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the Conduit

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Recovery Boiler Lower Furnace Problems

By Ronald Lansing, P.E. and Max Moskal

The lower furnace area has been a critical area in recovery boilers since the beginning of the recovery process. Furnace operators are well aware that a water leak into the molten smelt bed in the lower furnace is cause for them to shut down the boiler rapidly to avoid the worst possible situation—a boiler explosion. Many damage mechanisms can come into play in the lower furnace. These can range from normal tube thinning to stress assisted corrosion (SAC) cold side cracking.

The first high-pressure recovery boilers were introduced around 1960 to 1965. B&W used studded tubes, even for low-pressure boilers. Studded tubes were also used on the earliest high-pressure boilers. CE never used studs for new boilers even when they built high-pressure boilers. Their approach was to use tri-coat metalizing for the lower furnace. Bare carbon steel tubes were used in the lower furnace because pressures (and tube surface temperatures) were low. Bare tubes are still acceptable in these old boilers which have pressure up to about 600-psi. Coatings proved to be largely unsuccessful for the long term.

When studded tubes were used in the lower firebox (for better transfer of heat to the water-carrying tubes), the tube and stud material was plain carbon steel. The studs would corrode away by sulfidation at rates dependant on the liquor and/or smelt chemistry and temperatures. The tube wall thickness would also become thinner (Figure 1). Many low-pressure boilers still operate and experience long life with studded carbon steel tube panels. Evidently, their process variables (the tube life and inspection and/or maintenance costs) are acceptable.

Figure 1. Lower furnace studded tubes can become thin and difficult to test with UT between the studs. Thinned tubes can be seen in the orange area.

Two problems arose with studded walls—finding and monitoring the areas of tube thinning and new stud welds cracking due to sulfide contamination. The key variables to monitoring the tube thickness were determining the safe inspection interval (which takes repeated testing to determine) and limited tube surface access for the ultrasonic thickness transducer to measure the tube thickness (particularly after repeated re-stud application). The stud weld contamination could be solved by carefully cleaning the area before welding.

The next generation lower furnace tubes used bare stainless steel clad composite. The stainless steel did not experience sulfidation corrosion. The first Alloy 304 stainless steel composite tubes in North America were used in new CE and B&W boilers about 1981. Some of these boilers were high pressure, up to about 1250-psi. It was generally believed that composite tubes should be used for boilers above 900-psi, but some users wanted composite tubes for lower pressure boilers.

Two problem areas have been found in composite tube designed furnaces—air port area thinning and adjacent weld cracking. Most air port cracking in composite tubes has been due to thermal fatigue. The second problem area has been the floor where clad areas and membranes cracked.

At the air ports, inspections and

(Continued on page 2)

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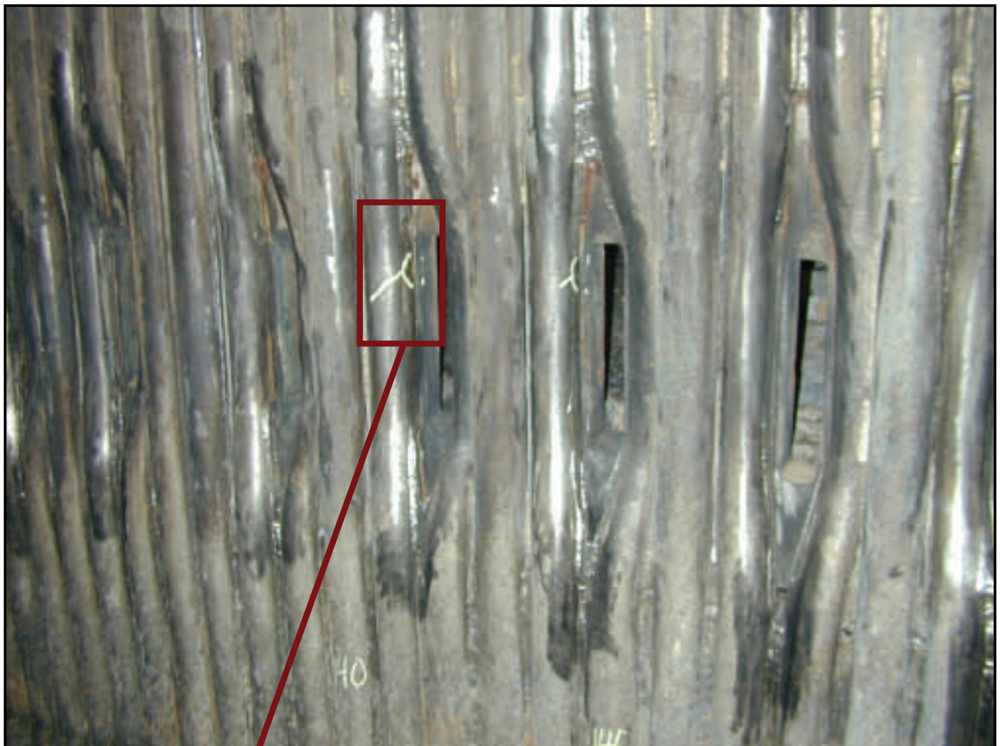


