



ADVANCED BOILER INSPECTION TECHNIQUES 2011

Contents

1. Reliability & Availability.....	5
.....	5
Industry overview	5
Boiler/Steam Generator.....	6
Development and History of Supercritical boilers:	7
Boiler Water Treatment.....	15
Emissions Performance NOx	15
Availability Improvements at Existing Units	17
2. Risk management.....	18
Data Driven Planning	18
Risk Driven Project Planning and Execution.....	19
Risk Driven Project Process \ Value-based Management	19
Formal repair selection criteria	20
Ranking of priorities.....	22
FAILURES AND NEAR FAILURES IN FOSSIL PLANTS.....	29
COSTS ASSOCIATED WITH BOILER TUBE FAILURES	30
REPEAT BOILER FAILURES.....	30
Proper Failure analysis	32
Choice of Corrective /Preemptive Action.....	33
Problem Definition	34
Multidiscipline Approach	34
Permanent Engineered Solutions	35
Boiler Condition Assessments how and why?	42
3. Human Resources	48
Equipment required for in plant boiler inspection teams.....	51
Utilization of supplemental Boiler Inspection Team Members	52
4. Outage management.....	53
Cost Control.....	53



ADVANCED BOILER INSPECTION TECHNIQUES 2011

Quality Assurance	54
Data forms	56
Inspection Check Lists Technical procedures.....	58
Planned Outage Preparation.....	60
Inspection Methods	61
Boiler Tube Repair and Replacement	61
Known Boiler Specific Failure Mechanisms	61
Recommended Actions	61
Inspection Photography.....	66
Report preparation	68
Forced Outage Procedures	69
5. Operational Factors affecting failures	75
Cycling the boiler.....	75
Start up shut down ramp rates	77
SHORT TERM OVERHEAT.....	78
Ligament cracking	80
DISSIMILAR METAL WELD (DMW) CRACKING	92
DEW-POINT CORROSION	100
SOOTBLOWER (Wall & Retractable) EROSION	103
Thermal fatigue (Quench cracking) from water lances and water cannons	110
Craze cracking (alligator hide).....	117
FALLING SLAG INTO HOPPER BOTTOM (countant).....	122
CREEP, HIGH TEMPERATURE	124
6. Fuel & Burners	138
FIRESIDE FURNACE CORROSION	141
Coal ash corrosion	143
ASH CORROSION	144
COAL PARTICLE EROSION.....	153
FLY ASH EROSION	155
PRB Coal Fuel.....	160
7. Component Replacements	170
Economic justification tips	170



ADVANCED BOILER INSPECTION TECHNIQUES 2011

Component Replacements \ Replace versus Repair the How's and Whys	172
Replacements versus Repairing.....	174
8. Selection and installation of pressure part components	177
STRENGTH BASIS OF MATERIAL SELECTION OF BOILER PRESSURE PARTS.....	177
OTHER CONSIDERATIONS IN MATERIALS SELECTION AND USE	180
9. Commercial issues of procurement of new pressure parts	183
Inspection of new fabrications in the assembly shop QA/QC.....	184
CREEP, LOW TEMPERATURE.....	186
10. BOILER CHEMISTRY	188
Boiler Cycle chemistry	188
Common water chemistry problems and their consequences.....	188
The elements of a good water chemistry program.....	189
Deposit Control.....	192
Conventional phosphate treatment:.....	193
Chelant treatment:.....	193
Boiler off line lay up procedures	194
Chemical cleaning?.....	196
Deposit Loading.....	197
Contamination-Required Cleanings	198
STRESS CORROSION CRACKING	199
CORROSION FATIGUE	201
PITTING.....	207
CAUSTIC CORROSION / GOUGING.....	210
ACID PHOSPHATE CORROSION.....	212
HYDROGEN DAMAGE.....	214
11. STEEL APPLICATIONS AND USE.....	218
Metallurgy	218
12. Hydrostatic testing yes or no?	231
BOILER FILL WATER TEMPERATURE REQUIREMENTS.....	232
13. Repairs	234
Tube replacement vs. repair.....	234
Pad Weld / Overlay Applications.....	236
Copper (Weld Repair Caution).....	239



ADVANCED BOILER INSPECTION TECHNIQUES 2011

Repair procedures.....	241
The use of overlay welding on tubes (<i>pad welding by a different name</i>)	244
Thinning weld repair guidelines	249
14. Thermal Spray Coating and when to use it?	253
15. How to handle a tube sample	258
16. What Are Refractories Used For?.....	261
17. Isomembrane and its usefulness:	266
What is ISOMEMBRANE?	266
18. ASME APPROVED BOILER TUBING STEELS	278

1. Reliability & Availability

Industry overview

This section will focus on recommendations that will improve existing coal-fired power plants' reliability and availability to eliminate or reduce forced outages and extend the time between planned maintenance outages. This suggested availability improvement program is meant to restore the plants' infrastructure to a level that restores the original reliability of the plants. Implementation of these recommendations will allow the plants to increase generation output above recent historical output without increasing gross generating capability.



We will show from the use of industry sources on reliability (GADS/NERC) and generation capacity (EIA) that there is a significant opportunity for the utility industry to increase the generation output from our existing fleet of coal-fired power plants by restoring portions of the plant infrastructure to their original condition.

Analysis of the U.S. utility industry's coal-fired plant infrastructure reveals a significant opportunity for increasing electricity output from these plants by taking measures to improve the reliability/availability of the older facilities. Maintaining or restoring plants that are over 20 years old to a condition similar to plants that are under 20 years old can result in more reliable facilities that will be available to play an important role in supporting the increasing strain on our electrical system's reserve margins and electrical demand growth.



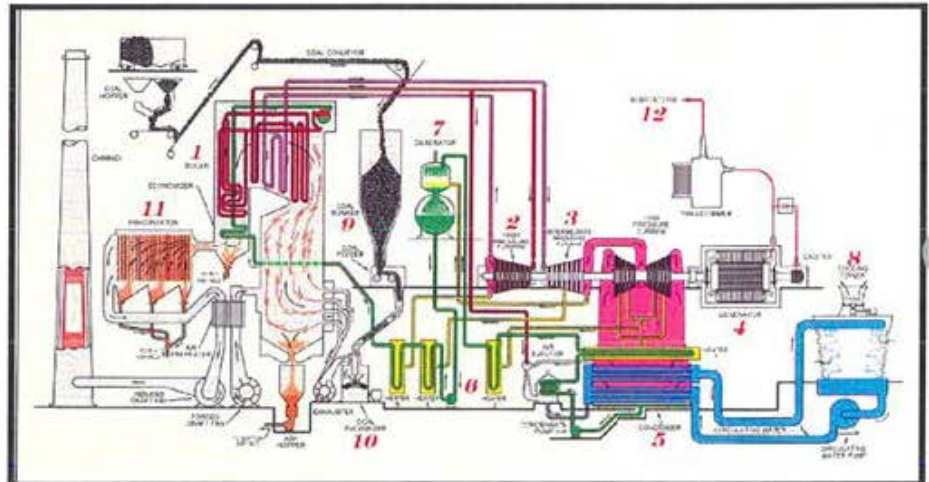
Specifically, our analysis has shown that this reliability improvement effort **can create 10,000 MWs** of equivalent generation capacity within our existing coal-fired fleet of plants. Of particular note is that over 90% of these MWs of capacity will come from component replacement and material upgrades of the boiler/steam generator at our facilities that are more than 20 years old. The U.S. EPA has focused on boiler/steam generator component replacement projects in its recent enforcement actions, applying New Source Review ("NSR") standards to repairs formerly considered routine maintenance, repair, or replacement. The potential regulatory consequences of the EPA's enforcement actions may prevent the utility industry from taking full advantage of this relatively inexpensive way to increase the availability of our national electric generating capacity, which could be implemented in a two to three year time frame.

The U.S. electric generating system's reserve margins have declined dramatically over the last 20 years. This situation has put pressure on the operators of our existing coal-fired fleet to restore, maintain, or improve the reliability and availability of their facilities to keep pace with the growing demand for electricity in the face of limited new capacity coming on line. The mandate for higher availability, lower forced outage rates, and longer time spans between planned outages is more critical today than ever in our history.

The causes of plant unavailability are well defined, and sound, technology-based solutions are commercially available to improve plant availability and help restore our historic reserve margins. Causes of plant unavailability and recommendations for solutions have been generally categorized according to the magnitude of their impact on plant availability in the following:

Boiler/Steam Generator

The primary cause of unavailability of our coal-fired plants is the reliability of the boiler/steam generator. Severe duty on both the fire side and the water/steam side of the various heat transfer surfaces in the boiler/steam generator cause frequent unplanned outages and lengthening of planned outages to repair failures to these critical components of the power plant. Replacement of these components will significantly reduce outages and increase the facility's availability and total generation output capability.



All areas represents between 50% and 70% (depending on age, design, and operating history of the unit) of all lost generation from our coal-fired fleet. The industry data sources referenced above indicate that if improvements to the boilers/steam generators on our plants that are older than 20 years can be made to restore these facilities to the condition of plants that are under 20 years, we will benefit from an attendant improvement in reliability/availability.

To help quantify this finding, plants older than 20 years are, on average, currently experiencing nearly **10% loss** of achievable generation due to problems in the boiler/steam generator. This compares to approximately **5% loss** for plants that are less than 20 years old. If we can recover only this differential through restoration of the boiler/steam generator, we will be taking advantage of nearly 9,000 MWs of available generation capacity in our existing coal-fired generating fleet. This figure is expected to increase significantly as our older generating units are dispatched more often to meet the growing demand for electricity considering the less than adequate new capacity coming on line.

Although the implementation of any (or all) of these recommendations will significantly increase plant availability, recent regulatory treatment of previously routine repairs, maintenance, and replacement as modifications by the EPA discourages utilities from pursuing these kinds of projects in their future plans for availability improvement for fear of triggering NSR with accompanying permitting and modeling requirements. NSR can radically undermine the economic feasibility of these projects, preventing recapture of lost generating capacity or increased reliability.

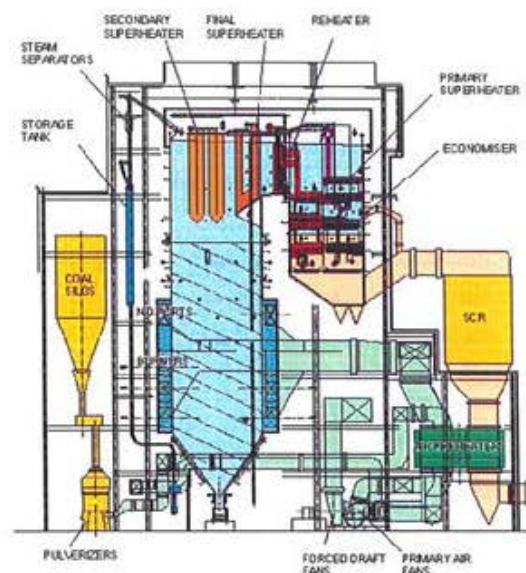
Development and History of Supercritical boilers:

General

This appendix addresses the comparative issues of sub-critical and super critical power cycles. The critical pressure point of water and steam is 22.1 MPa abs, below this pressure it is called sub-critical pressure and above this pressure it is called as supercritical pressure. In the supercritical region, co-existence of water and steam is not present, therefore in the absence of steam/water mixture, the recirculating boiler technology adopted for subcritical pressure could not be used. This was the key to the advancement of cycle efficiency through the adoption of economic and reliable once-through supercritical boilers.

Historical Perspective of Supercritical Pressure Plants

The drive for enhancing the efficiency of generating plants in an environmentally friendly manner has been realized mainly through advancing the steam conditions, i.e. increasing pressure and temperature. This was realized due to dramatic improvements in materials technology for boilers and steam turbines since the early 1980s for higher steam temperature, and a better understanding of power plant water chemistry, have led to an increased use of supercritical steam cycles in international markets.

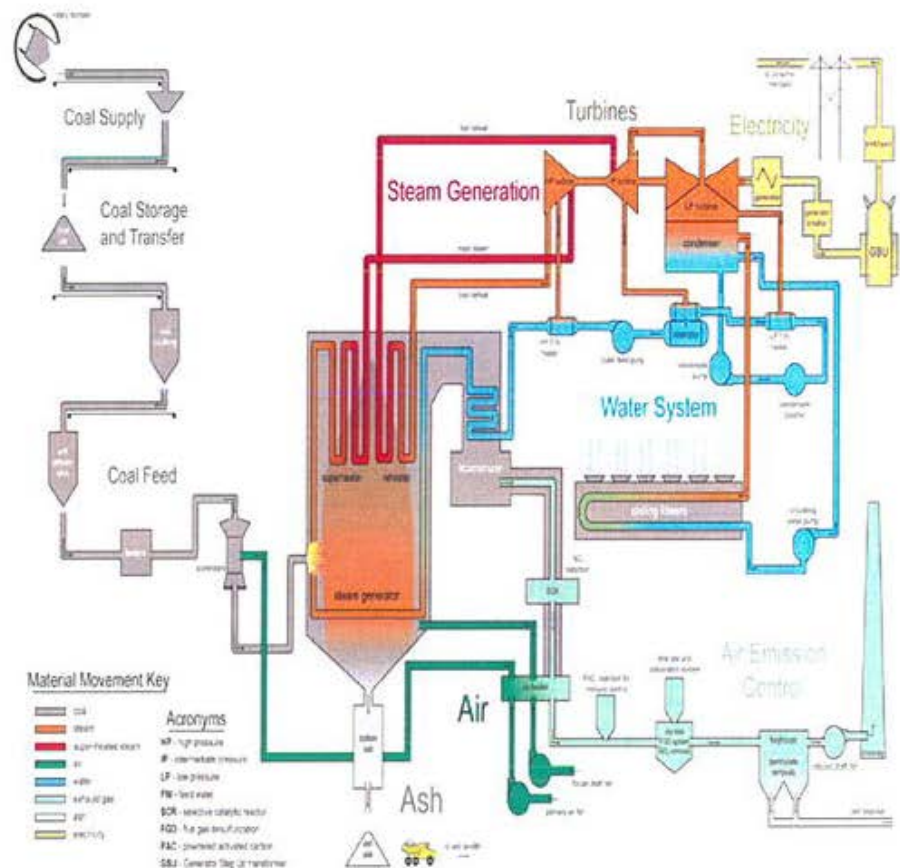


Boiler Type :	Once-Through, Benson
Generator Output :	677MW
Main Steam Flow :	4,317,000 lb/h
Steam Conditions :	3,800 psia / 1055 °F / 1055 °F
Fuel :	Eastern Bituminous
Commercial Operation :	2009, 2010

Development of Supercritical Boilers

In the 1950s when the USA showed interest in using advanced steam conditions, the two major holders of the "supercritical" boiler technology were Sulzer of Switzerland and Siemens in Germany. Sulzer boilers were known as 'monotube' boilers whereas Siemens the licensor of the Benson once-through boiler technology. The USA boiler manufacturers therefore turned to Europe and signed technology licenses with the Europeans. It was this USA push that spawned the majority of the supercritical boilers that operate in the world today. By comparison the number of supercritical plants of direct European origin is modest, although the numbers have grown in recent years. Combustion Engineering signed with Sulzer and Babcock and Wilcox and Foster Wheeler had an agreement with Siemens. Riley Stoker also built supercritical pressure units.

Between 1957 and 1960 six supercritical plants were commissioned in the USA using the European knowledge but with USA additions. Some ambitious steam conditions, up to 5000 psi, (34.5 MPa) and 1200°F (650°C) most with double reheat, were adopted. A number of these plants should be put in the category of 'pioneering plants' as they were not a commercial success. Design developments were undertaken in USA and in the mid sixties the second generation of supercritical units was being commissioned. Through their Japanese licensees supercritical units of the USA design were constructed in Japan. Babcock & Wilcox's once-through boiler was called the 'Universal Pressure' (UP) boiler, suitable for both sub and supercritical pressures.





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In USA from 1963 to 1970 about half of the sales of utility fossil fuel fired plant were designed for supercritical pressure. From 1971 to 1974 it had fallen to around 25%. The reasons for the reduction were:

- the poorer availability of the supercritical pressure plant (new control concept, larger units, pressurized firing)
- the poorer load changing and start-up flexibility of the supercritical plant at a time when the fossil fired plant needed to complement the growing number of nuclear plants which were operated at base load.

Since the 1960s experience improvements in design of the supercritical boilers were made such that in the 1980s the new plants could achieve similar availabilities to the sub-critical plants. (see "607 days (continuous) running", Electrical World June 1987). The number of supercritical plants sold in the USA in the decade starting 1965 amounted to 125 units. In total there are now some 150 units in service in the USA, the reduction in the rate of their installation being in part a result slowdown in the growth of demand and the trend towards gas fired combined cycle plants.

In the 1960s a number of the US type of supercritical boilers were installed in Japan with the Japanese licensees of the US boiler makers being involved. B&W were associated with Babcock/Hitachi, Combustion Engineering with Mitsubishi (MHI), and Foster Wheeler with IHI. Because of their high fuel costs the Japanese had a greater incentive than the US to adopt the advanced cycle conditions. Consequently a very high proportion of units installed in Japan have been supercritical units and within the following two decades the Japanese had advanced the design of supercritical pressure boilers further than their US licensees/associates.

The former USSR also embarked on a major installation program of supercritical units commencing around 1960.

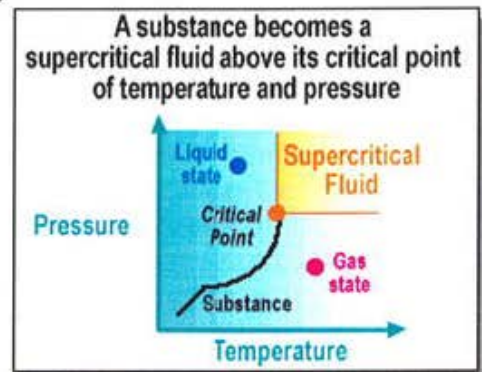
Around the mid to late 1980s when the pressure from the greenhouse gas issue began to be felt, Germany and Denmark embarked on a major program of advancing the efficiency of the conventional steam cycle for coal firing. This impetus may have been spurred on by the threat of competition from the new power generation technologies which were being developed at that time, integrated gasification combined cycle (IGCC) and pressurized fluidized bed boilers (PFB). As can be seen from the above the countries which have the most experience with supercritical pressure cycles are USA, (although most of the units installed are of an out-dated technology) Japan, Germany and Denmark. There are also a number of units in Korea, China and a lesser number elsewhere. Thus Germany, Japan and Denmark have a number of modern plants which could be described as 'world's best practice' in terms of efficiency and operational flexibility. It is natural that the major advancement in the technology has occurred in those countries where the high cost of fossil fuels is a major driver. In the case of Germany and Japan they also have the necessary industrial base and the major boiler and turbine designers who have the resources to develop advanced designs. In the European scene the major players are Alstom and Siemens on both boilers and turbines, and Deutsche Babcock on boiler design. In the case of Japan all the usual heavy industry manufacturers are involved, MHI and Hitachi with both boiler and turbines, and Toshiba on turbines, IHI on boilers. The major USA manufacturers also offer supercritical boilers of a similar design to those offered by the German and Japanese manufactures. Korean and Chinese manufacturers also offer supercritical boilers under the licensees from European and Japanese manufacturers.

In India, very recently BHEL made technology collaborations with Alstom for Supercritical Boiler and with Siemens for Steam Turbine Generator. NTPC started to construct first supercritical plant (3 x 660MW) in India near Sipat village in the state of Chhattisgarh.

Supercritical Boilers

With supercritical pressure boiler there is not only a need to increase the wall thickness of the pressure components and also use advanced materials but there is also a need to adopt a type of boiler which is different to the type normally used for sub-critical pressures. This need is related to the type of technology that can be used in the evaporation circuit of the boiler. It is this need for a different boiler technology which is the critical requirement in the adoption of supercritical pressure.

As stated earlier, at supercritical pressures, unlike at sub-critical pressures, there is no co-existence of the two phases, water and steam. Therefore the standard circulation system, which relies on the density difference between steam and water to drive the circulation for cooling the furnace wall tubes, and to separate the steam from the water to enable superheating to take place in the superheater tubes, is no longer suitable. Instead a once-through type of system must be used.



Supercritical Steam Turbines

Unlike the boiler plant the design of the turbine plant is little affected by the use of supercritical pressure. Of course the high pressure cylinder must be designed to withstand the higher pressure and temperature and also the reheater pressure and temperature will be higher, generally in proportion to the increase in the main steam pressure. With supercritical pressures, because of the greater steam pressure range in the turbine from inlet through to the condenser, there is greater scope for including an extra stage or stages of feedwater heating. In some plants the 'top' high pressure heater, which heats the return water to the final feed water temperature, takes its bled steam from a tapping on the HP cylinder rather than from the usual position at the outlet of the HP cylinder. This enables an even higher feedwater temperature to be achieved and thereby provide a further increase in cycle efficiency. Typical feedwater temperatures are around 290°C to 275°C compared to around 235°C to 250°C for sub-critical plants. With improved cycle efficiency, i.e. a lower heat rate, there will be a reduction in heat rejected to the condenser. There is a multiplying effect for a given improvement in heat rate. For example, if the heat rate is reduced by say 3.5% due to the use of supercritical pressure and higher steam temperatures, the heat rejected to the condenser is reduced by about 6.4%.



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The percentage reduction in the sizing of the condenser and cooling towers is nearly two times the percentage reduction in heat rate. In addition the water usage for a wet cooling tower will also reduce in the same proportion.

Efficiency Gains

It shall be noted that, as the pressure is increased, so the gains made by increasing the steam temperatures are marginally greater. Other factors which affect the cycle efficiency are the number of reheats, single or double, the condenser pressure, the number of feedwater heaters, whether there is a feedwater heater bled steam point part-way through the HP turbine, pressure drop through the reheater, etc. Therefore the figures shown in the above graph must be regarded as typical only. When the supercritical plant having steam conditions of about 25 MPa and 566/566°C is compared with modern sub-critical plants which operate at around 16 MPa 538/538°C, an efficiency improvement of about 3.5% is expected accordingly to the above graph.

Environmental Benefits

Gains in efficiency are reflected directly in the environmental benefits, i.e. savings in coal consumption that means lower amount of CO₂, NO_x and SO₂ emission per kWh of power generated using efficient supercritical plants. Comparative Costs (i) Capital Costs The key issues arising from a comparison of a supercritical pressure plant compared to a sub-critical plant of the same MW rating are: • An increase in cycle efficiency occurs leading to reduction in most flow quantities for a given unit size. • There is a reduction in the heat to steam and the heat rejected to the condenser and cooling towers. • A similar steam flow rate, kg/s per MW generated exists. Due to the reduction in enthalpy of steam with higher pressure, and a higher feedwater temperature, the enthalpy rise in the boiler is less than for a sub-critical boiler. However with an increase in main steam and reheat temperature giving an increase in the enthalpy pick-up, the specific steam flow kg/s per MW generated does not change significantly compared to a sub-critical pressure plant. • The higher pressures result in higher steam densities and lower volume flows of steam in both the main steam and the reheat systems. The higher pressure, the need for a once-through boiler and the above changes in the process variables leads to the following effects in the design of the plant: • Advanced and additional materials are required for containment of the higher pressure and temperature.

- There is a reduction in size of various plant items due to the reduction in thermal duty and general flow rates associated with the higher cycle efficiency: This includes: -Fuel and ash handling plant -Firing equipment and draft plant -Condenser -Cooling tower -Furnace size However the total heating surface area in the boiler may not change significantly as the heat is transferred at a higher average fluid temperature, thereby reducing the temperature differences between flue gas and the working fluid. • A more complex furnace wall system in terms of the tubing arrangement and the support of the furnace walls, leading to higher costs.



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- The lower volume flow of steam flow leading to lower piping diameters. Overall the cost of the boiler plant is higher mainly as a result of the thicker walls for pressure containment and the more complicated furnace wall system required for the once-through design. The cost of the turbine is expected to be marginally higher due to the thicker walled components or the higher grade material required because of the higher temperatures. There is no significant extra equipment required to meet the requirements of the supercritical plant, for e.g. supercritical pressure plants would require 100% condensate polishing where as recirculation sub-critical plants does not require this.

But of late, condensing polishing plants are widely used in recirculation sub-critical plants also. Because of the reduction in size of much of the ancillary plant, coal and ash handling plant, CW system, etc, which will partly off-set the increased cost of the boiler and turbine, the overall cost of a supercritical plant compared with a recirculation sub-critical plant should not be more than 5% above a sub-critical pressure plant. This assumes that moderate temperatures for steam conditions are used such as 570°C for main steam and 580-600°C of hot reheat. Higher temperatures and any higher pressure more than 25MPa may push the price increase above the 5% increase. (ii) Operational and Maintenance Cost

An increase in cycle efficiency results in substantial savings in fuel consumption. Therefore, the operational cost (fuel cost) of the supercritical plant will be significantly less compared to sub-critical plant. Otherwise, there should not be any significant differences in O&M costs between a sub and supercritical pressure plant.

Size Considerations/Selection

As indicated in earlier sections, one of the difficulties in designing once-through boilers is to provide adequate cooling of the water walls with a limited flow of fluid. With smaller boilers the perimeter of the furnace wall (as viewed in plan) reduces approximately as the square root of the unit size. Therefore the problem of covering the furnace wall with tubes whilst simultaneously maintaining an adequate cooling water velocity becomes more difficult for smaller unit sizes. Also as indicated earlier small turbine blade heights lead to higher losses. For these reasons supercritical pressures are more suited to large unit sizes rather than smaller sizes. Central Electricity Authority (CEA) emphasized on the urgent need for introduction of large-scale thermal power plants in an environmentally friendly manner. Thus, in order to achieve the twin objective of quick capacity addition and better efficiency, unit size of 800 MW supercritical power plant is ideally suited for this purpose. Selection of supercritical technology and higher steam parameters will result in higher efficiency leading to lower emissions per kWh of power generated. In view of lower emissions, the 800 MW supercritical units would rate higher in International acceptance also compared to sub-critical units.



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Start-up and 'Minimum load'

For start-up a minimum feed water flow must be established and maintained before firing commences. This minimum flow is typically around 30%-35%MCR flow and it determines the 'minimum once-through load'. This fixed minimum flow is necessary in order to provide adequate cooling to the furnace wall tubes. The excess water over and above the extent of steam generation is dumped from the start-up separator vessel by a level control loop to condenser. Once steam generation matches the minimum feed water flow the separating vessel will run dry and the true once-through mode is then established. The feedwater flow must then be increased to match the increase in steam generation.

The dumping of water and heat on start-up can be avoided by the installation of a start-up boiler recirculation pump. Without a boiler circulating pump it would not be economic to operate for any period of time below the minimum once-through load.

Water Chemistry

With the recirculation boiler most of the impurities in the feed water are retained within the recirculation system as only pure steam passes onto the superheater. Periodically the boiler water is 'blown down' to limit the concentration of impurities in the boiler water. With a once-through boiler there is no means of removing impurities from the system, any impurities therefore will either deposit on the furnace walls or be carried forward, either in particulate matter or in the vapour phase, to the superheater and turbine. During the late 1950s and early 1960s with the growth in the number of once-through boilers advances were made in the cycle chemistry and water treatment technology to match the demand. These days the feed water quality standards used for recirculation boilers and once-through boilers are very similar. There is virtually no distinction in the standard as to whether the boiler operates at sub or supercritical pressure. Because of late 100% condensate polishing plant are provided for sub-critical plants also. In addition, once-through boilers do not have a boiler blowdown. This has a positive effect on the water balance of the plant with less condensate needing to be fed into the water-steam cycle and less waste water to be disposed of. For the earlier supercritical boilers, the use of deoxygenated all-volatile treatment (AVT) resulted in increased pressure drop through the furnace walls due to scaling, and hence the necessity for frequent acid cleaning or metal temperature rise. The oxygenated water treatment (OWT) or combined water treatment (CWT) developed in Germany has been applied in supercritical boilers for more than 20 years operation. The use of OWT after initial start-up ensures the control of inner scaling of furnace wall tubes. Due to application of OWT in supercritical boilers, it is not necessary to perform periodic cleaning because tube inner scaling is controlled to a minimum rate. However, for sub-critical boilers periodic acid cleaning is required at an interval of 4 years.



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Load Change Rates

The maximum achievable load change rate on a boiler is controlled by two main factors:

The allowable heating rates on thick walled components and •The degree of overfiring required to raise the boiler metal temperature and stored fluid to a higher temperature. Excessive overfiring will lead to excursions in main steam and reheat steam temperatures. On both counts the once-through boiler is superior to the recirculation boiler. The thickness of the separating vessel on a once-through boiler is thinner than the comparable vessel on a recirculation boiler. This vessel may represent a limitation on the rate of pressure rising in a boiler from a cold but once the unit is on-load, where the temperature changes in these components are small, these components should not represent a limit to normal load changing. With respect to level of the thermal inertia, i.e., the metal and fluid mass, which affects the degree of overfiring (and underfiring) required on load changing, the once-through boiler has a lower inertia. The furnace wall tubes are smaller in diameter, the separator is smaller than the drum and no array of downcomers exist. Higher loading rates are therefore possible on a once-through boiler compared to a recirculation boiler. The load change rate of the supercritical plant will be in the range of 3 to 5% per min. which is faster than the sub-critical plant load change rate of 1 to 2% per min. As a result start-up time will be less in the supercritical plants.

Availability/Reliability

Supercritical plants have improved in reliability since their first introduction in the 1960s. These improvements have been realized through design improvements based on operating experiences and through advancements in material. Units installed in Japan over the past 10 years have achieved availabilities in the range of 98% to almost 100% with the exclusion of planned outages.

Plant Operation

The different control concept adopted in the once through supercritical boilers will require those operators having experience only on sub-critical recirculation boilers to be retrained to operate the supercritical plant in the different concepts. Particularly in India special trainings are to be provided to the operators for operating supercritical plants as all the operators are skilled in the sub-critical plants only.

Boiler Water Treatment

This issue goes hand-in-hand with the area described above. Performance of boiler heat transfer surface is highly dependent on the chemistry of the water/stream that keeps the surface cool. Upgrades of the boiler water treatment system should be coordinated with the upgrades described in Area 1. An added benefit of higher water purity standards is faster plant start-ups; and, therefore, a unit can come on-line more quickly and ramp up generation faster resulting in a higher overall generation output.



In addition, water purity has a cascading effect increasing the reliability of feedwater heaters and turbine blades and improving condenser performance.

Restoration of our 20+-year-old coal-fired plants to a condition similar to those that are under 20 years through the recommendations described in these eight areas can **create approximately 10,000 MWs** of additional availability from existing assets. We would expect this number to grow significantly as we increase utilization of our older plants to meet growing demand. Without implementing these recommendations, the forecasted increases in utilization will accelerate failures in these older facilities

increasing the need for the recommendations we have identified here.

Of particular interest is that 90% of the increased availability identified will come from component replacement and other projects involving the boiler/steam generator. The boiler/steam generator has been the focus of the EPA's allegations in its recent reinterpretation of the New Source Review program as part of its power plant enforcement initiative.

Emissions Performance NOx

Significant improvements in NOx emissions are being achieved in pulverized coal-fired power plants today. This is through both advances in Low NOx Burner Combustion technology and advances in Selective Catalytic Reduction systems, both of which are being widely applied. Low NOx Burner Combustion technology has resulted in combustion NOx levels being in the range of 0.15 to 0.30 lb/MBtu, depending on the coal. Selective catalytic reduction systems are in operation with NOx removal efficiencies up to 90-95%. An existing plant retrofit this year with an SCR will result in NOx emissions of approximately 0.301b/MWh, (approximately .03 lb/MBtu which is lower than the best natural gas combined cycle unit utilizing dry Low NOx Combustion, according to the most recent EPA actual operating data).



New pulverized coal power plants, through the application of commercially demonstrated Low NOx Burners and SCRs, can achieve NOx emissions as shown in the table below. In order to compare NOx emissions with natural gas-based power generation, the performance is reported in lb NOx per MWh.

The NOx emissions performance represented in this section of the report and in the two case studies is derived from applying the state of the technology, Low NOx Burners with the state of the technology Selective Catalytic Reduction Controls. These are applied to representative Eastern and Western coals and typical project parameters. The actual NOx emissions that can be obtained from a given new coal fired project will depend on the analysis of the actual coal to be burned. It will also depend to some extent on the local ambient air conditions and condenser water availability and temperatures, which will impact the available heat rate of the cycle. The actual achievable NOx emissions rate for a given project can only be determined after the specific project and fuel parameters have been defined.

It should also be noted that this section of the report only addresses new, coal-fired generating plants.

Boiler Inspections for June, 1882.

The one hundred and eighty ninth monthly summary of the reports of the Hartford Steam Boiler Inspection and Insurance Company's inspectors is given below, and will repay a careful perusal. From it we learn that 2,142 visits of inspection were made and 4,535 boilers were examined. The number of thorough annual internal inspections reached a total of 1,803, and 364 boilers were proved by hydrostatic pressure. The whole number of defects found which were considered sufficiently serious to be reported, was 2,898, of which number 661 were considered to be of so grave a nature as to impair the safety of the boilers in which they were found. The number of boilers condemned was 44. The usual analysis of defects is given below:

Nature of Defects.	Whole Number.	Dangerous.
Cases of deposition of sediment.....	311	56
Cases of incrustation and scale.....	442	43
Cases of internal grooving.....	26	12
Cases of internal corrosion.....	109	21
Cases of external corrosion.....	160	49
Broken and loose braces and stays....	88	58
Settings defective.....	87	15
Furnaces out of shape.....	105	27
Fractured plates.....	174	70
Burned plates.....	72	39
Blistered plates.....	311	36
Cases of defective riveting.....	297	18
Defective heads.....	38	26
Leakage around tubes.....	214	81
Leakage at seams.....	164	18
Water gauges defective.....	64	8
Blow-out defective.....	22	10
Cases of deficiency of water.....	9	4
Safety valves overloaded.....	31	7
Safety valves defective in construction.	18	8
Pressure gauges defective.....	154	25
Boilers without pressure gauges.....	2	0
Total.....	2,898	661

Availability Improvements at Existing Units

Utilities have many opportunities to increase electrical output at existing units without increasing fuel burn by improving efficiency or reducing forced outages through component replacement and proper maintenance. In some cases, utilities do so as a reaction to unexpected component failures (reactive replacement). In others, utilities replace worn or aging components that are expected to fail in the future or whose performance is deteriorating (predictive replacement). In some cases, utilities replace components because more advanced designs are available and would improve operating characteristics at the unit. Such component replacement can restore a unit's original design efficiency or, in some cases, improve efficiency beyond original design.



2. Risk management Data Driven Planning

The challenges of successfully completing projects within an Operations and Maintenance environment have increased over the last 10 years. Many plants have been operating at greater than 100% of MCR with the least practical outages leading to continuous decreases in maintenance cycles or downtime. In the "Do More with Less" corporate environments, maintenance staffs have experienced decreases in skilled staffing and decreases in budgets. Maintenance projects are typically driven by unrealistic time constraints and typically delivered late. Both the operations and maintenance staffs must find the right balance in planning and executing projects. Risk management is the key to finding the acceptable balance within the project management methodology.



The typical application of the boiler outage project planning process, is to back fit the work flow or logic into a given timeframe as developed by the boiler inspection scope of work, based on constraining completion times for the project and with consideration of resources constraints. The best practices have the identification of risks (boiler inspection results) beginning during a project selection process or during the early planning process. Yet, project teams usually address risk events in a cursory manner during the latter phase of the planning process, if addressed at all. These risk events, if addressed, are identified as mostly independent events when analyzed, and may have several independent responses put in place. Due to the project inspection team's lack of experience in risk analysis, lack of data or adequate time, and the complexity of many of the assessment tools, the responses usually consist of putting in place contingencies of time and money.

Risk Driven Project Planning and Execution

Implementing a risk Driven/Aware process within an organization's Project Management Methodology provides a key process allowing operation and maintenance project teams to reach a balance with schedules, resources, and costs. A Risk Driven Project contains all the planning elements of traditional planning approaches, a focus on detailed analysis of risk events and classification of risk events as critical risks events or non-critical risk events. Instead of the work flow or logic of a project considering only time



and resource constraints, the Risk Driven Project highlights the highest priority events and utilizes a pre conceived plan to monitor and control these critical risk events. The classification of critical risk events considers detailed risk events, chain of events, qualitative or scenario analysis of critical risk event paths, and defining responses based on Acceptable Project Value (APV) to Unacceptable Project Value (UPV) ranges.

