating/Creep
Short Term Overheating
Sootblower Erosion
Fireside Corrosion (Waterwall, Superheater, Reheater)

Table 1:   Leading BTF Mechanisms (in order of availability loss in MWh).

BOILER TUBE FAILURE MECHANISMS

In the last six years enormous strides have been made in addressing the top two mechanisms in Table 1. The third group of mechanisms relates to the importance of cycle chemistry which has improved in parallel. One area which is not high on the list but which is currently of major concern in the industry is that of waterwall fireside corrosion in units with low NO_x burners. Each of these failure areas will be briefly overviewed in this paper to represent the key technical developments over the last 6 years. Although it is very important to identify the mechanism and root cause of each failure to ensure low availability loss and to eliminate repeat failures, a large number of utilities often misdiagnose BTF mechanisms [14]. Careful attention has been given over the last six years to assemble the tools that utilities need to eliminate this [3]. An example is provided.

Corrosion Fatigue

Corrosion fatigue has been the leading single cause of availability loss in fossil plants for over 20 years. However, work conducted in the last 5 years has started to provide the tools to the industry for identifying and overcoming the failure mechanism. This work has also clarified the influence of stress and environment on the mechanism. An approach involving an "Influence Diagram" (Figure 2) integrates the three basic influences: stress, environment and operating history [3,5]; each will be briefly discussed here to illustrate the latest thinking.

Operating hours and the number of unit starts are combined into an equivalent operating hours. It is also clear that the number of chemical cleans is also important.
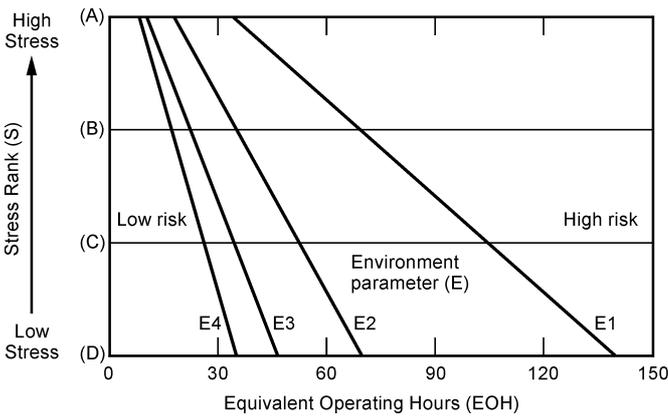
Figure 2.   Influence Diagram for Corrosion Fatigue in Waterwall Tubes.
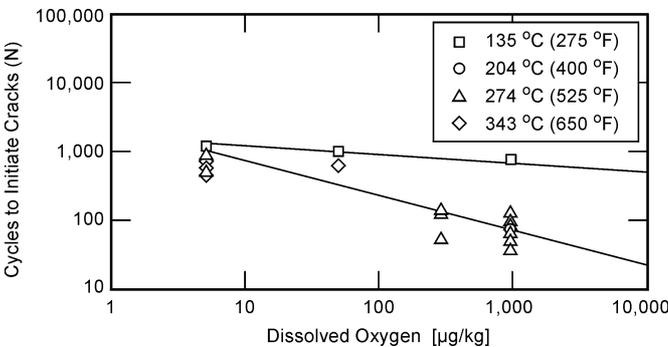
Figure 3:   The Influence of Dissolved Oxygen on the Cycles to Initiate Corrosion Fatigue Cracks in Boiler Water.

The influence of stress can be provided qualitatively through a Stress Rank, A - D, in order of decreasing stress for each of the 24 susceptible locations. However, it is now clear that corrosion fatigue is a discontinuous process involving the initial breakdown or fracture of the protective magnetite, and the repetitive breakdown (re-initiation) when the critical fracture strain for magnetite is exceeded. The German Technical Rules for Steam Boilers (TRD 301) have stipulated for numerous years that the applied oxide strain levels should be less than 0.1 % in tension. More recent monitoring on a boiler in Australia [9] which linked the results from small gauge length strain gauges with finite element analyses has indicated that the peak strains at corrosion fatigue sites are greater than 0.2 %.