metallurgical studies have shown

that the thinning mostly occurred in the stainless steel. Small bald spots (Figure 2) thin much slower and could be more easily monitored and re-clad as necessary. Many mills used weld overlay, such as Type 309L stainless steel, to repair bald spots at air ports. Experience has shown that the overlay corroded as fast as the original cladding, if not quicker. Nickel-based alloys were also not satisfactory in repairing bald areas.

Figure 2. Primary air port "balding" (rusty steel exposed) shown in both images.

Repeated weld overlay invited cracking of air port tubes. Some boilers have been rebuilt with "modern" air distribution systems for better efficiency. However, some of these air port designs have resulted in wide temperature fluctuations at the air port tubes with thermal fatigue cracking as the consequence. Removing fin and crotch plate welds has limited air port crack sites. Alloy 625 and Alloy 825 weld overlays have been found to be more resistant to air port thermal cracking than the original stainless steel.

Floor tube stress corrosion cracking (Figure 3) under the smelt bed was found to be due to contact with hydrated smelt in the critical tube temperature range of 300°F to 400°F. Most of these cracking problems occurred when boilers were reheated above 300°F for dryout while the tubes were in contact with the smelt. The cracking that had been tested using penetrant dye testing seemed to be present mostly within the stainless clad metal and self-arrested areas at the carbon steel interface. If cracking in floor tubes occurs, it is often best to wait until cracking becomes more widespread to replace the tubes, and then use the Alloy 625 or Alloy 825 (nickel base) weld overlay on the floor. The floor tube cracking has been regularly monitored in some boilers in-lieu of wide spread cladding replacement.

Floors have had other problems as well. Some second-generation boilers have decanting bottoms, which are not as sloped as the original floor designs. The almost horizontal floor tubes can be prone to low-flow problems, sometimes leading to localized tube

Figure 3. SCC cracking on a stainless steel clad floor tube can lead to spalling (circled).

Figure 4. Floor tube leak at weld. The low flow of the horizontal tube combined with weld drop-through initiated DNB boiling tube overheating/ thinning.

through the protective oxide inside the restrained tube gradually forming a crack-like corrosion groove and then finally an actual crack that leaks. Special procedure radiography has been the most effective test method for finding SAC. A regular inspection is critical to catching this progressive problem and determining the inspection interval requires repeated testing.

Careful monitoring with both nondestructive testing, engineering evaluation of lower boiler conditions and test results will help owner/operators catch these damage mechanisms before serious failures can occur.

overheating (Figure 4). In addition, sagging can cause "puddles" in the floor, which may further inhibit flow (Figure 5).

Cold-side cracking is a problem that has begun to plague some older boilers. Stress assisted corrosion (SAC)—sometimes called corrosion fatigue in other industries—occurs throughout the boiler on the cold side of tubes with highly restrained welded attachments. Since there are many such attachments in the lower furnace, SAC is definitely a damage mechanism that has disastrous potentials when adjacent to the smelt bed. SAC works its way

Figure 5. Decanting floor "puddle" area with smelt bed removed.

John P. Molloy, P.E.

John Molloy is now certified as a Professional Engineer!

Congratulations to John Molloy, Consulting Engineer for M&M Engineering Associates, Inc. John recently received his license as a "Professional Engineer, Metallurgical" in the State of Texas. John has over thirteen years of experience in the engineering field, specializing in turbine blade coating and casting assessment, accident investigation, failure analysis and laboratory testing. He received his BSMSE from the College of Engineering at the University of Florida. John has been an employee of M&M Engineering since February 2006.

Flow-Accelerated Corrosion is Still With Us...

By David Daniels

On May 9, 2007, a three-inch high-pressure feedwater water line at a Kansas utility ruptured killing two, one instantly and the second a few days later from burns suffered due to the incident. Others were also injured. While the final cause has not been confirmed, the preliminary indications are that the pipe failed due to flow-accelerated corrosion.

The mechanism of flow-accelerated corrosion is well understood and the design and metallurgical conditions that cause flow-assisted corrosion (FAC) exist in most US power plants. If FAC is possible, changes in chemistry will only be able to reduce the rate of corrosion, not eliminate it. There can be no substitute for regular ultrasonic thickness inspections of feedwater piping, particularly near elbows, tees, reducers, valves, and other areas of turbulent flow. Although a peak temperature range for corrosion has been identified, there have been documented failures well outside this range. Turbulent flow and metallurgy can trump other factors such as temperature and chemistry.

