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CURRENT EXPERIENCE IN TYPICAL PROBLEMS AND FAILURES WITH BOILER PIPING COMPONENTS AND SUPPORTS

by

James P. King, Design Manager
DB Riley, Inc.

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DB RILEY, INC.

Post Office Box 15040
Worcester, MA 01615-0040
http://www.dbriley.com

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ABSTRACT

This paper will provide some current experience with typical problems and failures of boiler piping components and supports, together with a description of the recommended actions and resolutions. The focus of the paper will be on recent experience in the areas of water induction in sloped steam lines and flow accelerated corrosion in water carrying lines. In addition, some problem areas with superheater crossover and outlet piping components will be described.

Water induction from condensing steam can occur at low point locations in piping lines, and lead to corrosion, pitting, and thermal quenching with resultant distortions, cracking, and failures. Flow accelerated corrosion is a very topical subject. It involves the thinning of piping components from the internal effects of water velocities and chemical make-up etc.

A detailed overview of water induction and flow accelerated corrosion in boiler piping components will be presented, in addition to recent examples in the form of case histories, together with their applicable findings, conclusions, and recommendations.

INTRODUCTION AND BACKGROUND

Over the past fifteen years, condition assessment programs have routinely been scheduled for fossil fired boiler piping components and supports as part of annual or major outages.

Initially, the primary focus of such programs was on the current condition of the high energy steam lines routed from the boiler to the turbine. This attention was driven by the occurrence of several catastrophic failure events in hot reheat steam lines fabricated with longitudinal seam welds. This paper focuses on recent experiences with the phenomena known as water induction which can occur in sloped steam lines including their small diameter branch and drain piping lines.

In more recent times, increased attention has been given to the feedwater piping lines to the boiler. This based on failure events recorded for such piping systems in both fossil and nuclear power plants. These failures have been attributed to a phenomena known as flow accelerated corrosion.

Over the years, increased attention has been given to the boiler proper piping lines. Problem areas have been identified on systems such as the superheater crossover and outlet piping, including the branch feedwater piping to the attemperator nozzles on the crossover lines. The problem areas include cracking in the piping component welds which have been attributed to over temperature conditions, thermal fatigue, and non-functioning supports.

Historically, electric utilities have scheduled unit outages on an annual basis, typically during the spring or fall months when the load demand is lower. Today the utilities have increased the intervals between major outages up to as long as thirty-six months. This pattern of scheduling less frequent outages requires much better record keeping, and more detailed planning for the inspection and maintenance tasks performed during the outage.

For a typical condition assessment program of a boiler steam piping system, the work tasks would include the following items.

- Review of Records
- Hot and Cold Walkdown Inspections
- O.D. and Circumferential Pipe/Header Measurements
- Ultrasonic Thickness and Shear Wave Testing
- Replication Metallography and Hardness Testing

If deemed necessary, a current stress analysis program would be performed for a piping system. This due to revisions in the piping geometry, changes in unit operation or the existence of deteriorated supports. For the latter item, proof testing of support assemblies can be done on-site to determine if the component is still capable of carrying its original design loading.

WATER INDUCTION

Water induction from condensing steam can occur in boiler piping lines and cause corrosion, pitting and thermal quenching, with resulting distortions, cracking and subsequent failures. This condition is most likely to occur in sloped, horizontal steam lines at low points. Water can also be introduced into steam lines from back flow through drains and sample lines. For boilers with horizontal secondary superheater elements; steam which becomes entrapped in the tubes during a cool down event will quickly condense and overflow into the outlet header and main steam piping, depending on the routing or location of the components.

Thermal quenching can occur when the condensate comes into contact with a header or pipe bottom section. Repeated cycles of this resulting thermal shock can eventually lead to excessive bending, permanent distortions, such as sagging, and cracking of the components. A sagging pipe condition can be initiated and/or aggravated by the existence of supports that are not functioning or carrying their load, as designed.