Risk Driven Project Process \ Value-based Management

Once projects are selected and planning is ready to start, key Risk Driven Project objectives are:

- Establishment of Unacceptable and Acceptable Project priority constraints by senior management;
- Consideration of inspection risk events, chains of risk events and risk responses in structuring the planning, execution, control & evaluation, and termination of repair items based on criteria. The following sections deal with criteria and priority which are needed to support this planning approach.

The choice will be based on a combination of cost and reliability. Cost-based decisions are based on experience, not information.



While most repairs do not result in a loss of efficiency, performance issues are generally not addressed when making Cost-based decisions. In order to make these decisions effectively; managers and engineers will require access to more and more data. Along with this need for information will come a new emphasis on reliability and heat rate, driven by competition for production time? Equipment unreliability often causes unit load restrictions or frequent start-ups and shutdowns. Improved reliability means less time in a transition or de-rated condition that can ultimately affect unit heat rate. While these effects are not directly related, the secondary effects of disturbances in operation cause a reduction in overall capacity. Conversely, by closely monitoring thermal performance at the component level, O&M personnel can improve component reliability by spotting problems early.

Utilities need to move from a "Cost-based" approach to asset management to a "Value-based" approach. The key difference between the two approaches is that the Value-based approach involves strategic decision-making that takes the long term affect of repairs into account when making replace, repair, and overhaul, retrofit, and refurbish decisions. The Cost-based approach relied on available budget (can we afford it?) for maintenance decision-making that often ignores equipment thermal performance considerations.



UDC Priority Assignment Analytics Matrix™					
Assessment Factors	Probability of Occurrence				
	Extreme (>90%)	Likely (>70%)	Moderate (>50%)	Fair (>30%)	Low (>10%)
Safety Concern / Failure / Restricted Accessibility	20	19	18	16	13
Environmental Impact / Failure / Moderate Accessibility	19	18	17	13	9
Failure / Satisfactory Accessibility	18	17	14	12	7
Failure / Performance Issue / Good Accessibility	17	15	13	8	6
Possible Failure / Preventative Measures Needed	15	13	11	6	4
Some Impact	10	7	6	2	1
Limited or No Impact	5	4	3	1	0

Priority 1 (FRIN >13)
(FRIN >13) Countermeasures should be implemented immediately

Priority 2 (FRIN ≥8)
(FRIN ≥8) Countermeasures should be implemented as soon as practical

Priority 3 (FRIN <8)
(FRIN <8) Countermeasures should be planned for future implementation

Initial Risk Index Number (IRIN: 1 to 20)
0

Weighted Adjustment Reference Chart	
Waterwalls	3
Superheaters	2
Reheaters	-1
Remaining Wall Thickness ≤ 35%	7
Remaining Wall Thickness ≤ 45%	3
Remaining Wall Thickness ≤ 55%	1
Variable Adjustment	
0	

Final Risk Index Number (FRIN: 1 to 30)
0



ADVANCED BOILER INSPECTION TECHNIQUES 2011

Formal repair selection criteria

You can calculate your own thresholds by calculating hoop stress based on ASME specifications and applying that information to your MWT of each component. MWT refers to Minimum Wall Thickness as established by the original manufacturer.

You can adopt a recognized criteria used by UDC. These suggestions are based on item one above.



<65% of MWT for replacements
<75% >65% of MWT for pad welds (if permissible)
<85% >75% of MWT for shielding

Replacements <65% of minimum wall

If a pressure part has thinned for any reason to below 65% of the MWT the first choice should be replacement. The strength has diminished to a level where the risk of failure is possible. Failure is not just the action of a pressure part thinning. The thinning in conjunction with other conditions such as attachments, internal corrosion, stress induced by membrane welds and other conditions can contribute to the eventual failure. This synergy is the true risk when the known condition of thinning is observed. Your view of risk management may affect what percentage of MWT you and your plant can be comfortable with.

Many will ask why we can't pad weld tubes below 65% MWT. Statistically the risk of failure increases with increase in percentage of pad weld. Remember we are now adding a heat affect zone (HAZ) to the synergistic risk profile mentioned above.

Pad welds <75% >65% of MWT (if permissible)

Due to the historical failure rates of pad welding, we believe that replacement is far superior to pad welding. These replacements will statically to reduce failures.

However in many cases pad welding is the only feasible repair. About 10 years ago when pad welding was required, we began an effort to install pad welds in a more survivable manner. This involved installing filler metal in the coolest possible way. Please note that pad welding should never be used to close a breach in the tube wall. It should only be used to refurbish or thicken the thin area. Experience has proven that a properly installed pad weld on a tube above 65% MWT will be less likely to fail than that below that threshold. See details on proper installation of pad welds and conditions when pad welds should never be used later in this manual.



Shields <85% >75% of MWT

The installation of shields will have the effect of reducing thinning. It will not structurally re enforce the material the way a replacement or pad weld will. This is the reason why it is the least dramatic choice of repair for a marginally thin tube above 75% MWT.

Ranking of priorities

Priority #1 problem must;

Safety or loss of life issue

Certain forced outage before the next planned outage

A certain forced outage can be calculated and supported from data gathered during the outage. This is usually thickness data. Thinning rates or progression must be established before proper application of the rules of priority. How long did the thinning take, days, weeks, months or years. This is the very reason good historical documentation is required. If we can determine the progression of the problem, an assignment of priority is straight forward. If we can not determine progression we must assume the worst case and assign a high priority.



The scheduled run time must be considered in applying the priority rules. You must affect a repair that will not be compromised within the scheduled operations time between scheduled outages. You may have to implement more conservative criteria to achieve the desired result. Depending on the circumstances, you may need to increase the MWT above design or to apply heavy shielding. When increasing MWT, consult your engineering department for their interaction, as this will affect performance of the boiler. Always consult engineering when considering a design change in the boiler.

The most important are components whose failure will directly affect the reliability of the boiler. Components that comprise the pressure parts of the boiler are given special attention since failure leads to forced outages and lost steam production. These critical pressure parts include:

- Drums - steam, lower, uptake, down comer, etc.
- Headers - both steam and water
- Tubing - superheater, boiler or generating bank, waterwall, economizer
- Piping - steam and feedwater
- Deaerator - may have special safety concerns
- Attemperators - sometimes called desuperheaters



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The following is a typical example of a priority #1.

P1

Report Sequence #: 151

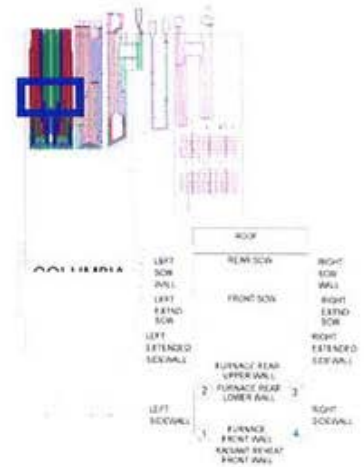
Report Name: 151-P1divpnl3upperadd-2222002

By: John M Cavote

Station:

Location: SHDivision Pnl 3 KNUCKLE TUBE

Item #1. The Tubes were counted from FC
Items were marked with <<<red>>> paint.



Repair item/s #: 2

Area SHDivision Pnl Front-Front Tubes knuckle tube

Action required: PAD PADWELD

Priority #: 1

Repair#: 2-a >>Record:# 1288 (PAD PADWELD).

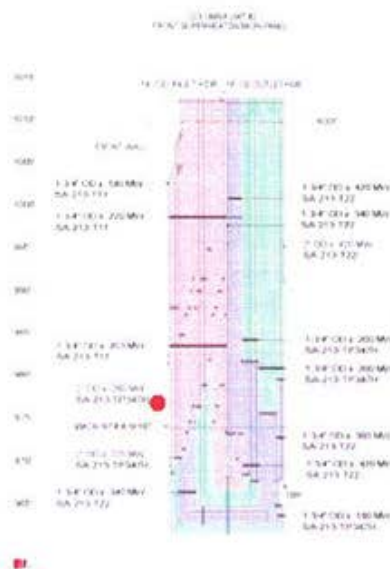
The location of this repair is on the SHDivision Pnl Front-Front Tubes knuckle tube

Tube configuration is right tube.

Tube #: 1 Element #: 3 at elevation 976'

The length of the repair required would be 0.3'

The cause of this problem is Abrasion. This condition appears as Gouge in tube.



This is a next weeks leak!

The material grade required is SA213T11
OD =2.00inch. The

(MWT) minimum thickness required is =0.220" The rod normally used for welding to the material should be #:



Priority #2 problem must;

Probable but not guaranteed forced outage before the next planned outage

Performance issue

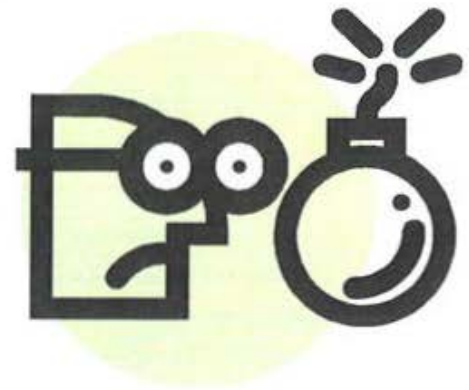


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Components that are more likely to have adverse effects on boiler performance as they deteriorate with age might include:

- Air heaters - recuperative (tubular), regenerative (Ljungstrom), steam coil
- Fans - induced draft, forced draft, primary air (pulverized coal firing)
- Burners
- Fuel preparation equipment (especially coal firing, i.e. pulverizers)
- Boiler settings such as casing and BRIL (brickwork, refractory, insulation and lagging)
- Structural supports

The first example on the next page is a non pressure part priority #2. This would be serious performance issue.





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The following is a typical example of a priority #2.

P2

Report Sequence #: 148

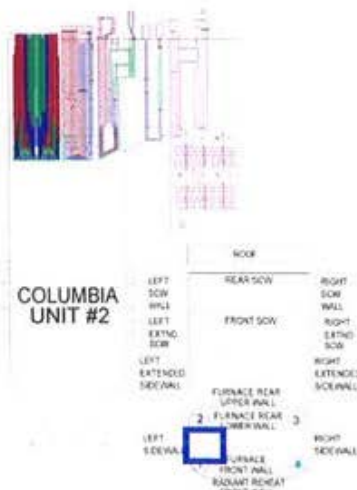
Report Name: 148-P1Corner1-2252002

By: P Keating

Station: Columbia Unit: 2

Location: Burner 1 addendum

Item #1. The Tubes were counted from
Items were marked with <<<red>>> paint.



Repair item/s #: 2

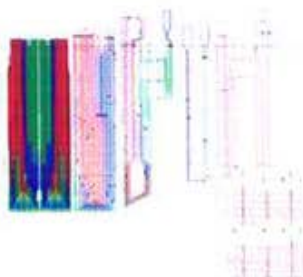
Area Burners 1

Action required: ALI ALIGNN & REATTACH

Priority #: 2

Repair#: 2-a >>Record:# 1402 (ALI ALIGNN & REATTACH).

Repair Comment: Pivot bar on coal nozzle tip E is unattached.



The location of this repair is on the Burner E coal

The cause of this problem is Fatigue (vibration). This condition appears as unattached.

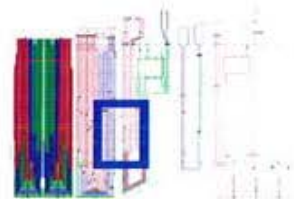
Charge code / Workorder : _____

Status of item: INSPECTED



#2 on a pressure part.

The example on the next page illustrates an example of a priority



P2

Report Name: 111-P2CrowsNest-2222002

By: P Keating

Station:

Location: Reheat CROWS NEST

Item #1. The Tubes were counted from left side wall to right side wall

Items were marked with <<< white >>> paint.

Repair item/s #: 2

Area Reheat Rear-Front Tubes crows nest

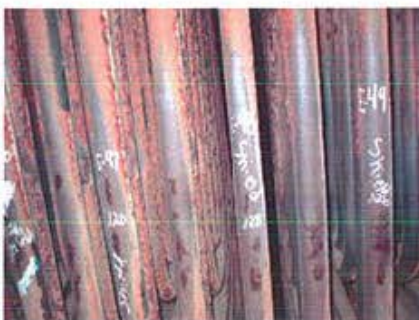
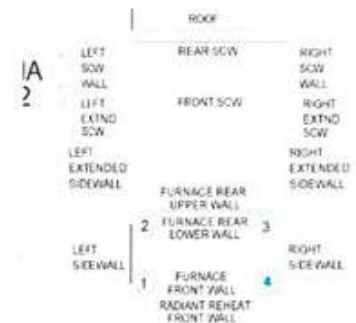
Action required: SHD SHIELD INSTALL

Priority #: 2

Repair#: 2-a >>>Record:# 1318 <<<db# 1318 >>> (SHD SHIELD INSTALL).

Repair Comment: Element/UT reading: 46/.126, 47/.120, 48/.128, 49/.126

The location of this repair is on the Reheat Rear-Front Tubes crows nest



Tube #: 4 Elements #: 46 through 49 at elevation 998.5'

The length of the repair required would be 2'
The cause of this problem is Erosion (soot blower). This condition appears as eroded.

The material grade required is SA213TP304 OD =2.12inch. The (MWT) minimum thickness required is =0.148" The rod normally used for welding to the material should be #: 347-16



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Priority #3 problem must;

Low grade performance issue

Long range mechanical optimization

Information or documentation issue.

The following is an example of several priority #3 examples.

P3

Repair item/s #: 3

Area Economizer Upper Bank on top of bank 1

Action required: MON MONITOR CLOSELY

Priority #: 3



Repair#: 3-a >>Record:# 1172 <<db# 1172 >> (MON MONITOR CLOSELY).

Repair Comment: Monitor erosion down in the bank

The location of this repair is on the Economizer Upper Bank on top of bank 1

Tube #: 4 through 8 Element #: 39 at elevation 972'

This is evident on all elements.

Material grade required is SA210A1 od=1.75inch.
The (MWT) minimum thickness required is =0.200"
The rod normally used for welding to the material

should be #: E7018

Charge code / Workorder : _____

Status of item: _____



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Repair item/s #: 4

Area Economizer Upper Bank top of bank 1 (center)

Action required: INFO ONLY

Priority #: 3

Repair#: 4-a >>Record:# 1176 >> (INFO ONLY).

Repair Comment: The following UT results were taken in on the op of bank 1 in the center SB path:
(Elements.UT)

1.217 2.224 3.228 4.216 5.229 6.225 7.220 8.219 9.209 10.220 11.208
12.218 13.215 14.213 15.225 16.217 17.222 18.215 19.205 20.220 21.221 22.213
23.221 24.220 25.222 26.205 27.217 28.207 29.202 30.208 31.215 32.213 33.209 34.220 35.208 36.219 37.216
38.216 39.217 40.208 41.212 42.214 43.221 44.221 45.211 46.206 47.215 48.220 49.224 50.214 51.222 52.224
53.221 54.220 55.221 56.215 57.221 58.219 59.217 60.225 61.225 62.216 63.224 66.220 67.223 68.224 69.221
70.224 73.211 74.225 75.223 78.230 118.229 119.124 120.215 126.211
127.217 128.216 129.229 130.216 131.220 132.222 133.220 134.217 135.219 136.221 137.226 138.222 139
.216 140.222 141.221 142.222 143.223 144.230 145.226 146.218 147.210 148.228 149.221 150.220 151.215
152.219 153.223 154.211 156.221 157.217 158.223 159.219 160.220 161.207 162.224 163.220 164.219
165.215 166.218 167.221 168.225

64&65-no reading 71&72 no readings 79-118 are slagged over. 118-124 slagged

The location of this repair is on the Economizer Upper Bank top of bank 1 (center)

This condition appears as no action required due to UT results.

Charge code / Workorder : _____

Status of item: _____

FAILURES AND NEAR FAILURES IN FOSSIL PLANTS

Boiler tube failures occur in fossil-fired plants throughout the world. Failures differ only in the types of failure mechanism experienced, and in the magnitude of the associated availability loss. Explanations of tube failure experiences amongst utilities are usually treated as unique incidents in individual boilers; rather than, as recognized common occurrences that can benefit from detailed knowledge and shared information about failure mechanisms and root-causes. This unique incident rationale results in consideration of each unit's boiler tube failure problem as a special case that requires extensive failure-cause analysis, special testing, and outside technical support. Generally, U.S. utilities take this approach to solve boiler tube failure problems primarily because they: (a) tend to accept tube failures as normal maintenance activity; (b) have tremendous pressure to return the efficient units to service quickly; and (c) seldom have the required technical expertise at the plant to study the problem and implement optimum correction or prevention solutions.



The photograph at the left shows what we call a golden tube. This type of inspection find will result avoiding a tube leak resulting in forced outage. This single inspection find can justify the entire planning and inspection effort for multiple years to come. Those potential savings are addressed on the following page.

COSTS ASSOCIATED WITH BOILER TUBE FAILURES

Boiler tube failures are the number one cause of forced outages of power generating units for U.S. electric utilities. The cost penalty is estimated to be in excess of \$7.5 billion a year in replacement power charges and maintenance costs.



Boiler tube failures account for a 4 %annual loss in large fossil unit availability on a national basis. Approximately 40 percent of all tube failures occur in furnace water wall tubing. Superheater tube failures are responsible for about 30 percent of the failures. Reheater tubes 15%, economizer tubes 10%, and cyclone burner tubes account for 5%.

REPEAT BOILER FAILURES

There are four primary reasons why boiler tube failures occur on a repeating basis. Repeat failures are defined as multiple failures in a single boiler having the same failure mechanism and root-cause. Repeat boiler tube failures occur for the following reasons:

Not Following State-of-the-Art Practices

State-of-the-art practices are defined as operation, maintenance and engineering practices demonstrated by experience to be necessary in the prevention of repeat boiler tube failures. Lets discuss an example of state-of-the-art practice relevant to each functional discipline, that is, operation, maintenance and engineering.



a.) State-of-the-Art operating practice



Major operating practices, which can influence boiler tube failures, are: cycle water chemistry; boiler, Superheater, and Reheater temperature control; combustion control; and lay up, both waterside and fireside.

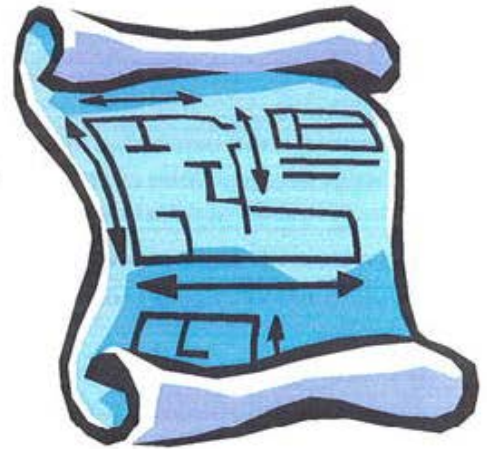
b.) State-of-the-art maintenance practice

Many cases of repeat tube failures caused by poor or improper tube repairs also are not uncommon and well documented.

It is not uncommon to hear, "The weld that was made as a repair failed 24 hours later", are typical. Again, the reason behind the root-causes, which are tube overheating due to blockage by welding debris, and incomplete fusion of the weld respectively, is the failure to take proper tube-repair quality-control-preventive-actions which follow proven state-of-the-art maintenance practices.

These repeat boiler tube failures can also be eliminated by the establishment and use of plant tube-repair maintenance procedures; where these procedures clearly define not only the repair method and materials to be used, but also proper quality-control action to be taken to ensure against boiler tube-repair repeat failures.

Maintenance practices also include maintenance of chemical treatment equipment for the makeup system and condensate polishers (where installed), maintenance of cycle components to prevent ingress of impurities into the feed water, and maintenance of chemical sampling equipment and analytical instrumentation. It is imperative to maintain tight condensers and to seal the areas through which air leaks into the vacuum section of the cycle, and to maintain efficiency of the air removal equipment. Appropriate chemical cleaning practices are also a part of complete a maintenance program.



c.) State of the art engineering practices

Many repeat failures occur because of neglect in determining the remaining life of tubes, with loss-of-life damage from the same failure mechanism causing the initial tube failure. Typical cases where, even though the root-causes were properly diagnosed and corrected, tubes that experienced loss-of-life damage from the same mechanisms and root-causes of previous failures are now beginning to fail. The root-cause of these repeat failures is the neglect to take state-of-the-art engineering preventive action, which is to perform residual life evaluation of tubes that have suffered loss-of-life damage. These repeat boiler tube failures can also be eliminated by the establishment and use of plant boiler tube inspection procedures; where the procedures clearly define not only the method for verifying the integrity of the tube repair, such as radiography and/or hydrostatic test, but also proper residual life preventive action to be taken to ensure against loss-of-life-damage repeat tube failures.

Proper engineering practices also include design and material selection for the boiler and pre boiler cycle components. This includes compatibility of all cycle materials with the selected water treatment, capacity of the deaerating equipment, design of chemical treatment equipment, boiler drum steam separators and blow down, and design of temperature, pressure, and water chemistry monitoring equipment. Engineering also has a major influence during life extension retrofits and equipment upgrading. Improvement of condenser integrity and replacement of copper tubing in condensers and feed water heaters by ferrous materials improve water chemistry control and reduce corrosion.

Proper Failure analysis

When a forced outage results from a boiler tube failure there is considerable pressure on plant personnel to complete the repair and return the unit to service as quickly as possible. Many times expeditious repairs result in inadequate problem analysis, which leads to subsequent repeat failures. Analysis of a tube failure incident should include:

- (1) inspections to determine the extent of primary and secondary tube damage
- (2) identification of the failure mechanism
- (3) determination of the root-cause
- (4) verification of the root-cause
- (5) determination of residual life/predictive maintenance.

A primary tube failure can cause secondary failure and/or damage to other tubes in close proximity of the primary failure. Lack of careful inspection of all tubes damaged during the failure incident, with appropriate wall thickness measurements, will result in future repeat tube failures.



It is very important to identify the correct failure mechanism of every tube failure since, for each mechanism (i.e. fire-side corrosion, fly ash erosion, etc.), there will be unique root-causes. Incorrect failure mechanism determination will usually result in taking wrong corrective and/or preventive action, and in having subsequent repeat tube failures.

To protect against repeat tube failures from incorrect root-cause analysis and/or determination, verification of the most probable root-cause should be obtained as soon as practicable. Appropriate measurements and tests should be conducted to support the assumptions and postulations made in the root-cause analysis.

A tube failure can result from either a corrosion and erosion failure mechanism, where the tube wall thickness is reduced to the point of tensile rupture.

These failure types have a high probability of producing repeat tube failures unless a residual life determination of other tubes experiencing similar degradation is performed. To prevent repeat tube failures before the next scheduled boiler outage, wall thickness measurements and residual life determinations should be made of all tubes adjacent to or in the close proximity of tubes that have failed due to these mechanisms.

During an analysis of corrosion failures (waterside and fireside), identification of the chemical species at tube and crack surfaces can help in determination of chemical root-causes of a failure. Involvement of the water chemist in failure analysis and a review of chemistry history are also helpful.

Choice of Corrective /Preemptive Action

Repeat tube failures can occur because a temporary rather than permanent solution is applied to correct and/or prevent the tube failure problem. An example of a temporary action is the use of sacrificial shields or metal/plasma sprays to inhibit fire-side corrosion or erosion. A permanent solution would be based on determining the respective root-cause, such as a reducing atmosphere in the furnace, and excessive flue gas velocity respectively, and taking appropriate engineering and/or maintenance preventive action. An example of a temporary action is the use of a window or pad weld to make a tube leak repair. Best practice would be to immediately replace the damaged tube with a new tube section (Dutchman), or to replace the window or pad welded section at the next scheduled boiler outage. Unfortunately, many temporary solutions are not replaced with permanent action, and therefore fail again within a short time interval.



In relation to corrosion failures, the corrective/preventive actions should include a reduction of impurity ingress, establishment of proper water chemistry practices, and a determination of tube life reduction by the corrosion damage. For example, hydrogen damage of boiler tubes cannot be reversed and a replacement of the severely damaged tubes will prevent annoying continuation of tube failures.

All scheduled major boiler inspections should include boiler tube wall-thickness measurements in areas experiencing erosion or corrosion damage, until erosion/corrosion rates are established. In areas experiencing damage, root cause analysis will be performed, and corrective, preventive and control actions taken to inhibit forced outages due to these mechanisms.

Problem definition and root-cause analysis of waterside corrosion failures is usually more difficult because of the need to review water chemistry history and data over an extended period of time.



Proper corrective and preventive action requires correct mechanism identification, root-cause analysis and verification. A formalized boiler tube failure prevention program satisfies these requirements through management mandates and support.

Problem Definition

Root-cause analysis of every tube failure is a prerequisite mandate for an effective formalized tube failure prevention program. Before the actual root-cause of a boiler tube failure problem can be determined, it is essential that the problem be clearly defined in terms of: the failure mechanism



Multidiscipline Approach

Activities associated with boiler tube failures, that is, mechanism identification, root-cause analysis and verification, and appropriate corrective and/or preventive action, are complex and usually require the expertise of several technical/experience disciplines. Examples could be: mechanism identification may require knowledge of the metallurgical characteristics of boiler tube steels at high temperature over time;



Root-cause analysis may require knowledge of feed water and boiler water chemistry, boiler tube wall temperature, scale thickness, and heat flux; verification may require a stress analysis of complex tube assemblies which are subjected to expansion restraints; short-term, extensive water-chemistry monitoring preventive action may require a change in operation or maintenance practices; etc. Effective boiler tube failure prevention programs recognize this complexity and address it by mandating and supporting a "team" approach to solving boiler tube failures.

Residual Life and Predictive Maintenance

Most repeat tube failures, (that is, failures in the same boiler over time, having the same mechanism and root-cause), occur not because the mechanism or root-cause is not known and understood, but because the remaining life of other damaged yet failed tubes was not determined. Most failure mechanisms use up tube life that cannot be restored even though the root-cause has been corrected. Good examples are fire- and water-side corrosion where the tube strength has been diminished due to wall thinning (fire-side corrosion) or changes in micro structural properties (hydrogen damage). When failures resulting from these or other mechanisms that use up tube life occur, residual life of other tubing, in areas and/or locations under the influence of the same root-cause, should be determined as soon as practicable.

This will expose other damaged tubing that is prone to failure prior to the next scheduled boiler outage, and establish corrosion/erosion rates for predicting maintenance requirements to inhibit future repeat failures. Formalized boiler tube failure prevention programs satisfy this requirement, by mandating residual life determination as an integral part of the program's correction, prevention and control processes.



ADVANCED BOILER INSPECTION TECHNIQUES 2011

Permanent Engineered Solutions

In many tube failure problems, temporary rather than permanent engineered solutions are used to solve the problem, with the result that the remedy is a continuing and costly maintenance burden. A good example might be where tubing is damaged by soot blower erosion because the blower is located too close to a corner or wall protrusion, yet rather than relocate the soot blower, the tubing is pad welded or shielded. Another example might be where water wall fire-side corrosion damage, due to a reducing atmosphere in the furnace, is repaired with metal or plasma sprayed coatings, rather than providing curtain air along the walls.

In most cases, temporary repairs should only be used in emergencies, with engineering fixes being the permanent solution. A formalized boiler tube failure prevention program with its team approach to permanent solutions satisfies this requirement.



Data management and documentation

For successful, continuous control of boiler tube failures, communication is the most critical requirement in a formal boiler tube failure prevention program. Correction, prevention and control of boiler tube failures requires that every functional group (management, engineering, operation and maintenance), charged with this responsibility be continuously informed so that single tube failures do not become major tube failure problems. One of the ways to insure effective, reliable, communication is by use of a computer-based centrally located, company-wide reporting and monitoring system. For this system to be successful, four prerequisites should be satisfied.

Investigation and Correction of Boiler Tube Failures

Information on many common fossil-fired boiler tube failure mechanisms is presented; typical locations where they occur in the furnace; identification of failure mechanisms; most probable root-causes; and preferred corrective and/or preventive actions.

This software / course and the data contained in it does not eliminate the need for a thorough metallurgical analysis during the failure investigation, but is intended to enhance the investigation process by providing descriptive information for use during communications with technical specialists. The report encourages the comprehensive acquisition of failure data and pertinent records to document the failure for immediate and future reference.



The software failure library is illustrated with color photographs as well as line drawings, and begins with a general introduction to failure mechanisms, root-cause determination and verification methods, and tubing steel used in fossil-fired boilers.

Failure Mechanisms: Primary and Secondary

Primary Failure Mechanisms

Since boiler tube failures have been the subject of immense concern to utility companies and boiler manufacturers, there is a tremendous number of investigations and reports concerning the different failure modes and mechanisms. A mechanism is defined as the process by which something comes into being. There are many different types of mechanisms that have been cited as causes for boiler tube failures. An extensive search was conducted to compile the more significant common failure mechanisms for inclusion in the report.

From this effort, six broad classifications were selected as follows:

- Stress Rupture
- Water-Side Corrosion
- Fire-Side Corrosion
- Erosion
- Fatigue



Secondary Failure Mechanisms

An important aspect of the initial inspection of the boiler after a tube failure incident is to determine if any tubes adjacent to the failed tube were damaged as a result of a secondary failure mechanism. For example, a secondary failure mechanism would be steam escaping from a tube leak, which entrains fly ash particles and projects them against an adjacent tube to produce erosion damage. This action is sometimes



called erosion washing or steam cutting. The escaping steam is not the cause of the erosion, but is accelerating the fly ash particles to a high velocity, which causes abrasion and wall thinning. This type of erosion can occur anywhere in the boiler since it is caused by an earlier failure in another tube.

Another example of a secondary failure mechanism is adjacent tube impaction. Impaction can result if the first failure is violent and causes the tube to whip about and strike adjacent tubes. In an unusual case, a bolt that was left inside a tube wore through the tube and was propelled into and through an adjacent tube and dented another neighboring one.

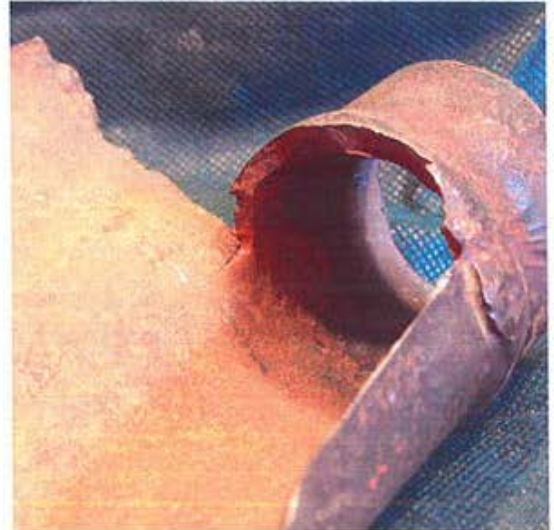
Ultrasonic thickness measurements should be used to determine remaining wall thickness of tubes that have received secondary damage.

Thinned tubes may have to be replaced before through-wall holes are present, if the remaining wall thickness is too thin to sustain additional service loads during the next operational period. Immediate tube replacement in these situations can prevent repeat failures.

Root-Cause Analysis and Verification Methods

Boiler tube failure root-cause analysis and verification methods include: (1) the gathering of physical evidence or data; or (2) the studying of available facts through systematic problem analysis. In most cases, combining both methodologies is necessary since gathering all the necessary data may be impossible or too time-consuming and costly. Important relevant parameters that may require determination by calculation, observation, or measurement are as follows:

- Tube metal temperature
- Tube metal stress
- Tube metal thickness
- Tube metal microstructure
- Tube metal material properties
- Boiler water and feed water chemistry
- Boiler water flow
- Fuel constituents
- Fuel fouling and slagging characteristics
- Flue gas flow pattern and velocity
- Flue gas temperature
- Tube deposit constituents and thickness



On-line monitoring, periodic sampling, and laboratory testing are three ways in which to quantify these critical parameters. Determination of the failure mechanism and probable root-causes are the key to minimizing data gathering requirements.

Each section of the report contains information on mechanism identification, on probable root-causes, and on verification processes. Information on probable root-causes should be used to minimize data needed to verify the actual root-cause. This approach will expedite the problem solving and corrective action processes.



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Forecasting of boiler tube failures (Pro action)

This is a systemic approach to tube failure forecasting and management. The ability to forecast tube failures is an illusive one. The best attempt we can make must be supported by empirical data. The quality and quantity of:

Collected data from team inspections

Life assessment studies

Lab analysis

These three efforts will determine just how proactive we can be in reducing tube failures. The adage "Garbage in Garage out" is well suited here. If your plant budget and planning have a minimum effort in the three primary areas mentioned above then your ability to forecast will be directly proportionate to that effort.



This is not rocket science. All failure mechanisms have been previously identified and catalogued by the industry.

With today's emphasis on developing competition through deregulation, heat rate gains and availability are becoming more and more significant. Cheaper fuels, better performance, and higher equipment reliability combine to become key indicators for unit dispatch and the economic viability of generating units for future competitive markets. Fuel, performance and reliability are not independent, and gains made in one area can often be offset by losses in another. Under deregulation, value, rather than cost, will drive decisions for more effective asset management. With advances in information technology, tracking performance and reliability will be required to ensure the long-term success of the organization.

Current and future goals for these organizations include the development of a business model that will allow for generation facilities to be operated in a highly efficient and effective manner. This is not to imply that the organizations were inefficient in the past, but rather, the decision-making paradigms need to be shifted to take into account the new competitive nature of deregulation. One of the changes necessary for utility managers to recognize is the need for increased thermal efficiency and availability at the generating facilities.

New technology solutions include the application of advanced computer systems for the identification of performance and maintenance problems.



Operations personnel play a key role in heat rate improvement and reliability at facilities where even small gains in thermal efficiency provide big dividends in terms of improved financial performance. A major point for plant management is to recognize the importance of efficiency and availability awareness among operators and to make this awareness part of all operators training. Including this awareness training in operator training is an important part of any optimization effort. In order to identify performance problems, the following are offered as inspection points that can have an immediate impact on controllable heat losses.

In some cases, emphasis on unit availability (stay running at all costs, regardless of short-term fuel expenditures, material and labor costs) has been the paradigm for many plants. This is not to imply that management was wasteful, but simply that the priority was on reliable delivery of power to the customers, regardless of cost. This approach is easily justifiable because the general public demands and expects the uninterrupted supply of electrical power. This approach spread across all segments of utility business.

Existing Operation and Maintenance Practices

Existing practices are often ineffective at identifying and correcting equipment problems that cause heat rate deficiencies. The reason for this goes back to the lack of emphasis on performance. In order to begin to take performance issues into account when making maintenance decisions, the daily workflow needs to be redesigned. Operators, maintenance supervisors or engineers should consult performance information before and after repairs are conducted.

An optimized approach for operations and maintenance includes the review of performance information once repairs are complete. In most cases this is not done because of a lack of emphasis on heat rate issues. Understanding the link between O&M activities and thermal performance is critical for reaching the goal of long term, competitive production environment.

Management needs to set the vision for overall performance improvements. The vision should include benchmarking of competitive cost and production targets. The results of an assessment can give guidance for the implementation of actual practical changes.

Reliability forecasting

One approach to improve reliability is to use forecasting procedures that rely on statistical methods that predict the future failures based upon past performance. A complete set of statistical reliability tools is provided in various software systems.

Equipment of a specific type, failure date and failure mode. Once this query is complete, the user applies a variety of statistical methods to the resulting dataset, including Weibull, Normal, Lognormal, and Growth.



Weibull Analysis allows the user to model a distribution that gives the user important statistical information about the population of data contained within the datasets generated from queries. Quantities such as Mean Time Between Failure (MTBF), Failure Rate and Failure Mode are calculated within the software and stored as documents related back to the asset entity family. These are the same assets that are stored and tracked in the Computerized Maintenance Management System (CMMS) system for the plant.