The influence of the boiler water environment has similarly been confused in the years prior to the last conference, basically because the initial laboratory studies clearly suggested that oxygen was important in increasing corrosion fatigue [6,8]. However, detailed monitoring undertaken in Canada, US and Australia [7,9] indicated that at the time when the peak strain is imposed on the tubing, the dissolved oxygen in the boiler water has usually decreased to low levels (< 20 µg/kg). Further monitoring of a large number of units operating with congruent phosphate treatment [10,22] indicated that these units can suffer from phosphate hideout and return; conditions which can superimpose a pH depression at the time of the peak strain. This recognition was followed by a second series of laboratory studies [11]. Figure 3 shows the effect of oxygen on corrosion fatigue crack initiation in boiler tubing. Below about 135 °C (275 °F) there is very little effect of increasing oxygen levels, whereas above this temperature there is a marked dependence:

$$N = 2445 \, DO^{-0.5256} \tag{1}$$

where N is the number of cycles to initiate cracks, and DO is the dissolved oxygen (µg/kg).

These results are very important in that they suggest that oxygen has very little effect on corrosion fatigue during the startup period when the peak strain on the tubing is highest.

pH was also shown to have a strong effect at constant low levels of dissolved oxygen (5 µg/kg). Figure 4 shows that the number of cycles to initiation is reduced to about one third at both 204 °C (400 °F) and 274 °C (525 °F) when the pH level was approximately 6 as compared to the base condition of pH 9.
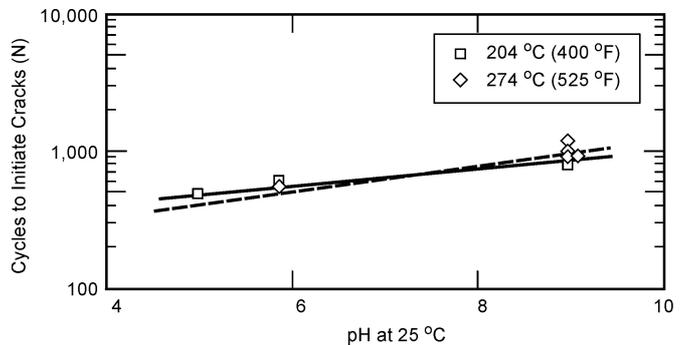
Figure 4:   The Influence of pH on Cycles to Initiation of Corrosion Fatigue Cracks in Deaerated Boiler Water (< 5 µg/kg oxygen).

The pH was controlled with phosphate solutions of different $Na:PO_4$ molar ratios.

These recent monitoring and laboratory studies have important implications for corrosion fatigue in boilers, as the recent results imply that cracks may only initiate, re-initiate and/or grow when the environmental conditions are conducive. Inactive cracks are found in field studies indicating that the process is not continuous but consists of a series of re-initiations at times when the strain on the inside tube surface is great enough to crack the magnetite (> 0.2 %).

It is clear that in the laboratory environment an increase in dissolved oxygen levels from 5 to 1,000 µg/kg will significantly decrease the number of cycles to initiate corrosion fatigue cracks at high temperatures (135 °C or 275 °F) (Figure 3). There is also no doubt that during a shutdown

period the oxygen level in boiler water can reach high, perhaps saturation, levels; but these periods do not generally occur at the same time as the peak in applied strain level. Thus it is important to know both the time dependency of elevated oxygen levels and the peak strain.

This situation should be contrasted with that for pH depressions, where the pH of the boiler water can be depressed during the period of peak strain at locations susceptible to corrosion fatigue.

Thus a detailed understanding of the major influences is not an easy process for each case of corrosion fatigue and requires a detailed field monitoring program (environment and strain).

