INSPECTION OF RECOVERY BOILERS

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ABSTRACT

This paper reviews the issues that should be considered when planning inspections to determine the fitness-for-service of recovery boiler pressure parts. The most often overlooked element in a recovery boiler corrosion inspection is a thoughtful and careful visual inspection by an experienced boiler inspector. Defects that may have been produced by each of the damage mechanisms that can occur in a recovery boiler can be located and sized by additional non-destructive test methods before they grow to cause leaks in pressure parts. Unfortunately, many mills focus almost exclusively on tube thickness measurements, and neglect other inspections that could substantially reduce the risk of failure. To set the scope of preventative maintenance required in a particular recovery boiler, an experienced corrosion inspector should tailor a non-destructive test program to evaluate potential damage, make a thorough visual inspection and review the test data before the shutdown ends. An appendix to this paper presents a generic scope of inspection for the first inspection of a new recovery boiler or for a unit with no prior inspection history.

Recovery boiler operators face constant pressure to minimize downtime and to reduce operating costs. Risk-Based Inspection (RBI) and Fitness-for-Service (FFS) methods are available to calculate the most cost-effective scope and frequency of inspection in a particular unit and to evaluate the consequences of defects discovered during an inspection. The paper industry has been slow to take advantage of the benefits of RBI and FFS methods. However, mills that use RBI and FFS measurably reduce inspection and maintenance costs and measurably increase equipment integrity.

Inspections of associated equipment and reviews of the procedures that ensure the safe and reliable operation of kraft recovery boilers should be conducted regularly to ensure both that the equipment is in good working order and that personnel are trained to properly handle routine and non-routine situations. These checks are normally part of a company's Recovery Audit program.

DISCLAIMER

Although this paper was prepared to document the opinions of experienced recovery boiler inspectors at the time of writing, following these recommendations does not guarantee the success of recovery boiler inspections.

INTRODUCTION

Within a kraft recovery boiler, at least seven distinctly different corrosion environments each produce particular types of corrosion, erosion or cracking (1). Corrosion control methods have been developed to minimize the thinning or cracking of pressure parts produced by each of these environments (1-6). However, even when corrosion mechanisms are well understood, it is not possible to predict tube thinning rates or crack progression rates from tube environment parameters, even if all the environment parameters have been measured continuously, which is generally not the case. Because recovery boiler corrosion cannot be predicted in advance, inspections must be scheduled to determine the extent and progress of damage; so that damaged parts may be repaired before they leak or rupture.

After noting the importance of routinely checking control systems, standard operating practices and operator training, this paper will describe the types of measurements that are being used to establish the integrity of recovery boiler pressure parts. These recommendations for setting the scope and frequency of recovery boiler inspections using qualitative and semi-quantitative approaches will be followed by an introduction to more rigorous Risk-based Inspection and Fitness-for-Service calculations.

BOILER SYSTEM INSPECTIONS

The evaluation of recovery boilers during shutdowns should include checks of the operation of critical control systems and safety systems in addition to corrosion inspections. If, for some reason, a particular shutdown has to be very brief, the minimum scope of these boiler system checks should include the following:

- ESP test, drum level trip test, low solids trip test and lift tests of safety valves using manual lift handles
- Calibration of boiler safety system instruments and switches

Detailed recommendations for routine boiler system checks have been developed by the Black Liquor Recovery Boiler Advisory Committee (7) and by insurance companies. These are beyond the scope of this paper, but a convenient summary can be found in the AF&PA Recovery Boiler Reference Manual (8).

AUDIT PROGRAMS

Prudent recovery boiler owners carry out regular audits that make a detailed evaluation of compliance to corporate standards and national codes, as well as to applicable regulatory and insurance standards. Such audits help to eliminate conditions that could cause explosions, interrupt operations, hazard personnel or cause environmental problems. Audits typically bring in a team to evaluate each boiler and its operation at least every second year. They also address the mill's progress on addressing previously non-compliant items. To be effective, audit programs must have energetic support from senior corporate managers. The scope of the audit program should be reviewed each year so that new areas of emphasis can be added and non-critical issues that are rarely out of compliance can be de-emphasized.

On-site audits usually involve the completion of checklists about personnel organizations, training programs, as well as operator checklists for standard and emergency operating procedures, periodic testing of boiler systems and their auxiliary equipment, and maintenance and inspection procedures for routine and emergency shutdowns. Actions required to achieve compliance are described in detail and initiate regular reporting to describe the mill's progress towards rectifying any non-compliant items.

PRESSURE PART INSPECTIONS

Introduction

Because of the very high risk associated with recovery boiler failures, the integrity of each unit's pressure parts and the adequacy of its operating systems must be closely monitored. In addition to inspections during boiler outages, routine walkdown inspections should seek unusual sights and sounds, including sootblower leaks, chemical leaks, areas of bulged casing, visible structural corrosion, missing insulation, evidence of air in-leakage and missing or damaged signage. Standard reporting and response systems must be in place, because findings from walkdown inspections may require immediate attention.

The integrity of its pressure parts is a necessary condition but not a sufficient condition for the safe and reliable operation of a recovery boiler. The organization and training of recovery department personnel, their standard and emergency operating procedures as well as preventative maintenance and repair strategies, are equally important in ensuring that a boiler operates efficiently, safely and reliably.

Detecting defects – the example of critical leaks

A study of explosions and critical exposures reported to the Black Liquor Recovery Boiler Advisory Committee between 1948 and 1990 (9) classified the primary causes of the critical leaks[1] that caused these incidents. More than half the critical leaks were associated with welds. Four times as many of the weld-related leaks occurred at external attachment welds than occurred at tube-to-tube butt welds. Tubes thinned by corrosion caused less than one-quarter of the critical leaks. Operational errors accounted for about one eighth of all the critical leaks, and the remaining one eighth of the leaks could not have been anticipated with existing inspection technology.

The industry's widespread emphasis on tube thickness surveys has substantially reduced the (already small) proportion of critical leaks attributed to corrosion thinning. However, we also need to realize that tube thickness measurements, which continue to be the main focus of most recovery boiler inspections, do not detect the major sources of critical leaks in pressure parts (i.e. crack-like defects at attachment welds). Thus, from the perspective of preventing critical leaks, traditional recovery boiler corrosion inspections have the wrong priorities.

Rather than address the detection of each type of potentially-risky defect independently, Risk-Based Inspection (RBI) takes a broader perspective, recognizing all the damage mechanisms that operate in a recovery boiler (10) and prioritizing inspections that will detect each type of damage before it can progress to threaten the integrity of the boiler.

We will now review the test methods most widely used to detect potentially hazardous defects. It is essential that the individuals who develop and perform recovery boiler inspections are familiar with the capability and

1. In this context, critical leaks are defined as pressure-part leaks that release water into the furnace cavity and therefore have the potential to cause smelt-water explosions.

limitations of each test method that is available to detect potentially hazardous defects.

Although rigorous RBI would use numerical calculations of the likelihood and consequences of each type of damage to plan the inspections in a particular unit, we will first present qualitative and semi-quantitative approaches to designing generic recovery boiler inspection programs. Later, we will review RBI and FFS approaches in more detail.

Tube thickness measurement using ultrasonic testing

The non-destructive test methods used to evaluate the integrity of recovery boilers fall into three categories - those that indicate the thickness of the pressure part, those that detect the presence of surface defects, and those that detect internal defects. Ultrasonic testing (UT) is the method most often used to determine tube wall thickness (11). A transducer, pressed onto a smear of sound couplant on the tube wall, sends a beep of very high frequency sound energy into the tube wall, and measures the time for this sound pulse to travel to the inner surface of the tube and reflect back to the outer surface. The UT instrument uses the velocity of sound in the tube material to calculate the wall thickness from the travel time of the pulse. Some instruments average a number of measurements and display the thickness in digital form. Others use an oscilloscope screen to display the intensity of all the reflected sound pulses as they return to the transducer. These oscilloscope instruments provide more information than digital instruments because they also indicate the depth of internal reflectors such as weld defects or laminations. More training is required to set up oscilloscope instruments and to interpret their output than is required to use digital instruments. Moskal (12) concludes that oscilloscope-type instruments are preferable both because they are typically operated by more skilled technicians and because they can also be used to locate thin spots by scanning areas where locally varying thicknesses or internal defects are suspected.

Thickness measurements from the inside of generating bank tubes

Because generating bank tubes are packed together very closely, there is generally insufficient access to measure their thickness from the outside. However, access from inside the mud drum or steam drum enables their thickness to be measured using special ultrasonic testing systems placed inside the tubes.

Measuring the thickness of generating bank tubes is important because they are typically installed with a particularly small corrosion allowance (zero to 0.050") in order to allow rapid heat transfer to the boiler water they contain. In order to detect external localized thinning of generating bank tubes where they exit the mud drum surface (13), instruments have been developed to inspect 100% of the 1”-2" length of each tube that is be subject to near-drum thinning (14-16). These instruments are inserted into each tube in turn from the mud drum and use UT (generally with the tube flooded with water that acts as a couplant) to scan the wall thickness of the generating bank tube and to detect cracks near the drum surface.