Remedial measures used to prevent or lessen the effects of thermal quenching are: adherence to specified boiler cool down rates, temperature monitoring of the top and bottom sections of components by thermocouples, and nondestructive examination of components to establish their current condition. Retrofit modifications have included steam line rerouting, enlarging of drain and vent lines, and the addition of valves in drain lines to prevent ingress of the condensate.

The subject of water induction and thermal quenching of steam piping components has been addressed in the Reference 1 and 2 papers.

DB Riley, Inc. has been involved in two studies, which include the assessment of steam piping lines with water induction problems, which are described as follows.

Main Steam Piping Line

A full condition assessment program was recently performed by DB Riley on the main steam piping line of a 1970's vintage fossil fired utility boiler. All of the work tasks, as listed earlier in this paper, were performed on the piping components, welds, and supports.

Both hot and cold walkdowns of the piping system were performed. Several anomalies were visually apparent. First, sagging was evident in the lower section of a long horizontal run of piping. The maximum amount of sag was later measured to be seven inches. (See the Figure 1 Photograph). Nondestructive testing tasks, including metallographic replication, were performed on the outside surface of the sagged portion of pipe. They revealed a more advanced stage of spheroidization than at other piping locations. However, there was no evidence of creep damage, loss of hardness, or component thinning. A near term recommendation was given to monitor the condition of the sagged portion of piping, including the taking of a core sample at this location, in order to record the microstructural and surface conditions on the inside of the component.

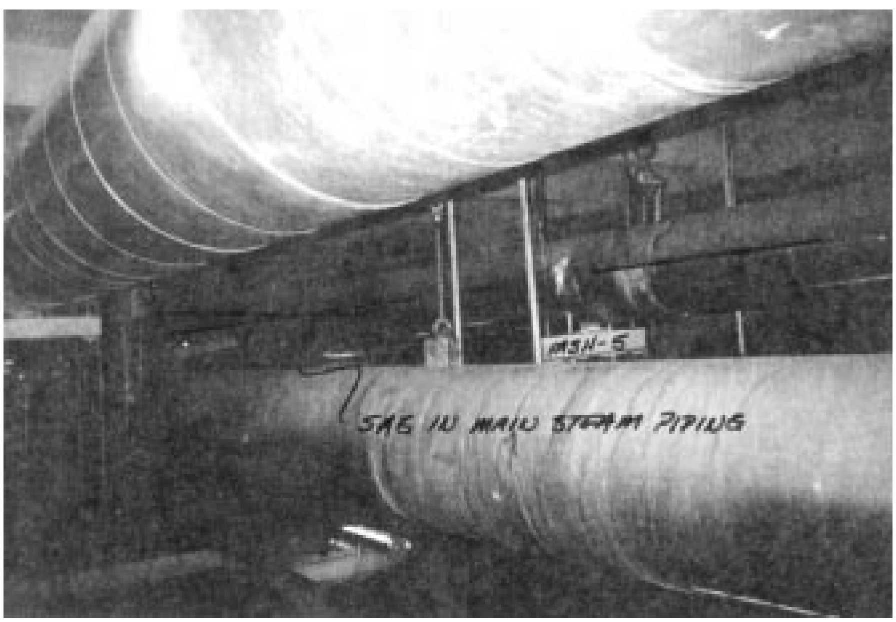

Figure 1 Main steam piping general view of sagged horizontal portion.

A second finding was the current overall condition of the support system of the main steam piping line. Several hangers were visibly damaged, and others had setting indications which showed the support to be malfunctioning or bottomed out. Of particular concern was the three pairs of dual constant force support assemblies, on the horizontal run of pipe, which were found to be skewed from the normal horizontal and vertical axes, in both the hot and cold conditions. (See Figures 2, 3, and 4 Photographs). Recommendations were given for a re-evaluation of the main steam piping hanger system to ensure its integrity, and for repair or replacement of hangers/supports, as necessary, to assure that they are carrying their design loads.