Fly Ash Erosion

In most countries, fly ash erosion (FAE) is the most serious or second cause of availability loss for fossil plants. Historically the approach has been to arbitrarily position solid shields and baffles or apply a variety of coatings in 'areas' where FAE was occurring. It was recognized in an earlier study that the use of these palliative repair techniques was the main cause of repeat failures due to fly ash erosion. They simply redirected the high velocity flow onto an adjacent tube area [3].

The rate and extent of erosive processes are affected by particle velocity, angle of impact, particle composition and shape, and erosive resistance of the tube surface including compositional and temperature variations.

Particle velocity is the most important parameter as the rate of erosive loss is proportional to the velocity raised to an exponent that ranges between two and four. Particle velocity is driven by the local flow velocity at any particular boiler location. The optimum long term solutions are based on identifying and reducing the highest velocity locations. It is important to note that local velocities, not bulk velocities across a section of the boiler are those of interest. As a rule of thumb, maximum design bulk velocities are on the order of 50 ft/sec or less. It has been observed that local velocities in excess of 100 ft/sec are required to cause fly ash erosion failures in 10,000 to 50,000 hours.

The primary tool to combat FAE is flow modification in conjunction with a cold air velocity test before and after modification. A comprehensive EPRI Guideline has been published since the last conference [12], which provides a step-by-step procedure. This overall approach is shown in Figure 5.

Where units have been evaluated by the cold air velocity technique (CAVT) to determine local velocity profiles, maximum local velocities of two or more times the nominal velocity have typically found, and these peak velocities usually correspond to the locations of know tube erosion damage.

The use of CAVT to identify regions of excessive velocity, followed by the installation of diffusion and distribution screens, should provide utilities with the most permanent solution to the problem.

However, the technique has not been adopted by sufficient utilities, which explains why FAE is still the second most important failure mechanism.

Waterwall Fireside Corrosion

Historically waterwall corrosion in coal-fired boilers and the associated boiler tube failures have been ranked seventh or

eighth in the overall ranking of availability loss (Table 1). The industry has been concerned about possible increased levels of waterwall corrosion ever since low NO_x burners were first installed over 20 years ago. Many millions of dollars have been expended by utilities on ultrasonic thickness inspections of large areas of waterwalls without finding any increased levels of corrosion.
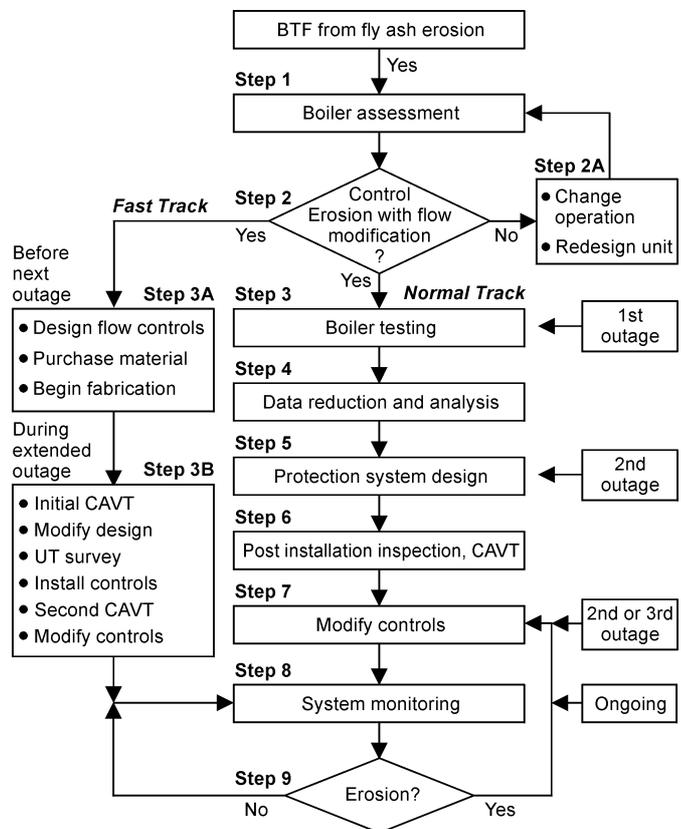
Figure 5:   Overall Approach to Fly Ash Erosion using the Cold Air Velocity Technique and Flow/Ash Modification.