Tube thickness measurement using eddy current testing

In some cases, eddy current testing has been used to determine tube wall thickness. In this method, an alternating current passed through an exciting coil inside or near the tube creates eddy currents in the tube. The condition of the tube is deduced from the effect of the applied field on the electrical impedance, induced voltages or induced currents in the exciting coils, or by the induced voltage in a receiving coil. Internal eddy current probes can measure tube thicknesses along the full length of generating bank tubes, although their readings are not accurate at bends and swages. Although these instruments detect sootblower erosion and can obtain data more rapidly than ultrasonic instruments, they are less sensitive and less accurate than the specialized ultrasonic probes developed to detect near-drum thinning.

Surface crack detection using liquid penetrant testing

There are two predominant methods for detecting surface cracks: liquid penetrant testing (PT) and magnetic particle testing (MT). In liquid penetrant testing, the surface is cleaned and degreased before light penetrating oil, usually bright red in color, is applied. The penetrant is left on the surface for a prescribed period, typically several minutes, and is then cleaned off the surface with paper towels or rags. This surface cleaning does not remove penetrant that has seeped into cracks open to the surface. In the third step an oil-absorbing white powder (the developer) is sprayed onto the surface. If a crack is present, the penetrant soaks back out into the developer and indicates the mouth of the crack like a narrow bleeding cut. Detecting cracks with these methods can demand particular skills, e.g. when examining composite floor and wall tubes for (typically very tight) fireside cracks (17).

Shear wave ultrasonic testing

A variant of ultrasonic testing known as "shear wave ultrasonic testing" sends an ultrasonic pulse into the tube surface at an angle. Because this pulse will be reflected by cracks in its path, the time it takes to return to the transducer can be taken to indicate the position of a crack (reflector). This enables the depth of surface-breaking cracks to be measured without grinding them out. It has also been used for estimating the depth of stress-assisted corrosion fissures. Shear wave ultrasonic testing requires technicians with particular training and experience because greater skill is needed that for conventional (straight beam) ultrasonic testing.

Surface crack detection using magnetic particle testing

In magnetic particle testing (MT), the metal surface is magnetized by an electromagnet yoke, while either dry magnetic powder or an aqueous slurry of fluorescent magnetic particles is sprayed onto the surface. The magnetic particles are drawn to cracks because cracks produce a non-uniform magnetic field. MT will detect finer cracks than can be found by PT – including some cracks that are not open to the surface. Because of the great sensitivity of this test method, MT inspections can raise unnecessary concern about defects that are either too small to affect integrity or have not grown since the tube was fabricated. Yoke-type rather than prod-type probes should be used to magnetize the surface, to avoid the formation of cracks produced by the electric arcs that can be formed when prods are used.

Internal crack detection using radiographic testing

Radiographic testing (RT) is used to detect cracks on the waterside surface of boiler tubes or within their wall thickness. In this method an X-ray source, or a radioactive source that emits gamma rays, is placed close to the metal surface. These rays pass through the tube material and produce an image on film placed on the far side of the metal. The intensity of the film image at any particular point depends on how much energy the beam has lost in traveling to that point. If the path of the beam includes a crack or void, less energy will be absorbed, so the crack or void will appear as a dark area on the film. Calibration standards called penetrameters allow semi-quantitative estimation of the depth/length of defects in the direction of the beam. Note that crack-like defects are not detectable by radiography unless they are aligned parallel to the beam direction.

Radiographic testing is routinely used to evaluate the integrity of welds in pressurized equipment and TAPPI has published guidelines for using it to evaluate the quality of butt welds in recovery boiler tubes (18).

Special radiographic procedures have been developed to detect stress-assisted corrosion (19). New digital radiographic imaging techniques (analogous to image capture by a digital camera) allow the contrast and density of digital radiographs to be manipulated with a computer. This enables areas hidden in the "shadow" of an intervening structure (like a buckstay) to be evaluated by subtracting out the "shadow". This enables stress-assisted corrosion inspections to be completed without having to cut away windboxes, smelt boxes and buckstays to place the film against the tube.

This review of inspection methods is necessarily brief. Additional information is available in other publications (11-24), or in encyclopedic form in Volume 17 of the ASM Metals Handbook (25).

The importance of visual inspection

Each recovery boiler inspection should be directed and coordinated by an inspector who is familiar with the condition of the unit in previous inspections and who has years of experience gathering and interpreting inspection data from similar units. The inspector's visual inspection skills are very important in finding critical defects and in directing non-destructive testing into areas that appear suspicious. Relying on a fixed protocol of measurement and testing without regard to the condition of the boiler increases the possibility of overlooking important defects and of overspending on inspection costs. An excellent set of visual inspection checklists can be found in Volume 1 of the AFPA Recovery Boiler Reference Manual (8).

In addition to the inspector directing the inspection, everyone else working in the boiler during the shutdown should be encouraged to look for and report conditions that seem unusual.

Consequences of cracks

Every indication of a crack-like flaw should be taken seriously and evaluated carefully. Both the ASME pressure vessel code that governs the design and original construction quality of most pressure parts in recovery boilers, and the National Board Inspection Code that governs the inspection and repair of operating boilers in most US state jurisdictions, state that linear indications cannot be tolerated in pressurized equipment. (Linear indications are defects that are at least three times as deep/long as they are wide). We will later discuss the API/ASME FFS-1 Fitness-for-Service code (26) which describes methods

for quantitatively evaluating the impact of cracks and other defects on the integrity of a boiler. These methods are particularly valuable because their results can be counter-intuitive. For example, a recent study (27) found that stress-assisted waterside corrosion (SAC) fissures that penetrated up to 32% of the tube wall did not decrease the burst strength of 46 tubes recovered from two recovery boilers. All these tubes failed away from the SAC fissures at pressures more than 7.6 times the operating pressure of the boiler. Evidently, the attachment welds that had initiated these fissures were able to provide external strengthening to the fissured area unless the fissures were extremely deep.

In the meantime we will simply note that the evaluation of crack indications requires skill, experience, knowledge of the precision of the inspection methods that reveal them as well as Fitness-for Service calculation methodologies. Decisions about the consequences of cracks should never be left to non-destructive testing technicians, because their training is to detect the location, shape and size of flaws, rather than to determine their impact on the integrity of the boiler.

Consequences of thinning

Like flaw data, tube thickness data need to be carefully studied and carefully interpreted. To interpret tube thickness data we need to understand the accuracy and precision of UT measurements. The precision of measurements made at any given inspection can be estimated from the standard deviation within data sets where thickness variations arise primarily from reading errors rather than from real thickness differences. Our statistical analysis of many thousands of tube thickness measurements obtained by several non-destructive testing contractors indicates that the standard error in UT wall thickness readings recorded during a boiler inspection is typically between 0.005" and 0.007" (28). Some part of this standard error may be attributable to the UT transducer not being placed on exactly the same spot as in previous tests, i.e., to spatial variations in tube thickness. In addition, the accuracy of the measurements (i.e. the standard error in the calibration of the UT instrument), is typically between 0.004" and 0.006". The accuracy of the measurements is indicated by the distribution of the measured tube thicknesses in each part of the boiler about the mean thickness in that part.

The square root of the sum of the variances of the reading errors (precision) and the calibration errors (accuracy) indicates that the combined standard error is about 0.007". If we assume that the tube thickness data belong to a normal distribution[2] this predicts that one in 20 tube thickness readings (95% confidence) will contain errors greater than 0.014", and one in 100 (99% confidence) will contain errors greater than 0.021". In a parallel study of actual measurements, Moskal (12) analyzed test data from 62 contractor UT technicians using ultrasonic instruments with oscilloscope displays and calculated the combined standard error in their measurements as 0.017" on normal tubes and 0.023" on tubes with hidden defects. The nominal thickness of the tubes was about 0.200". If we recalculate Moskal's statistics, omitting the largest errors (e.g., those greater than 0.030"), we obtain standard errors of about 0.007" and 0.010" on normal tubes and tubes with hidden defects.

Because the standard error in tube thickness measurements is greater than the annual corrosion rate in most parts of most recovery boilers, small errors in thickness measurement can produce large errors in calculated corrosion rates. This is particularly true when the measurements span only a short period of time. For example, consider a tube that is thinning at 0.003" per year. If the measured thickness is 0.007" (one standard deviation) high one year and 0.007" (one standard deviation) low the next year, a calculation based on only these two measurements would give a thinning rate of 0.017" per year. If the measured thickness were 0.007" low the first year and 0.007" high the second year, the calculation would show an apparent thickness increase of 0.011" per year. As a result, corrosion rates calculated from two thickness measurements made at the “same” location one year apart are almost always imprecise.