Plants with copper alloy feedwater heaters must be particularly careful. The oxygen scavengers (reducing agents) that they must use to prevent copper corrosion increase the rate of flow accelerated corrosion. Plants with no copper, (most combined cycle plants) should not, as a rule, be using oxygen scavengers. Increasing the pH of the feedwater (9.0 to 9.3 for plants containing copper and 9.2 to 9.6 for plants with no copper), will also help. However, good chemistry control is no substitute for regular inspections.

Piping that contains small amounts of chromium, molybdenum, and copper have been shown to be significantly less susceptible to flow accelerated corrosion. Alloys with 1.25Cr or higher have been successfully used in areas susceptible to FAC.

Some plants have been lulled into thinking that they do not have FAC issues because they have not had issues in the past. They may have even performed piping inspections before in areas of high probability for FAC, and found nothing. However, FAC can develop very slowly and changes in operating practices, particularly from cycling load to a more consistent full load operation, can accelerate FAC. Changes in piping, equipment, and feedwater chemistry, may also have an effect. The economic pressures that keep the plant operating at base load may also make it more difficult to find the time for a proper FAC survey.

However, as the failure at the unit in Kansas reminds us, FAC failures are typically catastrophic and often fatal. Finding and eliminating just one area that could fail is well worth the effort.

For further information on Flow Accelerated Corrosion, please contact M&M Engineering Associates, Inc.

Flow Accelerated Corrosion Evaluation: A Case Study

By Jonathan D. McFarlen

M&M Engineering Associates, Inc. performed an onsite flow accelerated corrosion (FAC) evaluation for the boiler feedwater piping and steam extraction lines at a Midwest power plant. During the plant visit, M&M Engineering personnel visually inspected the piping systems and selected areas for non-destructive testing.

In lieu of testing every inch of piping and fitting, knowledge regarding the FAC mechanism was used to identify areas where the damage was more likely, allowing the evaluation effort to be more focused. This makes routine monitoring of more susceptible piping locations economically viable.

The four major factors that affect the potential for FAC damage were weighed during the selection of areas for non-destructive testing.

Factor 1 – Metallurgy: According to information provided by plant personnel, the boiler feedwater piping was constructed using ASTM A106, Grade B, Schedule 80 seamless carbon steel pipe. The steam extraction lines were constructed using ASTM A106, Grade A, Schedule 40 seamless carbon steel pipe. Simulated FAC laboratory tests have shown that carbon steel components are highly susceptible to FAC whereas low alloy components showed great resistance. Studies have also shown that even trace amounts of chromium and copper improve resistance to FAC. Since the boiler feedwater piping and steam extraction lines both utilize carbon steel piping, it can be assumed both are equally susceptible to FAC damage.

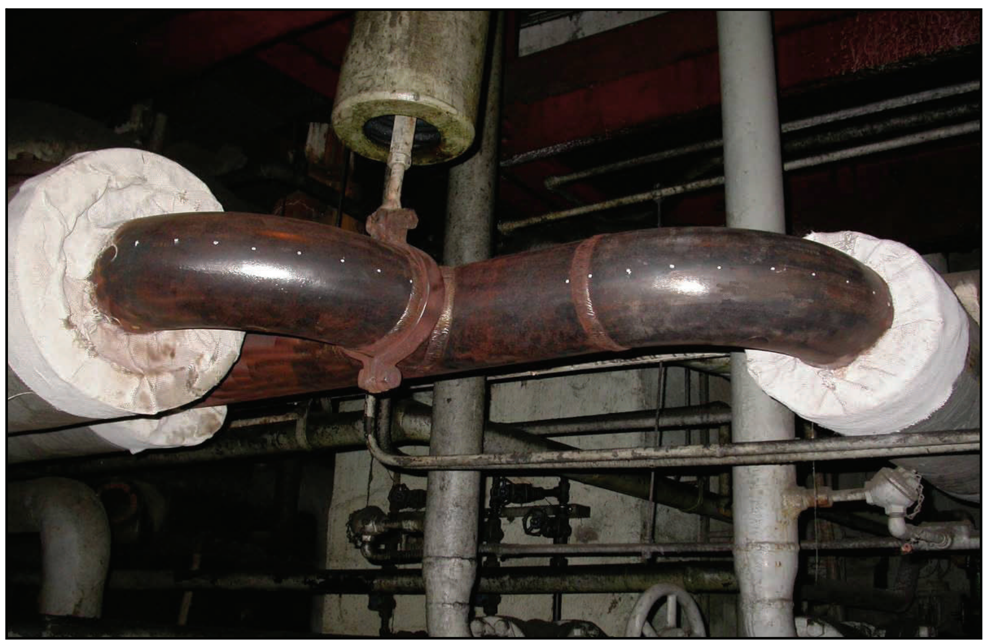
Factor 2 – Feedwater Chemistry: Since both units contained mixed metallurgy components (i.e., ferrous and copper based alloys), the water treatment program at the plant utilizes an oxygen scavenger which results in a reducing boiler feedwater environment. FAC damage can only occur in a reducing environment as opposed to an oxidizing environment. The oxidation-reduction (redox) potential may vary at different points within the boiler feedwater piping and the steam extraction lines. However, for the selection process, all piping was considered to have the same redox potential.