Population averages (mean) and standard deviation is calculated against the dataset under study. Growth analysis tracks improvements in MTBF as equipment reliability increases. Growth is also used in cases where the failure mode is unknown or MTBF is changing over time. Growth analysis conducted on a set of failure data is also used to predict the time until next future failure.



Reliability analysis conducted on the equipment failure data results in calculated values that are used to characterize plant equipment reliability. These values need to be measured in order to understand the ways to improve cost performance. If this information is not available to plant personnel, then they will continue to make the same decisions that were made in the past.

The following discussion illuminates the advantages of enhanced decision-making through the use of reliability analysis:

Boiler Design Problems - sorting of failure modes by equipment types (manufacturer, model, and size...) lead to the identification of commonly failed components on a single piece of equipment or among a population of similar equipment. The reliability analysis points to a deficiency in materials or in material

selection. These problems often behave in an "early wear-out" failure mode, which is easily identified with a Weibull analysis.

System Design Problems - sometimes the wrong piece of equipment is used in the design of plant system and frequent failures of this equipment occur as a result. Sorting of common failure modes by location can give some clues to this type of problem. Failures of similar systems can be subjected to the same analysis procedures that are conducted at the asset level. Problem systems are recognized by low values for MTBF as compared with other similar systems.

Construction Problems - sometimes during a startup (after a repair period, turnaround or outage) problems can occur that are often related to construction or repair activities.





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These problems occur as a result of inadequate or improper construction techniques and material failures. An example of this type of problem is an improperly poured foundation that prevents proper operation of a machine or system. These problems sometimes show up in the Weibull analysis as "infant mortality" failures, with low values for MTBF.

Inadequate Preventive Maintenance Activities - maintenance preventable failures are identified through sorting of work order backlogs and analyzing of spare parts usage. ERP systems often track spare parts usage, high usage rates might point to a problem with the parts themselves. Lower than expected usage rates indicate that adequate preventive tasks are not being performed. Inadequate PM activities show up in a reliability analysis as uncharacteristically low values for MTBF for equipment of this type, as compared with manufacturer or industry standards.

Inadequate Inspection Routines - unexpected equipment failures cause serious environmental and safety issues. Ruptured pressure vessels, leakage and fugitive emissions caused by cracks, weld failures and seal failures cause components to fail unexpectedly. Understanding the reliability behavior of equipment prone to these kinds of faults allows users to schedule inspections at appropriate intervals. By combining design, construction, engineering, operation, maintenance and inspection data with CMMS data, problems that relate to technical as well as procedural issues are addressed. The reliability of individual plant components is only improved once current levels of reliability are identified and tracked. An enterprise wide reliability system, like software products, makes this task manageable.



Boiler Condition Assessments how and why?

The increasingly competitive environment for power generation is requiring that utilities manage their operating plants to achieve least-cost generation. Reducing operating and maintenance costs is one element in that effort. Achieving such cost reduction while still maintaining plant safety and reliability requires a clear picture of the condition of key plant components.

The emphasis has been on components with finite lives where degradation and failure are associated with creep and creep-fatigue. Components such as steam outlet headers, main steam and reheat steam piping, all subject to eventual material failure from operating at high temperatures and stresses.

It is important to consider the objectives for the system. For example, the scope of the assessment and the remaining life analysis would be more comprehensive if the goal for the boiler is 30 years additional operating life as opposed to 5 years; or if the purpose of the assessment is to decide the merits of spending capital on a major upgrade versus installing new capacity.

Questions to be addressed in the planning of a condition assessment program include:

- How many years of service are required from the boiler?
- At what capacity will it be operated?
- Will it be base loaded or cycled regularly?
- Are upgrades under consideration and, if so, what systems may be upgraded or replaced?



Assuming that an assessment is required then we can consider the following information.

It is important to recognize that "Over 45% of Forced Outage on A typical major system is due to Boiler Tube Failures." Knowing this fact for example allows us focus our assessment activities in the right order.

Defining a Strategy for Boiler Condition Assessment

"The underlying driver for performing component condition assessment is the need to manage component life to achieve plant operating safety, reliability and economics objectives".

Condition assessment is the primary requirement for managing the useful life of plant boiler components, and it relies on the following three pieces of information:

- The degree of damage current in the component
- The rate of damage accumulation
- The degree of damage required causing failure

Determination of assessment priorities

The scope depends on factors such as the boiler design type, design temperatures and pressures, materials, fuels, age, unit history and future plans for the boiler or plant. We suggest a multi-level



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approach in the planning of the survey scope which is similar to the approach. Basic to all levels of the fitness survey is a comprehensive inspection by an experienced field Service representative.

2 A first level survey depends on minimal if any testing or nondestructive examination (NDE).

Level I

- Evaluate past operating and maintenance history.
- Identify any critical components on basis of history, experience with similar boilers, and objectives for future of unit.
- Perform complete visual inspections of all accessible areas of the boiler and/ or auxiliaries - photo-document problem areas as needed.

- Identify the root cause of damage found to the limits of level I survey.
- Develop a final boiler fitness report with recommendations.

Level II includes NDE testing with little material sampling although tube samples may be included.

Level II (in addition to items in Level I)

- Establish the outage inspection and testing plan.
- Define support requirements for the inspections including any materials that may be needed.
- Assess operation - may include hot walk down of boiler and piping, and data gathering to evaluate performance of auxiliary equipment.
- Implement inspection and testing plan. May include tube samples for basic condition assessment analysis.
- Perform preliminary life estimates and provide recommendations for immediate action as needed.
- Prepare for follow up operational testing as required/ planned.
- Estimate remaining life - analyze data and inspection results.
- Implement operational testing if required.

Level III surveys incorporate material testing, engineering studies and more extensive analysis in support of the assessment. Proceeding from a level I effort to a level III survey is dictated by the objectives of the project, i.e., the scope of data needed to predict future operation to the extent needed by the owner.

Typical multi-level activities are as follows.

Level III (in addition to Levels I and II)

- Perform engineering analysis such as piping stress analysis, finite element analysis, boiler performance/upgrade analysis.

Remove materials for laboratory analysis, i.e. boat samples, tube materials for accelerated creep rupture tests, fatigue tests, etc.

Perform specialized site testing such as strain measurements, support load testing, etc.

After the conclusion of the condition assessment program, the plant owner utilizes the results in the planning for the plant - whether long range or short range. The information may simply aid in the planning of re inspection and regular preventive maintenance to ensure reliable steam production. The assessment may be used to define the scope of a major upgrade or plant overhaul by determining what components need replacement.

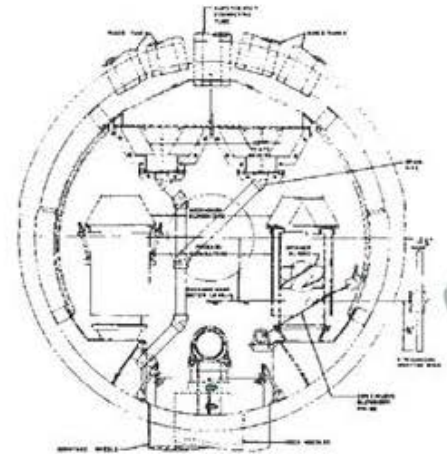
Scope of work of Critical Systems and Components

Described below are the types of problems found in the various components as well as the recommended NDE methods. In general, visual examination, the most basic of NDE, is done for all components. It is recommended to photo-document the inspection to provide a permanent record in the report. Internal inspections are frequently done by video probe and recorded on tape.

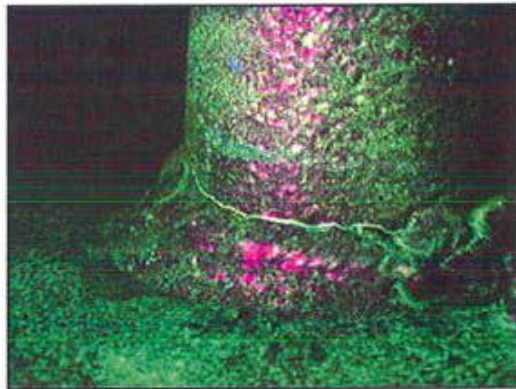
Drums:

The steam drum is the single most expensive component in the boiler. Consequently, any assessment program must address the steam drum as well as any other drums in the convection passes of the boiler. In general, problems in the drums are associated with corrosion.

Problems in the drums normally lead to indications that are seen on the surfaces - either ID or OD.



Assessment: Inspection and testing focuses on detecting surface indications. The suggested NDE method is Wet florescence magnetic particle method. Because WFMT uses fluorescent particles which are examined under ultraviolet light it is more sensitive than dry powder type MT and it is faster than PT methods.



WFMT should include the major welds, selected attachment welds and at least some of the ligaments. If locations of corrosion are found then ultrasonic thickness testing (UTT) may be performed to assess thinning due to metal loss. In rare instances metallographic replication may be performed. Replication is done by polishing the surface of the drum to a mirror finish, etching the polished surface with a nitric acid, and then lifting an image of the metal surface by applying a softened acetate tape (the replica). The procedure, analogous to

finger printing, allows the metal grain structure to be examined under a microscope.

Headers:

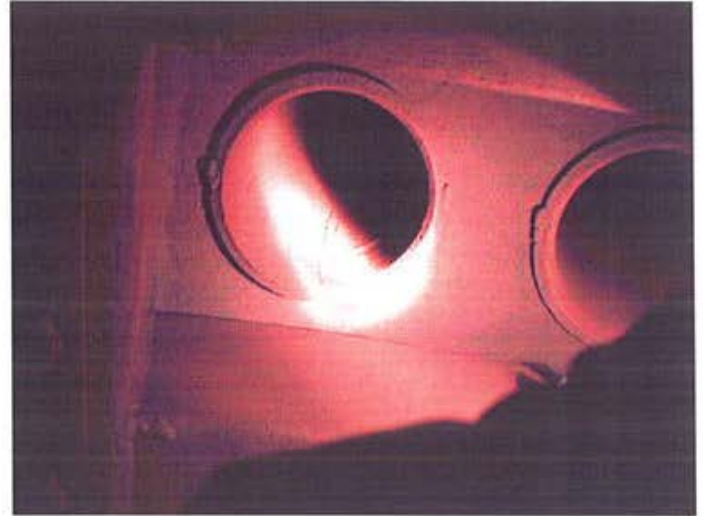


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Boilers designed for temperatures at or above 1000 F can have superheater outlet headers that are subject to creep the plastic deformation (strain) of the header from long term exposure to temperature and stress. For high temperature headers, tests should include metallographic replication and ultrasonic shear wave inspections of higher stress weld locations.

Lower temperature headers are subject to corrosion or possible erosion. Additionally, cycles of thermal expansion and mechanical loading may lead to fatigue damage.

Assessment: Inspection should include testing of the welds by MT or WFMT. In addition, it is advisable to perform internal inspection with a video probe to assess waterside cleanliness, to note any buildup of deposits or maintenance debris that could obstruct flow, and to determine if corrosion is a problem. Inspected headers should include some of the water circuit headers as well as superheater headers. If a location of corrosion is seen then UT to quantify remaining wall thickness is advisable.



Piping:

Main Steam: For lower temperature systems the piping is subject to the same damage as noted above for the boiler headers. In addition the piping supports may experience deterioration and become damaged from excessive or cyclical system loads.

Assessment: The NDE method of choice for testing of external weld surfaces is [WFMT](#), [MT](#) and PT are sometimes used if lighting or pipe geometry make WFMT impractical. Non drainable sections such as sagging horizontal runs are subject to internal corrosion and pitting.

These areas should be examined by internal video probe and or UT measurements. Volumetric inspection, i.e. shear wave, of selected piping welds may be included in the NDE; however, concerns for weld integrity associated with the growth of subsurface cracks is a problem associated with creep of high temperature piping.

Feedwater Piping: A piping system often overlooked is feedwater piping. Depending upon the operating parameters of the feedwater system, the flow rates, and the piping geometry, the pipe may be prone to corrosion or flow assisted corrosion (FAC). This is also referred to as erosion-corrosion.



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If susceptible, the pipe may experience material loss from internal surfaces near bends, pumps, injection points and flow transitions. Ingress of air into the system can lead to corrosion and pitting. Out-of-service corrosion can occur if the boiler is idle for long periods.

Assessment: Internal visual inspection with a video probe is recommended if access allows. NDE can include MT, PT or WFMT at selected welds. UTT should be done in any locations where FAC is suspected to ensure there is not significant piping wall loss.

Deaerators:

Deaerators have been known to fail catastrophically in utility plants. The damage mechanism is corrosion of shell welds which occurs on the ID surfaces.

Assessment: Deaerators' welds should have a thorough visual inspection. All internal welds and selected external attachment welds should be tested by WFMT.

Attemperators:

The spray flow attemperator, a device for controlling superheater outlet steam temperature, is normally located in the piping system between the primary (1st stage) superheater outlet and the secondary (2nd stage) superheater inlet. The attemperator is subject to failures associated with thermal fatigue cracking of its components and welds. Since it is in a non viewable area of the boiler, failures may go undetected until pieces of the attemperator lead to other damage, such as superheater tube failures. These steam temperature control systems should also be part of the boiler fitness survey testing.

Assessment: For the inspection is recommended by removal of the spray head assembly. The spray head is inspected visually and tested nondestructively by MT/PT methods. Following removal of the spray head from the body of the attemperator, the attemperator thermal liner can be internally inspected with a video probe.

Tubing: By far the greatest number of forced outages statically in all types of boilers is caused by tube failures. Failure mechanisms vary greatly from the long term to the short term.

Superheater tubes operating at sufficient temperature can fail long term due to normal life damage accumulation. Tubes are more likely to fail because of abnormal deterioration such as: water/steam-side deposition inhibiting heat transfer, flow obstructions, tube corrosion (ID and/or OD), and fatigue and tube erosion.

Assessment: Tubing is one of the components where visual examination is of great importance because many tube damage mechanisms lead to visual signs such as distortion, discoloration, swelling or surface damage. The primary NDE method for obtaining data used in tube assessment is contact UT for tube thickness measurements. Sample removal for laboratory analysis is by far the best test to conduct for the assessment of life in the component.

Summary



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To carry out a boiler condition assessment program successfully, Plant Personnel must have several key elements in place. These elements have been well-established by a successful BTF reduction program and are summarized as follows:

Support of Management

Cross-functional teaming (including maintenance, operations, and engineering personnel) in performing the program (Boiler Inspection Team)

Attention to long-term solutions to root cause problems Training

Documentation of results and periodic review

A Final Boiler Condition Assessment Document should include:

- Date the assessment was performed
- Summary of assessment activities, such as inspections, material tests, and results
- Estimate of Component Remaining Life and summary of basis
- Damage mitigation/prevention actions, if appropriate
- Follow-up inspections or monitoring actions and their timing, if appropriate
- Recommendations for next assessment, including operating changes/upsets that would prompt a re-assessment

3. Human Resources

Selection of the Boiler Inspection Team Leader

The most important constituent of the boiler inspection team, whether it is an in house or contracted effort is the team leader. The team leader is ultimately responsible for all inspection activities and is the consistent element of the total inspection effort. The key concept is consistency. Team support personnel may come from a number of resources including plant operations, lab, coal yard personnel, etc. Support personnel may also come from other plants within your system. Utilization of personnel not intimately involved with the subject boiler



or not schooled in the disciplines of boiler inspection technology may lead to inconsistencies in the total inspection philosophy. Additionally, their primary duties may take precedence over their temporary inspection team assignment. The team leader must take these factors into consideration and act accordingly to ensure consistency of the total inspection program.

Organizing an in house Boiler Inspection Team

Forced Outage Team members

During forced outages it is important that members of the repair crew also be boiler inspection team members or observers. During a typical forced outage situation there is limited warning. In most instances the people involved are welders and mechanics trained to locate and repair the leak or problem. Further training of repair personnel as boiler inspection team members adds technology, knowledge, and quality to the forced outage repair process. The forced outage responder is the best possible choice in assisting in the inspection, repair technique, documentation and final repair methods. Remember when the boiler has a leak it is an opportunity for us to gain insight into lurking problems that we have not been addressing during planned outages.





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Even though we are in a forced outage scenario we must inspect all the areas in and around the leak event as well as other areas easily accessed with out impacting the timing and duration of the original event. We suggest we inspect our way and to the leak and then back out. This is the very reason the repair / inspector should have all the tools and techniques to determine any collateral as well as like damage in the suspect areas.

Planned Outage team members

The boiler inspection team is commonly comprised of representatives from diverse areas of the plant. Utilization of personnel from different departments can add an element of diversity beneficial to the inspection team. It is suggested that personnel that do not have a heavy work focus during the outage period be utilized. These might include operations personnel, technicians, environmental, and lab personnel. Technically trained plant personnel are ideal candidates for inspection team members. Utilization of maintenance workers as planned outage boiler inspection team members is not recommended; in many instances their normal job duties interfere with the inspection effort.



A major mistake inspection teams make during a planned outage is the release of inspection team members too early. This reduces the effectiveness of the technical surveillance and follow up inspections. Many problems such as additional items found can be resolved in the time from the end of the initial inspections until hydro. The cost of maintaining the inspection team until hydro is a significantly offset by the increase in the overall quality of the outage.

It is important that the team members maintain consistency from unit to unit and from year to year. This will require incentives from management. An on going training program is essential to keep everyone on the same page.

Consistency

Training regimes of inspection personnel

It is essential that all inspection team members have formal inspection technology training. Insufficient boiler inspection training is the primary contributing factor to instances of poor performance of a boiler inspection team. Having a background that well equips an inspection team member for boiler inspection, in itself, is not sufficient. This includes engineers, managers, welders, and mechanics; no one involved with the inspection process should be exempt.





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Physical Capability

Boiler inspecting is a very physically demanding activity. Team members must be capable of climbing and crawling in unpleasant environments. Team members must be able to enter small openings with limited access. It is not recommended that individuals with fears of heights or confined spaces (claustrophobia) be part of the inspection team. Excellent vision, natural or corrected, is essential.

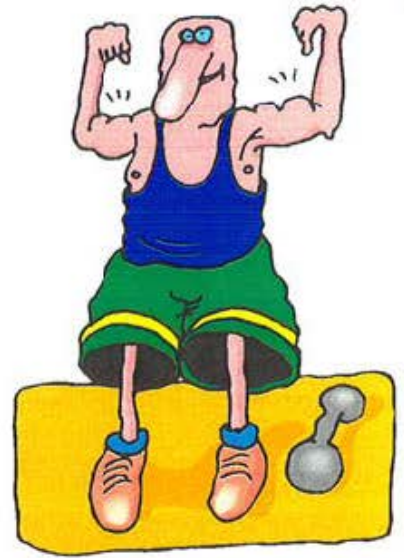
Team Player

Most importantly your team member must be a team player.

Technical Expertise

A good boiler inspection team member need not be a degreed engineer; however, the team member must have a fundamental understanding of some basic concepts in physics, metallurgy, mathematics, and strength of materials. Intelligent individuals with a strong work ethic and desire to learn make great boiler inspector candidates.

Remember: consistency is the primary ingredient in a successful in house inspection team.



Equipment required for in plant boiler inspection teams

Paint sticks are a good way to finely field identify problems. Usually we suggest that we write on the tubing with paint stick as it is fine enough to communicate thickness and or actions quite clearly. Paint sticks are also durable and when dry they are very much like paint. We have witnessed paint stick from previous outages still visible on the tubes after a 12 month run.

We suggest the use of a brightly colored paint to coarsely mark or identify a problem area. Some people use color codes to distinguish repairs such as red for replacement blue for pad welds and so one.

The problem with coding with colors comes when work scope is reduced or modified. In this scenario the paint would have to be removed.

A "UT" thickness meter is essential for the determination of actions based on thickness. Without this device all decisions are based on a guess. This is an absolute requirement for every inspector forced or planned.

A high quality flash light of the proper brightness and size are required. The controlled use of the flashlight will produce contrast required for inspections.

A digital camera is a must as a visual record is a requirement of a state of the art inspection program.





Utilization of supplemental Boiler Inspection Team Members

Intra Company

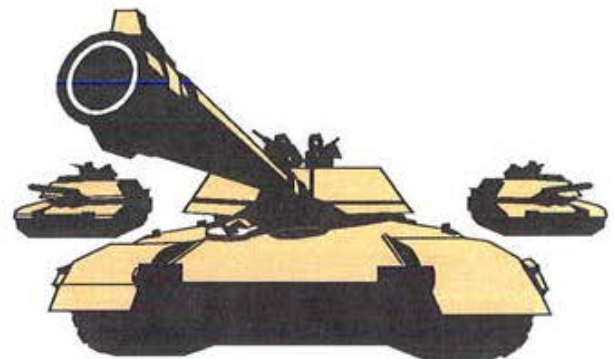
Personnel from other plants within your system are usually team leaders or members of their respective plant boiler inspection teams. This is a popular planned outage concept as plants within the same system typically remove equipment from service at different times. A wide range of experience is enjoyed with such a compilation of talent; however, their boilers and equipment may be of a different model and manufacture. Additionally, management policy may vary from plant to plant potentially confusing the relationship.



The team leader can address these problems by pairing the supplemental personnel with local boiler inspection team members. Local paring of human resources ensures the policies and interests of the subject plant are best served. Paring is also important in combining various levels of experience. Paring experienced inspectors with trainees or lesser experienced inspectors promotes camaraderie and on the job training, benefiting both the current inspection effort and the collective level of expertise of the entire company. It is incumbent on the team leader to take advantage of highly trained and experienced personnel in this manner to ensure optimal performance of the inspection effort.

Contracted Professionals

There are many advantages to contracting experts in the field of boiler inspection technology. Professional boiler inspection team members work together during many outages each year. A well traveled professional brings a wealth of expertise and experience to the outage. He is a valuable source for vital technical information. Professional consultants should be utilized extensively to conduct on the job training during the inspection period. Effective paring will facilitate this goal.



The selected inspection contractor should bring experience and knowledge of your specific equipment and the industry in general. They should be knowledgeable in all aspects of team activity as it pertains to your inspection program. They should be skilled, efficient, competent and able to easily adapt to your inspection program. If you use specific software as part of your inspection program, your contracted inspectors should be knowledgeable in those areas as well. It is important to research prospective inspection contractors thoroughly to ensure your technical requirements are met.

4. Outage management

Cost Control

The process of cost containment is not just a reduction of total costs. Cost control can only be effective if we focus the monies available in just the right locations. The shot gun approach or the process of spending money for the sake of using up the budget will not provide relief from tube leaks. Less money does not necessarily translate into lower availability.

How to increase our boiler repair budget

The most effective way to increase your boiler repair budget is to provide a comprehensive plan supported by inspections, lab results or other scientific results. This plan must have a financial component indicating the return on investment in the repairs. Data driven decision making is the only consistently effective method to support budgets. In many cases the data is best supported by good photography of the problem areas as well as a statistical analysis of failures or near failures that will likely be avoided. Varying lost generation scenarios at different times of the year usually works well at underpinning your budget requests. Simple, concise, data supported and to the point is always more effective than the Chicken Little "The sky is falling" technique.



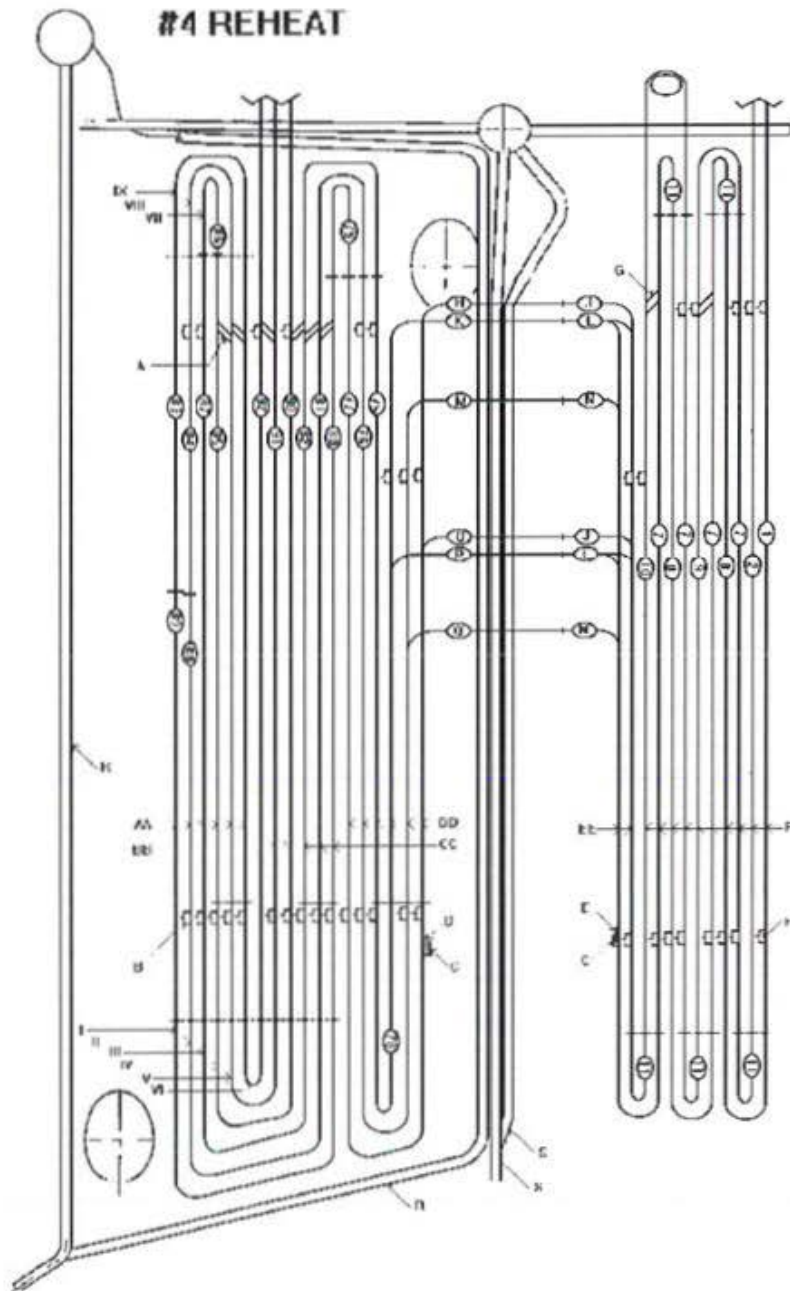
The quality and quantity of your inspections and subsequent data gathered typically has a positive physiological impact on financial decision makers. A compelling case well presented is likely to develop more money over time than a more abstract approach.

Quality Assurance

Preparation and use of Technical Information

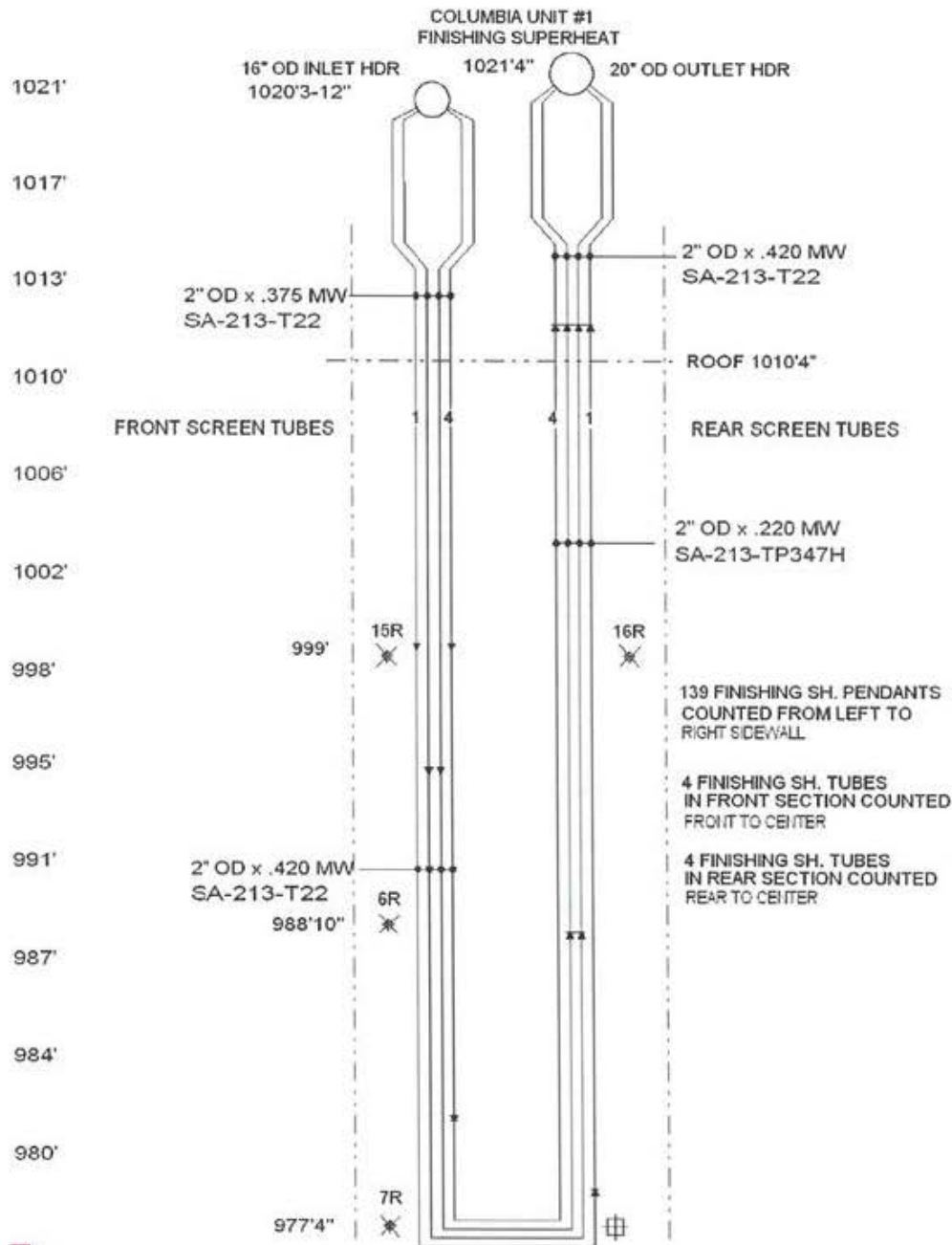
In every plant, technical information is available to the boiler inspection team, even if this is limited to just the boiler manual. This boiler manual will have pertinent information including tube materials and

nomenclature. In many cases you will also find part numbers and welding information. Small drawings showing pressure parts as well as details of insulation and refractory are usually available. Copy all relevant sections for use during the outage or scan them for use in your software systems. Drawings may be scarce, but an attempt should be made to copy, scan and reduce these for outage use. It is important that the boiler inspection team have quality drawings for use in the boiler during the inspection. Ideally color coded CAD drawings will be available for reproduction in color. Regardless of the type of drawings available, they should be utilized by the boiler inspection team. Effort is expended just finding the correct tube material. This should be done prior to the actual inspections. Time is precious during the outage; potential confusion must be minimized proactively. Errors made in materials selection and identification is a significant cause of tube leaks. Thus identifying materials and including this identification in the inspection report becomes essential.





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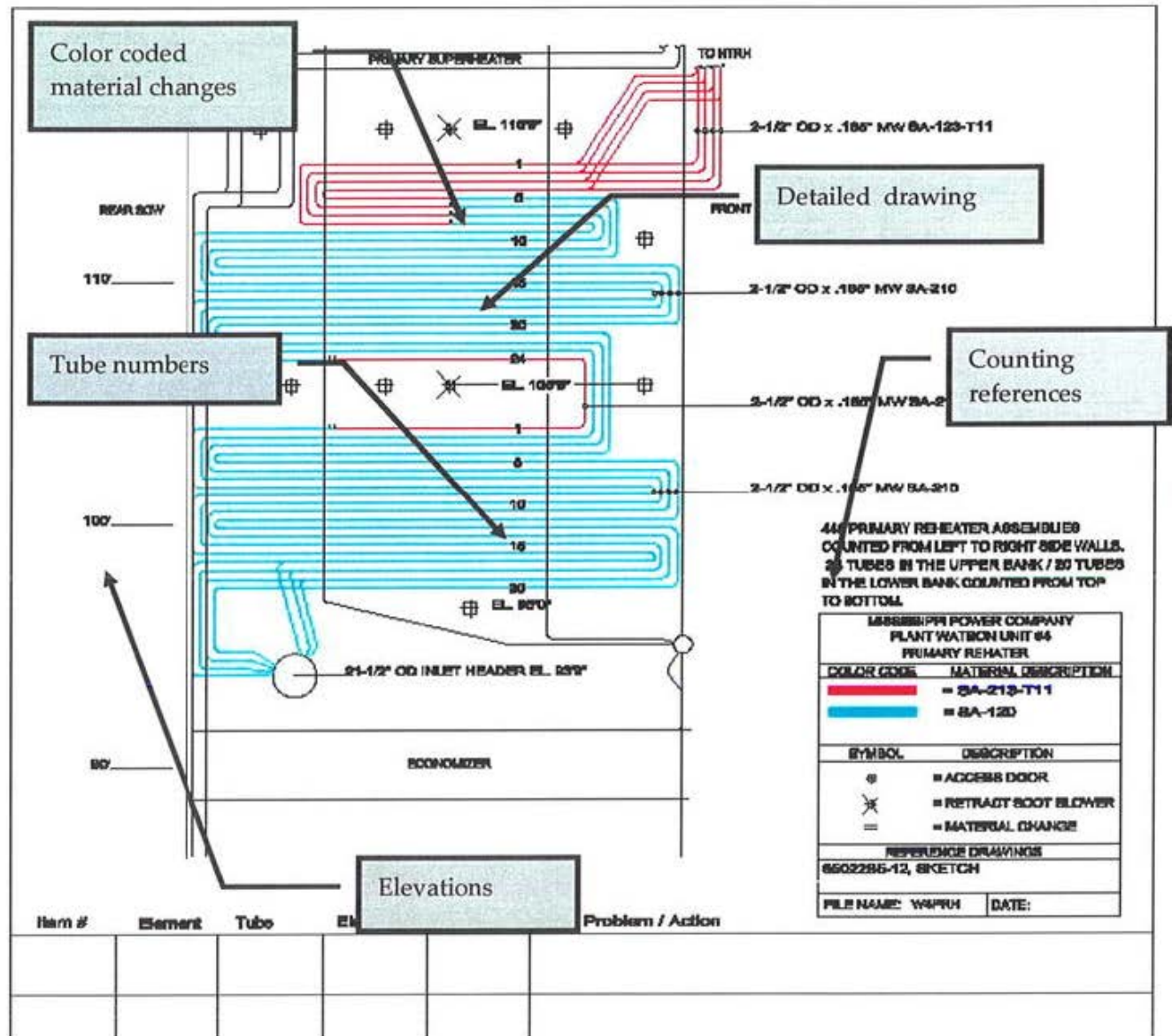
The inspection team should, and will most likely be, the most familiar with the materials in any given component. This single step reduces the possibility of mistakes in material selection.

The two illustrations demonstrate that a scanned image is acceptable; however, the color CAD image is much effective in clearly communicating information. The designers of the boiler equipment were quite specific as to the application of materials. We

must not change or modify these materials without careful consideration of the effects. In some cases it is acceptable to upgrade a material or increase the thickness of a material. A good rule of thumb is to replace materials per original design. In other words replace with exactly what was installed new. Use the drawings and documentation as a guide when selecting replacement material.

Data forms

As a continuation of drawings and documentation, check lists and inspection data forms should be utilized by your inspection team. Forms can range from basic printed forms to a complete software system. The graphic at the left shows a typical inspection data form. No matter what kind of data form you use it must contain the following elements:



- #1. Tube numbering system must be clear and concise.
- #2. Elevations must be included where relevant.



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#3. Material identification should be color coded. Data forms must include outside diameter, thickness, minimum wall, and grade as specified by the original manufacturer. Be careful to incorporate all relevant changes from design into the data sheets.

If you don't have color capability, encourage management to authorize a color printer. Color is now very affordable and easy to use.

#4. Counting references must be clear and easy to understand. Not all plants count the same way; however, your regular people will likely be familiar with the method you have employed. This is an essential element for visiting or supplemental personnel.

#5. Make a grid which has the principal elements required for this specific inspection. Items such as assembly, tube, elevation, length, problem description, repair, and action required should be the minimum information required on the data sheet.