Consequences of near drum thinning

Data obtained by ultrasonic testing systems that scan the area of generating bank tubes subject to near-drum corrosion requires particular care in interpretation. These systems scan 100% of the surface of generating bank tubes, but technicians typically record only the thickness of the thinnest reading, regardless of the size of the thinned area. Although the diameter of a single spot measurement made by one of these instruments is typically 0.030", so many overlapping readings are taken that the data display may show a data point (pixel) size as small as 0.001” x 0.002”. Since the

2. This is not exactly true, but a reasonable estimate.

impact of a small thin area on the integrity of a tube depends critically on its size and shape, inspectors should always record the size and shape of the thinnest area. If a significant area is thinned below the code minimum, the tube may need to be repaired or replaced. However, if the thinned area is very small, like a pit, it is prudent to examine its effect on the integrity of the tube by finite element analysis (26) rather than condemn the defect without further analysis.

Minimizing errors in tube thickness measurements

Three approaches can be used to minimize errors in corrosion rate calculations. The first (12, 20) is to verify the ability of testing personnel to obtain accurate UT measurements on blind samples, and to only allow those personnel who show a minimum competence to make measurements inside the boiler. The second is to require that UT technicians recalibrate their instruments after a certain number of readings (perhaps 100) or a certain length of time (perhaps 15 minutes) and repeat the last group of readings if the calibration is off by more than a certain amount (perhaps >0.003"). The third method is to recheck every thickness reading that is unusually low or high compared to neighboring tubes or to thickness predictions calculated from previous data (e.g. more than two standard deviations from the predicted value). Rechecking should be done by a different technician using a different instrument. In this author's experience almost all outlying thickness measurements made during recovery boiler shutdowns are found to be erroneous when re-checked. Experience shows that, when tubes are cut out after minimum thickness measurements were carefully rechecked, the UT measurements are almost always within 0.003" of the minimum thickness that can be found with a needle point micrometer.

SCOPE AND FREQUENCY OF RECOVERY BOILER INSPECTIONS

Inspection planning

The previous discussion has shown that established test methods are available to detect dangerous thinning in recovery boiler tubes, and to detect cracks that could propagate and fracture pressure parts. However it is important to remember that no inspection will find defects unless an appropriate test method is used at the location of the critical defect.

There are no North American standards for the scope, method, or frequency of recovery boiler inspections. In fact, industry standards would not be appropriate, because each boiler behaves uniquely and should be inspected uniquely. Useful advice for those who plan inspections is available in a number of publications (8, 10, 21-25, 28, 29). In particular, the first volume of the American Forest and Paper Association's Recovery Boiler Manual offers practical guidelines, checklists and photographs of many kinds of damage (8), and TAPPI's Technical Information Sheet describes how to survey the thickness of recovery boiler tubes (11).

Maintaining awareness of new technology

As a minimum, a recovery boiler owner must perform sufficient inspections and maintenance to satisfy state and federal laws and the requirements of his insurance carrier. However, many companies do much more to try to increase the safety and reliability of their recovery boilers. Their additional activities can include establishing programs to assure design and workmanship quality in new construction and maintenance as well as auditing operation, inspection and maintenance programs to check that they meet company standards. Boiler owners also need to maintain awareness of new inspection and maintenance technology through their corporate specialists or through contractors. Useful sources of new technology include industry groups such as BLRBAC, NACE International's TEG 198X (Technical Exchange Group on Recovery Boiler Fireside Corrosion), the Research and Development Subcommittee of AFPA's Recovery Boiler Committee, as well as direct or indirect sponsorship of recovery boiler research.

Three approaches to inspection planning

Since the cost of recovery boiler inspections depends on the scope of the non-destructive testing that is undertaken, we will now evaluate three approaches that have been used to plan the scope and frequency of recovery boiler inspections. These are: thickness testing in predetermined grid locations, inspection in proportion to the historical risk of critical leaks in particular parts of a boiler and thickness measurements based on previous corrosion rates plus additional testing in areas of concern. We will discuss each approach in turn.

1. *Inspection based on thickness measurements at predetermined grid locations*

Most recovery boilers are inspected at frequencies between 12 and 24 months. We have noted that there is no standard scope for tube thickness inspections and that inspection practices vary widely. For example, the AFPA Recovery Boiler Reference Manual (8) does not suggest any routine measurement of floor tube thickness, while some companies inspect every second tube along lines one foot from the front and rear walls

and at four-foot intervals between these lines. With regard to water wall tubes, the AFPA Manual suggests measuring every tube at four elevations, while some mills measure the thickness at the crown of the tube and each shoulder at each measurement location at elevations ranging from 2 to 3 feet apart in the lower furnace to 10 feet apart in the upper furnace.

Many surveys that measure tube thickness at large numbers of elevations only measure the thickness of every other tube or every fifth or tenth tube at any given inspection. Tubes surrounding ports and openings in the lower furnace typically have their thickness measured or scanned only at the top, center and bottom of the port. Roof tube thickness surveys range from a single line of measurements halfway between the furnace screen tubes and the front wall of the boiler to lines at 4-foot intervals from the front wall. Roof tubes are generally inspected less frequently than water wall tubes, although severe thinning has been reported (30) on roof tubes surrounding superheater tube penetrations. Some companies inspect screen tubes at a single point halfway up their vertical section as per the AFPA manual, while others scan the thickness of the outermost screen tube in each platen in the outermost part of the bend and at locations one and two feet each side of that location. Similar disparities exist in the extent of inspection of nose arch tubes, superheater, generating bank and economizer tubes.

Because of the wide disparity in the extent of recovery boiler tube thickness measurement in North America, a recovery boiler owner can find little assurance that he has ensured the safe and reliable operation of the unit by basing the scope and frequency of his tube thickness survey on those used elsewhere. More tube thickness measurements will not necessarily detect critical flaws with more certainty, because thin spots are typically much smaller than grid sizes. The value of thickness surveys is that they can highlight suspicious areas where evidence of local thinning requires further investigation and that they can provide data to calculate average rates of tube thinning in particular regions of a boiler.

It is very important to remember that most types of potentially hazardous service-related corrosion and cracking cannot be detected by tube thickness surveys. These include waterside pitting, waterside scaling (that produces insulating deposits which increase the tube surface temperature and hence the corrosion rate), waterside stress-assisted corrosion (31) - corrosion-fatigue-like fissures in the waterside of tubes where heavy attachment welds are present on the outside of the tubes – and fireside cracking of composite tubes (32, 33). Waterside corrosion and deposition cannot usually be assessed without removing sections of tubes. Waterside stress-assisted corrosion fissures are most likely to be found at highly restrained attachment welds in the lower furnace, e.g., welds at floor-to-wall joints, air port scallop bars seals, and buckstay welds.

Thinning of the outer stainless steel layer of composite tubes often occurs at small areas in the crotch of port openings in the lower furnace (34). Although this thinning is unlikely to be detected by thickness measurements at predetermined grid locations, it can be measured with magnetic lift-off gauges that measure the distance between the gauge head and the underlying carbon steel tube. These gauges are also useful for measuring the thickness of non-magnetic thermally sprayed coatings on carbon steel tubes. Eddy current gauges are available that can estimate the thickness of non-magnetic layers in less accessible areas. Thin areas in the outer stainless steel layer of composite tubes can be located by visual inspection or by touch and their thickness scanned to locate the thinnest spot.

Carbon steel water wall tubes can suffer fireside thinning alongside the welds that attach them to the (vertical) membrane bars that separate them. These thinned areas cannot be detected by ultrasonic thickness measurements, because they are too close to the membrane to be reached by conventional transducers. They can instead be detected using either templates or light shadowing[3].

Water wall tubes in older, non-membrane boilers, i.e., those with non-welded tangent tubes or with flat stud construction, are vulnerable to casing-side corrosion on the external surfaces that face away from the furnace, especially when the tubes remain moist for extended periods following water washing. This type of corrosion cannot be detected without removing sections of the insulation and casing on the outside of the boiler. Casing-side corrosion is usually most severe between the levels of the secondary air ports and the nose arch. It is best evaluated visually, using ultrasonic thickness testing for measurements in the areas that look thinnest in light shadowing inspections.

Because UT thickness surveys will not detect cracking, areas to be inspected for fatigue cracks or thermal

3. Using a flashlight held parallel to the tube surface.

fatigue cracks should be designated by a knowledgeable inspector for inspection by other methods. Liquid penetrant (PT) or magnetic particle (MT) testing methods should be used to detect these cracks. Locations vulnerable to fatigue cracking include areas beside strong restraints like fixed supports, headers or vibration restraints. Areas subject to thermal fatigue include attachment welds to composite tubes, pin stud and flat stud attachments, tubes surrounding smelt spouts and air ports and areas where smelt washes up and down against the surface of lower furnace tubes.

Because so many types of potentially harmful defects cannot be detected by thickness measurements on predetermined grids, it is essential that other types of non-destructive tests and expert visual inspection be added to tube thickness surveys to complete an inspection.