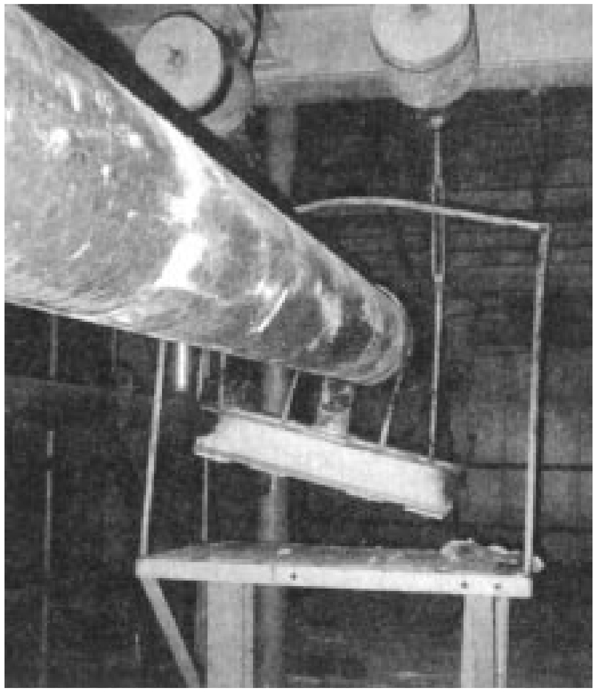

Figure 2 Main steam hanger in cold condition. View shows the severely skewed support which indicates that the constant supports are not functioning properly.

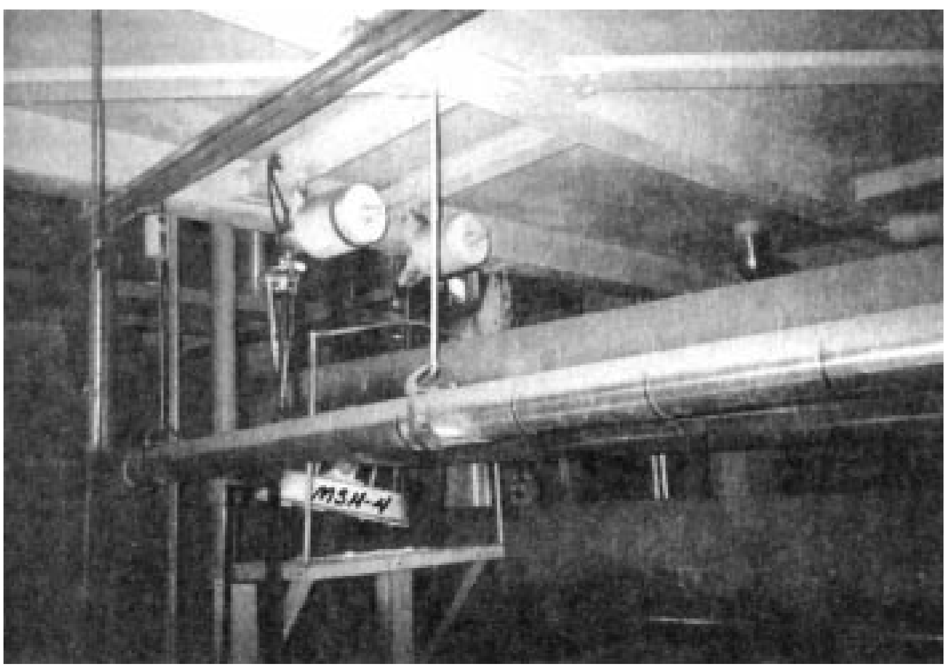

Figure 3 Main steam line. Constant force supports in hot condition. It can easily be seen as skewed.