Above all else make the data sheet easy to use in the boiler while inspecting. Filling out the data sheet in the office is the wrong thing to do.

Inspection Check Lists Technical procedures

Over a period of time a boiler inspection team will identify problem areas specific to the subject boiler. These should be recorded so that this specific experience can be shared with inspectors that follow. The check list system can range from a hand written and copied piece of paper with attached drawings or sketches to a complete software system. The following is an example of a checklist.



The first section below shows the framework for a technical procedure required to complete an inspection and required repairs. The second section shows the detailed inspection procedure.

Primary Superheater:

(278 elements, 2380 PSI, 1000 degrees F). (Vertical tubes)

GENERAL:

Elements are numbered from 1 to 20, from the left side wall to the right side wall.

Tubes are numbered 1 to 20 , top to bottom, with O.D.s

Vertical tubes are numbered 1 to 20 , from front to rear.

Primary Superheater inspection before debris removal

Inspect:

- ☐ 1. Tubes. Record percent free area and tubes deep for plugging of gas lane. Record general areas of possible tube erosion.
- ☐ 2. Bundles. Identify gas lanes with spacing greater than 6 inches. Sketch fly ash, bridging. Estimate percent free, area lost, and areas of bridging between tubes within bundle.
- ☐ 3. Flow baffle. Indicate plugging resulting in flow area of mesh reduced > 50%, worn or eroded screen locations > four square inches. Sketch configuration including dimensions and angle of baffle.



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Primary Superheater inspection after debris removal

Inspect:

- ☐ 1. For overheating. Record excessive sagging of tubes, blackened appearance, elephant hide, bulging, and burnt shields, tube, element, cause of overheat, and measure tube outside diameter.
- ☐ 2. Fly ash erosion of tubes or fins. Record tube, element length of eroded area (spot "UT" thickness examine), cause (misdirected flow), and wall loss > 20%.
- ☐ 3. For misalignment. Record misalignment into gas lanes > 1/4 diameter, erosion, rubbing, bundle, tube, and element.
- ☐ 4. Pad welds. Record cracking, erosion, proper metal, tube, and element.
- ☐ 5. Existing shielding. Record holes, bent, loose (redirection of flow), overheated shield conditions, missing (if missing "UT" thickness examine), tube, element, and wall.
- ☐ 6. Gas lanes. Measure distances (center to center), record debris (shields lodged, any blockage redirecting gas flow), bundle, tube, and element.
- ☐ 7. Bends. Record polishing, erosion (rear bends), tube, element, tube wall loss > 20%.
- ☐ 8. Convection pass side walls. Inspect side walls for missing refractory, fly ash erosion, record tube # that erosion is adjacent to, and wall.
- ☐ 9. Gas baffles. Record holes in mesh > 4" square, missing angles, and measure baffle (include height, width, angle).
- ☐ 10. Hangers tubes (if existing). Record bowing, rubbing, cracked welds, missing pins, erosion, hanger, and element #.
- ☐ 11. Inlet header (if accessible). Record condition (spot "UT" thickness examine), low temperature corrosion, nipple cracking, tube, and element #.
- ☐ 12. Left and Right Convection Wall peg fins. Inspect peg fins especially and corners. Record missing, cracked, or broken fins, adjacent tube, elevation, and refractory.
- ☐ 13. Front and rear wall to element support brackets, and attachment welds.
- ☐ 14. For retract blower erosion. Tubes are worn flat. Spot "UT" thickness examine erosion. Record tube, retract blower, elevation, and tube wall loss > 20%.

Planned Outage Preparation

Planning and preparation for an outage is vital to a successful experience. All relevant information should be easily available to all of the team members in the team work area. The boiler inspection team should prepare by reviewing the following items:

Boiler Operating Environment

Relevant information can be extrapolated from the yearly boiler operating environment. This can include management decisions on operational procedures such as soot blowing and load management.



Cycle Boiler Water Chemistry

If a chemical problem develops during the cycle it is important that the team leader examine the potential impact on the boiler and its inspection. Conclusions may warrant additional or more detailed inspections.

Effects of Boiler Operation

The team leader must be cognizant of operational problems such as high/low temperatures, high/low loads, fuel changes, ash pluggage, and soot blower problem areas.

Corrective and Preventive Programs that may be in Place

Experience may reveal certain corrective programs to be more successful than others. It is in the best interest of the boiler to repeat and optimize relevant programs.

Remaining Life Assessment Results from Previous Outages

The purpose of remaining life assessments is not just to generate data for one time analysis. By consulting previous assessment data the team leader can follow up and track the progress of items uncovered during each assessment.



Inspection Results from Previous Outages

By reviewing results of previous inspection efforts, the team leader can follow up and track the progress of items identified during each inspection cycle. It is not uncommon for many items slated for repair to remain outstanding. Based on the inspection results and documentation of the prior outages, the team leader can develop a scope of work for an upcoming outage prior to the boiler being removed from service. In many instances lower priority maintenance items become higher priority repair items.



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Inspection Methods

Every boiler has its own unique characteristics. Identically designed boilers in a plant may in fact prove to be more dissimilar than expected by design. Specific inspection and repair methods may prove more successful than what is generally accepted as the industry standard. This fact lends credence to the philosophy that team leaders must examine relevant boiler histories in aggregate to maintain a proactive posture.



Boiler Tube Repair and Replacement

It is vital to know exactly when and where boiler tubes have been replaced. This awareness helps to preserve the quality of tube thickness histories and can alert the team leader to a potentially catastrophic event while still in its genesis.

Known Boiler Specific Failure Mechanisms

The boiler history may reveal specific failure mechanisms that are prominent. If the team leader remains cognizant of these failures, they can be addressed from a preventive maintenance standpoint during the inspection. With this information, past areas of concern can be focused on and inspected with greater scrutiny.

Recommended Actions

Historically successful inspection and repair techniques should be applied to the current outage as appropriate. Individual equipment needs vary; identification of the most advantageous methods of inspection and repair rests with the team leader. He must be in a position to take advantage of what has proved most successful in the past. This does not necessarily preclude considering other possible repair methods.

Achieving High Quality Repairs with Minimum Outage Duration

The team leader should take an active role in the planning process. This is especially true if financial issues and schedules heavily influence the status of the identified scope of work. All parties working closely for a common goal is essential for effective utilization of scarce plant resources.



Provide General Planning Documentation

This process identifies activities and resources needed to implement a successful total outage.

Boiler Operating Environment

Post the written philosophy of management regarding the operations of the boiler. This can include policy on soot blowing and load management. Some inspection findings could be affected by these policies.

Boiler Water Chemistry

If there were water treatment events in the past operating period, they should be recorded and made available to the team for review. This knowledge may demand additional or more detailed inspections be conducted.

Effects of Boiler Operation

The team should be aware of operational anomalies such as high / low temperatures, high / low load, fuel changes, plugging occurrences, and soot blower problem areas.



Existing Corrective and Preventive Programs

Any current preventive programs in place should be in writing and available to the inspection team. Preventive program documentation should be filed or attached to the component that is affected.

Past Outage Remaining Life Assessment Results

All assessment information should be available to the inspection team for review prior to the inspection. By consulting a previous assessment the inspection team can follow up and track the progress of a problem discovered during the assessment inspection.

Past Outage Inspection Results

By reviewing a previous inspection effort, the inspection team can follow up and or track the progress of a problem uncovered during the previous inspection. It is not uncommon for identified work to remain not repaired.

Inspection Methods

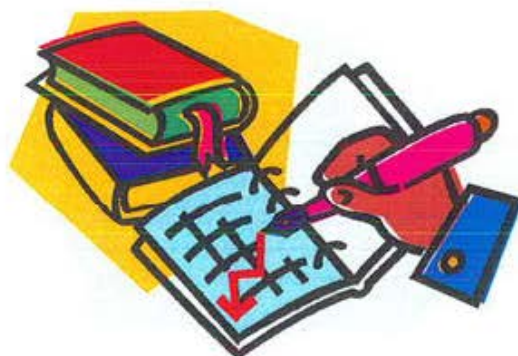
Inspection procedures should be in writing and available to the inspection team.

Boiler Tube Repair and Replacement

Have drawings available with tube replacement information ready for each component. It is vital to know exactly when and where boiler tubes have been replaced.

Known Boiler Specific Failure Mechanisms

History of the unit may involve specific failure mechanisms that are prominent. The team should be up to date on these failures so they can be addressed specifically during the inspection.



Recommended Actions

Historically successful repair techniques should be applied to the current outage; they should be posted in writing and filed or attached to the individual component information package. They should include the repair criteria for various action levels. Guidelines for thickness or tube condition for classification as various priority ratings, such as priority #1, #2 and #3. Guidelines should be clear and recalculated for each component area.

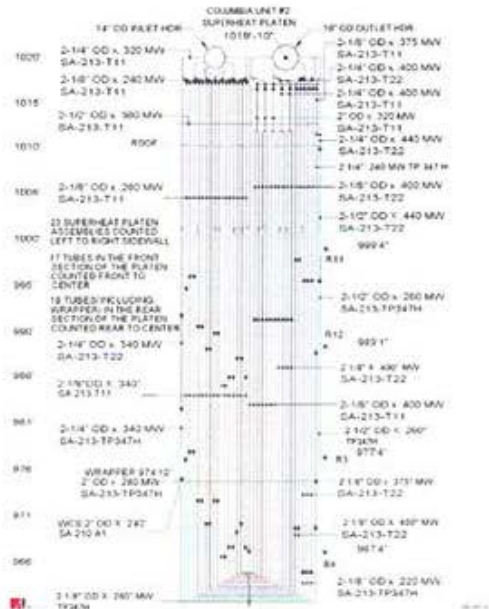
Manpower and Scheduling

If you are going to cover multiple shifts with inspection team members, have a plan for shift coverage. Group team members that compliment each other on each shift. Always field lesser qualified inspectors with experienced boiler inspectors. The inspection effort is also best served by grouping local inspectors with visiting inspectors. Spread out experienced team members for optimal coverage. Inspectors should always be paired for efficiency and safety reasons.



Pre-Inspection Briefing

The boiler inspection team leader should brief each inspection team before the actual inspection occurs. This usually occurs after the team has examined all of the documentation available. The team leader can impart that subtle information that is hard to glean from the printed record. This may include: the leak history of the area, upgrade or replacement materials, special repairs, or safety access concerns. The team leader is most abreast of all available resources. This is also a good time to set repair criteria and priorities. The inspection team can approach their inspection with new insight that could not be gained without this briefing.



Check #10

Inspection Report

Date: 10/16/00 Page 44

Report Sequence #: 10

Report Name: 15-Stream Drum
Path: G:\WP5\Reston\Unit #2\Sept 2000\Reports

By: Hyngard, J. Hallert, K. Weber

Station: Weston Unit 2

Area: Steam Drum

CONTINUATION:

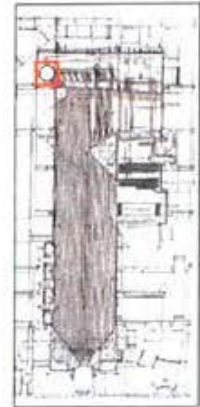
Repair Item #: 43

Priority #: 3

Action required: REMOVE DEBRIS



Status of Item: Suspected



Repair #:

43-a

43-a

(REMOVE DEBRIS)

The location of this repair is on the steam drum at elevation 115'.

The cause of this problem is work quality (defect). This condition appears as debris on drum.

The drum has some debris located just inside the manway and also on the opposite man access.

WORK DONE:



2. 15-Stream Drum, N2, 10/17/00

PM Cavote: Serial number: Service Copy

Full Library (Check) Options

End Edit Print Help Drawing Properties Data Sheet Data Set

UNITED DYNAMICS CORPORATION NO 81005

Georgia Power Company TECHNICAL PROCEDURE REVISION 0 DATE 1/98

STATION: Plant Bowen

TITLE: Superheat Pendant Plates

1.0 Purpose

This procedure provides instructions for performing the specified inspection activity and allows for documentation of the area condition and repair recommendations.

2.0 Description/Equipment Data

This procedure applies to boiler and boiler-related equipment.

3.0 References

3.1 Unit instruction manual.

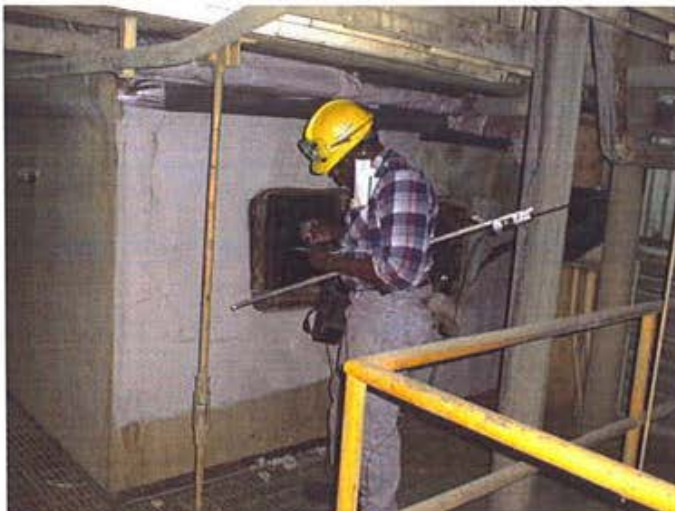
3.2 Unit drawings.

Back Exit Forward >>

Graph 1 Graph 2 Graph 3 Graph 4 Graph 5

The boiler inspection team leader should brief each inspection team before the actual inspection occurs. This usually occurs after the team has examined all of the documentation available. The team leader can impart that subtle information that is hard to glean from the printed record. This may include:

- The leak history of the area
- Upgrade or replacement components and materials
- Special repair techniques
- Safety and access concerns
- Special tools required for the inspection



The team leader is most abreast of all available resources. This is also a good time to discuss repair criteria and priorities that are currently in use. The inspection team can approach their inspection with new insight that could not be gained without this briefing.

Inspection Photography

This is the beginning of the third millennium so if you don't have a digital camera, get one! Select a durable camera, one which can withstand the rigors of the boiler inspection environment. Keep moving parts to a minimum, as the fly ash may foul its internal components. The team should utilize cameras during all inspection, without exceptions. All photos may not be used in the report; however, it makes the process of report generation much easier. Communication is key and photographs can convey an areas condition with a minimum of words. If you discover a problem in the field:



Paint the problem brightly for location in the future; include the repair.

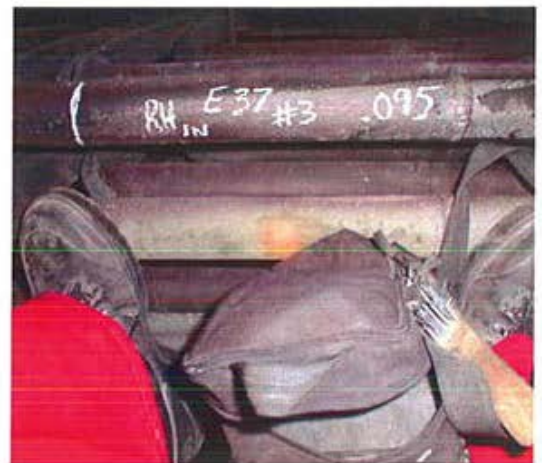
Mark the tube/element number clearly on the problem area with paint stick.

Take a photograph which clearly shows the problem and the identification you have marked with paint stick.

Take extra photos at different angles and positions.

Identify in your notes what each photo represents and which photo number pertains to specific items.

Select the best photo for the report if more than one picture is available. Add as many as may be required. Archive all photos and include them in your appendix at the end of you final report. Include captions with each photo for easy identification. Captions are very important as hundreds of pictures will be taken during a typical outage.



Problem Identification in the Field

One of the most difficult problems in the inspection process is the repair crew finding the specific area to be repaired. We can aid this process by clearly and uniformly marking the problem areas. This can be accomplished by employing simple techniques.

When beginning any inspection count and number all the elements and tubes in the inspection area. Identify soot blowers and other landmarks that might be of use during the inspection/repairs. Write on every fifth element for easy reference during the inspection and subsequent repairs.



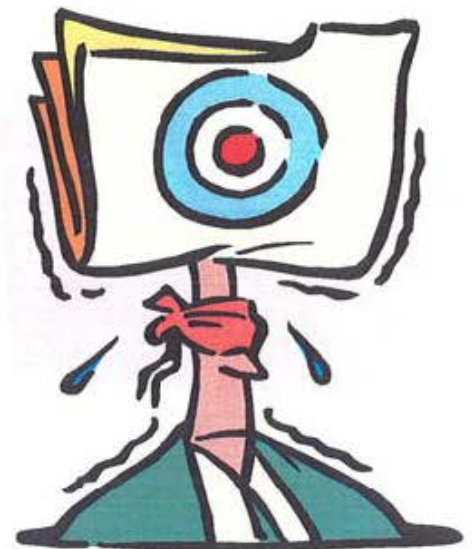
Brightly mark the area of concern with either bright paint or with a tag. If painting, do not paint into an area that will require pad welding. This makes the preparation process more difficult for the repairman. We suggest you circle the area to be pad welded. If using paint, use a bright color in contrast with the fly ash you are encountering. Mark the repair and tube identification on the tubes with paint stick.

Tags are the preferred method for identification. Prepare about 300 tags at the beginning of the outage. Give each boiler inspection team member a group of consecutively numbered tags. Record the numbers given each. Each tag should be consecutively numbered 1-300. Each tag should have a rubber band or a metal wire to hang the tag on the repair area.

Use a single tag for each repair item. On the tag mark the identification (tube number, element, etc.) and the required repair. Record the tag number as part of your notes. If you are inspecting an area where tag attachment is not possible, such as a furnace wall, then write the tag number on the wall and destroy the tag bearing that number.

Post Inspection Briefing

When the team returns from the inspection area they should be debriefed by the team leader. The key points of the inspection should be discussed with the team leader to get the leader's insight into the report preparation. Due to the quantity of work discovered and time left in the outage, the team leader may re adjust the priorities previously assigned. This reprioritizing of items is the main reason we need good notes and proper identification of the repair areas. Once the debriefing is complete then the team can prepare a report.



Report preparation

The boiler inspection team is in constant competition with other teams for the pool of available budget money. It is a process of convincing management that the boiler team needs the money more than another area of the plant. While overall system availability is important to everyone, if forced outages due to tube leaks rise, the inspection team will likely bare the brunt of the responsibility. Therefore we must protect our areas of responsibility. Experience has shown that a well done inspection report will help convince otherwise passive management. This report preparation system is more efficient and overall more cost effective even though the process requires more man-hours to complete than that of lesser effort. You will find in time that the extra effort is money well spent. Some obvious advantages are:



- A quality report communicates more effectively with management.
- The repair crews will have fewer questions and reduced confusion.
- Less time will be required during the planning stages of the repairs as materials specifications and quantities are listed in the report.
- Fewer mistakes on material selection are made.
- Higher quality welds are made, as the welders know exactly what they are welding to and how thick it is.





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Inspection Report preparation
AREA: Reheat inlet pendant.

By: Cavote and L Keating
Path

The area was numbered from boiler left side to boiler right side.

Items were marked with white paint stick and orange paint.

The total number of repair items for this area is 9



PRIORITY #1 REPAIRS TOTAL = 6

Repair item #: 17 Priority #: 1
Area: Reheat inlet pendant
Action: PAD WELD.

Repair #: 17-a Record:# 41 (PAD WELD).

General location is Reheat inlet pendant Rear.

Specific location: Tube #: 18 Element #: 2 Elevation= 169'.

Length= 1.5'

Cause = Erosion (soot blower).

Appearance= a flat on tube.

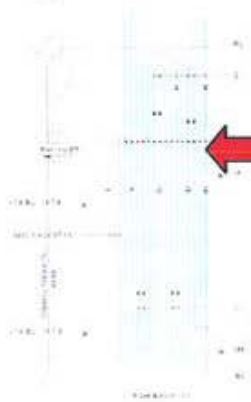
Material= 2.5" OD x 0.165" MWT x SA-178A Electrode= 7018.

The UT Reading is .120.

These tubes are below 75% of MWT and above 65% MWT. They are also located at the following locations; 7, 8, 9, 17, 19, 23, 46, and 58.

Pad weld using vertical stringers. Do not horizontal weave pad weld. Down hand is suggested to keep the temperature as cool as practical. Do not pad weld if copper deposition is present on the internal surface of the tubing. Use TIG if the tube remaining wall is less than .125".

Forced Outage Procedures





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During forced outages it is important that members of the repair crew also be boiler inspection team members or observers. During a typical forced outage situation there is limited warning. In most instances the people involved are welders and mechanics trained to locate and repair the leak or problem. Further training of repair personnel as boiler inspection team members adds technology, knowledge, and quality to the forced outage repair process.

Ultrasonic thickness measurements should be used to determine remaining wall thickness of tubes that have received secondary damage. Thinned tubes may have to be replaced before through wall holes are present, if the remaining wall thickness is too thin to sustain additional service loads during the next operational period. Immediate tube replacement in these situations can prevent repeat failures.



(1) Personnel responsible for reporting boiler tube failures should be trained in all aspects pertinent to reliable reporting of tube failures, i.e. exact designation of failure location, standard mechanism cause codes, probable root causes, verification of root cause, type of repair, etc. This is typically the welder / mechanic affecting the actual repair. This is why the welder / mechanics should be a well-trained part of the boiler inspection team.

(2) Standard report forms should be used for all boilers and should be required documentation for every tube failure and repair.

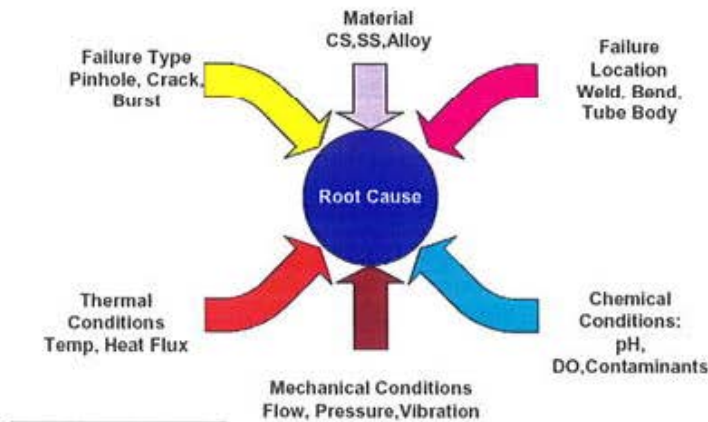
(3) All boiler tube failure reports should be processed through the boiler inspection team leader for continuous tracking and trending on a specific unit, plant, and system basis.

(4) Monthly and annual reports should be issued and formatted, specific to the "need-to-know" and "action" requirements of the inspection team.



During forced outages it is important that members of the repair crew also be boiler inspection team members or observers. During a typical forced outage situation there is limited warning. In most instances the people involved are welders and mechanics trained to locate and repair the leak or problem. Further training of repair personnel as boiler inspection team members adds technology, knowledge, and quality to the forced outage repair process.

Failure identification and cataloging techniques



Boiler tube failures have been the primary availability problem for all utilities with fossil plants for as long as reliable statistics have been kept. The majority of boiler tube failures have been repeated failures, indicating that the return to service of a unit has traditionally been more important than understanding the mechanism and root cause of each boiler tube failure. Failures have emanated from poor initial design, environments, and lack of proper management support.

Boiler tube failures occur in fossil-fired plants throughout the world. Failures differ only in the types of failure mechanism experienced, and in the magnitude of the associated availability loss. Explanations of tube failure experiences amongst utilities are usually treated as unique incidents in individual boilers, rather than as recognized common occurrences that can benefit from detailed knowledge and shared information about failure mechanisms and root-causes.

Boiler Failure libraries are expert systems used to diagnose boiler tube failure mechanisms from information on the tube location, appearance, and possible initiating events. Once the failure mechanism is known, the expert system provides a list of potential root causes along with recommendations for root cause verification, repair and inspection procedures, and guidelines for preventing future failures.

Through the use of available software, potential problems can be readily identified before failures occur allowing the user to target effective predictive maintenance. This concept places the team leader in control and allows him to focus maintenance dollars when and where they are needed. Software can be used in real time during outages, generating inspection reports and documents currently prepared by more manual means. These systems can save precious outage time while increasing productivity, efficiency, and accuracy. This can be done without increasing the current man-hours required for existing methods.



Over a period of time plants typically catalog leaks. This can consist of hand written documentation or integrated software systems. Regardless of the type system used there are minimum requirements that must be included. The system must consider the following 12 points at a minimum:

Every boiler tube failure should be recognized as an indicator of a potentially serious problem. Too often, repeat tube failures are considered normal maintenance, so serious problems go undetected until high costs or generation losses





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get the attention of senior management. Information should be recorded and reported for every tube failure in a comprehensive manner, which describes specific boiler and tube location, failure mechanism, and root-cause. Repeat tube failures result when the tracking and trending process, which is necessary for early problem detection is not performed.

Early warning signals of potential problems in similar boilers cannot be recognized if information on boiler tube failures is not documented and cataloged.

Every failure problem should be analyzed by a responsible, trained, full time boiler inspection team of personnel to define its locations, extent, failure mechanism, and most probable root-cause, and to perform a cost/benefit analysis of alternative corrective/preventive actions for management approval and boiler inspection team implementation.

Every failure will require a pre-repair inspection to: determine the extent of damage to the failed tube, tubing in the close proximity of the failed tube, and tubing in other locations subject to the same root cause, and to determine and/or a sample specimens appropriate for root-cause failure analysis. A trained and experienced boiler inspection team member should conduct this inspection. ("Taking the welders word for it" is not sufficient.)



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G:\Columbia\Tracker\Columbia2\COLUMBIA2

Files Reset Table Reports Attachment Tools Help >>Edit "OFF" >>Error "OFF"

Workorder: [] Report [] Leak Date: 08/07/2000

? Area: Division Panel Specific: Front-Rear Tubes Detail []

? FTube 4 LTube [] F-Elem 4 L-Elem [] ? Elev 1002 Dist 0 Config [] Post Off []

Material: ? SA213TP304 OD 2.50 ? Thick 0.148 Rod []

Cause: [] Erosion (coal particle) Outage []

Appear [] Broken "U" bar

Repair: [] CCR Casing/seal Patch Length 3

Repair Comment: []

General Comment: []

Status [] By: new

Welder ID []

Weld Proced []

Weld Traveler []

Priority: 3 User [] Photo Off []

[X] Photo-1 G:\columbia\Tracker\Columbia2\March outage 2000\DMcoutan\FIPIC00002.JPG

Zoom Clear Import Filter Sort New Edit Del Exit Update Goto Rec 786

Every repair should be inspected and/or tested to verify tube pressure integrity before repair is considered complete.

A boiler tube is considered repaired when a section of damaged tubing is shielded, pad welded or removed and replaced with new tubing.

Every repair should include quality assurance provisions for: welder and inspector certification and recent qualification; welding materials; procedures; and selection of tube material.

Every problem and failure report will be processed for the purpose of monitoring, trending, and control of individual plant, boiler and system performance, and communicating data/results specific to the needs of management, engineering, operations and maintenance personnel.

All scheduled major boiler inspections will include boiler tube wall-thickness measurements in areas experiencing known erosion or corrosion damage, until erosion/corrosion rates are established. In areas experiencing damage, root cause analysis will be performed, and corrective, preventive and control actions taken to inhibit forced outages due to these mechanisms.

All modes of boiler operation, (that is, start-up, load increase and/or limit, planned or immediate removal from service and lay up) will be involved, where the failures are occurring in the boiler, when and how



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many failures have occurred, if changes in fuel or operating practices occurred during or before failures started, etc. Each boiler tube failure mechanism can have more than one probable root-cause although not usually more than three.

Photographs allow easy identification and classification of new tube leaks. Digital cameras should be used liberally.

A drawing used as a key for the location of the problem further aids the user in assessing new problems.

A complete text dialog is required to fully describe the problem in complete detail. See the description below for an example of the dialog styles required.

Prerequisites for a Reporting and Monitoring System;



(1) Personnel responsible for reporting boiler tube failures should be trained in all aspects pertinent to reliable reporting of tube failures, i.e. exact designation of failure location, standard mechanism cause codes, probable root- causes, verification of root-cause, type of repair, etc.

(2) Standard report forms should be used for all boilers and should be required documentation for every tube failure and repair.

(3) All boiler tube failure reports should be processed through a central focal point for continuous tracking and trending on a specific unit, plant and system basis.

(4) Monthly and annual reports should be issued and formatted, specific to the "need-to-know" and "action" requirements of the team functional groups.

Implementation of a formalized boiler tube failure correction, prevention and control program, incorporating these four critical program elements, should virtually eliminate repeat boiler tube failures, and significantly improve the availability of fossil plants.

5. Operational Factors affecting failures

Cycling the boiler

General

Improper warm-up is one of the most severe hardships a steam boiler must endure. Going through the cycle of start-up, operation, and shutdown creates high equipment stresses and consequently, more severe maintenance issues than continuous operation at maximum rated capacity. Good design and slow transition from start-up to operation prolong life and reduce the possibility of failure. A typical boiler is constructed of different materials including very thick drum metal, thinner tube metal, refractory and insulation materials, and thick iron castings. All these materials heat and cool at different rates. This situation worsens when a material is exposed to different temperatures at the same time. For example, a steam drum that is operating at normal water level has the bottom half of the drum cooled by water and the

top half initially cooled by air and eventually cooled by steam. On a cold start, the water heats up very quickly, so the bottom half of the drum expands much faster than the top half, which is not in contact with water. Consequently, the bottom of the drum will become longer than the top, causing the drum to warp. When severe, this phenomenon is called "drum humping" and can lead to stress fractures of the generating tubes between the steam and mud drums. Refractory damage is the most prevalent damage associated

with too rapid warm-up from a cold start. Refractory transfers heat slowly and therefore completely heats up much slower than metal. Also, when the air inside the furnace is cool, the refractory absorbs moisture from the air. A gradual warm-up is required to prevent refractory cracking and to drive moisture from the refractory before it becomes steam and causes the refractory to spall as the steam escapes. The standard warm-up curve (Figure 4) for a typical boiler provides for boiler water temperature increases of no more than 100°F (55°C) per hour.

The main thrust of the following information is to evaluate high temperature materials problems in steam plants, with steam temperatures up to 1050°F. In steam plants the main problems will involve the performance of dissimilar metal welds DMW and austenitic alloys under cycling conditions.

Typical operating conditions in a modern coal fired steam plant are 1050°F inlet temperature to both HP and IP turbines. Although there are many components that can suffer cyclic operation in current plants, the main concerns during cycling are the steam drum, Superheater and Reheater headers, and connecting piping. All of these are prone to creep fatigue.

The historical problem with Superheaters, Reheaters and associated components has been that of thermal fatigue, in which the problems are exacerbated by weak, heavy section components, complex geometries and bending stresses. A low co-efficient of expansion and low elastic modulus is obviously advantageous.





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Fatigue stresses can result from piping movement in the plant, during heat up and cool down when load changes occur. Here, the advantage is with strong thin wall members having innate flexibility, and whose deadweight does not overwhelm pipe support systems. However, during start up, rapid changes in temperature in the plant can lead to significant through wall temperature differences. In this case, as well as good high strength properties, a high thermal conductivity is needed.

Recent discussions suggest that the rate of fireside corrosion is only marginally worse under these conditions. The situation seems to be similar with respect to furnace wall corrosion on the boiler. More problematic is possible oxide spallation from the steam side of austenitic Superheater tubes.

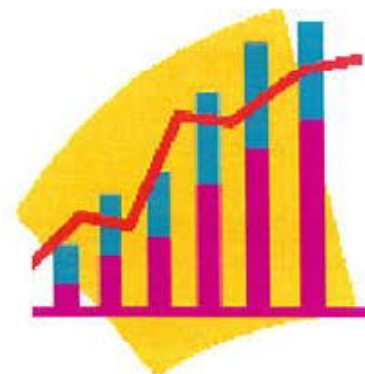
The formation of this can be suppressed by chromizing the surface, cold working or the use of fine grained material, all of which enhance diffusion of chromium and promote Cr_2O_3 formation. The rate of oxide growth is thereby suppressed, so the possibility of spallation is reduced.

Start up shut down ramp rates

General

During shut downs the temperature changes are more problematic, but a major issue during such start ups is the build up of condensate in Superheater pendant legs, and the subsequent carry over of such condensate, leading to thermal shock of headers etc.

3 Recent research and modeling has confirmed in plant physical data that typical operating transient data was used to conduct thermal transient analysis and elastic plastic creep stress analysis with three dimensional FEM models simulating ligament parts of headers. Creep fatigue life was predicted by strain range partitioning method based on the analytical results and creep fatigue properties of a header material.



The results obtained were as follows.

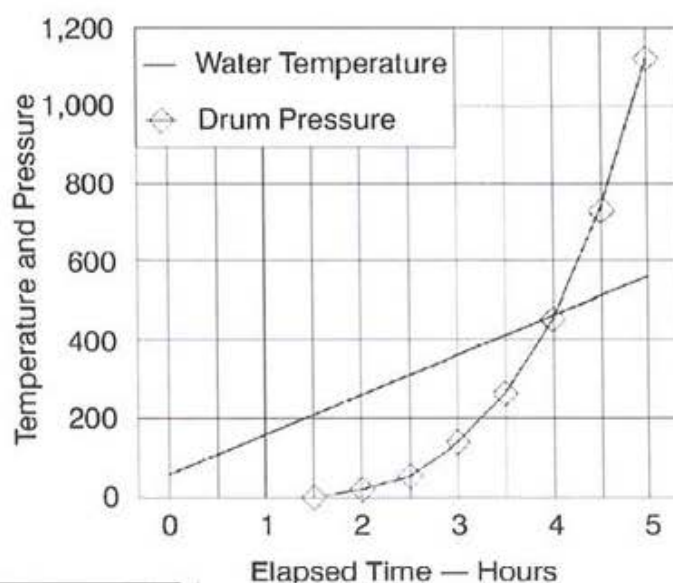
- (1) Cracking was expected in ligament parts with inelastic strain produced by thermal transient during start up and shut down operation.
- (2) The points where ligament crack was predicted to initiate coincided with ones reported in actual plants failure cases.

The effects of operational condition and size of header on ligament crack initiation life were evaluated by this analysis. It was found that the ligament crack initiation life tends to be shorter in the case of the faster ramp rate and the larger header diameter.

Weekend shut downs have the worst effect, in terms of temperature changes, and the risk of air getting into the system is very high.

The common view is that this will lead to thermally induced corrosion fatigue of feed heaters and economizers, where high local stress and temperature gradients will lead to the cracking of protective magnetite films.

This is particularly the case if there is significant bending or increased loads, if the plant has been in service for a long period while an oxidation notch was forming.



Failures due to ramp rate excursion

SHORT TERM OVERHEAT

LOCATION:

This condition occurs in tubes in the furnace walls as well as superheater and Reheater tubes.

Short-term overheating can occur in steam-cooled and water-cooled tubes at locations that:

- (1) Have become plugged by debris, scale, or condensate from incomplete boil out.
- (2) Have exposure to high heat transfer rates from improper firing of fuel burners.
- (3) Have experienced low coolant flow due to poor circulation or upstream tube leak.

Short-term overheating failure occurs as a result of one incident of high tube metal temperature.



PHYSICAL DESCRIPTION:

Thick brittle dark scale (oxide) layer on both external and internal surfaces

PROBABLE CAUSE:

Either a reduction of coolant flow or excessive combustion gas temperature causes overheating. A reduction of coolant flow can be caused by a blockage in the tube circuits, loss of boiler water drum level.