2. Inspection based on risk of critical leaks

A second approach to determining the scope and frequency of recovery boiler inspections is to inspect different parts of the boiler according to the historical risk of failures in that part of the boiler. Our previous study of explosions and critical exposures reported to BLRBAC (9) showed that 32% of critical leaks occurred in lower water wall tubes, 15% in upper water wall tubes and 3% at unspecified wall tubes. 12% occurred in furnace screen tubes, 12% in boiler bank tubes (with an additional 3% reported to have been at the mud drum ends of these tubes and 3% at the steam drum ends of these tubes), 8% in floor tubes, 6% at the spouts and 5% in other parts of the boiler. If the grid size for ultrasonic thickness measurements were made inversely proportional to the historical likelihood of critical leaks in particular areas, the grid size should be smallest on the lower water walls, about twice as large on the upper water walls, furnace screen and generating bank tubes, about twice as large again in the floor, in the superheater and economizer, and so on. Because of the unusually high risk of failure in the small areas of tubes exposed at spout openings and at the top and bottom ends of generating bank tubes, a "leak-risk" based inspection would probably scan tube thicknesses in 100% of these critical areas.

Although the concept of inspecting according to the risk of failure has great merit, we have pointed out (9) that, because the BLRBAC data do not record explosions that were avoided by the discovery of incipient problems that were repaired before they propagated to cause leaks, they do not indicate the overall effectiveness of particular types of inspection in detecting critical leaks. The BLRBAC data should be regarded more as an indication of what careless inspectors have missed than of what careful inspectors have found. As a result, historical information about critical leaks has more value for planning quality assurance programs to verify critical aspects of the design and construction of new recovery boilers than for planning the scope and frequency of boiler inspections.

3. Inspection based on calculated corrosion rates, visual inspection and other non-destructive tests

The AFPA Recovery Boiler Handbook affirms that ultrasonic tube thickness surveys should be conducted to survey tube thicknesses and to calculate rates of tube metal wastage in different parts of the boiler. To improve the accuracy of metal wastage calculations, thickness measurements should be made at exactly the same locations during successive inspections. The AFPA Handbook recommends installing benchmarks for this purpose, preferably on the tube-to-tube membrane, so that chalk lines can be applied to mark the exact height of the thickness measurement locations.

The development in recent years of computer-based data management programs for tube thickness measurements has greatly facilitated this type of calculation. Commercial programs are available that indicate tube thicknesses on computer-generated maps of the boiler surfaces. These maps indicate patterns of tube thinning much more clearly than the tables of thousands of data points they replace. Unfortunately most of these programs calculate corrosion rates by comparing thicknesses at particular locations at successive shutdowns. Such calculations are neither accurate nor precise, as was shown above, because of inherent limitations of the ultrasonic data.

Careful analysis of thickness data is required to determine the regions in a boiler within which the tube thicknesses belong to the same statistical population. This might be done, for example, by dividing a large wall area into 9 separate sectors (high, middle, low and left, center and right) to determine whether the tube thickness distributions in the sub-areas differ significantly. Analysis of thinning rates in about 30 statistically distinct areas of several recovery boilers has shown that calculated thinning rates averaged over the life of a boiler range from about zero to about 0.006" per year. The highest rates of metal wastage typically appear on wall tubes at port and sootblower openings. As has been discussed above, the standard error of about 0.007" in tube thickness measurements precludes attempts to calculate corrosion rates at

individual locations from repeated thickness measurements at single locations. However, realistic corrosion rates within particular areas of a boiler can be calculated by comparing the sums of thickness measurements taken at the same locations at successive shutdowns. To calculate average thinning rates, it is necessary to compare measurements taken at 100 or more thickness measurement locations on at least four separate occasions.

Some data management programs, such as the UTmost program developed by Westvaco, regress these sums of thickness data to calculate corrosion rates. This type of program can also combine the corrosion rate data with current tube thickness data and allowable minimum thickness data to estimate the remaining service life of particular sections of a boiler. Such estimates are extremely valuable. They allow thinned portions of a boiler to be replaced on a scheduled basis, coordinated with other major work anticipated in the mill, which always costs much less than unscheduled replacement.

Inspection strategies to equalize the risks from thinning and cracking

Despite the fact that more than half the critical exposures reported to BLRBAC occurred because of cracks at welds, most recovery boiler inspections continue to devote far more effort to evaluating corrosion thinning than to locating and evaluating fireside and waterside cracks. This emphasis on thinning rather than cracking arises because most inspections are managed by testing companies rather than by boiler inspectors. It is easier for testing companies to sell their ability to measure tube thickness, than to take responsibility for finding all significant crack-like defects in a boiler and evaluating their effect on the integrity of the unit. Most testing companies do not have staff skilled in making fitness-for-service determinations and do not wish to be held responsible for such determinations.

To reduce the hazards associated with cracking to the same level of risk as the hazards associated with thinning, inspection programs must emphasize visual inspections (including crack detection inspections) by experts familiar with recent findings in similar recovery boilers around the world. Based on findings elsewhere, the expert chooses areas susceptible to external cracking that will be inspected by liquid penetrant testing or magnetic particle testing, and areas subject to waterside cracking to be inspected by radiography or shear wave ultrasonic testing. If cracks are detected, the inspector establishes their size and shape, either by additional non-destructive testing or by grinding. The impact of remaining cracks on the integrity of the tubes should be quantitatively evaluated by a fitness-for service expert[4].

Role of original weld quality in cracking at attachment welds

Both fireside cracking of composite tubes (33, 34) and waterside stress-assisted corrosion of carbon steel tubes (31) are influenced by the design and quality of the original attachment welds. Many types of weld defects that can develop to threaten the integrity of a tube are relatively easy to detect during fabrication and erection, but very difficult to detect after the boiler is built, when access and inspection time are restricted. Because more than half the critical leaks reported during recent years were associated with welds, it is critically important when purchasing a new recovery boiler or rebuilding an existing unit to thoroughly review the vendor's proposals for the design, fabrication and erection to insure that appropriate quality requirements have been incorporated in the purchase specifications. The design and quality of attachment welds should be reviewed with particular care.

Quality specifications should always be established before bids are sought for new or replacement boiler parts, because additional requirements introduced later are likely to produce significant cost escalations. The owner should clearly establish his/her own accept/reject standards for quality based on expert advice and industry experience, e.g. to require radiography of butt welds in places where this may not be required by the (generic) ASME code, and to require careful inspection of attachment welds to water-filled tubes. Quality assurance requirements established for new construction should also be applied to repair and replacement work once the boiler is in service. Inspections by owner personnel, or by contractors reporting directly to the owner, should be scheduled to verify that the quality control programs established by boiler fabricators, erectors, and their sub-contractors have ensured that critical quality specifications have been met.

Recommended strategy for corrosion inspections

4. See discussion on Fitness-for-Service, below.

We have shown that it is not necessary to take tens of thousands of tube thickness readings each year in order to establish rates of corrosion thinning. In addition we have shown that increasing the number of routine tube thickness measurements has little effect on the likelihood of finding the thinnest areas of the thinnest tube, because the inspection grid is so much larger than most of the thinnest areas Therefore, rather than decrease inspection grid sizes in the (unrealistic) hope that increased numbers of measurements will discover local thin spots, it is wiser to measure tube thicknesses carefully in repeated inspections at selected and identifiable representative grid sites and look to human inspectors to map thinned areas and examine suspicious indications. Corrosion rates should then be calculated for each distinct portion of the boiler. Additional inspection should be made in areas found to be thin in previous inspections and to examine suspicious features found during the current inspection.

Regardless of the size of the pre-determined inspection grid, criteria should be established in advance of the inspection so that if unusually thin tube measurements are obtained and verified, the thickness of surrounding tubes will be investigated using a much smaller inspection grid or by scanning the thickness of the surrounding tubes. The most cost-effective inspection strategy involves the repetition of thickness measurements at selected points to determine corrosion rates plus additional inspector-directed measurements to seek the thinnest tubes and critical defects. Visual inspection and other types of testing will also be needed to detect cracking and thinning in areas not normally measured or inaccessible to ultrasonic transducers (e.g. between non-welded tangent tubes, and on wall tubes adjacent to membrane bars).

OPPORTUNISTIC INSPECTIONS

If a recovery boiler becomes unexpectedly available for inspection, e.g. because of an emergency shutdown, opportunities should be sought to inspect as follows:

- Visual inspection of all tubes surrounding smelt spouts, primary and secondary air ports
- Visual check for out-of-plane wall tubes and visual check for out-of-plane pendant tubes from scaffold boards in sootblower lanes
- Visual inspection from access doors in sootblower lanes
- Waterside inspections from inside the mud drum and steam drum
- Tube thickness measurements more than 12 months overdue
- Replacement of tubes projected to thin below code within 24 months
- Visual inspection of smelt spouts
- Hydrostatic test at 90% of normal steam outlet pressure to detect leaks

In order to take advantage of unexpected opportunities for recovery boiler inspection, the final report of each inspection should recommend not only the scope of the next scheduled inspection, but also a short list of items that should be checked if the opportunity arises.

RISK-BASED INSPECTION

The development of Risk-Based Inspection was begun in 1993 by a group of refinery and petrochemical companies. This eventually led to the publication of the American Petroleum Institute's Recommended Practice 581: "Risk-Based Inspection Technology" in 2002 (35). RBI offers users a rational strategy for designing inspection and maintenance programs to reduce the risk of equipment failures. Items with a relatively high probability of failure and a relatively high consequence of failure are given a higher priority for inspection resources than items with a lower probability and lower consequence of failure. Institution of an RBI program typically reduces both operating hazards and total cost of operation (i.e. operating cost + inspection costs + maintenance costs). This is shown schematically in Figure 1.