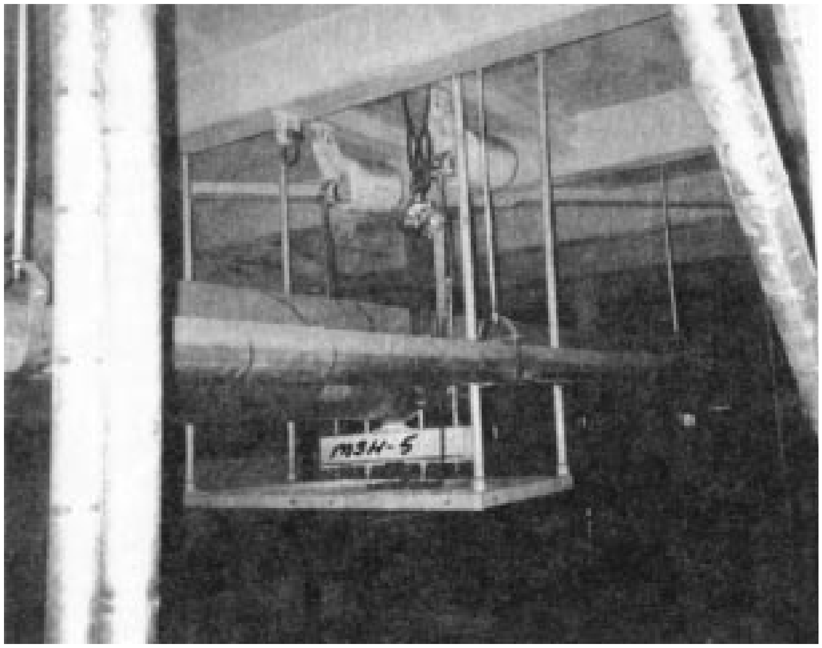

Figure 4 Main steam constant force support in hot condition. They are also damaged and observed to be skewed.

Cold Reheat Piping Line

DB Riley and others were involved in the failure evaluation of a ruptured portion of a cold reheat steam lead to a boiler. This is a mid 1960's unit. The rupture initiated in a horizontal piece of the pipe and propagated into part of a bend at the inlet to the boiler.

Due to the lower operating pressures and temperatures of a cold reheat line, the piping components are typically made from plain carbon steel material. Quite often, and for this particular case, the pipe fabrication was from rolled plate which is longitudinally seam welded. The area of crack initiation was at a low point in the horizontal length of seamed piping where condensing steam had collected during boiler cool down events over the past years. For this section of pipe, the longitudinal weld was located on the bottom. Corrosion and pitting had occurred along the weld due to the cyclical presence of the condensation. Over time, the pitting had aligned with eventual crack formation, propagation, and ultimately a rupture.

A check for this potential condensate corrosion damage on cold reheat piping lines should be a part of scheduled piping inspection and assessment programs. A visual walkdown will locate potential condensate entrapment regions. Internal video inspections can determine the existence of any corrosion, pitting, or cracking.

SUPERHEATER CROSSOVER PIPING

Superheater crossover systems are part of the boiler piping and are designed to convey the superheated steam from the primary to radiant, and radiant to secondary superheater sections. Attemperators located in the superheater crossover piping are used to control the steam temperatures by introducing spray water to the steam flow.

Condition assessment programs should be scheduled for components of superheater crossover piping components and welds including the attemperator assemblies, since cracking has been found in these components during routine examinations. The condition assessment of attemperators is discussed in detail in the Reference 3 paper.

The cracking is typically due to thermal fatigue, a result of over temperature conditions and cyclic or load swing operation. Distress in components located downstream of the attemperators can additionally be attributed to the frequency and duration of water spray events.

The condition of crossover piping supports should also be documented on a scheduled basis, since such hangers have been found to be non-functioning or inadequate, resulting in over stress conditions on the piping components. A case study of crossover piping problems is described in the Reference 4 paper. A typical radiant superheater crossover piping system is shown in Figure 5.