The Clean Air Act Amendment of 1990 required decreased levels of NO_x (0.45 - 0.5 lbs NO_x/MBTU or 204 - 214 g/GJ NO_x), necessitating deeper levels of staging of the combustion process and the addition of separated over-fire air ports (SOFAs). This resulted in a drastic increase of corrosion in a number of boilers to levels in the range 50 - 120 mils/yr (1.25 - 3 mm/a). At these corrosion rates, waterwall tubes only last a few years and have major negative effects on the unit availability and on the cost of electricity.

The mechanism of waterwall fireside corrosion is well understood [3]. Macroscopically, waterwall tubes affected by fireside corrosion will demonstrate a large loss of wall thickness on the fireside of the tube. The damage usually affects more than one tube at any given location. The maximum attack is generally found at the crown of the tube facing the flame and can encompass about 120° of the tube circumferentially. If a tube failure occurs, it is often in this location; longitudinal cracking may be evident.

Damage is usually found with hard fired inner-layer deposits on tubes with loosely bonded ash on the outer layers. Unburned carbon, iron oxides and iron sulfides are found in scale overlaid by sintered deposits. These are indicative of

poor combustion, flame impingement or local reducing conditions.

The mechanism for waterwall fireside corrosion is sulfidation due to the presence of a substoichiometric environment adjacent to the tube wall. Reducing environments (i) lower the melting temperatures of deposits, and (ii) produce hydrogen sulfide which is considerably more corrosive than sulfur dioxide that predominates under oxidizing conditions. Gas analysis of the reducing environment next to the severe corrosion sites has indicated H_2S levels about 800 ppm and CO levels above 10 %.

Under conventional firing conditions with oxidizing environments, the iron oxides magnetite (Fe_3O_4) and hematite (Fe_2O_3) are the commonly found corrosion products. With substoichiometric environments, mixtures of magnetite and iron sulfide (FeS) are found. Nearest to the tube surface are alternating layers of Fe_3O_4 and FeS; further towards the combustion process the size of the FeS islands increases until at corrosion rates above 120-150 mils/yr (3.0 - 3.8 mm/a) the FeS becomes continuous. On the outside of the oxide scale/deposit, there is always clear evidence of unburnt coal particles and fly ash spheres.

The sulfide scales allow higher rates of transport (diffusion) of iron cations than oxides, and are thus less protective. The greater the thermal gradient through the deposit, caused by increased heat flux, the faster will be the diffusion process.

Based on the observations of accelerated waterwall corrosion on boilers with low NO_x burners and SOFAs the following characteristics have been found:

- both wall-fired and tangentially-fired boilers can be affected;
- mainly supercritical boilers, but drum boilers have also been affected;
- the coals being burnt are generally eastern bituminous with sulfur levels above 1.5 %; however, blends with low sulfur levels and chlorine above 0.2 % have been used
- all the affected units have SOFAs;
- the worst areas appear to correlate well with flame impingement areas, where the level of deposition is slightly less, and tube temperatures could be elevated;
- heat flux is important, but the worst areas might not correlate exactly with the highest heat flux area.

All the currently applied solutions depend on the introduction of a high chromium (> 20 %) alloy between the tube and the corrosive furnace environment [13]. The chromia (Cr_2O_3) oxides formed are more resistant than the iron based oxides (Fe_2O_3 and Fe_3O_4) to sulfidation.