Figure 1: Reduction of risk using RBI (35)

RBI programs offer three types of benefits. By defining and quantifying the risk of process equipment failure they enable managers to plan inspection and maintenance programs that support safe and profitable operations. Second, they allow plant management to quantify the safety, environment and business-interruption risks they face based on their cost. Third, RBI programs reduce the likelihood and consequence

of failure by focusing inspection resources in high-risk issues. RBI typically uses existing inspection procedures, but uses risk calculations to set inspection scopes and priorities. RBI can also be used to fine-tune equipment design, process safety management and other issues that affect the overall mechanical integrity and safety of a process unit.

The risk of failure in most process equipment follows a "bathtub" curve. Initial failures related to imperfect design and manufacture typically decrease rapidly and then remain rare. However, as the equipment approaches the end of its design life, time-dependent damage mechanisms begin to increase the likelihood of failures.

RBI enables inspection resources to be allocated in a rational manner. RBI calculates the risks associated with operating equipment as the product of the likelihood of each type of potential failure (in events per year) and the consequence of that type of failure (in cost per event). The likelihood of failure depends on the predicted rate of deterioration and the effectiveness of previous inspections in detecting and characterizing the damage to the equipment. Note that uncertainty about the condition of a boiler may be a major component of the risk it presents.

In a typical process plant, 80 to 85% of the risk is associated with 5 to 20% of the equipment items (36). RBI refocuses inspection and maintenance resources on the high-risk items. This progressively reduces total risk (calculated as the annualized cost of risk) to an acceptable and predetermined cost. RBI can be applied at three levels. Level I is a simple, qualitative prioritization of equipment inspections, (e.g. focusing on equipment that contains either corrosive liquids or high pressures). Level II RBI uses semi-quantitative methods to develop priorities and support inspection planning. For example, the probability of failure in a recovery boiler from a particular damage mechanism could be ranked as 1: Very high, 2: High, 3: Moderate, 4: Low or 5: Very low. Similarly, the consequence of failure from that damage mechanism could be ranked as A: Catastrophic, B: Very serious, C: Serious, D: Significant or E: Minor.

Figure 2 combines these rankings in a risk matrix. RBI biases the scope and frequency of inspections to find damage that would culminate in High Risk or Medium-High Risk damage.

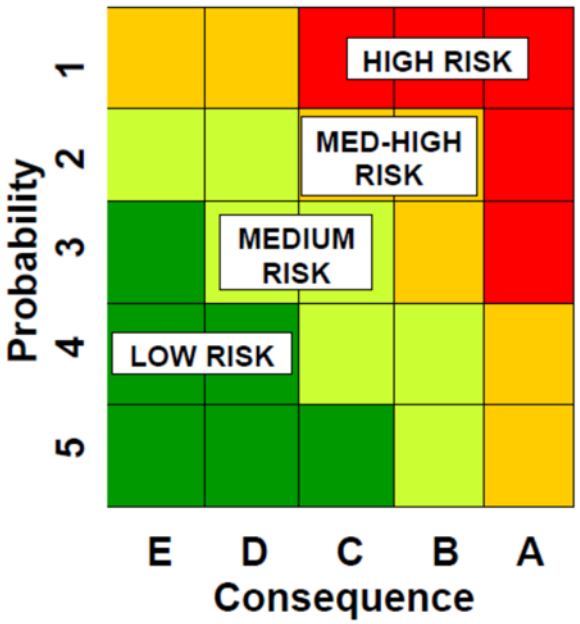


Figure 2: RBI Risk-ranking matrix

Level III RBI analysis requires much more data, but produces a numerical calculation of the financial impact of inspection on equipment reliability and operating costs. Potential inspection strategies can then be chosen on the basis of their impact on the annualized cost of risk.

Calculations about the consequences of defects are based on established assumptions. For example, particular types of cracks that cause loss in containment of process fluids (e.g. boiler water) are assigned particular sizes and particular durations, which depend on the type of leak involved. The consequence of a particular amount of fluid release is calculated using factors like the proximity of mill workers to the failure location, the impact of the process interruption in terms of lost production and repair costs, and in some cases to the cost of environmental cleanup required by a leak or rupture. The area impacted is calculated from the volume released, assuming that the spreading liquid maintains a standard depth.

The probability of a leak is calculated assuming that each degradation mechanism (thinning, crack propagation, etc.) is time-dependent. The likelihood of finding a given type of defect is based on the inspection procedure and established Probability of Detection factors. The certainty with which it is known that pressure parts and welds are free of potentially harmful defects, and maximum propagation rates for each type of damage established by panels of experts, are used to

set the frequency of inspection, based on the probability of each type of failure in future years.

Nowadays most RBI analyses are performed with software that has been developed for this purpose. The total annualized cost of risk in a piece of equipment, a unit process or a mill department is a key performance indicator. The return on investment of inspection and maintenance programs can be quantitated by their impact on the calculated annualized cost of failure. Additionally, calculations can assess the relative merit of alternate inspection strategies.

Reference 37 compiles practical advice about initiating and maintaining RBI programs in process plants. At least one OEM offers a program for assessing the condition of industrial boilers (38) based on EPRI's condition assessment guidelines (39) and offers recommendations for assessing pressure parts during a boiler life extension program (40). The use of RBI and FFS methods for the inspection of coal-fired power plants had been documented by Price (41) and by Jovanovic and others (42).

FITNESS-FOR-SERVICE

Design codes like the ASME Boiler and Pressure Vessel Code enable engineers to make simple and conservative calculations to determine whether in-service equipment still meets the requirements of the code to which it was designed and built. The operating code that applies to most U.S. recovery boilers - (ANSI/NB23 - National Board Inspection Code) is less conservative (43). However, the development of computer power has enabled much more sophisticated assessment of metallurgical conditions and local stresses and strains that can more precisely show whether particular fabrication defects or in-service deterioration can threaten the integrity of a part. Such analyses provide a sound basis for decisions to run as-is, to monitor, repair, alter or retire the equipment.

In 2000, for the first time a compendium of consensus methods for calculating the fitness-for-service of process equipment containing defects was published by the American Petroleum Institute (44). These methods showed whether particular defects compromise the integrity of refinery and petrochemical equipment under operating conditions. The fitness-for-service evaluations could be made at one of three levels that involved different levels of rigor and complexity. If the defect was found acceptable using the first-level methodology, no more investigation would be required. If it failed the first-level methodology, it would be re-examined by the second-level methodology, and so on.

Because most of the jurisdictions that license the operation of boilers and pressure vessels would only allow equipment owners to apply API RP 579 to refinery and petrochemical equipment governed by the petroleum industry's API 510 or API 570 pressure vessel and piping codes, pulp and paper mills were generally not able to use these new tools.

Although ASME had established committees to develop its own post-construction codes in the early 2000s, it later decided to cooperate with API to develop a fitness-for-service code that could be applied to equipment in all industries in all countries. API and ASME formed a Joint Committee that brought together not only representatives of their own associations but also of many other groups including the National Board, the Chemical Manufacturers Association, and organizations concerned with the fitness-for-service of equipment in Europe and Asia.

The first edition of this Joint Committee's code - "API 579-1/ASME FFS-1 Fitness-For-Service" (26) was published in 2007. It had three purposes: (i) to ensure safety of plant personnel and the public when aging equipment is operated; (ii) to provide technically sound fitness-for-service assessment procedures to ensure that different service providers furnish consistent life predictions; and (iii) to help optimize the availability, operation and maintenance and long-term economic viability of existing facilities, particularly older plants. Because the National Board was involved in the development of FFS-1, U.S. state jurisdictions are much more likely to accept its use than that of its predecessor RP 579.

If flaws or damage are found, recovery boiler owners can use FFS-1 to calculate their fitness-for-service at one of three precision levels. A Level 1 assessment offers a conservative screening criterion with a minimum amount of inspection information and component information. Level 2 assessments are less conservative and require more detailed calculations using inspection data. Level 2 calculations are typically performed by engineers. Level 3 assessments are the most rigorous and typically require more detailed inspection and component information. They are based on numerical techniques such as the finite element analysis method, and are intended to be performed by engineers who specialize in FFS calculations.

FFS-1 contains consensus methods for evaluating the following types of defects:

- Brittle fracture
- Local metal loss
- General metal loss
- Pitting corrosion
- Hydrogen embrittlement
- Weld misalignment and shell distortion
- Crack-like flaws
- Operation in the creep range
- Fire damage
- Dents and gouges
- Laminations

To take just one example, neither the (ASME) design code nor the (NBIC) operating code for a recovery boiler allows the presence of crack-like flaws such as the waterside fissures found in Stress-Assisted Corrosion. In contrast, the Fitness-for-Service code (26) allows a user to calculate whether a fissure characterized by non-destructive testing will propagate in service, with a predetermined margin of safety.