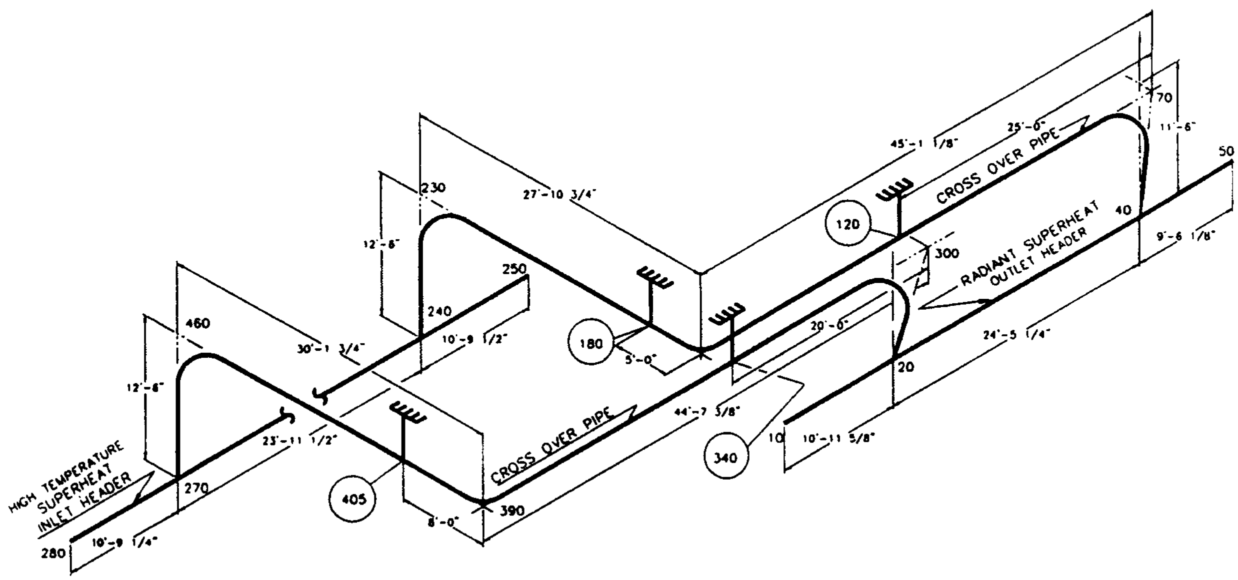

Figure 5 A typical radiant superheater crossover piping system

For such condition assessment programs, the following crossover superheater piping components should be evaluated.

- The nozzles and welds at the piping to the superheater inlet and outlet headers.
- The attemperator components including the spray nozzle, liner and attachment welds, and feedwater pipe welds.
- Pipe elbow welds.
- Radiographic plugs.
- Pipe support assemblies.

SUPERHEATER OUTLET PIPING

Several years ago DB Riley performed an evaluation of an elbow with severe internal gouging, located in the outlet steam piping on an industrial boiler.

This 1983 boiler is rated at 275,000 lbs per hour. This elbow component is located in the superheater outlet piping between the superheater outlet header and an attemperator station in the penthouse of the boiler. The attemperator is used to cool the outlet steam to the turbine.

The inside surface of the elbow was characterized by localized deep gouging at a location corresponding to the extrados. Associated with some regions of gouging were internal deposits. Laboratory measurements confirmed that the deepest gouge had penetrated about 75% of the elbow wall. As part of a detailed evaluation of this condition, DB Riley performed optical metallography, scanning electron microscopy, x-ray diffraction, and alloy and chemical analysis.

The conclusion to this comprehensive analysis of the gouged elbow is that the condition was due to a combination of fluid impingement coupled with a corrosion mechanism. The pattern of gouging indicated some physical impingement consistent with water spray, especially during low steam flow conditions. High sodium content found in the inside surface deposits suggested that the corrosion mechanism was caustic gouging.

Recommendations were given for inspection of the remaining steam line and attemperator components, replacement of the subject elbow, possible re-routing of components, and review of the water chemistry and the steam temperature versus water spray flow requirements.

FLOW ACCELERATED CORROSION

In recent years there has been a serious industry concern with a number of instances of failures in feedwater and wet steam piping components due to thinning by a phenomena known as flow accelerated corrosion.

Flow accelerated corrosion (FAC) is relatively slow thinning of an inside pipe or component wall which can lead to break-before-leak type failures. It occurs in piping systems with higher flow velocities at more turbulent regions. This would include piping sections following valves, tees, reducers and bends.

The following parameters have been found to influence wall thinning of plain carbon steel piping by flow accelerated corrosion.

- Piping Configuration / Geometric Location
- Fluid Chemistry
- Temperature
- Pipe Material
- Fluid Velocity

Condition assessment tasks for feedwater piping system components include ultrasonic or eddy current thickness testing, alloy testing, and internal video inspection in areas or components of susceptibility.