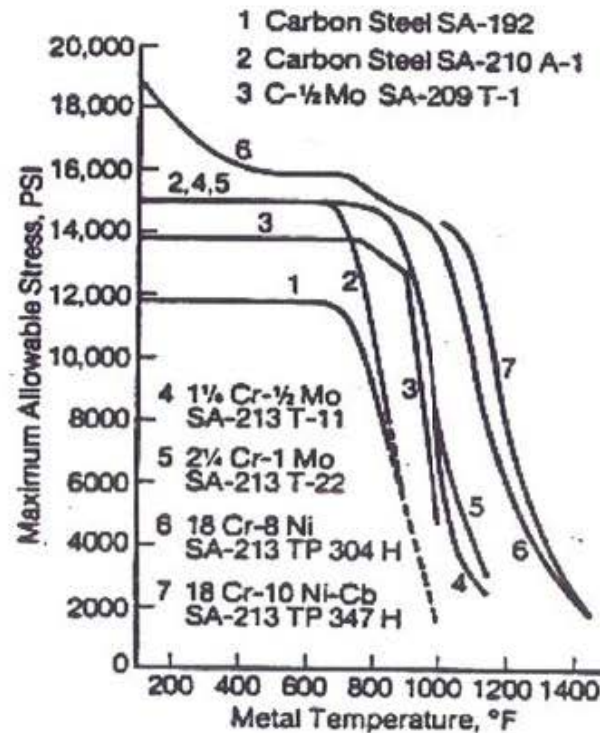
Long term overheat. Since different alloys can successfully operate at different temperatures the failure temperatures are specific to the alloy. The temperature table below is the point in which excessive oxidation will result.

Short-term overheating produces considerable tube deformation in the form of metal elongation and reduction in wall area or cross section. A fish-mouth type, longitudinal rupture with thin-edged fracture surfaces is typical for ferritic steel when it has failed before reaching its upper critical temperature. Other appearances are possible depending on the material and the extent of the overheated portion of the tube. (See photograph above).

Overheating is not detectable by normal NDE methods since the failure event results from sudden temperature rise and the metal degradation is rapid. Laboratory metallurgical examination of fracture surfaces and microstructure features can provide information pertinent to the failure investigation.

The root causes of overheating can be verified by investigating the coolant circuitry and combustion operating conditions. Removal of tubes may be necessary to examine for internal blockages or flow restrictions. Plant records may indicate that water level or circulation was lost by either equipment malfunction or operator error. Measurement of the tube metal and furnace gas temperatures may verify over firing or uneven firing. Model testing may be used to verify adequate flow rates and turbulence inside the tube.

Corrective actions involve measures to prevent blockages of tubes, control drum water levels, assure coolant circulation and reduce excessive firing rates. Redesign or relocation of inclined or horizontal tubing may be required to prevent film boiling which will contribute to this problem.



Effect of temperature on ASME Boiler Code allowable stresses for grades of steel tubing

Ligament cracking

Location

This condition occurs in tubes in thick wall devices like steam drum and headers.

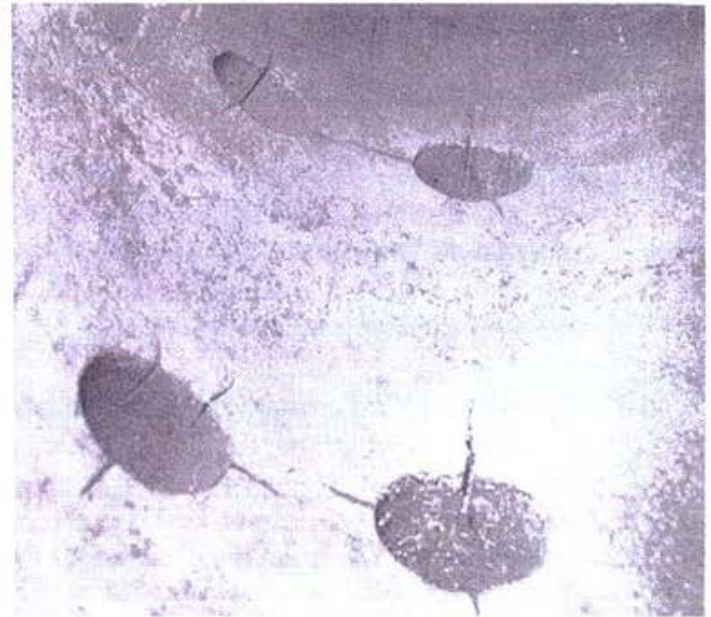
General description

There are three factors, relative to boiler operation, that influence ligament damage in high temperature headers: combustion, steam flow, and boiler load. Most boiler manufacturers design the boiler with burners arranged in the front and/or rear walls depending upon the size and capacity of the unit. Heat distribution within the boiler is not uniform: burner inputs can vary, air distribution is not uniform; and slagging and fouling can occur. Even if burners are optimized for equal firing, the temperatures of the combustion gases exiting the furnace are lower near the side walls than at the middle of the boiler. This occurs since the perimeter of the furnace is constructed of water cooled tubes and there is greater heat transfer from the combustion gases near those cooler wall tubes. Air distribution can also vary from side to side, across the unit, causing unbalanced flow of combustion gases exiting the furnace. On coal-fired and some oil-fired boilers, slagging and fouling occur causing biasing of combustion gas flow and uneven heat absorption in the furnace and convection passes. The net effect from these combustion parameters is to cause variations in heat input to the superheater and reheater.



Combined with the combustion parameters, the superheater and reheater experience differences in the steam flow in individual tubes within the bank. A tube carrying greater steam flow will experience less of a steam temperature increase than a tube with reduced flow, assuming equal heat is absorbed by both tubes. Spatial variations in gas temperature and tube-to-tube variations in steam flow can combine to result in significant variations in tube outlet leg temperatures entering the outlet headers. Since the overall bulk header temperature is close to the controlled outlet steam temperature, large temperature differences can occur at tube bore locations. As shown in Figure 7, a 70°F temperature difference between an individual outlet leg and the bulk steam temperature is not uncommon, even under normal base load conditions. It should be noted that on tangentially corner-fired boiler designs the combustion gases flow in a cyclonic path within the furnace. As a result more heat absorption is expected to occur toward the outside of the superheater such that the temperature distribution will vary from that shown in Figure 7. Figure 7 Steam temperature variations in a header. As a consequence of the through-wall temperature differences and the temperature differences between individual outlet legs and the bulk header steam temperature, the header experiences localized stresses much greater than the stress associated with steam pressure. Further, during increasing and decreasing load changes, the reversal of the through-wall temperature differences and the reversal of individual tube leg steam temperatures relative to the header cause reversal of corresponding stresses at the borehole penetrations. These increased and reversing stresses .

Boiler start-ups and shut-downs result in significant transient thermal stresses as a result of the steam temperature changes in the thick-walled headers. Changes in boiler load have the effect of further increasing the temperature difference between the individual tube legs and the bulk header temperature. As boiler load increases, the firing rate must increase to maintain pressure. During this transient, the boiler is temporarily over-fired to compensate for the combined effect of increasing steam flow and decreasing pressure. As a result there is a temporary upset in steam temperature from individual tube outlet legs relative to the bulk header temperature. During load decreases the opposite occurs; firing rate decreases slightly faster than steam flow in the superheater with a resulting decrease in tube outlet temperatures relative to the header bulk temperature



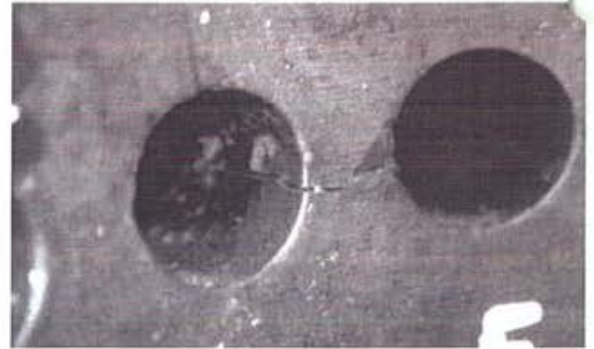
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External Appearance

Internal Appearance:

Cause

Too rapid start up or too rapid cooling during startup and shut down. During cold start up of the boiler the superheater headers are subject to humping as a result of top-to-bottom temperature differences.



Operations have a great impact on the longevity or failure of pressure parts. This comes from operational practices that contribute to reduced time to failure.

In the case of water lances or water cannons the results will be quench cracking as well as thinning.

Prevention \ Correction

Acceptable repairs

Ligament (or borehole) cracking is a significant, life-limiting problem in headers subjected to elevated temperature service. Ligament cracking is most frequently found in secondary or finishing superheater outlet headers. Ligament cracking generally initiates as numerous longitudinal cracks in tube bore holes. These cracks extend (either initially or eventually) to the inside surface of the header, appearing as a "starburst" pattern when viewed from the inside of the header; Some of these cracks continue to grow along the inside surface of the header, eventually linking up with similar cracks emanating from adjacent tube bore holes. These cracks continue to propagate, growing simultaneously from the header ID toward the OD and between adjacent bore holes.

Inspection techniques

Assessment of the high temperature headers most often focuses on nondestructive examination and testing (NDE/NDT) followed by evaluation of the NDE/NDT results.

Phase I - Pre-Outage Planning

1. Review operation and maintenance history
2. Review design characteristics
3. Perform preliminary analysis if required
4. Establish outage inspection/test plan NDT procedures i.e.;
 - a. Magnetic Particle testing
 - b. Dye Penetrant testing
 - c. Ultrasonic testing
 - d. Eddy Current Testing
 - e. Radiographic testing
 - f. Non destructive Oxide Thickness Inspection Service (NOTIS)
 - g. Metallographic replications
 - h. Borescope
 - i. Dimensional measurements
 - j. Visual examination
 - k. Alloy Analysis (nuclear alloy analyzer instrument)
 - l. Boat sample

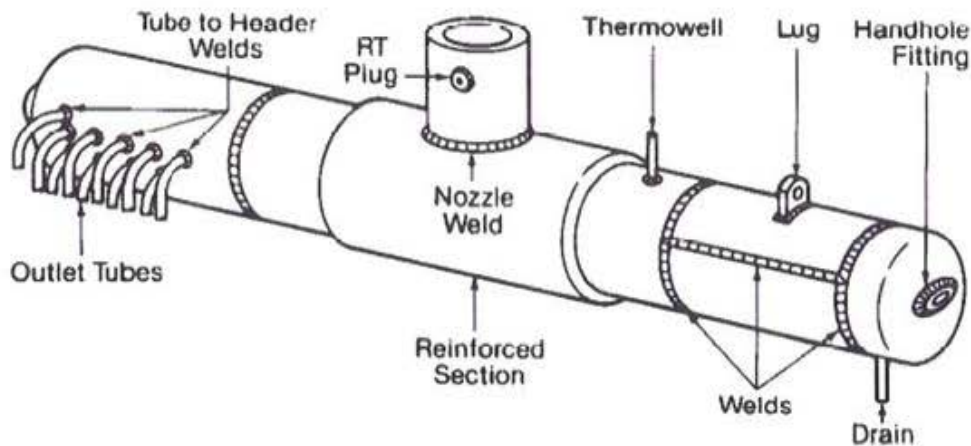
Phase II - Outage

1. Implement inspection/test plan
2. Perform root cause analysis as needed to ensure all necessary data is obtained during the outage. Install instrumentation to support online testing if required by the phase I plan or for root cause analysis.

Phase III - Post Outage Testing and Engineering Analysis

1. Perform final remaining life analysis
2. Conduct operational testing and analysis as required

Develop recommendations for follow up - repair, replace, or re-inspect based upon the analysis

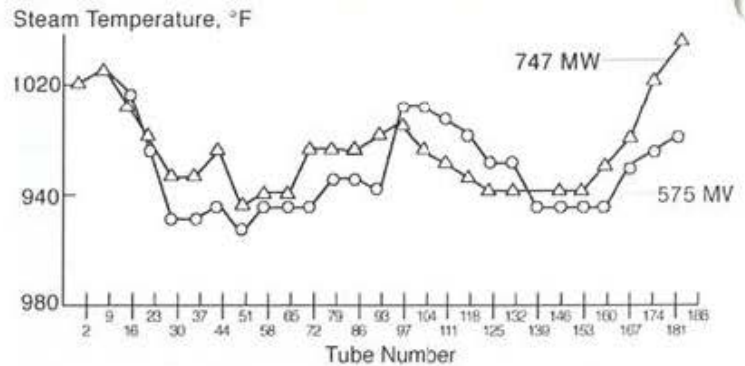


Inspection case history

See below in metallurgical considerations

Metallurgical characteristics

In this case history none of the sites replicated exhibited creep degradation. All replicated microstructures were similar, exhibiting spheroidized carbides in a decarburized ferrite matrix. Replications are only OD surface inspections. The absence of creep degradation, and the spheroidized carbide in a ferrite matrix microstructure, was confirmed through subsequent metallographic micro examination of the ligament crack boat sample. The ligament crack was created by two transgranular thermal fatigue cracks initiating from inside the header at the respective borehole penetrations, which subsequently propagated together. The ligament crack was oxide filled and exhibited little overall distortion. The ligament crack grew completely through the header from ID to OD. Additional fatigue cracks are also evident 180° opposite of the ligament crack, that is, across the bore holes. Circumferential cracking is as expected from the applied loading. Cyclic stresses exceeded the endurance limit of the P22 header material causing the ligament cracking failure. Elevated temperature exposure (1100°F to 1150°F), the number of cycles of start-up and shut-down, plus potentially unbalanced header supports, cracked the high-temperature reheat header (HRH). After cracking repairs, the high-temperature reheat header (HRH) material remains metallurgically sound for further service deployment since time and temperature creep degradation is not yet evident.



As seen in the chart above the temperature profile across any superheater or reheater can fluctuate from side to side. In these locations where the temperature is spiked up will be the most likely place this damage will be seen.



Figure 1. Tube location 63 of Unit #4 high-temperature reheat header (HRH) that experienced ligament cracking.

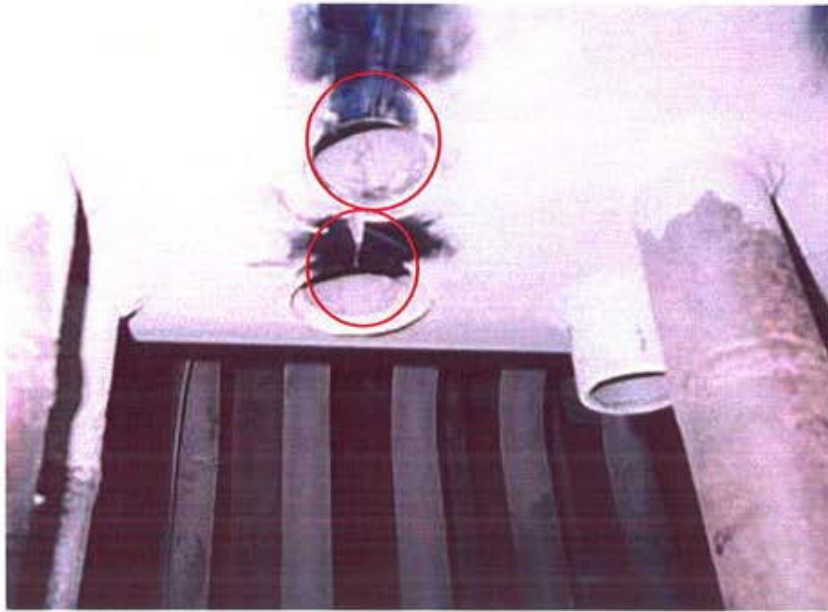


Figure 2. Sliver is missing from the ligament crack. Sites prepared to perform replications. Bore hole cracking is evident. Additional cracks are also evident 180° opposite of the ligament crack, that is, across the bore holes.

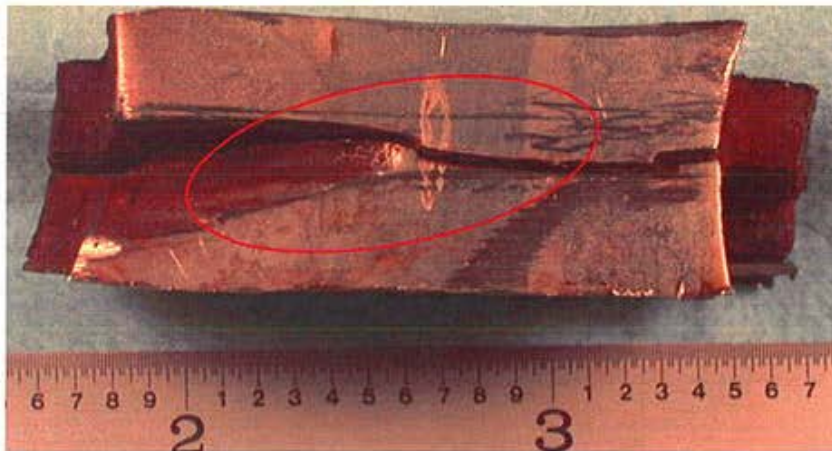


Figure 3. Cracked ligament boat sample at Tube 63 location. Circled area presents wedge that fell out of fracture when tubes were removed from the boreholes. Boat sample fell apart when removed from header.

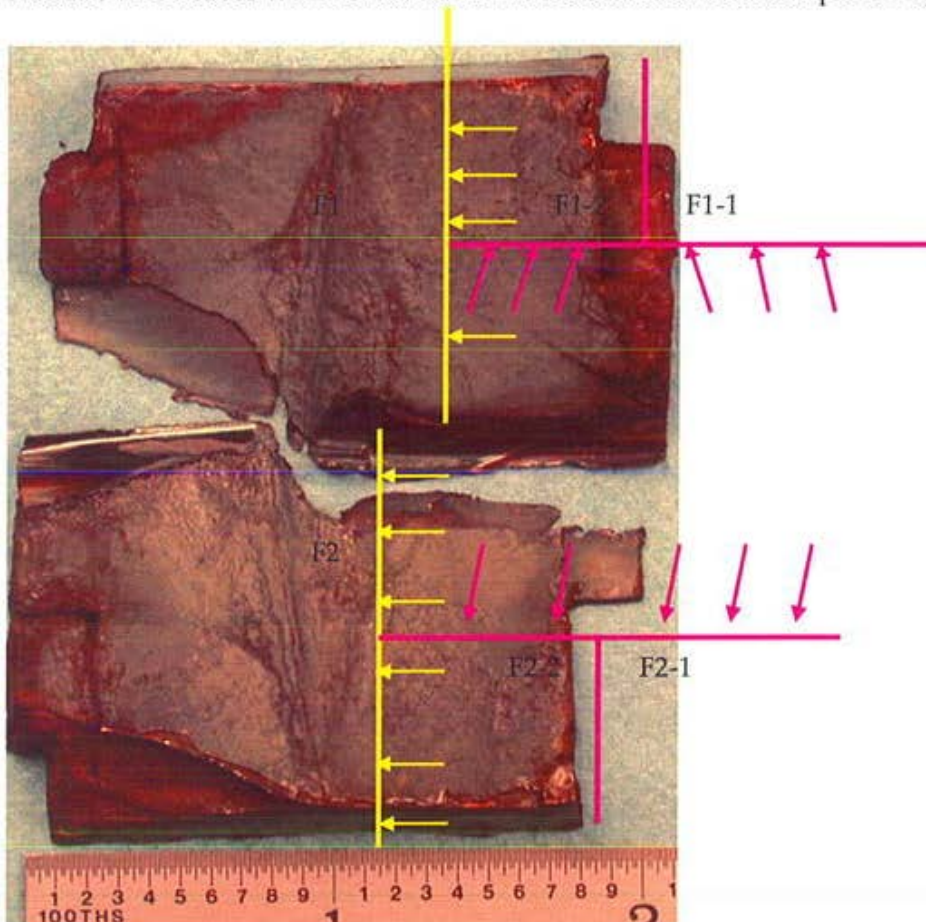


Figure 4. Cracked ligament boat sample with sample extraction locations illustrated. Samples were taken parallel and perpendicular to the boreholes.

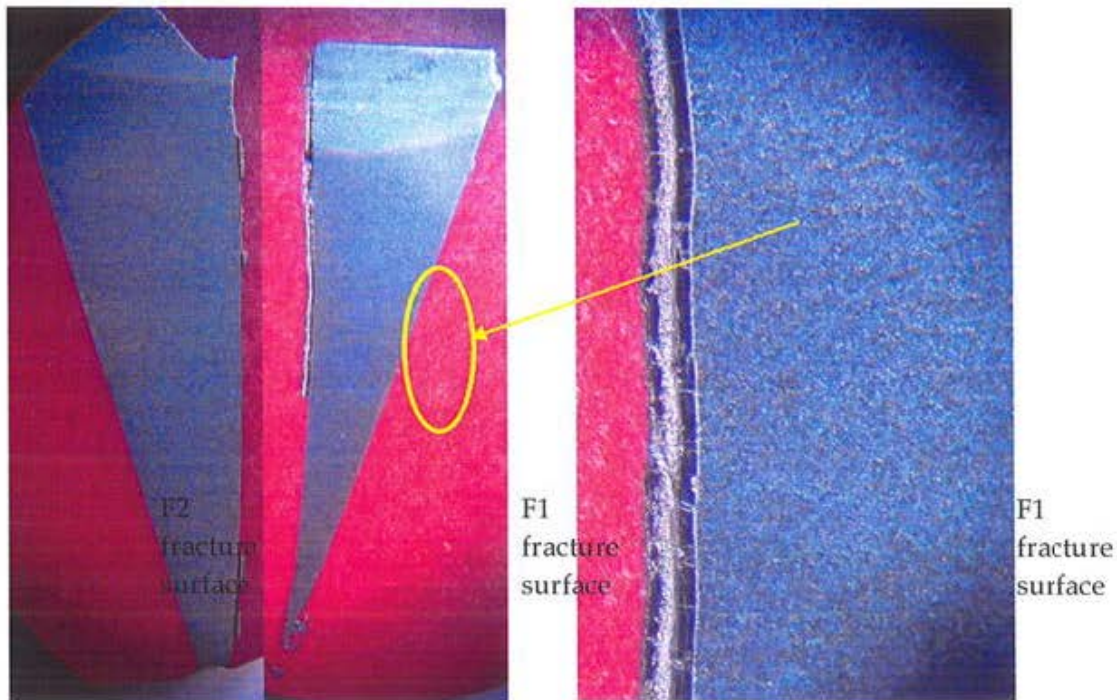


Figure 5. Stereoscopic view of boat sample parallel to the boreholes. Oxides were present on the fracture surface measuring 15 mils thick. 3.25x and 17x magnifications.

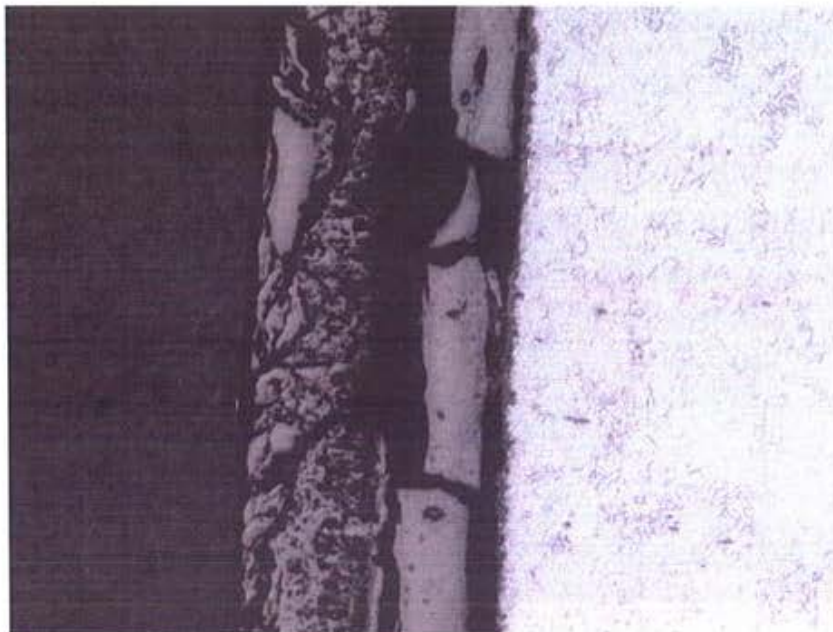


Figure 6. F1 – Fracture surface exhibits a transgranular oxide-filled fracture surface, typically seen with thermal fatigue. No creep was observed. Material is SA-335-P22. 100x magnification, nital etch.

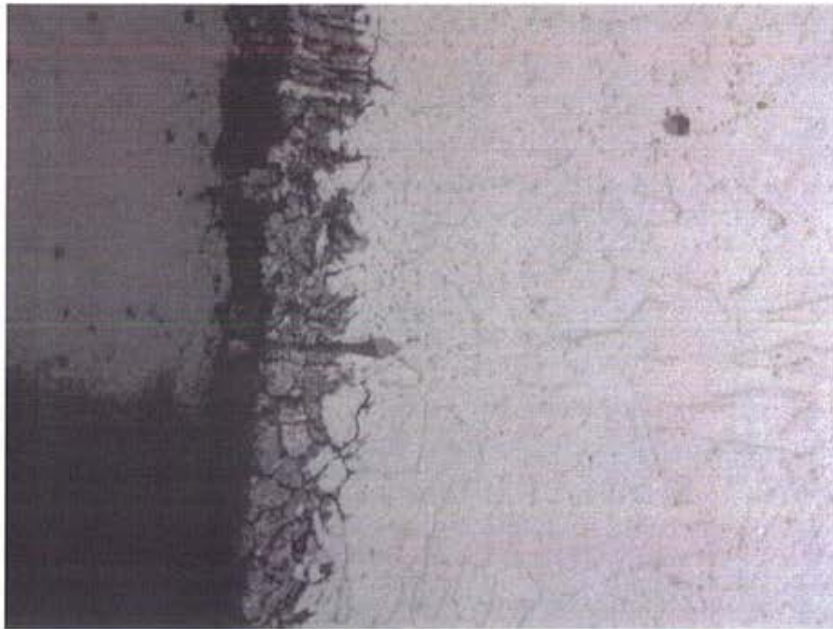


Figure 7. F1 – Fracture surface exhibits a transgranular oxide-filled fracture surface, typically seen with thermal fatigue. Microstructure consists of spheroidized carbides in a ferrite matrix. Material is SA-335-P22. 800x magnification, nital etch.

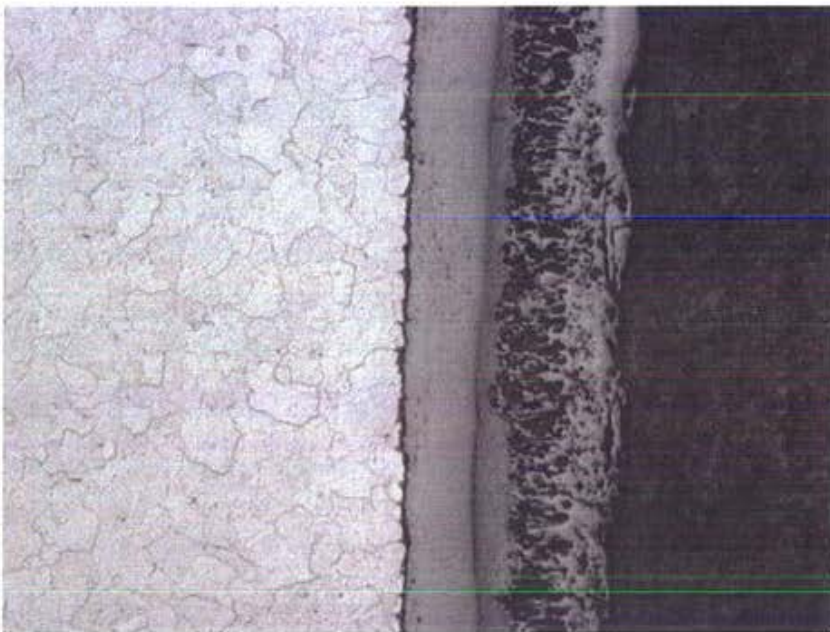


Figure 8. F2 – Fracture surface exhibits a transgranular oxide-filled fracture surface, typically seen with thermal fatigue. Creep is not observed. Material is SA-335-P22. 100x magnification, nital etch.

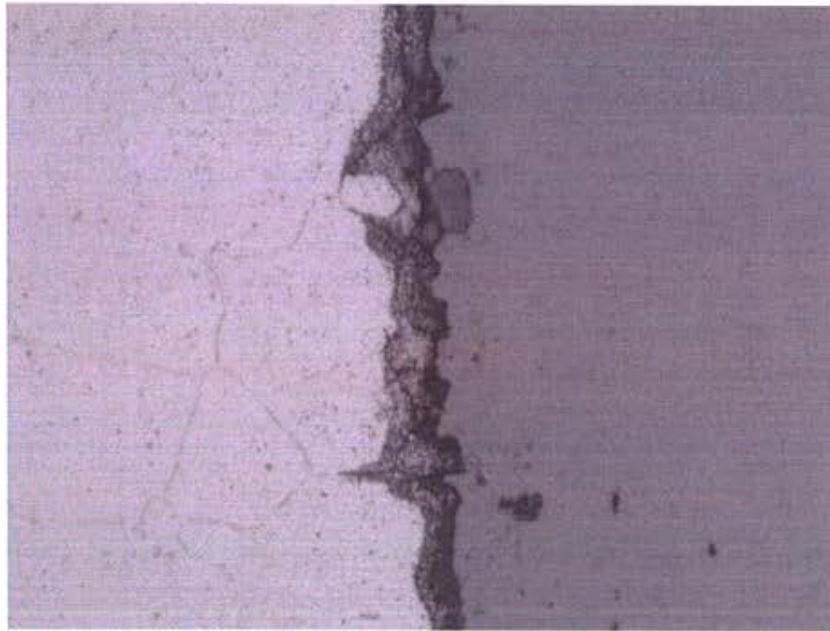


Figure 9. F2 – Fracture surface exhibits a transgranular oxide-filled fracture surface, typically seen with thermal fatigue. Microstructure consists of spheroidized carbides in a ferrite matrix. Material is SA-335-P22. 800x magnification, nital etch.

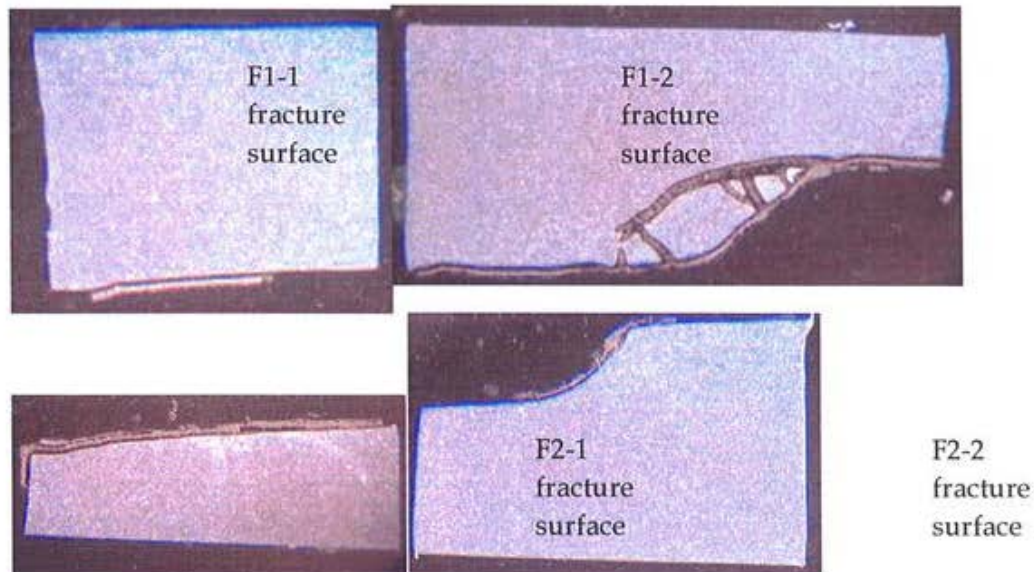


Figure 10. Stereoscopic view of boat sample perpendicular to the boreholes. Oxides were present on the fracture surface measuring 15 mils thick. 4.5x magnification.

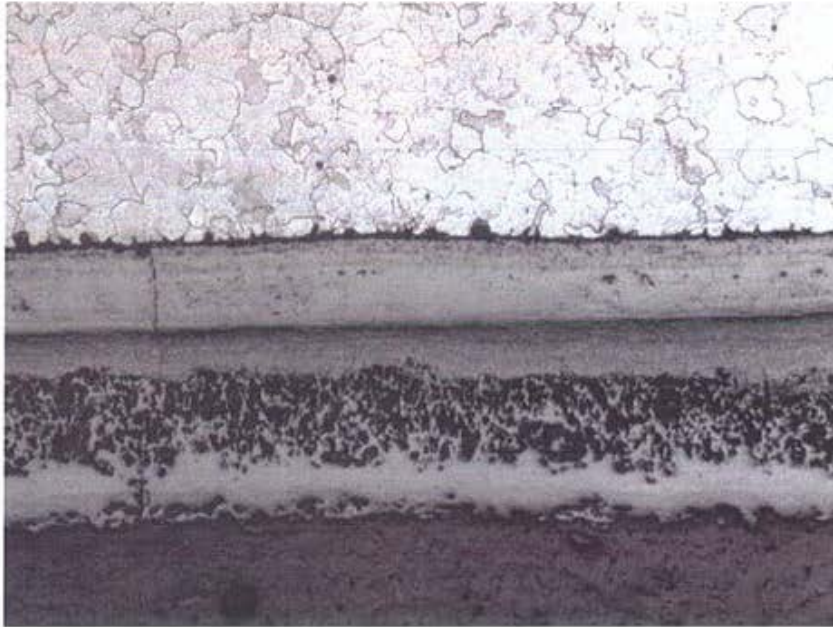


Figure 11. F1-1 – Fracture surface exhibits a transgranular oxide-filled fracture surface, typically seen with thermal fatigue. Creep is not observed. Material is SA-335-P22. 100x magnification, nital etch.

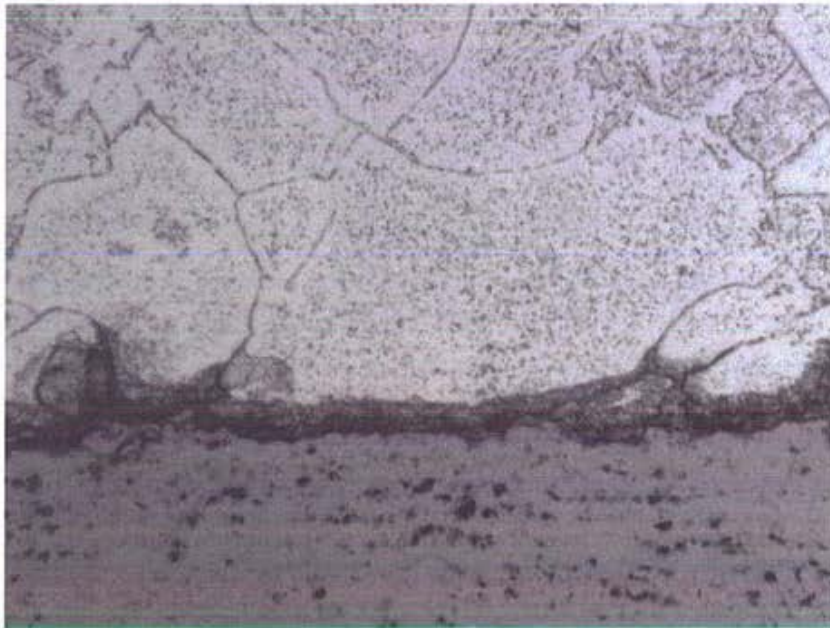


Figure 12. F1-1 – Fracture surface exhibits a transgranular oxide-filled fracture surface, typically seen with thermal fatigue. Microstructure consists of spheroidized carbides in a ferrite matrix. Material is SA-335-P22. 800x magnification, nital etch.

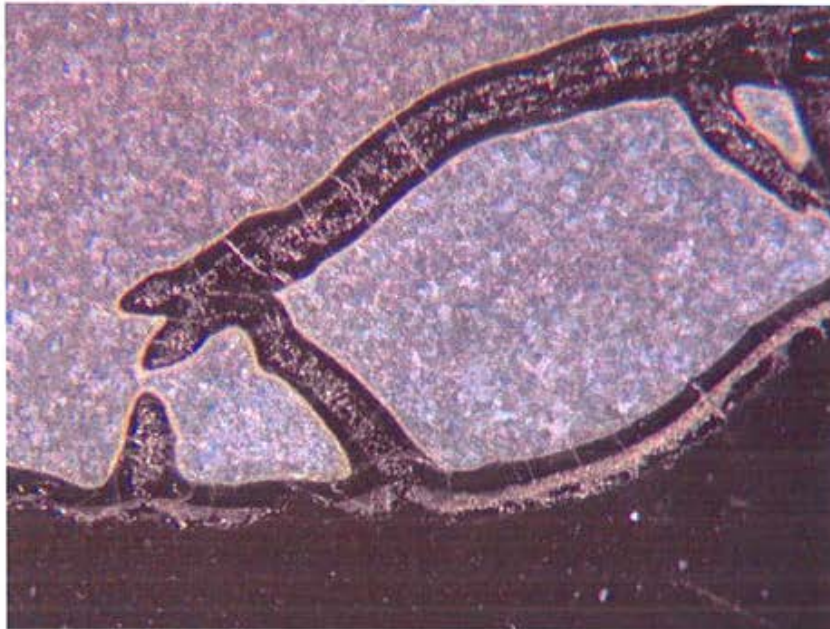


Figure 13. F1-2- Presents a closer view of the intersection point where the fatigue cracks met in the center of the ligament between boreholes 62 and 63. Transgranular, dagger shaped, oxide-filled cracks are present. 27x magnification.