The shortest and least reliable solutions (1 - 3 years) are those applied by thermal spraying with the variability very dependent on the preparation and application procedures.

The longest protection (8 - 10 years) is currently predicted to be provided by weld overlaying with IN 625 alloy, or by applying chromized tubing. However, neither option has had more than a couple of years exposure under the very severe reducing and corrosive environments. Laser welding is the newest of the options, but again there is no long term operating experience.

An EPRI waterwall fireside corrosion burner rig has been developed at Leeds University which provides excellent reproduction of the field morphologies. This rig is being used to develop a correlation between corrosion rate and the key variables (temperature, heat flux, H_2S and CO en-

vironment), and will be used to determine the useful life of the established overlay and chromized solutions, as well as assessing the possible use of other alloys such as Fe-Al.

Superheater/Reheater Long Term Overheating (Creep) or Fireside Corrosion in Coal-Fired Units

Two of the most often misdiagnosed BTF mechanisms are failure of a tube by (i) long-term overheating, with or without accelerated oxidation, leading to a final failure by creep, and (ii) fireside corrosion by molten alkali sulfates, also resulting in subsequent creep. Table 2 provides a list of primary macroscopic and microscopic features of the two mechanisms. When distinguishing between creep and fireside corrosion, it is important to note that many of the features are superficially similar. For both mechanisms the final failure mechanism is creep which is easy to identify. The problem is recognizing the dominant underlying root cause.

In the case of long-term overheating, the tubes operate above the design temperature limits. This can occur (i) from unit startup because of poor design, (ii) as a result of the accumulation of internal oxide scale which results in increased tube metal temperatures, (iii) because of steam flow imbalance, or (iv) out-of-plane tubes (resulting in the heat flux being too high). Wastage occurs, generally at the 10 o'clock and 2 o'clock positions on the tube as a result of increased oxidation. The outside tube surface generally has an "alligator hide" appearance. The internal scale that develops is usually thick, multi-laminated and cracked.

In the case of fireside corrosion, the overriding cause is a corrosive coal ash. This causes the formation of a liquid ash deposit which fluxes away the protective oxide. The tube does not necessarily have to be overheated, although it can be for the same reasons as listed above for long-term overheating. The appearance of the external tube surface can be the same as for long-term overheating (thick, dark, "alligator hide" oxide), and there can be thick, cracked internal oxide as well. The key feature that will identify fireside corrosion wastage is the presence of low melting point ash compounds in the external deposits.

It is now clear that the preferred method for estimation of the tube remaining life for each root cause is based on the oxide thickness technique [15].

IMPORTANCE OF CYCLE CHEMISTRY IN BTF PREVENTION

Cycle chemistry has a major influence on 10 BTF mechanisms in water-touched tubing, and on 5 BTF mechanisms in steam-touched tubing [3]. The challenge is not trivial. BTF are related not only to the choice of boiler water chemistry, but very importantly also to the feedwater chemistry. Corrosion products are generated in feedwater heaters and flow into the boiler where they deposit in high heat flux locations and provide the initiating event for the underdeposit failure mechanisms (Table 1). Over the last three years the original EPRI interim consensus guidelines have been replaced by specific boiler water guidelines for all-volatile treatment [16], phosphate treatment [17], oxygenated treatment [18], and caustic treatment [19]. There are also three feedwater choices: all-volatile (ammonia plus an oxygen scavenger), all-volatile (ammonia only), and oxygenated treatment (ammonia and oxygen). It is imperative that each unit has the optimum cycle chemistry [20] together with a comprehensive set of guideline limits.