The power industry awareness to the potential for piping failures due to flow accelerated corrosion began as a result of a pipe rupture at the Surry Unit No. 2 nuclear plant in 1986. After this failure, a study was undertaken by the Nuclear Power Group of the Electric Power Research Institute (EPRI), to better understand the flow accelerated corrosion mechanism and prevent its occurrence. In contrast, the phenomena was almost unknown among fossil plants until the mid 1990's.

A fossil plant contains hundreds of feet of water piping components, and flow accelerated corrosion can occur anywhere, under the right circumstances. EPRI has issued the Reference 5 Technical Report to help identify the most susceptible systems and components for inspection. The report also addresses the development of long term strategies to avoid future problems, including changes in water chemistry, system design, and materials. One of the key inhibitors in the resistance of FAC in carbon steel piping components is the amount of chromium present in the material.

In conjunction with the report, EPRI offers a predictive software program called CHECUP, which models FAC wear in susceptible fossil plant systems and components based on flow and operating conditions.

Feedwater Piping

Over the past three years DB Riley, Inc. has been involved in the assessment and failure evaluation of feedwater piping components of fossil plants.

The assessment tasks involved ultrasonic thickness testing, where a grid pattern of measurements was taken on the uncovered outside surfaces of elbow, bend, reducer, branch connection, tee and straight pipe locations in higher flow and turbulent regions. Where accessible, internal inspections were performed and recorded by use of videoscope equipment. An example of the inside surface condition of a section of pipe exposed to flow accelerated corrosion is shown in the Figure 6 photograph.

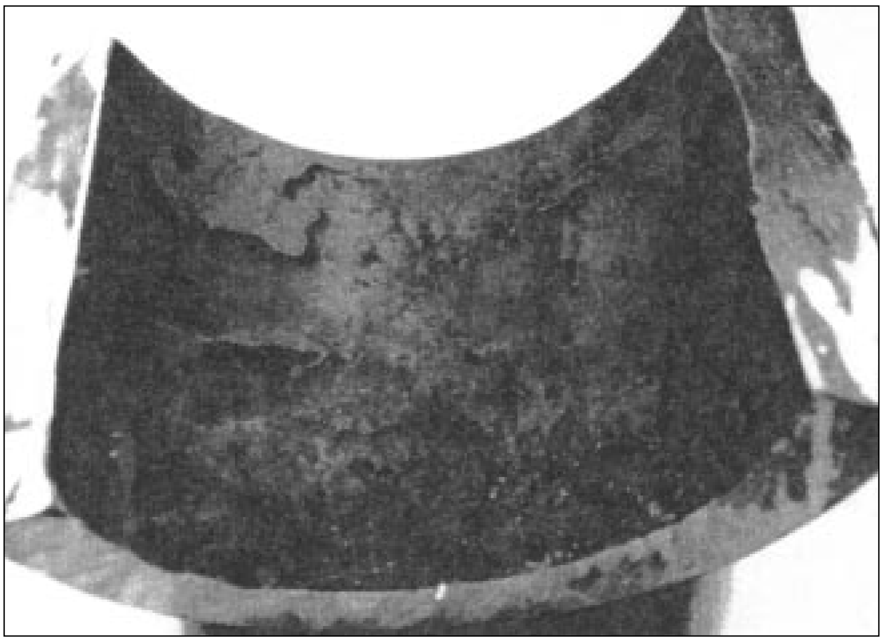

Figure 6 Typical example of a piping section with evidence of flow accelerated corrosion on the inside surface.

DB Riley and others were involved in the failure evaluation of a ruptured section of feedwater piping in a fossil fired boiler. The rupture occurred in a straight portion of pipe, downstream of the check and control valves, in the branch leg, from a tee junction to the boiler's economizer inlet header. A thorough investigation confirmed the presence of thinning by FAC, localized to the area of rupture. Extensive inspection and testing of the other pipe sections and fittings of this system revealed no other locations with severe thinning.