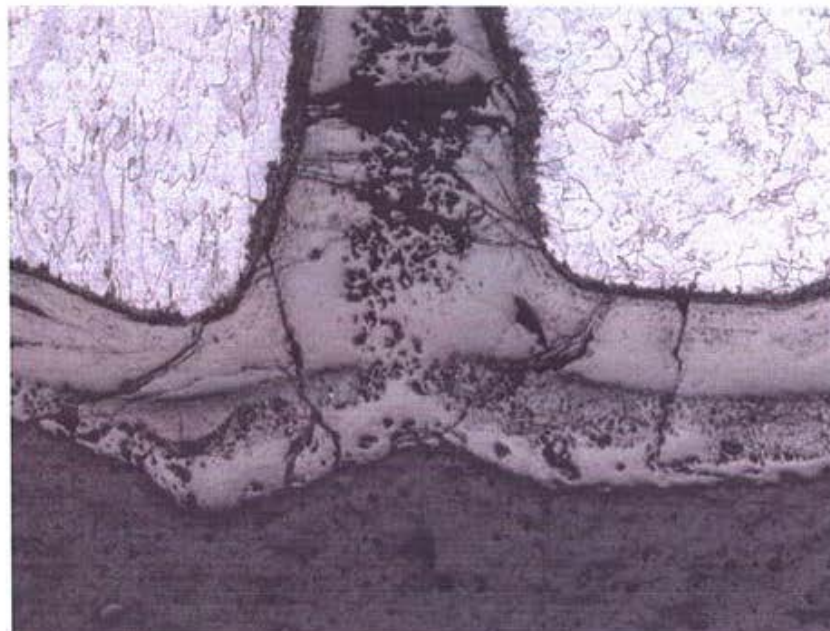
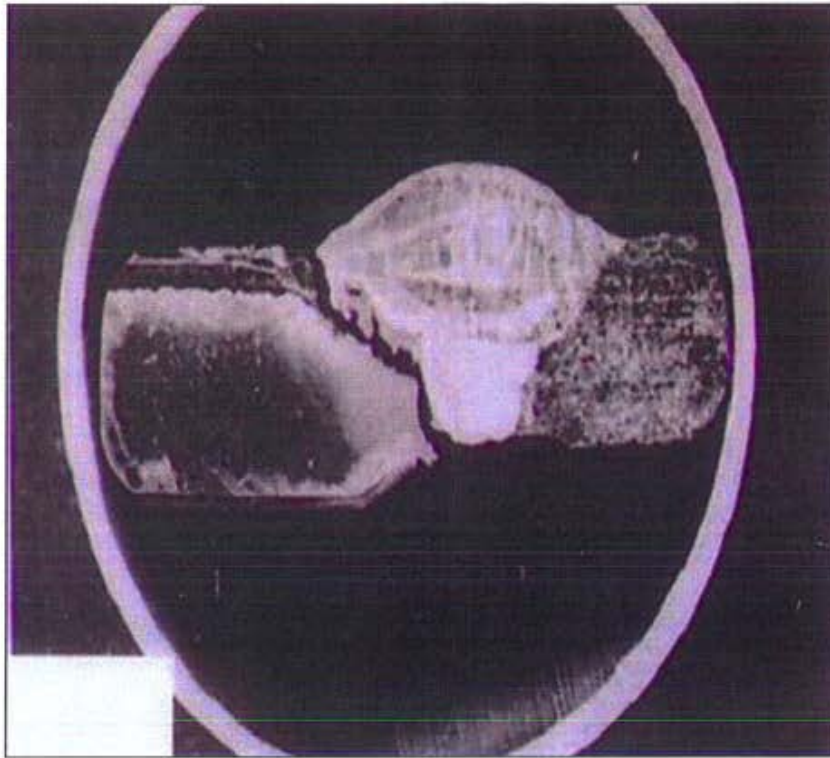


Figure 14. F1-2 – Fracture surface exhibits a transgranular oxide-filled fracture surface, typically seen with thermal fatigue. Creep is not observed. Material is SA-335-P22. 100x magnification, nital etch.

DISSIMILAR METAL WELD (DMW) CRACKING



Dissimilar metal weld failure; note the failure is on the ferritic side (T-22 in this example) of the weld.

COMMENT:

Dissimilar metal weld (DMW) cracking is caused by the application of temperatures and stresses that exceed the expected values and accelerate the creep process. The total stress applied to the joint includes stresses that arise from differences in the coefficient of thermal expansion; from internal steam pressure, tube dead weight, and through-wall thermal gradients; and from constraints to thermal expansion due to tube support malfunction. Variations in the lifetime of the joints are directly related to cycles of boiler operation.

LOCATION:

Dissimilar metal weld cracking can occur in superheater and Reheater tubing at weld joints that:

- (1) Have been exposed to temperatures exceeding the expected or design values.
- (2) Have been exposed to stresses exceeding the expected or design values.

Stresses are from intrinsic loads, primary loads, and secondary loads.

EXTERNAL APPEARANCE:

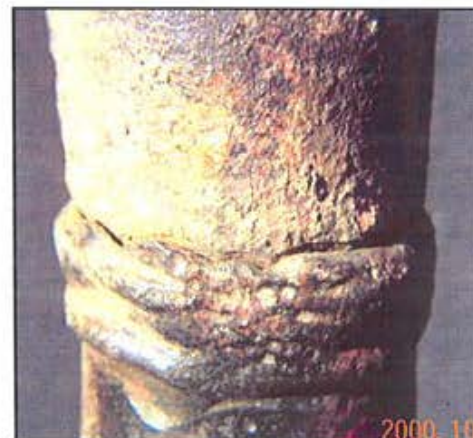
Cracked circumferentially

INTERNAL APPEARANCE:

Dissimilar metal weld cracking produces a circumferential fracture in the joint. The fracture is parallel to the weld fusion line in the ferritic steel.

The fracture surface will have a shape like weld beads and appear as though the ferritic steel had not been fused to the weld metal.

Initiation of the crack can occur anywhere along the fusion line. A brittle, thick-edged fracture results from the linking up of creep voids adjacent to carbide precipitates along the grain boundaries.



PROBABLE CAUSE:



The root causes of DMW cracking can be verified by determining the actual operating temperature and applied stresses experienced during the service lifetime. A technique is being developed to quantify the amount of damage that has occurred in a weld due to excessive temperature and stresses.

Dissimilar metal weld cracking produces a circumferential fracture in the joint. The fracture is parallel to the weld fusion line in the ferritic steel.

Radiographic and ultrasonic methods have been applied to detect cracking in dissimilar metal welds made with iron base filler metals.

The specific techniques used require careful interpretation since other weld defects and geometries can also produce NDE indications. Representative tube sampling may be required to determine if incipient damage is present.

Stress and temperature are the critical factors; improved DMW performance can be obtained by controlling these factors. The weld joint can be relocated to a position at a lower temperature. Nickel base



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filler metal can be used to lower the stress from differences in thermal expansion. Frequent inspection and maintenance of tube hangers, supports, and spacers can be performed to reduce secondary loads.

CORRECTIVE ACTION:

Radiographic and ultrasonic methods have been applied to detect cracking in dissimilar metal welds made with iron base filler metals. The specific techniques used require careful interpretation since other weld defects and geometries can also produce NDE indications. Representative tube sampling may be required to determine if incipient damage is present.

Stress and temperature are the critical factors; improved DMW performance can be obtained by controlling these factors. The weld joint can be relocated to a position at a lower temperature. Nickel base filler metal can be used to lower the stress from differences in thermal expansion. Frequent inspection and maintenance of tube hangers, supports, and spacers can be performed to reduce secondary loads.

REPAIR PROCEDURES:

Replace before failure occurs. Utilization of a safe end for this purpose is recommended. Safe ends are fabricated with a carbon steel end and a stainless steel end joined together with a Inconel weld.

Leaks may be re welded using 309, see repair section of this manual.





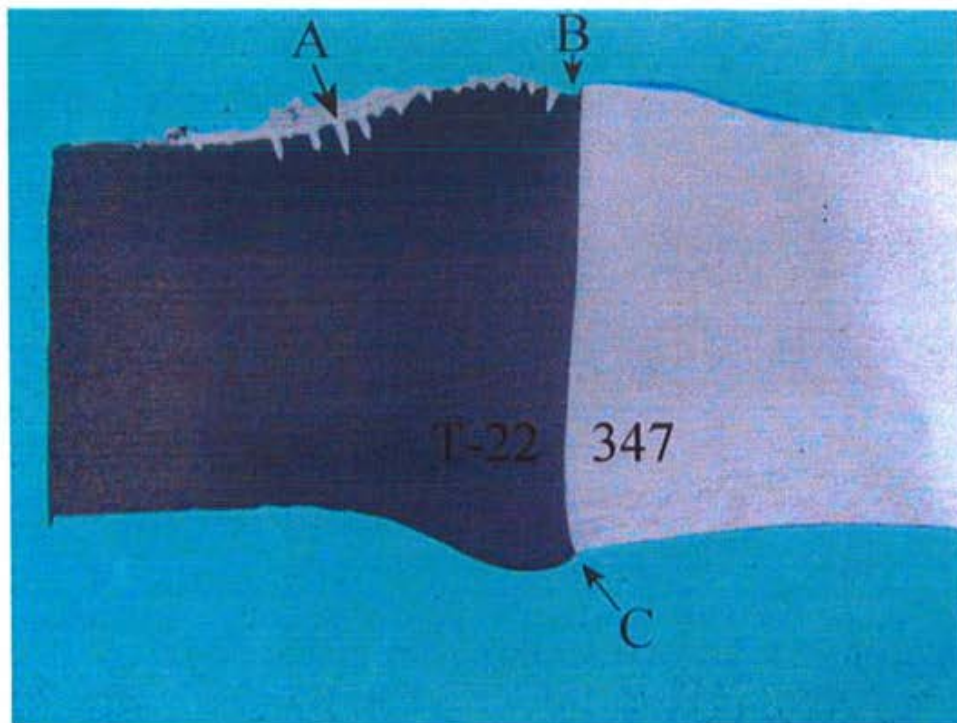
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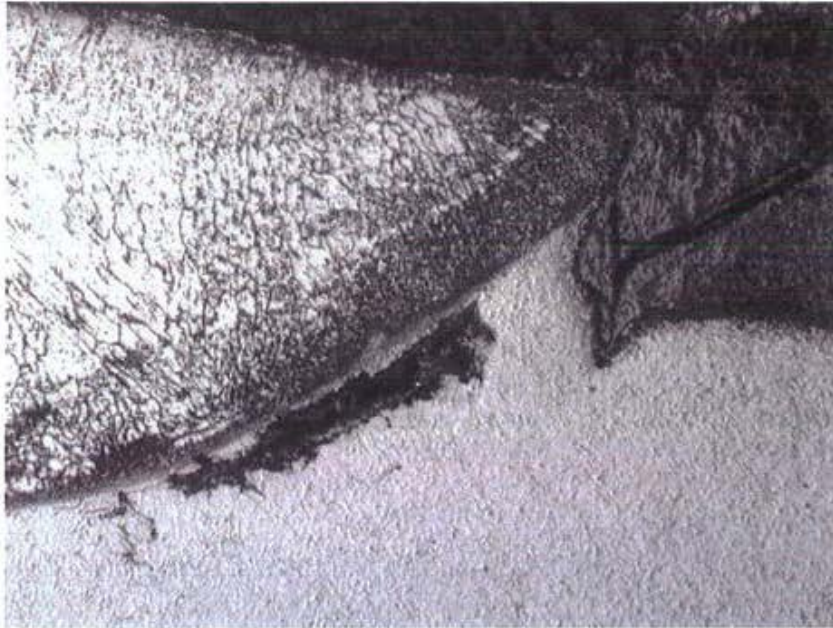
Inspection case history

Metallurgical characteristics

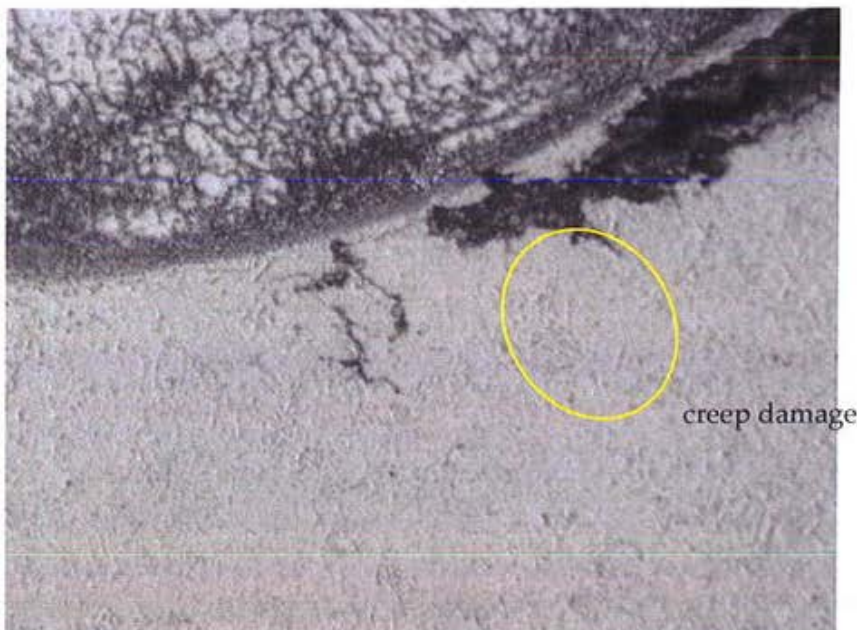
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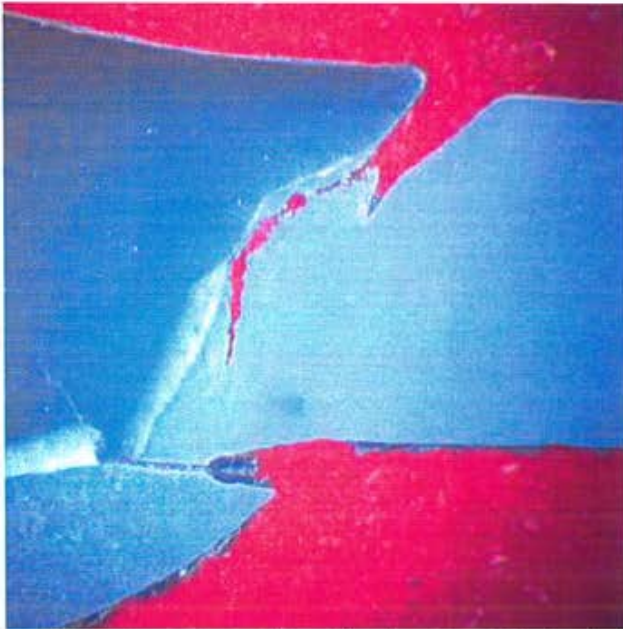




6 o'clock. Oxide wedge growing along the weld fusion line. Magnification 100x. Nital etched. Stainless steel weld metal on Cr. 2 (T22) chromium-molybdenum low-alloy steel.



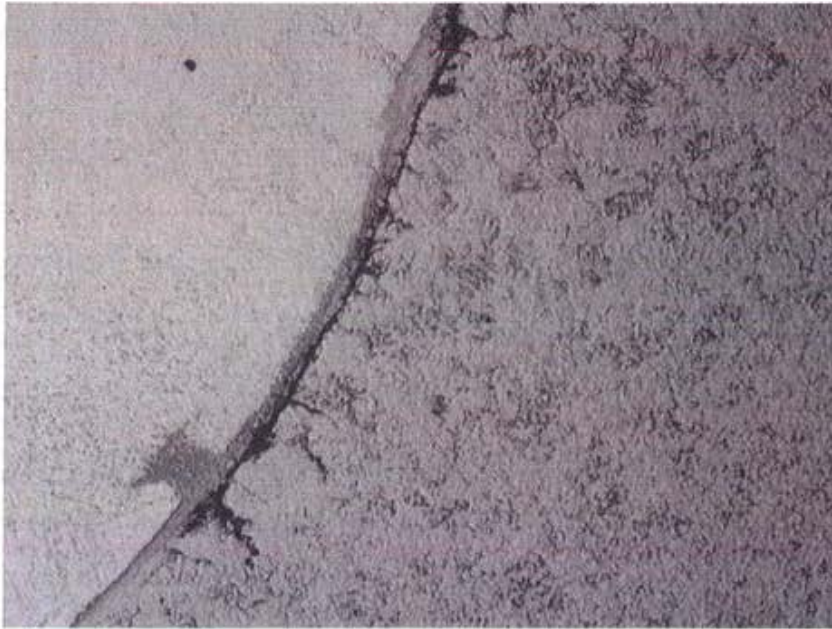
6 o'clock. Localized creep damage near oxide wedge growing along the weld fusion line found during examination of 16 micros from 4 tubes at 4 clock location. Magnification 200x. Nital etched. Stainless steel weld metal on Cr. 2 (T22) chromium-molybdenum low-alloy steel.



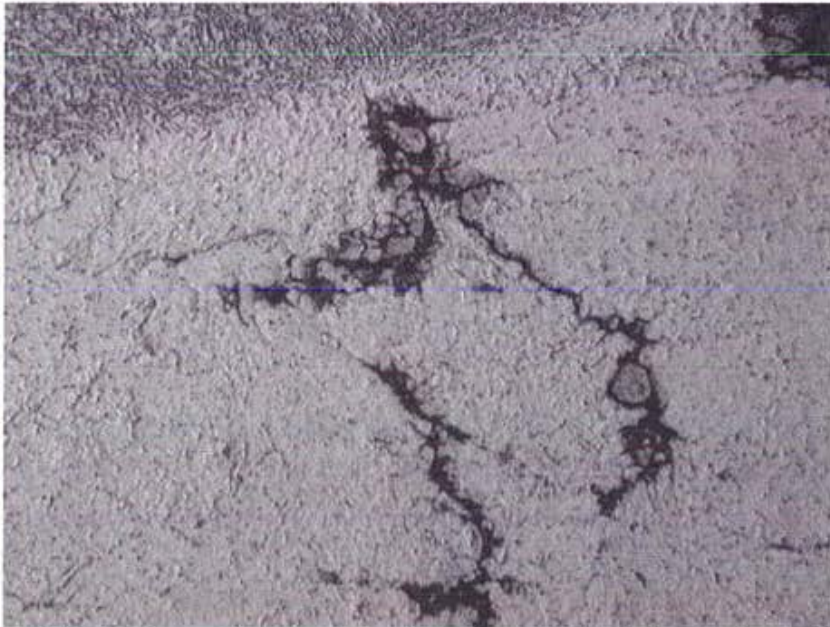
weld cross-section. Magnification 7x. Nital etched. Stainless steel weld metal on Cr. 2 (T22) chromium-molybdenum low-alloy steel.



nipple-tube weld cross-section. Creep damage. Magnification 100x. Nital etched. Stainless steel weld metal on Cr. 2 (T22)



nipple-tube weld cross-section. Creep damage. Magnification 100x. Nital etched. Stainless steel weld metal on Cr. 2 (T22) chromium-molybdenum low-alloy steel.



6 o'clock. Creep damage. Magnification 800x. Nital etched. Stainless steel weld metal on Cr. 2 (T22) chromium-molybdenum low-alloy steel.

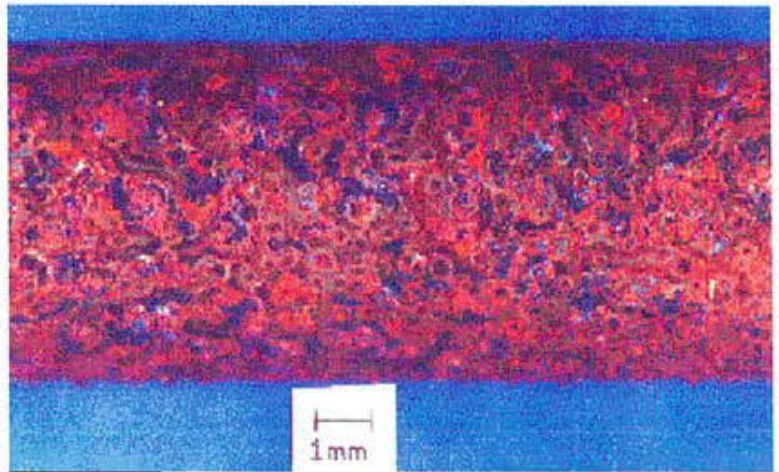
Low load operation

General Discussion

Low temperature corrosion can occur at locations in the economizer that:

- (1) Have boiler tube metal temperatures below the acid dew point, so that condensate will form on the metal.
- (2) Have flue gas temperature below the acid dew point, so that condensate will form on the fly ash particle.

Low temperature corrosion is caused by the formation and condensation of sulfuric acid from the flue gases. The amount of sulfur trioxide formed in the combustion process is an important factor since an increase in the SO_3 concentration results in an increase in the acid dew point temperature. Low temperature corrosion is a more significant problem in oil-fired boilers than in coal-fired boilers due to the vanadium in the oil ash deposits and the smaller quantity of constituents.



The root causes of low temperature corrosion can be verified by determining the acid dew point temperature, which is defined as the temperature at which the combustion gases are saturated with sulfuric acid. The acid dew point varies directly with the amount of SO_3 in the flue gas. The metal and gas temperatures in the economizer can be measured to ascertain that they are above the acid dew point obtained during the various phases of boiler operation.

Low temperature corrosion produces tube wall thinning that eventually results in ductile rupture of the steel. A thin-edged fracture surface is produced when the load-carrying ability of the steel is exceeded. The external surface will have a gouged appearance where the corrosion activity has occurred.

Specific failures caused by low load operation

DEW-POINT CORROSION

The combustion of most fossil fuels, natural gas being one exception, produces flue gases that contain sulfur dioxide, sulfur trioxide and water vapor. At some temperature, these gases condense to form sulfurous and sulfuric acids. The exact dew-point depends on the concentration of these gaseous species, but it is around 300oF. Thus surfaces cooler than this temperature are likely locations for dew-point corrosion. Any point along the flue-gas path, from combustion in the furnace to the top of the chimney, is a possible site. Any flue-gas leak can also cause this type of corrosion.

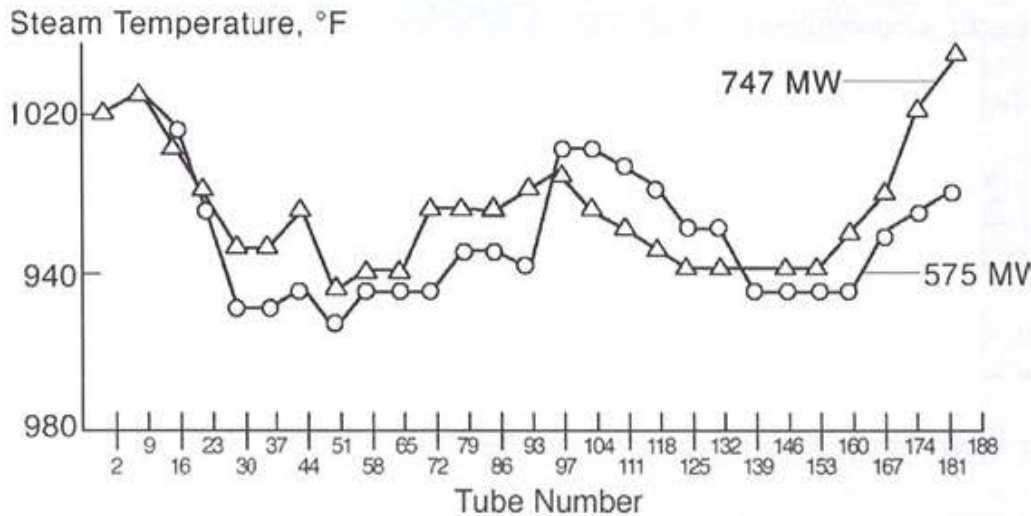
The obvious locations are openings to the furnace, support penetrations through the roof, leaks around superheater, reheater and economizer penetrations, and, of course, and the air preheater. In boiler terminology, "acid dew-point" refers to the sulfuric-acid dew-point, as this is the highest dew-point temperature. Both sulfurous acid and hydrochloric acid condense at lower temperatures. For hydrochloric acid, the dew-point may be as low as 130oF. While the precise dew-point for sulfuric acid depends on the sulfur-trioxide concentration, at 10 parts per million sulfur trioxide in the flue gas, the dew-point is 280oF.



Dew-point corrosion is exacerbated in coal-fired boilers by the presence of fly ash. Fly ash accumulates throughout the flue-gas path, and the resultant deposit acts like a sponge to collect both moisture and acid, especially during shutdown cycles.

One other corrosion problem associated with oil ash is the potential for acid corrosion following water washing. While strictly speaking this is not a dew-point corrosion, a solution of oil ash in water does result in an acid pH. Thus, unless these salts are neutralized, a strong acid forms in the wash water just before it evaporates to dryness. To prevent fireside pitting corrosion during water washing, the final rinse should be a basic solution. The most common and least expensive is washing with soda (sodium carbonate) dissolved in water. Such a solution will neutralize the acids in the oil ash and prevent pitting.

Operational upsets



Operations have a great impact on the longevity or failure of pressure parts. This comes from operational practices that contribute to reduced time to failure.

Some of these include:
Over blowing
(frequency) of the soot blowing system. By over blowing the soot

blower system we will remove tube metal by accelerated particle erosion thinning the tubes prematurely.

In the case of water lances or water cannons the results will be quench cracking as well as thinning.

Under blowing (frequency) of the soot blowing system. If the blower system is under blown the area affected will accumulate ash and lead to:

- Poor heat transfer as the surfaces are covered with ash or slag.
- Slagging which will result in an uneven gas flow over the heat transfer surfaces. This stratification can lead to uneven tube metal temperatures. This difference in tube metal temperatures can lead to premature overheating failures
- Increased fly ash erosion. The velocity of the flue gases will pick up the loose ash and drive it into the adjacent tubes. This will thin the tubes and lead to thin wall tube failure.



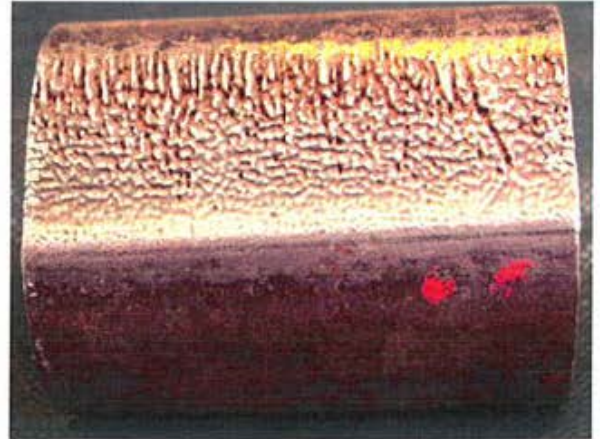
Over pressurization of the soot blowing system will cause excessive cleaning which will result in thinning of the tubes due to accelerated particle erosion of the tubes. By over pressurization of the soot blower system we will remove tube metal by accelerated particle erosion thinning the tubes prematurely.

Under pressurization of the soot blowing system (see under lowing frequency above).

High superheater / reheater temperatures causes reduced life in the tubes and headers. This will significantly reduce the life of these components.

Improper drum level control. Since the drum acts a water distribution device as well as steam separator, low level will usually produce waterwall overheating and failures.

In adequate feed water heating. If the feed water is not adequately heated (heater) then the water walls have to make up the difference. Over time this will result in a higher heat flux in the water walls and result in overheated tubes.



Improper operation of Deaerator system will result in the potential for O₂ in the feed water. This will result in pitting of the ID of the tubing.

Water not drained from soot blower system will cause increased erosion of tubing leading to failure.

Poor burner performance can result in:

- Flame impingement causing overheating of the tubing at the point of impingement.
- Low oxygen firing (sub stoichiometric) can cause increased fireside corrosion.
- Localized high heat flux, resulting in the potential for overheat and exacerbation of waterside deposit corrosion.

Poor mill performance (see Poor burner performance)

Start up / shut down thermal ramp violated.

If the boiler is started /stopped too quickly (cold to load to cold) stress and cracking will occur in the steam drum and headers.

If the condensate is not boiled away from the superheater / reheater lower loops it will restrict cooling flow and overheat and possible failure will result.

Operating above MCR (maximum continuous rate) will cause increased fly ash erosion in the convection pass.

Failure conditions caused by soot blower misuse

SOOTBLOWER (Wall & Retractable) EROSION

COMMENT:

Soot blowers are the principal means of controlling fireside deposits in boilers. This accumulation of fireside deposits can significantly affect heat rate, even in some cases where the deposits are present in only a thin layer on the boiler surfaces. In addition to thermal efficiency, the effects of ineffective boiler cleaning can include boiler stability (steam temperature control), particulate emissions, and boiler tube erosion. Of particular interest is the impact of fuel variations, fuel switching, and fuel blending.

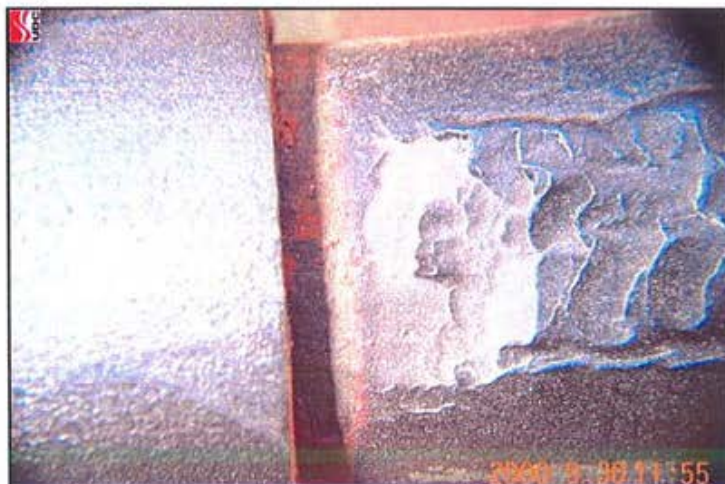
LOCATION:

Soot blower erosion occurs in a direct path of a wall blower or retractable Soot blower discharge.

In the furnace area where there is direct impingement from wall blowers near Furnace corners, slope areas and division walls, any tube or tubes bowed out of plane allowing exposure to the soot blower. Look at any intersection of tubing in line with the discharge path of a soot blower.

Usually the first tubes adjacent to the soot blower opening where condensate will first vent. Inside opening tubes for pre blow or blowing of the soot blower before it clears the tube wall.

In the direct path of retractable soot blowers in the hottest (outlet) sections of adjacent reheaters or superheaters.



In any location the soot blower can drive wet steam or fly ash. This would include economizers, superheaters, and reheaters both vertical and horizontal in orientation.

EXTERNAL APPEARANCE:

Appearance may be a planed or smooth effect and may contain some wavelike contours aligned perpendicularly to the steam flow. The tube will usually appear with a flat side. (See the photo.)

PROBABLE CAUSE:

Improper location or operation of a soot blower causes soot blower erosion or malfunction of the soot blowing system. Operation of the blowing system with condensed water in the media or with a pressure that injects a large amount of ash at a high velocity blower that is inserted incorrectly, stuck in one position, or too close to a corner or wall protrusion can result in accelerated tube wear.

The blower may cause a high velocity stream carrying condensed water droplets directly to tube surfaces. This causes physical abrasion and accelerated oxidation resulting in metal loss. Fly ash entrained in the stream will aid in erosion thinning to rupture.

- A malfunctioning condensate removal system in the steam supplies.
- Poor alignment of adjacent tubing.
- Pre blow of the soot blower.
- In adequate shielding.
- Stuck in one position.
- Missing or damaged blower lance head.

Visual examination and ultrasonic (UT) tube wall thick-ness measurements are used to detect and monitor soot-blower erosion. Visual examination can reveal signs of polishing but UT thickness surveys are necessary to determine the amount of wall reduction. UT surveys should be conducted after a tube failure to determine the extent of damage and to provide data for planning corrective actions.

CORRECTIVE ACTION:

Corrective actions involve surveillance and improved maintenance of soot blowers and soot blower system. Visual examinations of soot blower operation and calibration of system components during boiler over-haul periods provide long-term actions for the prevention of failures by soot blower erosion.

The root cause of soot blower erosion can be verified by investigating the operation of the soot blower device or the soot blower system.

Malfunction or misalignment of the soot blower device can be revealed by visual means.

Malfunction of the system can be detected by measuring blowing pressure, testing moisture traps, or checking travels and sequences times.



REPAIR PROCEDURES:

Replacement is the repair of choice.

Shields may be installed (non furnace areas) to prevent erosion.

In many cases blocking the medium that is causing the erosion can arrest thinning. This is true only if the pressure boundary has not been reduced to an action level more severe such as replacement or pad welding. You should utilize clear and concise criteria for established this action level.



a. Tube shields should be 210° to 225° circumferentially instead of 180° to allow the shield to actually clamp onto the tube helping it to remain in place longer. (Figure 1)

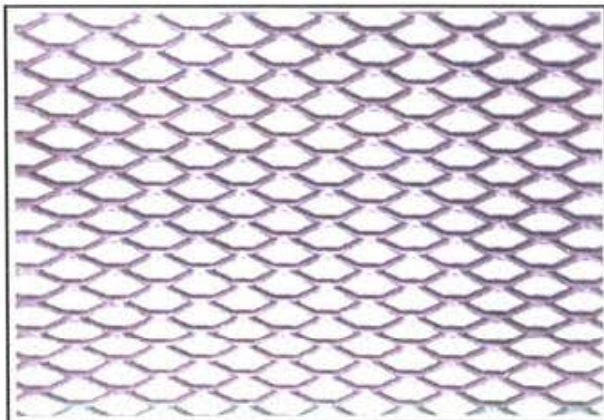
b. Tube thickness and material should be:

Up to 1750° F. inclusive 14 gauge SS AISI type 304 (2) Over 1750°F. 10 gauge SS AISI type 309 or 310

c. Tube shields should be limited in length to 18" to 24". Longer shields tend to warp and distort and will break away from the tube. If longer sections are needed they should overlap approximately 1" starting from the bottom and working up.

d. Tube shields should only be attached to clean tubes. Clean tubes actually help to cool the shield while a tube with slag may cause the shield to overheat sooner.

e. Tube shields should be attached to the tube by 1" wide straps on 6" - 8" centers. Through experience we have found that the durability of the shield is improved if the clips were attached with a GTA weld using bare filler wire. Each shield should then be welded to the tube in one spot to secure it and to allow for thermal expansion.



f. In cooler areas of the boiler tube shields can be attached using straps less than 1" or no strap at all and use a 1-1/2" stitch weld on each side.

g. In some cases, tube shields may not be the best solution. Lowering sootblower pressures, repairing traps, or installing baffles may be more appropriate. Remember, tube shields treat problems, not cure them.

Thermal Spray Coating

In the simplest terms possible, thermal spray coating involves heating a material, in powder or wire form, to a molten or semi-molten state. The material is propelled using a stream of gas or compressed air to deposit it, creating a surface structure on a given substrate.

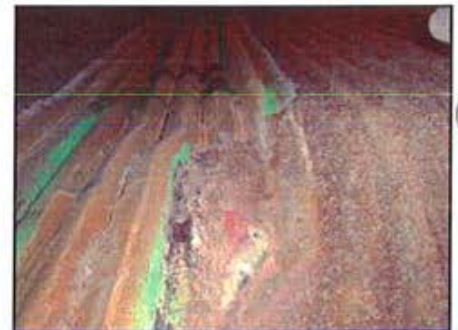
The coating material may consist of a single element, but is often an alloy or composite with unique physical properties that are only achievable through the thermal spray process.