Similarly, tube thinning can be evaluated using technology-based rules, rather than by automatically cutting out all tubes that no longer meet the requirements of the original design code.

Because fitness-for-service calculations can be complex, it is wise to have a specialist at the mill or on-call during recovery boiler inspections. Fitness-for-service calculations provide a reliable basis for evaluating the impact on the integrity of the boiler of defects found by inspectors. Not all "significant indications" require removal. The same calculation methods can be used before an inspection to determine the maximum safe parameters for particular types of defect. This enables inspection methods to be tailored to detect and record all the defects that are currently unsafely large or could grow to be unsafely large in a given time period, without reporting defects that are too small to be of concern in the foreseeable future.

Note that a fully quantitative FFS assessment can be viewed as a very high level RBI likelihood analysis. RBI involves evaluating the risks posed by specific damage mechanisms and enables a user to evaluate when, where, and how to look for defects or degradation. Once a defect has been characterized, FFS evaluates the acceptability for continued operation and RBI establishes an appropriate monitoring and inspection interval. Therefore, RBI and FFS are complementary technologies.

Recovery boiler operators face constant pressure to minimize downtime and to reduce operating costs. Risk-Based Inspection (RBI) methods and Fitness-for-Service (FFS) methods can be used to calculate the most cost-effective scope and frequency of inspection in a particular unit and to evaluate the consequences of defects discovered during an inspection. FFS methods are gradually being adopted, but applications of RBI have so far been only qualitative or semi-quantitative. The pulp and paper industry's reluctance to implement RBI arises from its focus on short-term costs rather than long-term profitability. The refinery and petrochemical industries face similar pressures to maintain the availability for operation of aging equipment, but continue to use RBI because of its demonstrated return on investment. Data from other industries also show that RBI and FFS measurably reduce inspection and maintenance costs while measurably increasing equipment integrity.

CONCLUSIONS

- Volume 1 of the AFPA Recovery Boiler Reference Manual provides useful guidelines for the planning of recovery boiler inspections.

- Non-destructive testing techniques are available that can indicate excessive thinning or incipient cracking if they are applied to the area where the damage is occurring.

- To increase the probability of detecting the thinnest tubes, and to detect incipient cracking, additional testing should be performed during each shutdown at the direction of an inspector who has years of experience inspecting similar boilers, and is aware of recent industry findings and state-of-the-art inspection methods.

- Typical UT thickness data obtained by contractor personnel have a standard error of 0.005 to 0.007" in their precision and 0.004 to 0.006" in their accuracy. As a result, corrosion rate calculations based on the difference between two thickness measurements made at successive shutdowns at the same location are almost always imprecise.

- Rates of tube wastage in different parts of a boiler, calculated from tube thickness data, can be used to schedule the replacement of different sections of the boiler as anticipated outlier tube thickness

measurements approach the minimum tolerable thickness.

- Risk-based inspection techniques developed in the petrochemical and refinery industries can be used to plan cost-effective recovery boiler inspection programs.

- Calculation of the annualized cost of defect-related risks in a recovery boiler enables an owner to evaluate the return on investment of inspection and maintenance programs.

- The FFS-1 standard offers recovery boiler owners a reliable basis for evaluating the impact on the integrity of the boiler of defects found by inspectors.

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APPENDIX: RECOVERY BOILER INSPECTION PROCEDURES

SUMMARY

The inspection procedures used for a particular recovery boiler should be tailored to its own design and operational history. This document proposes a generic scope of inspection for the first inspection of a recovery boiler with no prior inspection history, and describes how the scope and frequency of future inspections should be refined using Rick-Based Inspection methods as successive inspections reveal where, and how rapidly, corrosion and cracking are propagating.

INSPECTION PHILOSOPHY

A Recovery Boiler Inspection Coordinator should be appointed to take responsibility for the integrity of each recovery boiler. This person should, by virtue of his/her training and experience be competent to plan an inspection thorough enough to discover and quantitate the factors that limit the service life of an individual recovery boiler, to describe the present condition of a recovery boiler in simple writing and photographs, to determine whether specialists should be called in to assess the significance of particular defects and to define the type of repairs required to make the recovery boiler fit-for-service until its next scheduled inspection.

Because recovery boilers of many different designs operate in different ways that cause many different types of corrosion, cracking and mechanical damage, it is neither wise nor cost-effective to use a standard scope and frequency for all recovery boiler inspections. Fixed inspection scopes can overlook newly-discovered types of damage found elsewhere in the industry and can waste money when a reduced inspection scope could verify that a well-established pattern of corrosion is being maintained. Inspection should be increased when or where the condition of a unit is uncertain or when new damage is discovered. A rolling 6-year plan, which describes all the inspections proposed for that time period, should be developed for each recovery boiler.

Whenever operations wishes to significantly alter the operation of a recovery boiler the Recovery Boiler Inspection Coordinator should lead a Management of Change process, to establish and document the consequences of the proposed change on corrosion and cracking in the unit.

INITIAL INSPECTION PLAN

Before starting up a new or rebuilt recovery boiler, a pre-service tube thickness survey should be completed on the new tubes. With these baseline data in hand, indications of thinning can be confirmed during the first in-service inspection, rather than during the second in-service inspection. An example of the scope of an initial inspection is presented below. This same scope could be used for the first inspection of a recovery boiler with no previous inspection history.

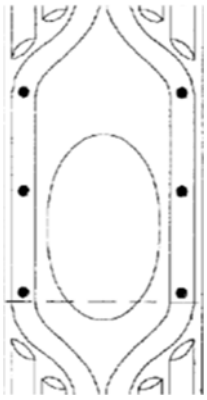
After the first inspection, data from subsequent inspections will enable the Recovery Boiler Inspection Coordinator to develop a clearer and clearer understanding of where thinning and cracking are occurring and of the rate at which they are propagating. This understanding will enable the Recovery Boiler Inspection Coordinator to increase the scope and/or frequency of re-inspection in areas of particular concern and to gradually reduce the scope and/or frequency where repeated inspections show no cracking and corrosion rates that are low and predictable. .

<u>Boiler inspections to be made every year:</u>

Every carbon steel tube around a spout opening and every carbon steel tube alongside a primary air port

100% visual inspection

Measure the thickness of each tube beside each spout opening and primary or secondary air port opening at the center of the opening and at the center of the upper and lower bends, i.e. at the location of the black dots in the sketch below.



Within the bent areas, move the Ultrasonic Testing (UT) transducer to find the lowest thickness location on each tube next to the opening. At the center of the opening, move the UT transducer to find the lowest thickness direction on each tube beside the opening.

Every composite tube beside a smelt spout, air port and every composite floor tube within 6' of a smelt spout

100% visual inspection and archival photography by an experienced visual Recovery Boiler Inspection Coordinator to document extent of balding and cracking and need for repair, using non-destructive tests - Eddy Current (EC), Copper Sulfate or dye-penetrant testing (PT) - as necessary to identify areas of balding, thinning or cracking

Every smelt spout

100% visual inspection of the condition for mechanical damage and for steel exposed by the corrosion of overlay

In each spout that will not be replaced, make thickness measurements at the inlet, outlet, mid-length and quarter points at the base of the trough and at the smelt line on either side of the trough. Move the UT transducer to find the thinnest locations at the inlet and outlet ends of the trough and at the smelt lines.

Where spouts are chromized, measure the surface chromium content (e.g. with a portable XRF alloy analyzer) to determine the remaining thickness of the coating instead of making thickness measurements.

Every tube protected by a coating

100% visual inspection of all thermally-sprayed or chromized tubes every year, with careful documentation by archival photography of the location and extent of local coating failures

Carefully document and photograph every location where spalling is visible and measure the thickness of the exposed underlying tube metal

Every second year, survey the thickness of intact thermally-sprayed coatings using appropriately calibrated NDT methods e.g. on every 10^{th} tube at every scaffold level.

Monitor the integrity of chromized coatings by measuring their surface chromium content with an XRF alloy analyzer.

Carbon steel floor tubes in boilers with sloping floors

100% visual inspection of floor tubes for mechanical damage

Thickness survey on every 5^{th} tube every 4' (crown, +45°, -45°) beginning on a line 1' from the wall opposite the spout wall and then on lines 4' apart from there to the spout wall

Within 4' of the spout wall, measure the thickness of every 5^{th} tube on lines 1' apart

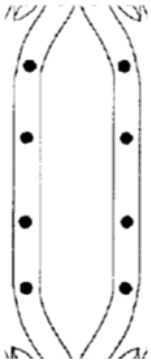
If thinning is found, extend the scope of the inspection, but continue to measure thickness at the locations listed above to establish thinning rates

Smelt line

After determining the location of the severest tube thickness loss at the smelt line by scanning the tube thickness across the area of interest on each wall, measure the thickness of every 5^{th} tube at the smelt line around the boiler cavity.

Every tube around a secondary air port, a start-up burner and beside a liquor gun

Measure the thickness of each tube beside each opening at four levels as shown by the black dots in the sketch below. Within the bend area, move the UT transducer to find the lowest thickness location on each tube next to the opening. In the straight portion of the tube, move the UT transducer to find the lowest thickness direction on each tube beside the opening.