SUMMARY

Current experience with typical problems and failures of boiler piping and supports has been presented herein. Emphasis has been focused on the effects of water induction and flow accelerated corrosion on piping components. In addition, some problem areas with superheater crossover and outlet piping have been described.

It has become a common practice with electric utilities to schedule less frequent outages for their fossil fired boilers. This pattern of scheduling requires much more detailed planning for the inspection and maintenance tasks which are performed during the less frequent boiler outages.

Water induction from condensing steam occurs mostly in low points of sloped horizontal runs of steam piping lines. Thermal quenching can occur when the condensate comes in contact with the pipe bottom. Repeated cycles of the resulting thermal shock can lead to excessive bending, permanent distortions such as sagging, and cracking of the component.

Two case studies have been presented. One involves a main steam piping line with a sagged horizontal section, and a number of malfunctioning and bottomed out supports. The second case presents the details of a rupture in a section of cold reheat piping upstream of the boiler. The findings, conclusions and recommendations from these studies are described herein.

Superheater crossover piping system components, including attemperators, should be scheduled for inspection and assessment during outages, based on instances of cracking found by DB Riley during routine examinations. The cracking is typically due to thermal fatigue, a result of over temperature conditions and cyclical boiler operation.

A case study has been presented of a damaged elbow found in the superheater outlet piping on an industrial boiler. The results of a detailed metallurgical investigation showed that the severe internal gouging was due to a combination of fluid impingement (spray water) and a corrosion mechanism.

There have been some recent failures and distress in feedwater system piping components due to internal thinning, caused by a phenomena known as flow accelerated corrosion. Parameters which have been found to influence the wall thinning of plain carbon steel piping components include piping configuration, fluid chemistry and velocities, temperature, and pipe material. The presence of only a small percentage of chromium in the carbon steel can lessen the severity of the thinning process.

DB Riley and others were involved in the failure evaluation of a ruptured section of feedwater pipe, located in a branch leg between the upstream valves and the boiler's economizer inlet header. A thorough investigation confirmed the presence of thinning by flow accelerated corrosion, but localized to the area of rupture. Recommendations are given herein for the assessment of feedwater piping components, as a check on the presence of flow accelerated corrosion.

RECOMMENDATIONS

Condition assessment programs should be performed at three to five year intervals. The frequency would be dependent on the age of the unit, the type of operation, and severity of problems experienced to date.

Based on the recent experience with problem areas due to water induction, flow accelerated corrosion and thermal fatigue, described herein, it is recommended that inspection and assessment programs be carried out for the high energy steam piping, superheater crossover and outlet piping, and feedwater piping lines.

Remedial measures used to prevent or lessen the effects of thermal quenching due to water induction in steam lines are adherence to specified boiler cool down rates, temperature monitoring of the top and bottom sections of components by thermocouples, and non-destructive examinations of components to establish their current condition. Retrofit modifications have included steam line rerouting, enlarging of drain and vent lines, and the addition of valves in drain lines to prevent ingress of the condensate.

For hot and cold reheat steam line piping fabricated from rolled plate with longitudinal seam welds, it is recommended that internal video inspections be performed at low point locations on horizontal sections, especially if the longitudinal seam is located towards the bottom of the pipe.

There is a listing of components in superheater crossover lines, presented herein, which should be included in a condition assessment program. This essentially involves the piping circumferential welds and attemperator components. For the circumferential welds, wet fluorescent magnetic particle and ultrasonic shear wave testing are recommended as a check on outside and subsurface cracking.

For feedwater piping components which could be susceptible to flow accelerated corrosion, recommendations are offered for ultrasonic or eddy current thickness testing, alloy analysis, and internal video inspection. This would typically be at more turbulent locations and those with higher fluid velocities, including piping sections following valves, tees and bends.

In general, for all the boiler piping systems addressed herein, should hot and cold walk-down inspections note a number of damaged or malfunctioning pipe supports, then remedial actions are needed. They can include a current stress analysis of the system and repair or replacement of suspect supports. If necessary, proof testing of support assemblies can be accomplished on-site to determine if the component is capable of carrying its original design loadings.

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