BAFFLES may be utilized in the prevention of soot blower erosion.

PAD WELDS

It is possible to restore the thickness of the tubes that have been eroded by soot blowers.

For SMAW use 3/32" diameter electrodes for tubes over 0.125" thick. Before using this process a minimum thickness of 0.125" is required. Follow the weld layer sequence and general techniques of the aforementioned instructions. The E7010-Al electrode may be used for hard to weld areas and where the electrode may not be kept within 20° of perpendicular to the tube. Otherwise use the E7015-Al or E8015-B2L electrode match electrode to tube metal. Always use the lower half of the recommended amperage range. Maintain the stringer bead technique to minimize penetration.



For GMAW use only the short-circuiting type of arc. This process may be used on tubes 0.090" or heavier wall. The thickness is based upon using 75% argon - 25% carbon dioxide shielding gas. Carbon dioxide (100%) may be used for the shielding gas with the advantage of less penetration but more spatters would be present. Voltage and amperage values should be in the lower half of the range specified, but carefully balanced for good weld ability. This may be used after depositing one bead layer on thin tubes with the gas tungsten arc process. Less heat input is used when compared to manual metal arc allowing for thinner sections to be welded.

For fill welds this is best suited for use on thin sections or holes. Filler metal should be added for all passes unless a bead is not completely fused. A pass without adding filler metal may be used, but is not recommended. By starting on the heavier section of tube, a puddle is established before entering a thin area. Once a weld puddle has been established, begin adding filler wire to the front of the puddle. By laying the wire on the surface and passing over it, the filler wire absorbs some of the heat reducing penetration and the change of burn through. Repair of holes, leakage points, and severe notches or dislocations are best repaired by this method.

Use TIG Tungsten or oxy acetylene on extreme thin wall tubing less than .125" thick for the first pass.



ADVANCED BOILER INSPECTION TECHNIQUES 2011



Thinning weld repair guidelines

When to apply

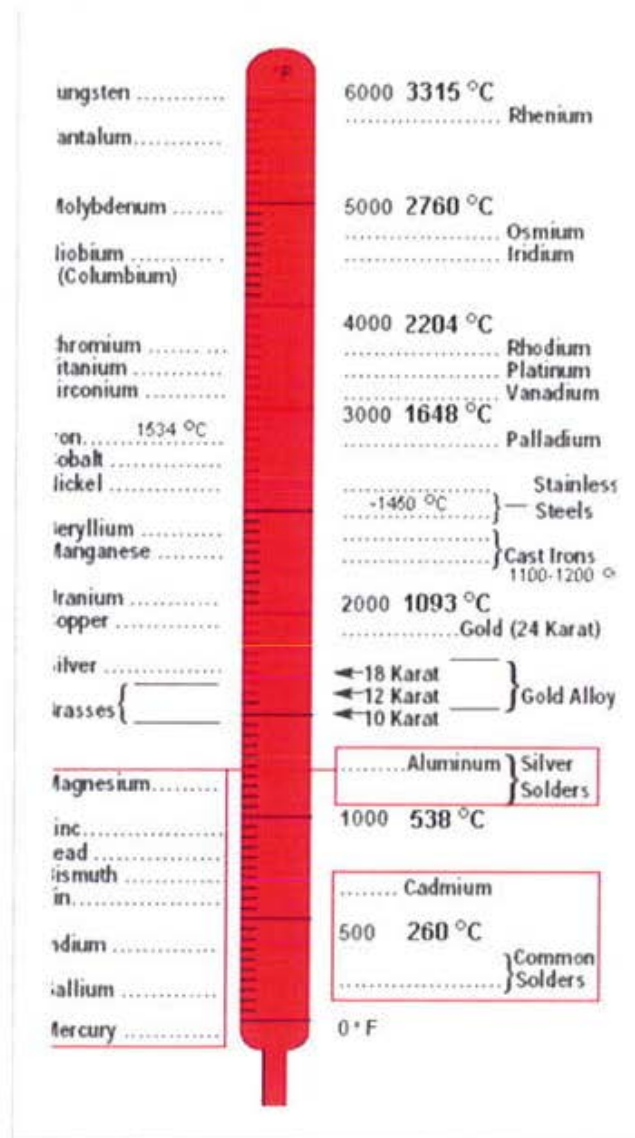
1. Most of the wear is general erosion of a localized area.
2. Notches and dislocations are present in a random manner. These may penetrate deeply into the wall, possibly extending through the wall (leakage).
1. Repairs may have to be made in all positions.
2. Tubing to be repaired will be some form of carbon steel.
5. Wall thickness to consider: Must be above 65% of design MWT.
6. An aluminum or stainless steel coating may have been applied to various areas of the tubes by metalizing.

Base Metal Preparation

Prior to cleaning, the tubing has been exposed to service environment and is covered with grease, oil, paint, dirt, coal dust, and/or slag. For areas requiring repair, and six inches around the area, all loose material must be removed. For one inch around the defective area, the tube shall be cleaned to base metal, removing all foreign matter.

The above requirements are valid whether or not any metalizing is present. If either the aluminum or stainless steel has been applied, this must be removed. These coatings are not compatible to the parent base metals if diluted with weld metal. Due to the very thin nature of the remaining base metal in the defective area, grinding in this area is not recommended. Either a power steel brush or a flexible flap wheel will clean the defective areas properly. Grinding may be used to complete cleaning to white metal around the weld joint.

After cleaning the defective area to sound parent metal etching the surface will reveal any remaining foreign materials. This is left to the discretion of the individual. If it is felt that no metalizing, other coatings, or foreign material remains, the etching is not required.



Melting points of various materials

You should never pad weld under the following conditions.

- If a copper deposition on the waterside of the tubing is likely.
- If a hole or crack breaches the tube inside diameter.
- If the remaining wall of the tubing is very thin ($<0.0625''$ $1/16''$).
- If the lengths of the pad weld exceeds 18".
- If the work quality of available welders is questionable.
- If you have HIGH TEMPERATURE CREEP see page 87
- If you have STRESS CORROSION CRACKING see page 85
- If you have CORROSION FATIGUE see page 85
- If you have Corrosion fatigue metallurgical considerations see page 85
- If you have PITTING see page 85
- If you have CAUSTIC CORROSION / GOUGING see page 85
- If you have ACID PHOSPHATE CORROSION see page 85
- If you have HYDROGEN DAMAGE see page 85
- If you have THERMAL FATIGUE see page 85
- Deposits on the internal surface of any kind



Thermal fatigue (Quench cracking) from water lances and water cannons

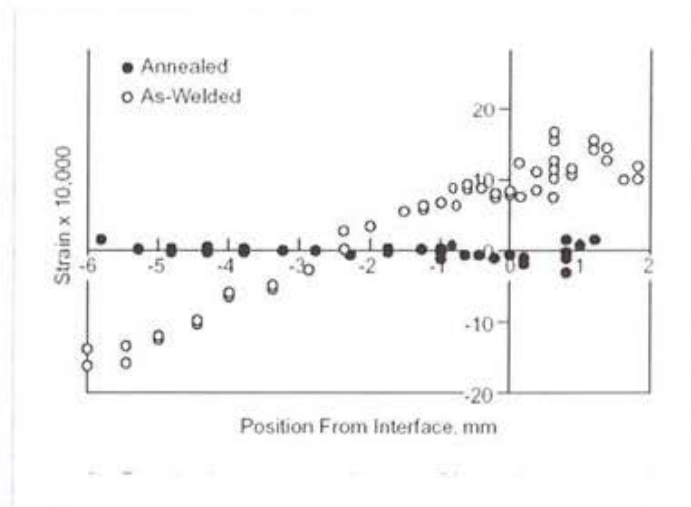
GENERAL:

The tubes are all 2" OD X .220" MWT SA-210-A1.

HISTORY:

The customers waterwalls have been extensively sprayed with either water lances or water cannons. This has

resulted in significant but controllable quench cracking. The cracking manifests itself in two forms spider vein type usually occurring on the crown or crown to membrane location on the tubing in the sprayed areas. The second form is a membrane to tube location where the tube fractures at the membrane and opens up much like a zipper. Two different inspection techniques are required to detect these conditions.



The location of the quench cracking is not limited to any specific locations. All exposed areas must be considered and a reasonable strategy must be developed. This strategy must include historical failure and replacement data as well as blowing patterns and cycles. The plant will ultimately determine the level of risk they are willing to accept. Since we have had a moving target we have had to employ the shot gun approach some sampling in all areas with greater scrutiny in what we project to be high risk areas. These would be areas of failures, high lance \ canon use or unusual blowing programs. This strategy will evolve over time when the variables begin to remain constant.

SPECIAL INSPECTION TECHNIQUES

Technique #1. Common water lance quench cracking

The spider type cracks can be identified by establishing a search grid of a spacing of 10 tubes and a height of 6 feet between elevations. The search grid is an area affected by the water lances typically about a 10' radius from the center of the lance. Don't stop at the obvious cleaned circle created by the water lance. Cracking has been found outside these areas as far as 3' in radius. Increase intensity of inspection to 3' between bands in elevation and every 5 tubes in areas determined to be of high risk. Clean the tube to a semi polished condition. This will require some grinding sandblasting is helpful but not sufficient by itself for this process. Once the area has been polished then a visual inspection can be done to determine if cracking is present. "PT" penetrant testing can be used however in most cases is not required to identify these cracks. Remove the visible cracks by grinding. Re inspect and verify thickness remaining by using "UT" ultrasonic thickness meter. When the remaining wall is less than .149" mark the tube for removal. Never recommend pad welding even though it appears the crack is removed. The reason for this is that this type of cracking is usually spread over a large area and removal by grinding would be extensive and not cost effective. The problem is not all the cracks will be removed. Don't take the risk, remove the tubes at these thresholds. Next conduct a search to determine if additional tubes are involved. This will involve a vertical and horizontal tube to tube search to establish the dimensions of the panels required. Don't chop

the panels up too much as this adds a lot of prep cost. Determine what panels are available and try to fit these in without compromising the repair.



depth of the quench cracks.

The photo at the right and left show various degrees of Thermal fatigue as seen in the field. (Quench cracking). Notice the spider vein pattern of the cracking.

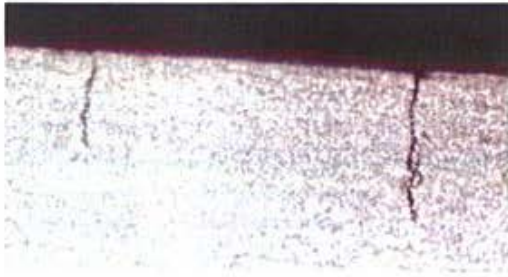


This photo (left) shows an affected tube section of the cracked area. Notice the

Technique #2. Water cannon quench cracking.

Unlike water lance damage this type of problem may affect a single or small group of tubes. This is problematic as a wide search grid will likely miss some problem areas.

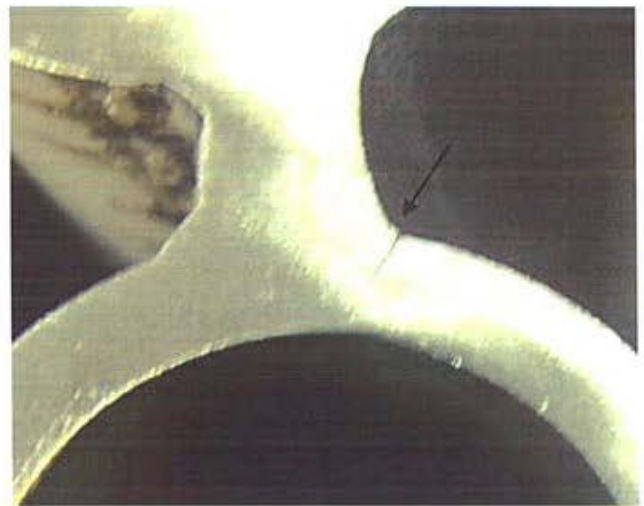
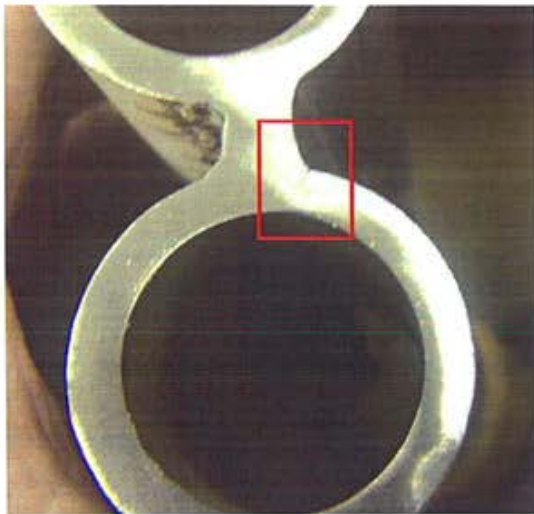
Only experience will dictate the optimum search grid locations. We have insufficient data to establish exact search criteria but we do know that corners #1 and #3 have had the most failures of this variety. They have been occurring above "D" band soot blowers and extend to above "C" band soot blower elevations. Near the corner offset tubes 40 tubes from the rear have been problematic in the past.



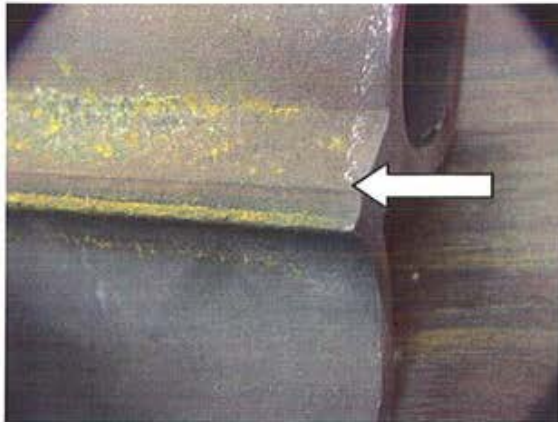
The photo at the right shows a tube that has failed due to this condition.



The membrane to tube cracking can be identified by establishing a search grid of a spacing of 10 tubes and a height of 3 feet between elevations. The search grid is an area affected by the water cannons spray pattern. Determine overlap areas and locations where the cannon might hesitate. In these areas increase the search concentration to a 5 tube spread using 1' increments. Make sure the area of the tube at the membrane connection is clean either by grinding lightly or sand blasting. Next "PT" test this area. Include the entire face of the tubing to determine if spider cracks may exist. Look for a crack longitudinal in orientation at the membrane to tube intersection. If it bleeds extend search to locate the ends of the crack. Next conduct a search to determine if additional tubes are involved. This will involve a vertical and horizontal tube to tube search to establish the dimensions of the panels required. Don't chop the panels up too much as this adds a lot of prep cost. Determine what panels are available and try to fit these in without compromising the repair. This type of failure mode may be limited to a tube or two.



The photographs above show a crack at the tube to membrane connection caused by quenching. Red area indicated magnified area at the right.



The photo at the left shows how far the crack penetrated the interior before the failure actually occurred

This photo shows how well the cracks hold penetrant material. "PT" is a very effective method for isolating the membrane cracking.

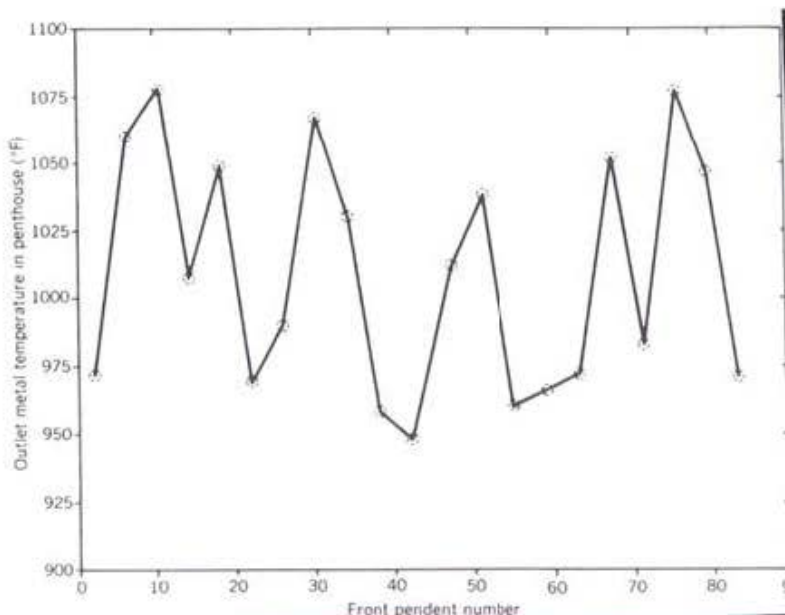


Client typically repairs all P1 and P2 repairs; occasionally repair P3.

ACTION LEVELS: Apply standard criteria to various MWT throughout the waterwalls. Pad weld = .165"
Replacement = .143". Be careful not to pad weld in any quench cracked areas of the waterwalls.

Thermal monitoring?

Thermocouples are designed for welding directly to boiler tubes. These thermocouples sense tube surface temperatures up to 2012°F (1100°C.) with a corrected minimum accuracy of $\pm 2\%$. Normally furnished with a 310 stainless steel sheath over the compacted magnesium oxide insulation, with type "K" wires. These thermocouples can be supplied with a Hastelloy X sheath material for superior resistance to the most corrosive atmospheres. Thermocouples are easy to install, yet rugged enough to withstand the roughest handling.



This section of the manual introduces heat flux sensors. These sensors can be used in boiler water wall applications for detection of fouling (Boiler Fouling Sensor)

Heat Flux Sensors

Heat flux sensors measure the flow of energy to or from a certain object. Heat flux is expressed in BTU / square foot. In many boilers, the furnace walls suffer from fouling (also called slagging). In many cases it is possible to put heat flux sensors on the waterwall tubing. By monitoring the heat flux from the boiler to the steam / water mixture in the tubing, the process of fouling can be detected. An added thermocouple can also be used for estimating tube surface temperature (so-called chordal thermocouple).

The total system leads to:

1. Automation of the process of soot blowing. (Intelligent soot blowing)
2. Better system efficiency
3. Savings on servicing.
4. Optimal estimation of tube lifetime
5. Extension of tube lifetime

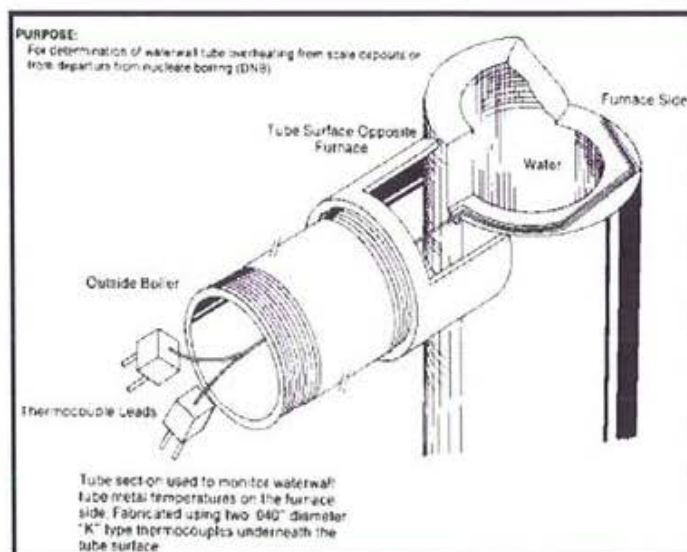


Figure 2.1.1 Boiler waterwall (2) with incorporated heat flux & temperature sensor (2). The sensor is connected to an external readout (3).

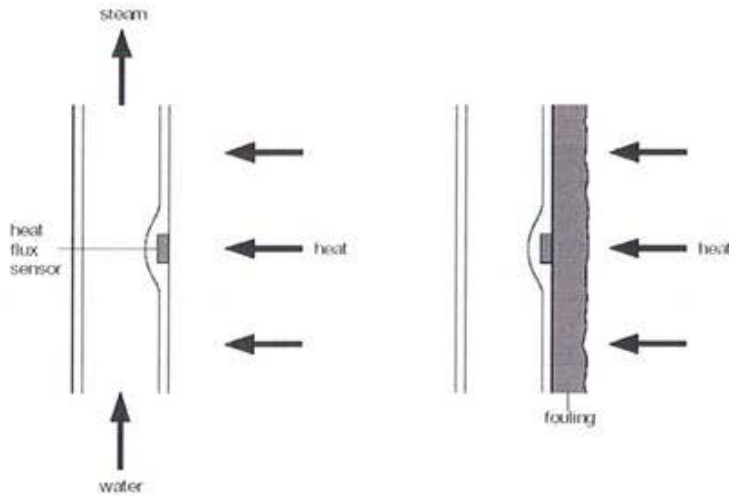


Figure 2.1.3 The heat flux signal, starting with a clean tube that gradually fouls. (From left to right in figure 2.1.2) There is

a change in heat flux level, and at the same time, the spectral content of the signal changes; the fast changes are damped by the added heat capacity of the soot.

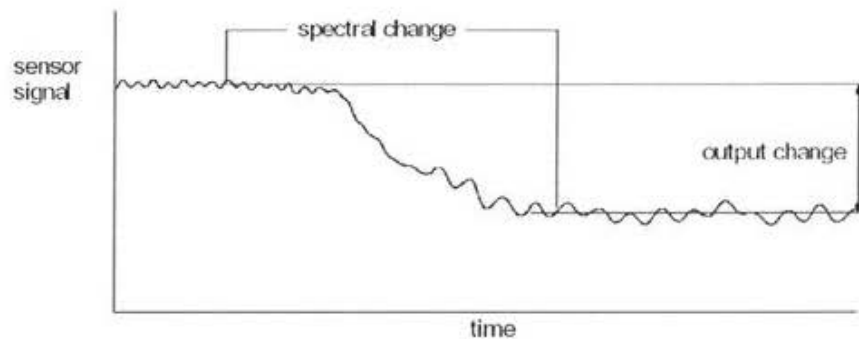


Figure 2.1.3 The heat flux signal, starting with a clean tube that gradually foules. (from left to right in figure 2.1.2) There is a change in heat flux level, and at the same time, the spectral content of the signal changes; the fast changes are damped by the added heat capacity of the soot.

Craze cracking (alligator hide)

Failure location

- Water walls

General description

In some supercritical boilers cracking has been detected in the waterwalls. These boilers operate at metal temperatures higher than normally applied in subcritical boilers. The circumferential cracks in the tubes were filled with magnetite and sulfides, indicating the presence of a sulfidizing atmosphere.

The mechanism of this condition is summarized as;

- initiation of intergranular corrosion and sulfidation on the grain boundaries
- because of high heat fluxes, compressive stresses on the outer tube metal surface and plastic deformation take place at high stresses
- at lower heat fluxes, residual stresses are present
- because of intergranular penetration there is stress concentration on the crack tip during thermal cycling
- propagation of the crack and sulfidation on the crack tip

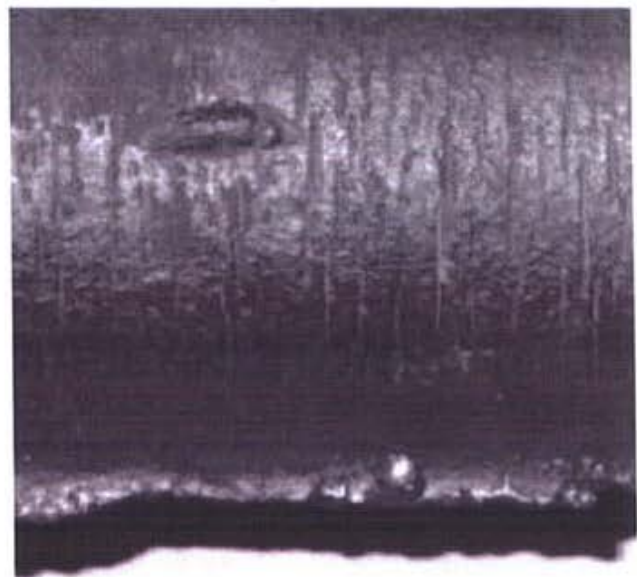
This mainly occurs in supercritical units but can occur in sub critical boilers. This condition is also known as; Circumferential cracking, Horizontal cracking, transverse cracking, craze cracking, elephant hide, and alligator skin cracking.

External Appearance

Scale covered circumferential cracking consists of multiple cracks that lay parallel one to another or perpendicular to the direction of maximum tensile stress. It is common that this condition is also seen with significant fire side wastage

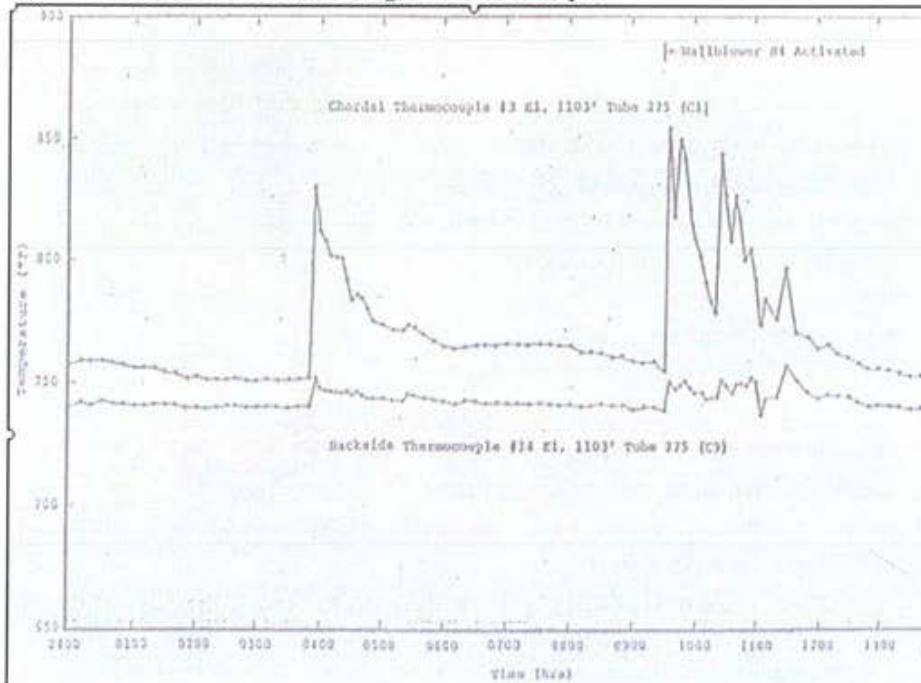
Internal appearance

N/A



Cause

Corrosion enhanced thermal fatigue, increased tube surface temperature, and cyclic stresses from load changes and start ups.



In water walls and Superheaters, grooving occurs as the ash deposit is shed and the temperature "jumps" when the insulating ash layer is removed. Circumferential grooves form in a manner similar to thermal fatigue cracks from the use of water lances/ cannons.

Prevention
It is unlikely that the root

cause can be eliminated as ash must be removed from the water walls. Therefore we must address the symptoms.

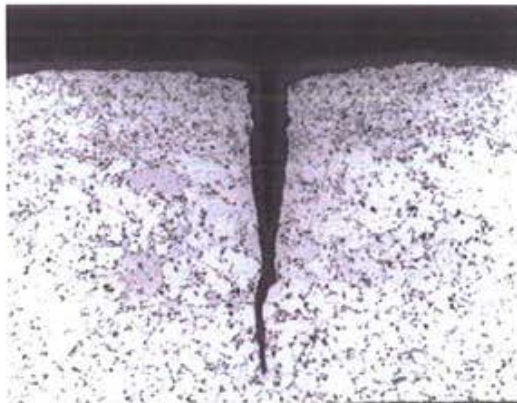
Clean and inspect areas of the furnace to determine the presence of cracking.

Acceptable repairs

Replacement is the only suggested repair.



Metallurgical characteristics



Older cracks fill with oxide, may stop and restart (note jog part way along the crack), and do not necessarily have a change in section thickness to initiate the crack. 100x, etched.



Cross section of a water wall tube with severe circumferential cracking. In this example, the deepest grooves are more than 75% through the tube wall.



Metallographic sections through thermal-fatigue cracks indicate origin (here at the toe of an attachment weld) and shape.



ADVANCED BOILER INSPECTION TECHNIQUES 2011

Inspection techniques

The area affected will require visual inspection of the severity of the cracking. In some cases the ash and slag will require removal before the inspection. The tubing will be ranked slight medium and severe. These visual observations will be recorded and compared to establish what tubes will require replacement proactively.

GTRACK v 1.8 c 1995-1998 UDC 40109 502 955 9400 Page 1

Inspection Report

report9d

Date: 10/6/98

By: Cavote / Mardis

Station: Unit: 4

Area: Furnace Left Side Wall

Item #1. IDENTIFICATION: The area was numbered from left side wall to right side wall. Items were marked with white paint.

See attached data sheets for detail and orientation.

The codes used are as follows;

P-1= Pad weld 1", **EA**= Excessive attachment to tube,

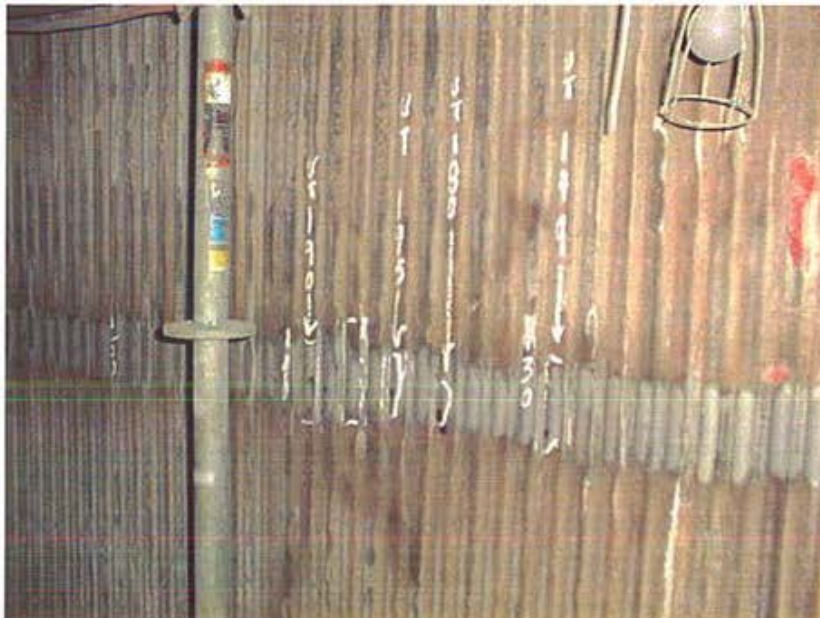
S= Slight craze cracking, **M**= Medium craze cracking, **H**= Heavy craze cracking,

TC= Tube crack, **MC**= Membrane crack, **B**= Tube bowed, **MH**= Membrane hole, **DS**= Dutchman too short.

Repair item #: 2

Priority #: 1

Action required: Pad weld tubes



Repair #: 2-a (Pad weld tubes).

These are located at; 605-47, 610-205, 583-200. These are marked P-?. (Are we pad welding over cracks here?)

Repair item #: 3



ADVANCED BOILER INSPECTION TECHNIQUES 2011

Priority #: 1

Action required: Grind out cracks in tubes.

Repair #: 3-a (Grind out crack in tubes at 629-63, 629-80, 590-256, 622-2. These are marked as **TC**.)

Repair item #: 4

Priority #: 2

Action required: Grind out cracks or replace membrane as required.

622-89, 622-90, 587-71, 587-79.

Repair item #: 5

Priority #: 3

Action required: Monitor tubes that were identified as Medium craze cracking.

Repair #: 5-a (Monitor for future determination.) These are identified as **"M"**.

610-70, 610-74-76, 587-72-78, 598-168, 594-185-188.

Repair item #: 6

Priority #: 3

Action required: Monitor tubes that were identified as Slight craze cracking.

Repair #: 6-a (Monitor for future determination.) These are identified as **"S"**.

605-34, 608-35-42, 610-48-49, 603-48-49, 596-59-67, 590-73-75, 590-79-81, 583-135, 605-170, 598-178, 598-187, 608-189, 610-188-189, 608-217-223, 590-200-201, 587-204, 587-206, 590-209, 590-211, 590-228-229, 608-233-235.

Repair item #: 7

Priority #: 3

Action required: Grind away excessive attachments that are welded to the tubes.

Repair #: 7-a (Grind to original contour of tube.) These are identified as **"EA"**.

622-8, 590-8, 587-8, 622-10, 605-10, 590-10, 587-10, 605-17, 608-235, 608-236, 587-259, 590-261, 612-80.

Repair item #: 8

Priority #: 3

FALLING SLAG INTO HOPPER BOTTOM (coutant).

LOCATION:

Slag erosion can occur at the lower furnace wall, which directs ash into the bottom ash. The sloping wall tubes within 3 to 4 feet of each sidewall near the bottom will experience the greatest erosion.

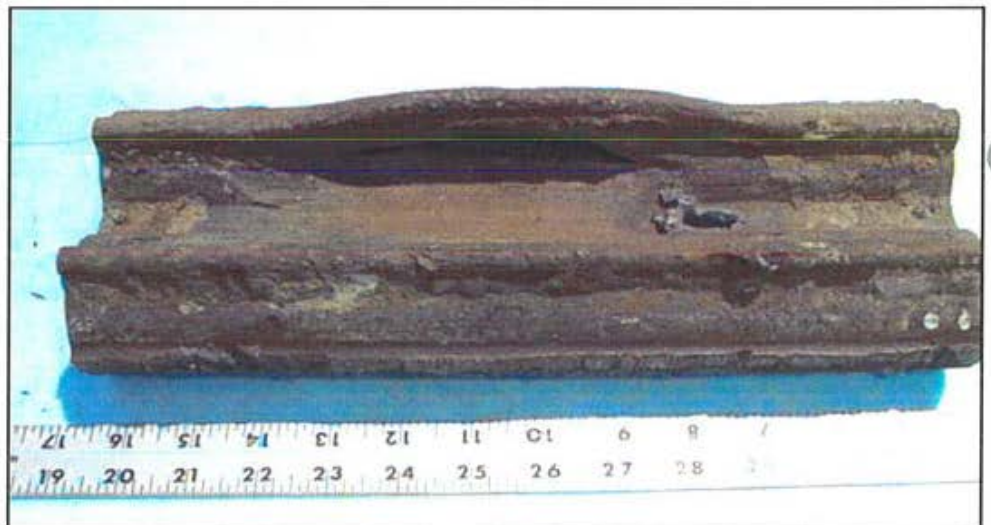
PHYSICAL DESCRIPTION:

Falling slag erosion produces flat surfaces from metal removal. A longitudinal thin edged fracture results when the wall thickness can no longer restrain the internal pressure.



PROBABLE CAUSE:

Slagging of coal that results in solid ash buildup on the furnace walls and the pendant superheater tubes causes falling slag erosion.



Massive pieces of slag fall and erode or severely damage the sloping waterwall tubes. Both coal properties and boiler designs are important factors in evaluating slagging problems.

The root cause of falling slag erosion can be verified by evaluation of the slagging potential of the fuel. Various coal ash properties are used in the evaluation but ASTM Standard D 1857.

Determine the important factors, which result in a slagging problem.

Analysis so far indicates that silica percentage and ash softening temperature can be used for categorizing the slagging tendency of a coal.



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Visual examinations and ultrasonic (UT) tube wall thickness measurements are methods to detect and monitor falling ash erosion.

UT surveys should be conducted during boiler overhaul outages to determine the extent of erosion and to provide data for planning corrective actions.



Corrective actions depend on the severity of the erosion problem. If erosion is severe, the reduction in boiler availability due to tube failures must be included in costs for burning a high slagging fuel. If a change in fuel is not justified, increasing tube wall thickness or installing wear bars can provide additional time before failure will occur.

CREEP, HIGH TEMPERATURE

COMMENT:

High temperature creep failures occur from a relatively continuous extended period of slight overheating above the design metal temperature, from a slowly increasing level of temperature or stress, or from the accumulation of periods of excessive overheating.

LOCATION:

Occurs primarily in high temperature locations such as superheat and reheat areas.