Generating bank tubes

First inspection: Scan the thickness of every 5th tube from the plane of the outer surface of the mud drum near-drum area to a plane 1.5" farther from the center of the mud drum.

Subsequent inspections: Plan the scope and frequency of subsequent inspections according to the findings of this first inspection, boiler operating practices and sootblowing practices.

Pendant tubes at roof penetrations

Visual inspection of every pendant tube where it comes through the roof penetration, seeking evidence of thinning by corrosion or wear

Make thickness measurements as directed by the visual inspector

Mounting clips and vibration restraints

Visual inspection of all mounting clips and vibration restraints

Inspect by Magnetic particle testing (MT), PT or UT where the inspector sees evidence of cracking or wear

Locations subject to stress-assisted corrosion

In boilers that have operated for 5 years or longer, initially inspect at least 20 of the areas judged to be most vulnerable to waterside stress-assisted corrosion (including floor-to-sidewall and sidewall-to-sidewall seals, primary airport windbox corners, smelt spout box corners and nose-to-sidewall seals). Such inspections may be conducted using digital radiography with suitable penetrameters for estimating fissure depth or other methods that have been proven to provide reliable fissure depth data. If fissures deeper than 10% through-wall are found, their fitness-for service should be evaluated[5]. If fissures deeper than 10% are found to be fit-for-service, their size and depth should be monitored by re-inspection at future outages. If no indications >10% through-wall are found, the most vulnerable areas should be re-inspected 4 years later.

Locations subject to flow-assisted corrosion

Inspect 4-6 sites anticipated to be vulnerable to Flow-Assisted Corrosion[6]

Survey the metal thickness in these 4-6 sites using guided wave testing or using conventional UT with a 0.5" x 0.5" grid size.

Where significant FAC damage is found, expand the inspection to include additional potential sites

If no damage is found, re-inspect in 4 years or when 50% of the remaining corrosion allowance is predicted to be consumed.

<u>Boiler tube thickness measurements to be made every second year:</u>

Composite floor tubes

100% inspection of composite floor tubes within 10' of the spout wall, using appropriate NDT procedures to detect cracking, e.g. visual, PT, copper sulfate and shear wave UT.

Tertiary and higher air ports

Measure the thickness of each tube beside each upper air port opening at equally-spaced heights, e.g. 4 – 6" apart and at the center of the upper and lower bends as described above for tubes around primary and secondary air ports. Within the bend area, move the UT transducer and record the lowest thickness location on each tube next

5. Use API 579-1/ASME FFS-1, "Fitness-for-Service" published ASME, New York NY, 2007. See also W. B. A. Sharp, "The Strength of Recovery Boiler Tubes Containing Stress-Assisted Corrosion", 11th International Symposium on Corrosion in the Pulp and Paper Industry, Charleston, SC, June 8-11, 2004, published TAPPI Press, Atlanta, GA, 2004.

6. Where unalloyed carbon steel experiences water velocities > 8-10 fps (particularly at changes in geometry like elbows and reducers that produce turbulence), pH between 7 and 9.5, oxygen concentrations <20 ppb and temperatures between 212° and 480°F . See "Guidelines for detection, monitoring and prevention of flow-accelerated corrosion in the pulp and paper mill," TAPPI Technical Information Paper TIP 0402-36 (2103), published TAPPI Press, Atlanta, GA, 2013.

to the opening. In the straight portion of the tubes beside the opening, move the UT transducer and record the lowest thickness on each tube beside the opening.

Wall tubes below liquor guns

Make 3 measurements of the thickness of every 5th tube (crown, +45° and -45°) at 2 elevations per scaffold level, e.g. every 3' elevation. Note carefully how these elevations are to be established, so that they can be re-established accurately.

Wall tubes between liquor guns and about 8' above upper air ports

Make 3 measurements of the thickness of every 5th tube (crown, +45° and -45°) at one elevation per scaffold level, e.g. every 6' elevation. Note carefully how these elevations are to be established so that they can be re-established accurately.

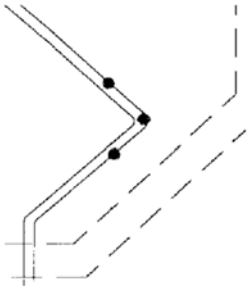
Wall tubes from about 8' above upper air ports to boiler roof

Make 3 measurements of the thickness of every 5th tube (crown, +45° and -45°) at one elevation per scaffold level, e.g. every 6' elevation. Note carefully how these elevations are to be established so that they can be re-established accurately at subsequent inspections.

Nose tubes

Visually inspect the top surface of all nose tubes for damage from falling material

Measure thickness of every nose tube (crown, +45° and -45°) at the outside of the bend, 1' above the bend and 1' below the bend as shown by the black dots in the sketch below (Dashed lines are furnace screen tubes).

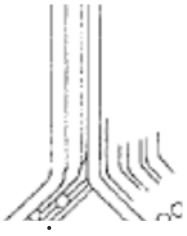


Furnace Screen tubes

Measure thickness of all screen tube surfaces (crown, +45° and -45°) at the bend, +1' and – 1' from the bend as shown in the sketch below.

Measure the thickness of each screen tube that faces the furnace at locations 5-6' apart between the bend and the side wall (crown, +45° and -45°).





Visually inspect the screen tubes for corrosion pitting that could indicate the formation of acidic bisulfate deposits.

Visually inspect the top of the sloping section of furnace screen tubes for mechanical damage from falling material

The windward lower corner of all superheater tubes

Measure the thickness of the outermost superheater tube in each platen at its windward lower corner at the center of the bend, and where this bend blends into the adjacent straight portion (crown, +45° and -45°)

The horizontal straight portion of the lowest superheater tube in each platen

Measure the thickness of the bottom surface of the horizontal portion of the lowest superheater tube in each platen 1', 2' and 3' from the outermost bend (crown, +45° and -45°).

The vertical portion of the superheater tube nearest the furnace in each platen

Measure the thickness of the vertical portion of the windward side of the superheater tube nearest the furnace in each platen 1', 2' and 3' above the outermost bend (crown, +45° and -45°).

The bottom bends of the hottest tubes

Measure the thickness of the hottest superheater tube in each platen at the center of the bottom bend and where this bend blends into the adjacent straight portion (crown, +45° and -45°)

The bottom bends of out-of-plane tubes

Measure the thickness of the bottom bend of all out-of-plane superheater tubes at their windward lower corner - at the center of the bend, and where this bend blends into the adjacent straight portion (crown, +45° and -45°)

Tubes at sootblower ports

Measure the thickness of the 3 wall tubes nearest the sootblower entry location at the center, the top and the bottom of each sootblower port (crown, +45° and -45°).

Tubes in sootblower lanes

Measure the thickness of the 5 pendant tubes nearest each side wall at the height of the sootblower lance in every sootblower lane (crown, +45° and -45°).

Measure the thickness of every 5th pendant tube at the height of the sootblower lance along every sootblower lane (crown, +45° and -45°).

Boiler tube thickness measurements to be made every fourth year:

Generating bank tubes

Thickness scans of full length of all generating bank tubes (IRIS or EC), paying particular attention to thinning at the elevation of sootblower lanes

Economizer

Thickness measurements of every 5th tube at 1' height intervals in all accessible portions of economizer

Boiler tube inspections to be made every sixth year

Carbon steel floor tubes in boilers with decanting hearths.[7]

100% visual inspection of floor tubes for mechanical damage

Thickness survey on every 5th tube every 4' (crown, +45°, -45°)

"Flat-bar" vibration restraints

Move "flat bar vibration restraints to contact different areas on the tubes

Casing-side corrosion of tubes in boilers with tangent-tube walls

Measure the depth of corrosion pitting on the cold side of tangent tubes in at least three locations where removal of the casing has exposed a 1' x 1' area of the back of the cold side of wall tubes at heights between the secondary air ports and the nose. Also inspect for cold-side corrosion behind the nose and in accessible areas around buckstays.

Other boiler inspections

The scope and frequency of inspections should change as the Recovery Boiler Inspection Coordinator becomes more aware of the damage mechanisms and rates in particular recovery boilers. In addition to these changes, additional inspections should be added as new types of damage are discovered elsewhere. The Recovery Boiler Inspection Coordinator is responsible to learn about newly-discovered types of damage in recovery boilers. Useful sources of this information include BLRBAC, TAPPI's Corrosion and Materials Engineering Committee, NACE International's STG 38 (Corrosion in Pulp, Paper, and Biomass Conversion) committee, boiler OEMs and contractors. When new types of damage are reported, new inspection procedures should be added to detect and quantify them.

The mill should clarify who is responsible for the integrity of additional items related to the recovery boiler such as the deaerator, FD and ID fans, precipitator and stack. Also, because waterside deposits influence fireside tube temperatures and corrosion rates, the Deposit Weight Density (DWD) and composition of waterside deposits should also be routinely monitored during recovery boiler inspections.