Characteristic	Long-Term Overheating/Accelerated Oxidation	Fireside Corrosion by Molten Alkali Sulfates
Fracture Surface and Appearance of Failure	• Generally thick-edged, brittle final failure. • Generally accompanied by external tube wastage, which may be small, at the 10 o'clock and 2 o'clock positions.	• Tube wastage, particularly at the 10 and 2 o'clock positions. • Longitudinal cracking, final failure can be, but is not necessarily by overheating.
Internal Scale?	Yes, generally extensive, multi-laminated and exfoliating.	Yes, particularly if tube metal overheating was an influencing factor.
External Scaling?	• Yes, thick, laminated and often longitudinally cracked. • Usually two layers (i) a hard, porous outer layer with composition typically that of fly ash, and (ii) a black glossy inner layer (mostly oxide, but may contain some sulfates and sulfides of iron).	Yes, with multi-layers: (i) a hard, porous layer - composition typically of fly ash, (ii) an intermediate layer containing complex alkali sulfates, and (iii) a black, glossy inner layer mostly of oxides, sulfates and sulfides of iron.
Outside Surface Appearance After Removal of Scale/Deposits	Characteristic longitudinal grooving and pitting ("alligator hide") appearance.	Characteristic longitudinal grooving and pitting ("alligator hide"). Sometimes "orange peel" appearance at extremities of severe corrosion; sometimes the corroded areas are smooth and featureless.
Composition of External Scales/Deposits	Does not contain low melting point ash compounds such as alkali iron sulfates.	Does contain low melting point compounds such as alkali-iron sulfates (coal-fired units).
Wall Thinning?	Typically wastage flats at 10 o'clock and 2 o'clock positions caused by accelerated oxidation, however, depending on tube position, could just be on one side. There is always a layer of oxide adjacent to the tube.	Primary feature of failure, may be worse at the 10 and 2 o'clock positions, however, depending on tube position could just be on one side. Depending upon the rate of corrosion, a protective oxide layer may remain on the surface or may have been fluxed off.
Ratio of Wall Loss to Steamside Oxide Thickness	Typically less than 3:1.	Typically greater than 3:1, for ratios greater than 5:1 fireside corrosion or erosion is the dominant mechanism.
Tube Material Degradation	Yes, generally extensive signs of overheating and/or of creep damage, particularly near the crack tip. Creep voids will not be found away from crack tip.	If overheating has been a problem, yes; otherwise, no. Molten sulfate corrosion can occur in a tube at design temperatures.
Change in Material Hardness	Localized softening near the rupture is typical	Hardening is not necessary; if there has been no overheating, there will be no change in hardness.

Table 2: Distinguishing Characteristics of Long-Term Overheating (Creep) and Fireside Corrosion in Superheater/ Reheater Tubing of Coal Fired Units [3].

Cycle Chemistry Parameter		AVT (Mixed Metallurgy)	AVT (All-Ferrous)	Oxygenated Treatment (OT) (All-Ferrous)
pH	-	8.8 - 9.1	9.2 - 9.6	8.0 - 8.5 [a] 9.0 - 9.5 [b]
Ammonia, NH_3	mg/kg	0.15 - 0.4	0.5 - 2.0	0.02 - 0.07 [a] 0.3 - 1.5 [b]
Cation Conductivity	µS/cm	< 0.2	< 0.2 (< 0.15)	< 0.15 (< 0.1)
Iron, Fe	µg/kg	< 10 (< 5)	< 5 (< 2)	< 5 (< 1)
Copper, Cu	µg/kg	< 2 (< 2)		
Oxygen, O_2	µg/kg	< 5 (< 2)	1 - 10	30 -150 [a] 30 - 50 [b]
ORP [c]	mV	<< 0	0 - 80	> 100

Table 3:   Comparison of Normal Cycle Chemistry Limits at the Economizer Inlet for AVT Feedwater and Oxygenated Treatment for BTF Reduction.

[a] For once-through units   [b] For drum units   [c] Oxidizing-reducing potential
Values in parentheses represent the achievable and desirable levels.