Factor 3 - Temperature: Various published papers on FAC agree that FAC damage occurs within a temperature range of 70°F to 480°F with a peak temperature of about 300°F where the highest rate of thinning occurs. That being the case, areas for nondestructive testing within the boiler feedwater piping (particularly downstream of the feedwater heaters) were of higher priority than the steam extraction lines, which operated at lower temperatures.

Factor 4 – Flow Conditions: Flow conditions were the final and main consideration in prioritizing areas for nondestructive testing. Areas containing fittings (tees, elbows, valves, etc.) where flow disruptions would be expected were especially considered. Furthermore, areas containing multiple fittings in close proximity were selected so that more testing could be performed in a smaller area requiring minimal pipe insulation removal. This approach allowed for "more bang for the buck". For example, the photograph below shows one of the areas selected for thickness testing. This particular area contains multiple elbows common to a line branch. Minimal insulation had to be removed to allow testing of the two elbows and branch and/or tee.

After weighing the four major factors, eight areas were selected on each unit for a total of sixteen areas. Six of the areas were located on the boiler feedwater piping and two areas were on the turbine extraction piping.

Surprisingly, evaluation of the boiler feedwater piping determined that very little thinning had occurred during the past fifty years of operation. Localized thinning down to 67% of the nominal thickness was measured on one elbow. On average, boiler feedwater piping thicknesses were near the nominal thickness. Since little thinning had occurred, it was recommended that future inspections of the boiler



feedwater piping be reduced to fewer areas with the main objective being to establish a baseline thinning rate.

Greater thinning was measured on the steam extraction piping. Thinning down to 55% of the nominal pipe thickness was measured. On average, the thickness of the steam extraction piping was near the nominal

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thickness. Thinning was localized in bends and short segments of straight pipe downstream of valves. Given the degree of thinning detected, it was recommended that the number of locations examined during future inspections of the steam extraction piping be increased.

Minimum pipe thickness values were calculated for the boiler feedwater piping and steam extraction piping per the ASTM B31.1 Power Piping Code. The calculations only considered the required minimal thickness for internal pressure and did not account for bending loads due to weight or thermal expansion.

Although significant thinning was identified in the steam extraction, comparison of the lowest thickness values to the calculated minimum thickness showed that sufficient thickness remained. Therefore, it was concluded that the piping was suitable for continued service but should be re-inspected within two to three years.

M&M Engineering Associates, Inc.
Will See You at These Conferences

Engineers' Society of Western Pennsylvania
International Water Conference
October 26-30, 2008
The Crowne Plaza – Riverwalk
San Antonio, Texas

2008 TAPPI Engineering, Pulping and Environmental Conference
August 24-27, 2008
Portland, Oregon

Seminars and Workshops Attended

HRSG Users Group Meeting
Austin, Texas

The HRSG Users Group met in M&M Engineering's home town on April 7-9 this year. The meetings were very well attended with over 300 attendees. Prize drawings during the conference provided benefits to a number of lucky conference participants. This year, the grand prize, held at the end of the conference, was a ride in an F-16. M&M Engineering provided a walking tour of downtown Austin including the State Capitol building and Congress Avenue bridge, just in time to see the emergence of Austin's bat colony.

Of course, the highlights of the conference were the presentations and technical exchange that provided everyone who had a question with the combined knowledge and experience of the group. Discussions were moderated by Bob Anderson, the Users Group Chairman and the questions covered many aspects of HRSG operation including mechanical repairs, operation, environmental compliances and water and steam chemistry. Next year's conference will be April 6-8, 2009 in Jacksonville, Florida.

M&M Engineering Associates, Inc. attended

The Western Turbine Users, Inc. 2008 Annual Membership Meeting

at the Town and Country Resort & Convention Center in San Diego, California April 6 - 9, 2008.

***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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