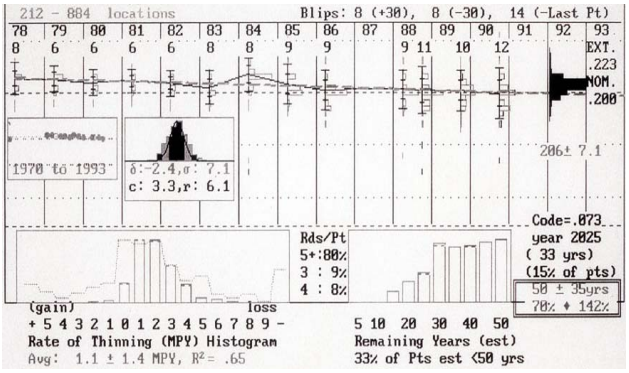
The scope and frequency of inspections in each recovery boiler should be reviewed and potentially updated every year, so that they continue to conform to "recognized and generally accepted good engineering practice."

REFINING THE SCOPE OF A RECOVERY BOILER INSPECTION

7. The smelt bed must first be removed by smelt pumping or hydroblasting

Calculation of remaining life from boiler tube thickness measurements

Boiler components should be re-inspected more intensely as they near the end of their service life. Software programs are available to calculate corrosion rates and remaining life from boiler tube thickness data. However, many of these programs calculate corrosion rates by comparing thicknesses at particular locations at two successive shutdowns. Because typical UT thickness measurements have a standard error of 0.005 to 0.007" in their precision and 0.004 to 0.006" in their accuracy, corrosion rates calculated from the difference between two thickness measurements at successive shutdowns should not be regarded as reliable. Two other approaches provide more reliable estimates of remaining life within individual regions of a boiler where all the tube thicknesses belong to the same statistical population. The first is simply to compare the sum of tube thickness measurements taken at the same 100 or more thickness measurement locations on at least four separate occasions. The second and more powerful approach has been enabled by the development of computer power. For example the graph below shows the output of a trending program developed as long ago as 1990[8].



By regressing the distributions of tube thickness measurements (presented as vertical histograms in the figure above), such programs can calculate the distribution of apparent thinning or thickening rates, the year in which the thickness at each measurement location will fall below the code minimum, and the distribution of the remaining lives of tubes in future years.

Remaining life estimates provide additional valuable information. For example, if the tube thickness data are widely scattered, it will be cost-effective to replace individually thinned tubes. If the remaining lives of tubes are closely bunched, it will be more cost-effective to replace complete panels on a scheduled basis, while other major work is being completed elsewhere in the mill.

The use of thickness trending programs to extrapolate previous thickness data to the time of future shutdowns can inform the mill about the range of thickness readings that is statistically likely to be found at future inspections. This enables the Recovery Boiler Inspection Coordinator to flag unlikely readings and have UT technicians re-measure them. When re-measured, the majority of outlier readings will be found to be erroneous.

RECORD KEEPING

Documents to be filed

Documentation of each recovery boiler's complete history should be maintained in a central file at the mill. The filed information should contain the following:

- Boiler design specifications, design calculations, U-1 certificate, certification of every subsequent repair or modification to a code-covered pressure part including materials test reports and the inspection documentation required by the regulating authority.

8 "Inspection of Recovery Boilers," by W. B. A.(Sandy) Sharp, TAPPI Kraft Recovery Short Course, Orlando, FL, 1991, published TAPPI Press, Atlanta, 1991.

- If available, reports of Quality Assurance inspections during the fabrication and erection of the boiler. If available, radiographs of original construction welds.
- Complete set of certified, as-built, drawings
- Pre-service measurements of thickness of pressure parts at clearly designated locations.
- Boiler start-up date
- Maintenance history including locations and details of repairs, alterations, replacements and service changes, with materials test reports and inspection documentation as required by the regulating authority.
- Inspection reports signed by the inspectors and NDT technicians involved, showing their qualifications for this work. Inspection methods and results; photographs, inspection notes, radiographs (if taken) and recommendations for repair (if applicable).
- Reports of fitness-for-service evaluations of particular defects, with any additional limitations on required wall thickness or other parameters.
- Estimates of corrosion rates in different regions of the boiler, of remaining service life in these regions and planned re-inspection year documented in a 6-year rolling inspection plan.

Six-year rolling plan for future inspections

A rolling six-year inspection plan should be developed for each recovery boiler, to reduce costs by combining inspections that require scaffolding in particular years and by combining inspections that require little or no scaffolding in other years, and to schedule major maintenance work at the time of other major maintenance elsewhere in the mill. An example of an excerpt from a multi-year boiler inspection plan is reproduced on the next page. The six-year inspection plan should be updated after each successive shutdown inspection to add additional requirements where the condition of the unit is uncertain or known to be of concern and to seek opportunities for reducing future inspection costs without increasing risks. The Recovery Boiler Inspection Coordinator should apply the qualitative principles of Risk-Based Inspection but preferably apply quantitative Risk-Based Inspection[9] methods when future inspections are planned

EXAMPLE EXERPT FROM A MULTI-YEAR ROLLING INSPECTION PLAN FOR A RECOVERY BOILER

Part to be inspected	Inspection Guidelines	Previous condition of RB7	2009 inspection	2010 inspection	2011 inspection	2012 inspection	2013 inspection
Carbon steel floor tubes	See Generic Inspection Plan	Nominal 0.200”; 2004 min 0.196”; t_{min} 0.072”.	No action	No action	No action	Remove bed with smelt pumps, not jackhammers. Water blast to clean off remainder. 100% visual of all floor tubes. UT based on visual findings.	No action
Carbon Steel wall tubes at smelt line	See Generic Inspection Plan	Nominal 0.200”; 2004 min 0.194” 2005 min 0.180” 2007 min 0.185” t_{min} 0.072”.	No action	TML on every 5th wall tube at the smelt line.	No action	Scan every wall tube across smelt line and record thinnest reading. Crown and 45º each side on each tube.	No action
Spout opening tubes	See Generic Inspection Plan	Nominal 0.200”; 2004 min 0.199” 2006 min 0.148” 2007 min 0.172” t_{min} 0.072”.	Carefully remove smelt bed in front of each spout and in front of 3 tubes on either side without denting any tubes.	Remove bed in front of spout tubes only where 2008 scanning showed localized thinning 4 tubes each	Remove bed in front of spout tubes only where 2008 scanning showed localized thinning 4 tubes each side of opening; 3 elevations on each. Crown and 45º	Remove bed in front of spout tubes only where 2008 scanning showed localized thinning 4 tubes each side of opening; 3 elevations on each. Crown and 45º each side at each	Remove bed in front of spout tubes only where f 2008 scanning showed localized thinning 4 tubes each side

9. Quantitative RBI allows potential inspection strategies to be evaluated on the basis of their impact on the annualized cost of risk. Although quantitative RBI is costly to start up, plants that have implemented it have typically seen a reduction in their maintenance costs of 30-50% at constant risk.

			4 tubes each side of opening; 3 elevations on each. Crown and 45º each side at each TML. Scan inside of bottom bend and front of innermost tubes for smelt washing and smelt line thinning. Record thinnest readings.	side of opening; 3 elevations on each. Crown and 45º each side at each TML.	each side at each TML.	TML.	of opening; 3 elevations on each. Crown and 45º each side at each TML.

NOTES (moved from end of Inspection Plan document)

1. Red type shows requirements that are new to this checklist.

2. Green type shows inspection scope reductions below general guidelines.

3. Scaffold furnace cavity to roof in 2008 and 2012.

4. Scaffold furnace cavity only to load burners in 2010.

5. Scaffold upper furnace only in 2009 and 2011.

6. If superheater loops must be scaffolded to replace the 3 suspicious loops in 2008, measure superheater thicknesses in 2008 because of uncertainty about previous data and do other upper furnace thickness measurements in 2008 to avoid having to scaffold upper furnace in 2009 as well as in 2008.

Outage reports

The final report of each recovery boiler inspection should contain a 1- to 2-page prose summary of the most important findings of the inspection. After reviewing the inspection data, the Recovery Boiler Inspection Coordinator shall update and revise as necessary the rolling 6-year inspection plan for the boiler. The final report should also include a short list of items that should be checked if the opportunity arises (e.g. if a recovery boiler becomes unexpectedly available for safe entry). These items would be in addition to the normal checklist for an opportunistic inspection, e.g.

If the boiler cannot safely be entered

If the boiler can safely be entered:

Visual inspection of all tubes surrounding smelt pouts, primary and secondary air ports
Visual inspection of smelt spouts
Tube thickness measurements more than 12 months overdue
Replacement of tubes projected to thin below code within 24 months with hydrostatic test at 90% of normal steam outlet pressure to detect leaks

A summary report of the integrity of each recovery boiler should be submitted to mill and corporate management each year and should include all the following information:

Operational failures, if any, that occurred during the previous year
Status of year-end compliance with inspection program requirements
Scheduled inspections that were not attempted, that were not completed, or that were late
Savings achieved by Risk-Based Inspection and by Fitness-for-Service analyses.