Three of the major cycle chemistry changes which have taken place since the last conference, and can directly improve unavailability due to BTF, are delineated here:

• Oxygenated treatment (OT) was introduced into the US for units with all-ferrous feedwater systems. About 100 units have been converted. From a BTF perspective, the majority of these units easily achieve much less than 1 µg/kg iron at the economizer inlet during normal operation (Table 3). This reduces markedly the deposition on the waterwalls of supercritical units and eliminates the formation of ripple magnetite. Most importantly, OT has eliminated the circumferential cracking BTF mecha-

nism, which was predominant in these units. It also eliminates the need to chemically clean the boiler.

- For units with all-ferrous feedwater systems, the ability to eliminate the reducing environment (imposed by the oxygen scavenger, such as hydrazine), and change to an oxidizing one (ORP > 0 mV) has also reduced iron transport [21] (Table 3). From a BTF perspective, this eliminates the flow-accelerated corrosion of economizer inlet header tubes.
- The acid phosphate corrosion (APC) mechanism (under-deposit corrosion) on waterwalls of drum units operating with congruent phosphate treatment has both been identified [22] and understood in the last 6 years. The application of one of the new phosphate chemistries (equilibrium phosphate treatment (EPT) or phosphate treatment (PT)) introduces conditions where APC cannot occur [17]. The key points here are that acidic phosphate chemicals (mono-, or di-sodium phosphate) should not be injected into the boiler to counteract phosphate hideout, and that up to 1 mg/kg of NaOH is allowed in the boiler water.

The elimination or reduction of phosphate hideout and return, by adopting EPT/PT, also produces major improvement in the corrosion fatigue resistance of boiler waterwalls as discussed in a previous section.

CONCLUDING REMARKS

Goals and BTF Reduction Program

The set of goals for BTF reduction (Table 4) has been revised as a result of the technical advances over the last 6 years.

• Active BTF reduction program and corporate philosophy – Comprehensive documentation
• Availability loss due to BTF of less than 1% – Less than one BTF/boiler/year
• No cycle chemistry influenced BTF
• No maintenance influenced BTF
• Cycle chemistry guidelines for all units – Optimized feedwater treatment – Optimized shutdown, layup, and startup – Elimination of the need to chemically clean
• Established NDE procedures
• Qualified metallurgical analysis
• Established life assessment methodology

Table 4:   Goals for BTF Reduction.

It is felt that these goals are achievable. However, the state-of-the-art understanding of BTF mechanisms, root causes, maintenance, NDE and cycle chemistry are <u>not</u> by themselves sufficient to reduce the unavailability due to BTF. Without an overall corporate approach and philosophy document [4] the goals will not be reached, and the unavailability will continue to increase (Figure 1).

A new combined and integrated boiler tube failure reduction (BTFR) and cycle chemistry improvement (CCI) program has been developed [23], based on the latest technical BTF understanding [3] and the most recent cycle chemistry guidelines [16-19].

The powerfulness of such programs is clearly illustrated in Figure 1 by two groups ("10 utilities" and "6 utilities") that demonstrated the procedures. The figure indicates a target unavailability of 1.45 % which was derived from the individual goals of the participating utilities prior to starting the program. The first group of 10 utilities, representing around 44,000 MW of capacity, started the demonstration below the national average and continued to decrease at a faster rate. The one increase in 1989 was due to hydrogen damage failures in one unit. By 1991 they had almost reached their collective goal.

The second group of sixs utilities, representing around 16,000 MW of capacity, started the demonstration above the national average and by the conclusion of the program had reduced the unavailability to 1.4 %.

Future Activities

As indicated in the introduction, the changes taking place in the industry are directly affecting utility BTF programs.

As part of the corporate wide BTFR approaches, it is suggested that prevention through prediction and proactive measures will be needed, and the key indicators will have to be monitored. The loss of expertise due to manpower reduction is also a feature that needs to be addressed.

Even in utilities that adopted corporate BTFR approaches, serious increases in unavailability can occur (see after 1991 in Figure 1) if the programs are not refreshed each year by training.

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