High temperature creep can occur in steam-cooled tubes at locations that:

- (1) Have become partially blocked by debris, scale, or deposits restricting flow.
- (2) Have exposure to radiant heat (line of sight) or excessive gas temperature due to blockage of gas passages or are located before the final outlet header.
- (3) Are located before the change to a higher grade of steel or have incorrect or lesser grade of steel material.
- (4) Have higher stresses due to welded attachments and orientation.

EXTERNAL APPEARANCE:

High temperature creep produces a longitudinal fracture. The extent of the fracture and its appearance may vary. A small fracture will form a blister opening while a large fracture creates a wide gaping fracture type of appearance. The fracture surface is thick edged with extensive secondary cracking adjacent to the main fracture. The tube surface may have a thick hard oxide scale with oxide, which have an alligator hide appearance. (See photo for details)

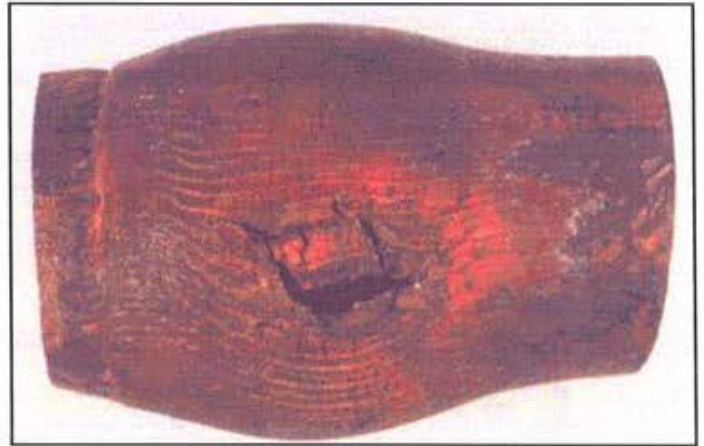
INTERNAL APPEARANCE:

The tube internal surface may also have a thick hard oxide scale with oxide, which have an alligator hide appearance.

PROBABLE CAUSE:

The root causes of high temperature creep can be verified by investigating the coolant circuitry, the gas passages, and the tube material properties. Tube sampling may be necessary to check for blockages and deposits that restrict the transfer of heat. Measurement of the tube metal and furnace gas temperatures can verify abnormal gas flow patterns. Tube material properties testing can verify the application of that material to the temperature experienced by the tubing.

Wall thickness measurements are necessary to verify that stress levels have not increased due to erosion or corrosion .



As mentioned before these ruptures occur primarily in the superheat and reheat areas. Long term

overheat is a result of operating problems wrong material incorrect flame patterns and restricted coolant.

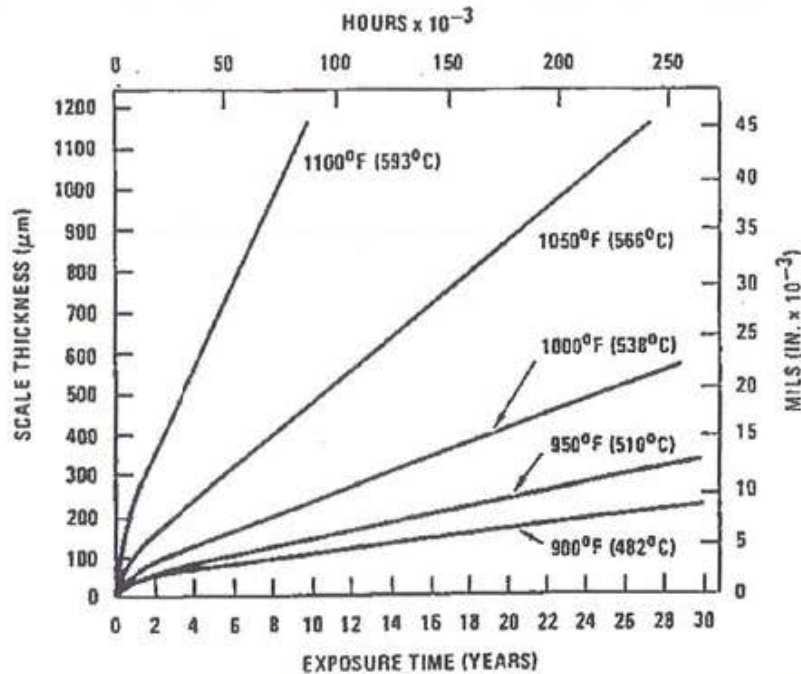


Fig. 5.30. Correlation (from Ref 56) between oxide growth and exposure time for

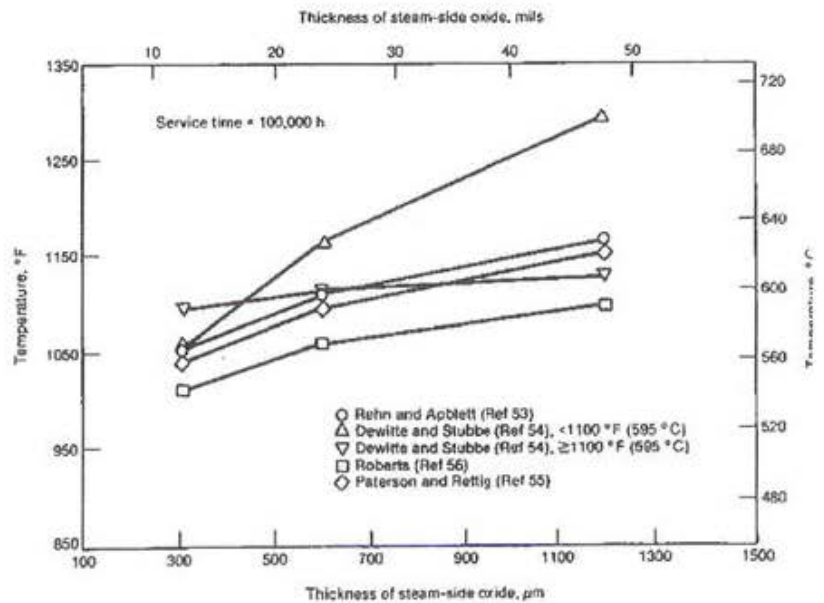


Fig. 5.31. Estimates of mean operating temperature made by various correlations for 2 1/4 Cr-1 Mo steel tubes having inside-surface oxides with thicknesses of 300, 600, and 1200 μm (11.8, 23.6, and 47.2 mils) after operation for 100,000 h (Ref 52).

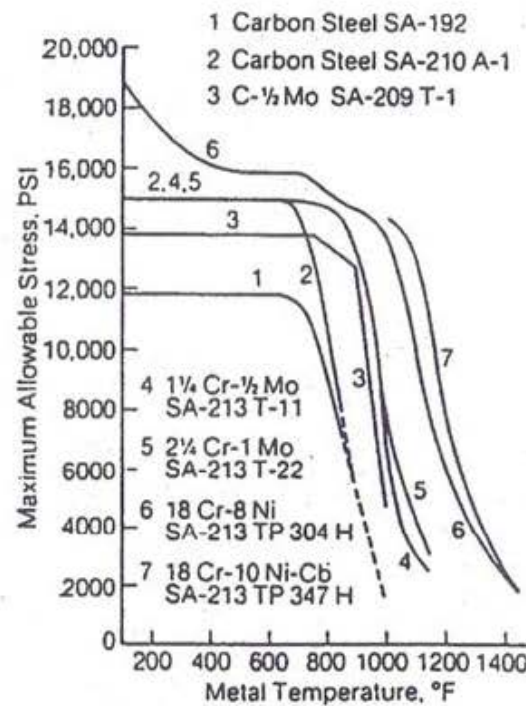
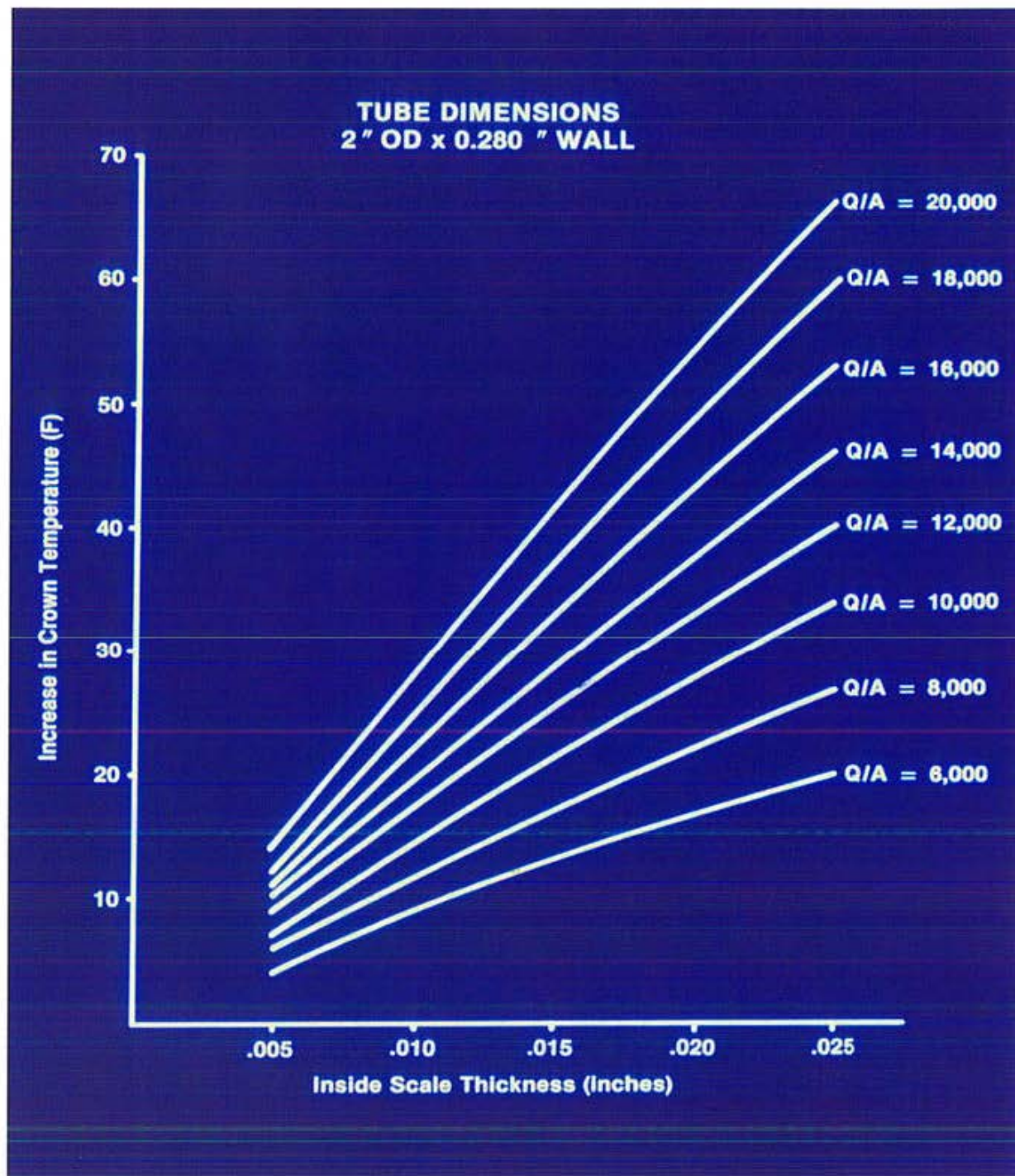
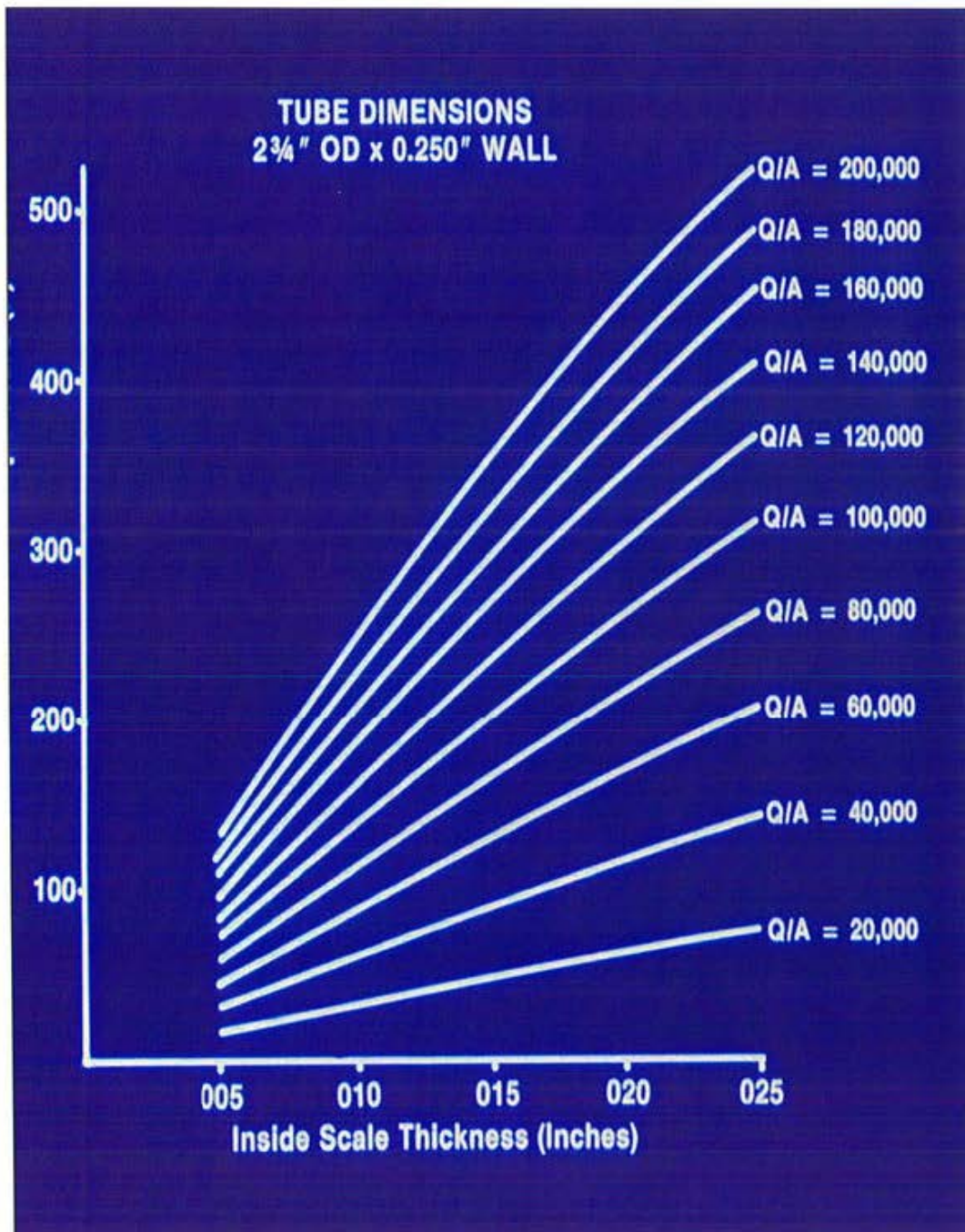


Fig. 5.2. Effect of temperature on ASME Boiler and Pressure Vessel Code allowable stress for several grades of steel tubing.



Effects of steam side scale formation on the tube metal temperature in a superheater or reheater tube where fluid side cooling is by convective heat transfer to the steam.



Effects of steam side scale formation on the tube metal temperature in a water wall tube where fluid side cooling is by boiling heat transfer to the water.

TEMPERATURE GRADIENTS DUE TO RESISTANCE TO HEAT TRANSFER FROM

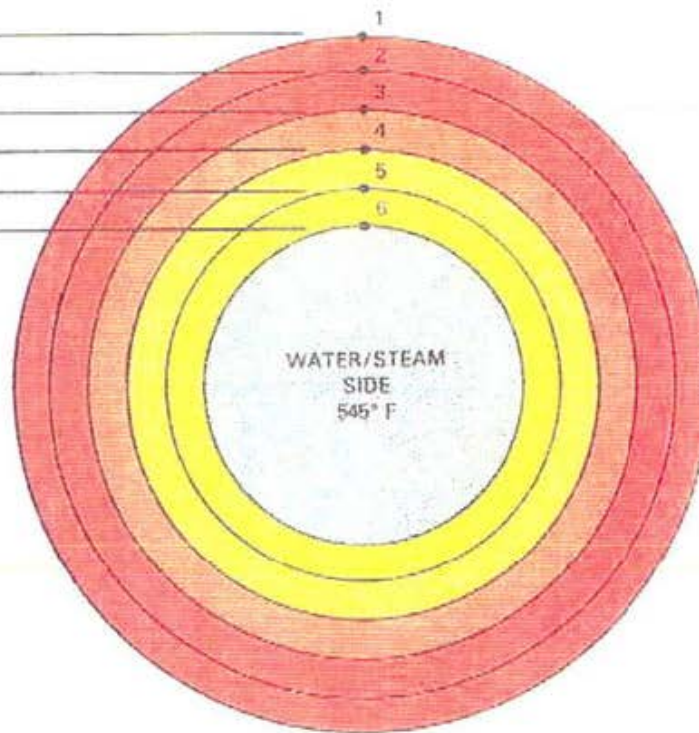
- 1-2 HOT GAS FILM RESISTANCE - VARIES WITH ASH OR SCALE THICKNESS
- 2-3 ASH OR SLAG LAYER RESISTANCE - VARIES WITH THICKNESS
- 3-4 TUBE METAL RESISTANCE - 90°F FOR 0.1 INCH WALL
- 4-5 INTERNAL SCALE AND DEPOSIT RESISTANCE - VARIES WITH THICKNESS
- 5-6 WATER/STEAM FILM RESISTANCE - 20°F

Effect of
Internal
Scale

INTERNAL SCALE THICKNESS

10 MIL	20 MIL	30 MIL
1750° F	1650° F	1600° F
1400° F	1620° F	1645° F
1170° F	890° F	1015° F
570° F	800° F	925° F
565° F	565° F	565° F
545° F	545° F	545° F

FURNACE
GAS SIDE
2500° F



1°C = 1.8°F
1 MIL = 0.0254 MM

TEMPERATURE GRADIENT FOR WATERWALL
TUBES DUE TO RESISTANCE TO HEAT TRANSFER

Thickness on Tube Metal Temperature. When the internal scale thickness increases, the tube metal temperature will increase accordingly. Temperatures are for the 1.5 Inch diameter tube with a 0.1 inch wall thickness. A heat flux of 100,000 BTU per square foot per hour was used.



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CORRECTIVE ACTION:

Ultrasonic wall thickness measurements are taken to check for wall thinning from erosion, corrosion, or oxidation. Tube outside diameter measurements may indicate that swelling has occurred due to creep degradation. Thermocouples can be placed on the tubing to ascertain the actual metal temperature that is achieved at selected locations. Tubing locations just before the transition to a higher grade of alloy steel are of particular concern.

Corrective actions involve the determination of the remaining life of the tubing based on the actual temperature, stress level, and material properties. Parametric analysis methods, such as the Larson-Miller parameter method, can be applied to estimate the effects of various actions.

High-pressure liquid flushing or chemical cleaning may be performed to remove internal scales, deposits, and blockages and reduce the tube metal temperature (see Appendix F). Material upgrades may be necessary to provide more creep-resistant steel at the location of high temperature. Corrective actions such as tube shield-log, padding, or thermal spray coating may be performed to reduce the rate of any wall thinning caused by corrosion or erosion.

REPAIR PROCEDURES:

This condition can be monitored until such time that the wall thickness becomes too thin for reliable operation. When this occurs we suggest a tube replacement.



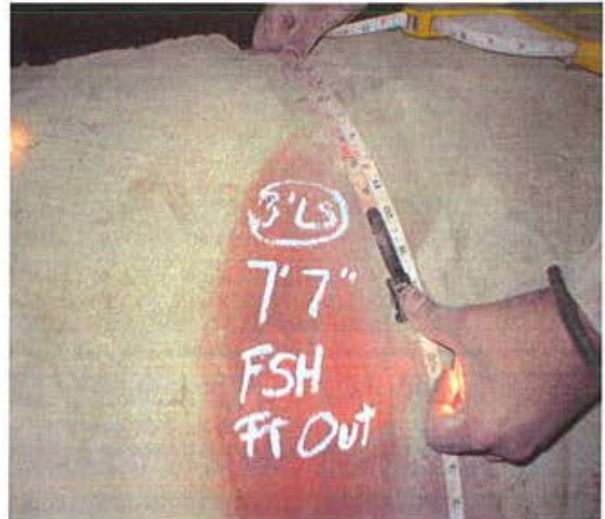
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Case Study report records

Repair #: 47-c Record:# 111
(INFORMATION ONLY) Priority #: 3

General location is Penthouse,
FSH Front outlet header.
Original OD = 28.75"

UDC has taken PI Tape measurements
(Circumference) to determine creep levels
from left to right side. Measurements
have been taken in 7 locations across the
length of the header: @



(3' in from the left edge)=7'-7"

(13' in from left edge)= 7'-6' 15/16"

(23' in from the left edge)= 7'-6 7/8"

(3' in from the right side expansion box)=7'-7"

(13' in from the right side expansion box)=7'-6 15/16"

(23' in from the right side expansion box)=7'-7"

(34' in from the right side expansion box)=7'-7 1/8"

The header was originally 90.275" OD. These measurements indicate
that the header is 1.009% in creep towards the right side of the header.

The maximum allowable creep for this header is 1.224% for a total of 122,393:52
hours of operation. This is within the tolerance by 18%. It is
important to note that the damage may not be linear for all of the
hours. This is the reason why we recommend re-examination of the headers every five years to establish a
current base of information. With two or three points of data we
can safely predict the useful life of the headers and connecting
tubing.

Recommendations for complete life assessment of header:

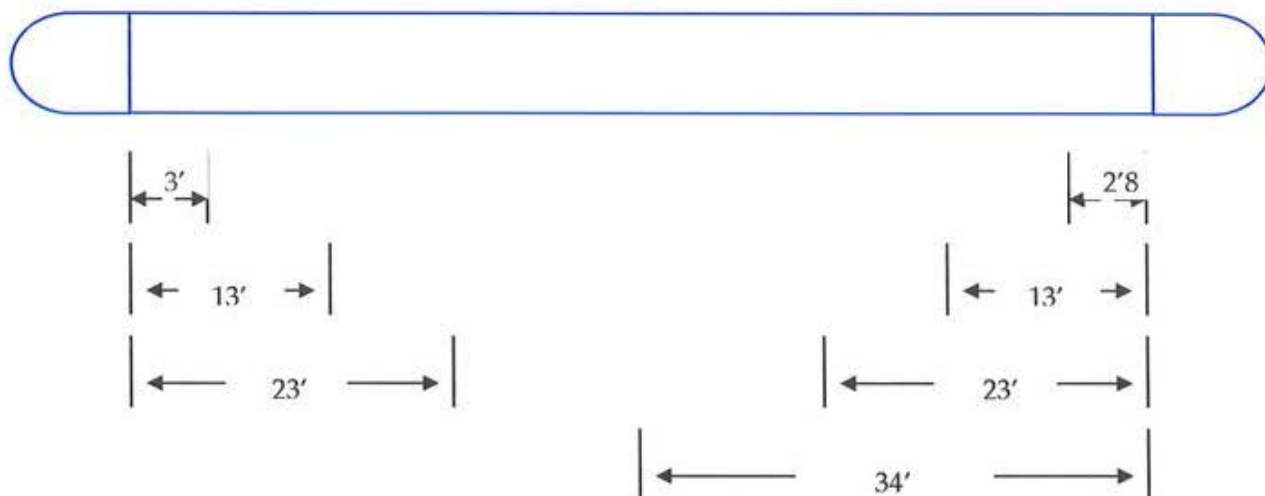


ADVANCED BOILER INSPECTION TECHNIQUES 2011

The suggested inspection work scope would include metal replications, Bore Scope inspection of ID orifice ligaments, and magnetic particle examination of the header tube ligament sections. This should be done at header on the right side at or near the outlet link connections, and all girth welds shall be MT examined as well. The header ligament areas are statistically the locations of failures due to creep.

Due to the apparent creep and the lateral movement we suggest that metal replications be made of the header on the left side at or near the outlet link connection.

Work Order: _____ Status: Inspected

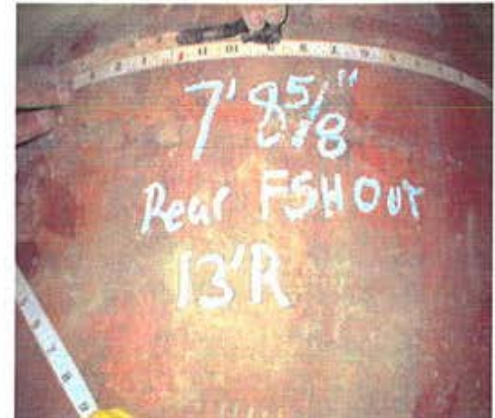




ADVANCED BOILER INSPECTION TECHNIQUES 2011

Repair #: 47-d Record:# 112
(INFORMATION ONLY) Priority #: 3

General location is Penthouse,
FSH Rear outlet header.
Original OD = 28.75"



UDC has taken PI Tape measurements
(Circumference) to determine creep levels from left to right side.
Measurements have been taken in 7 locations across the length of the header: @

(3' in from the left edge)=7'-8 5/8"

(13' in from left edge)=7'-8 9/16"

(23' in from the left edge)=7'-8 7/16"

(3' in from the right side expansion box)=7'-7"

(13' in from the right side expansion box)=7'-8 5/8"

(23' in from the right side expansion box)=7'-8 9/16"

(34' in from the right side expansion box)=7'-8 5/16"

The header was originally 90.275" OD. These measurements indicate
that the header is 1.026% in creep towards the center of header.

The maximum allowable creep for this header is 1.224% for a total of 122,393:52
hours of operation. This is within the tolerance by 16%. It is
important to note that the damage may not be linear for all of the
hours. This is the reason why we recommend re-examination of the headers every five years to establish a
current base of information. With two or three points of data we
can safely predict the useful life of the headers and connecting
tubing.

Recommendations for complete life assessment of header:

The suggested inspection work scope would include metal replications; Bore Scope inspection of ID orifice
ligaments, and magnetic particle examination of the header tube ligament sections. This should be done at

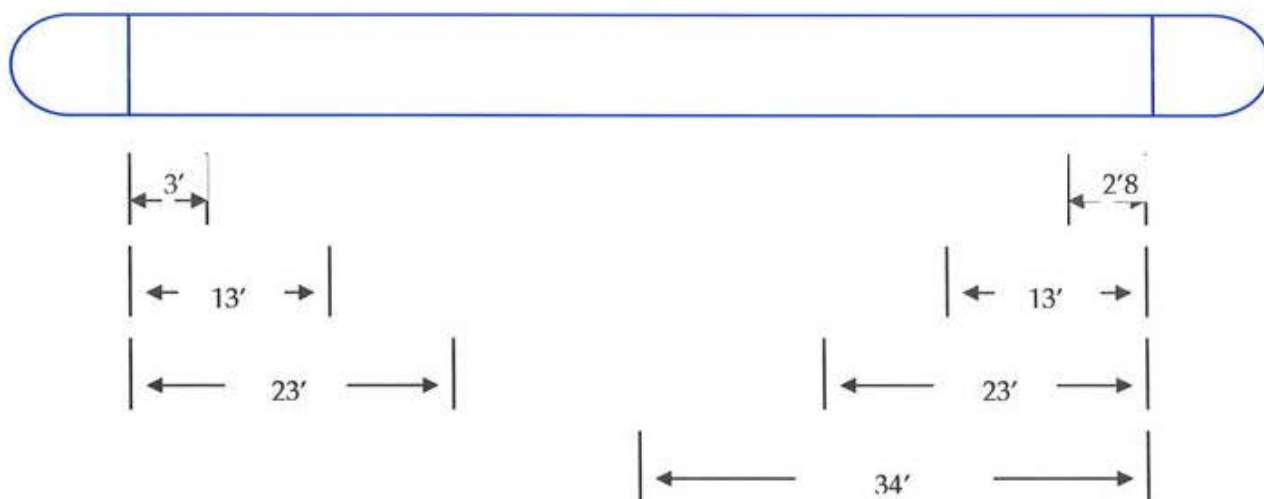


ADVANCED BOILER INSPECTION TECHNIQUES 2011

header on the right side at or near the outlet link connections, and all girth welds shall be MT examined as well. The header ligament areas are statistically the locations of failures due to creep.

Due to the apparent creep and the lateral movement we suggest that metal replications be made of the header on the left side at or near the outlet link connection.

Work Order: _____ Status: Inspected



Exfoliated tubing is typically found in the penthouse on the outlet terminal tubes.

High temperature creep may be evident in pendants and platens where blockages occur, incorrect steel is used, have exposure to line of sight radiant heat, or are stressed due to welded attachments.

Debris or restricted flow allows the area to operate for a continuous extended period of time overheated above the design metal temperature, slowly increasing level of stress.

Bulging is typical if creep is evident.

Overheat is usually long term and may be only slightly bulged, occurring in temperatures of 1200 to 1300 F.

Intermediate overheat usually occurs in temperatures of 1300 to 1600F, indicative of creep.

95% of superheat short terms overheat occurs during start up or below 20% operation, and always in a temperature above 1600F.





Internal blockage in a lower loop
from exfoliation.

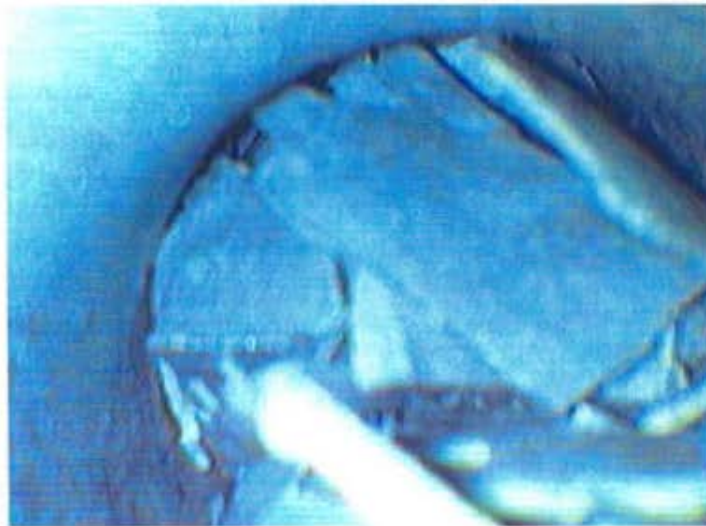


Figure 1 presents a comparison between predicted Corrosion rates due to pyrite deposition and actual measurements of waterwall wastage. The input conditions for utility furnace models vary substantially and are often highly uncertain. In addition, there are a number of additional mechanisms by which waterwall tube material is removed. Given these limitations, the accuracy of the prediction in terms of the rate and location of the high corrosion region is remarkable.

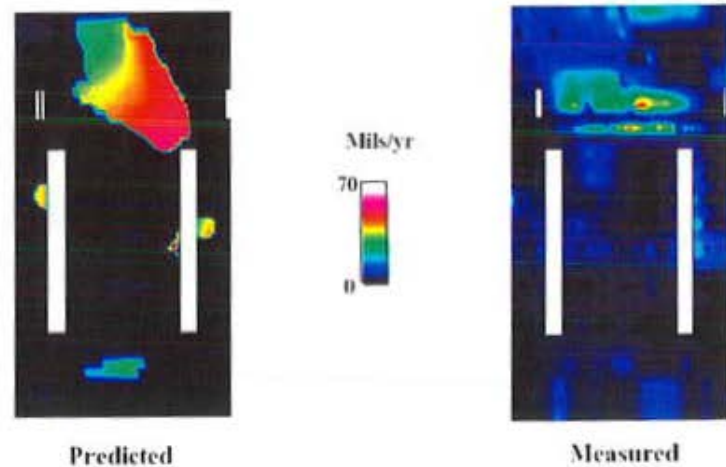


Figure 1. Prediction of Waterwall Corrosion Rates in a Coal-fired Boiler.

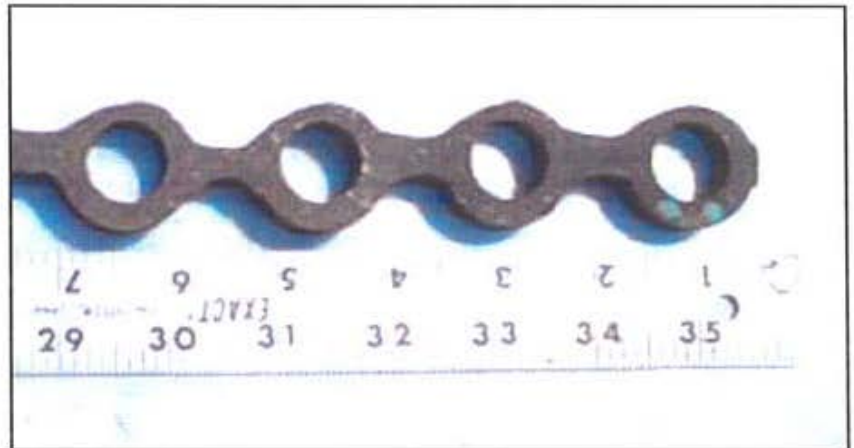
Failures caused by burner fuel issues

FIRESIDE FURNACE CORROSION

LOCATION:

Waterwall fireside corrosion can occur at locations that:

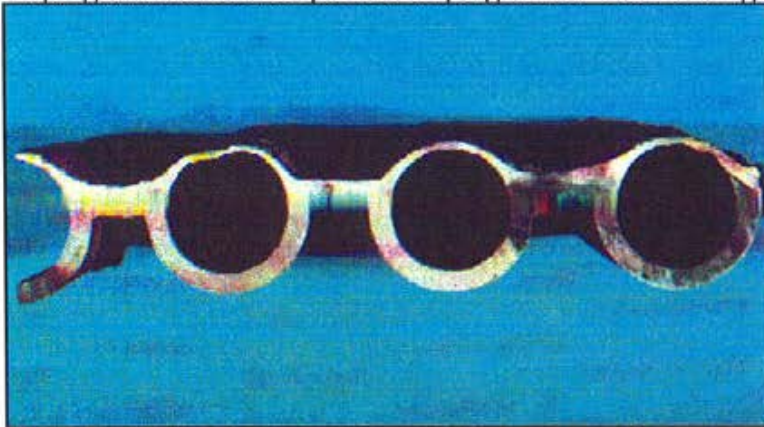
- (1) Have incomplete combustion conditions and a reducing atmosphere at the waterwall.
- (2) Have corrosive ash deposits.
- (3) Have any flame Impingement.



PHYSICAL DESCRIPTION:

Waterwall fire-side corrosion is caused by corrosive conditions in the combustion zone, which are due to inadequate oxygen supply, high concentration of sulfur and increased chlorides in the fuel, improper alignment of the fuel burners, and formation of molten ash on the waterwall tube surface.

Visual observation through inspection ports may show a defect in combustion such as direct flame impingement or carbon particle impingement. Field-testing may be required to determine the carbon monoxide level near the waterwall and the amount of unburned carbon in the ash.



PROBABLE CAUSE:

Waterwall fireside corrosion produces wall thinning that eventually results in ductile rupture of the tube in a longitudinal direction. Wall thinning is uniform across several tubes in a particular location. Circumferential grooving or cracking with deep finger-like penetrations into the tube

wall has been found on super-critical boilers. Hard, dark ash deposits are usually found on the external surface.

Ultrasonic (UT) wall thickness measurements are taken to establish the corrosion rate and extent. Removal of the ash deposit and iron oxide scale by sandblasting or grinding is necessary in order to obtain accurate UT thickness data.

The data can be input into computerized data analysis programs for plotting the location of the thinning, for trending of periodic measurements, and for calculating the remaining service life of the waterwall tubing.

Corrective actions depend on operating conditions; adjusting burner alignment, increase coal fineness, spraying thermal corrosion-resistant coatings, and bleeding air into the sidewall area. Long-term actions include furnace modification to improve combustion conditions or installation of co-extruded tubing or other surface modified tubing to provide a corrosion-resistant material on the outside of the tube. An estimate of the remaining life of the tube should be performed based on the corrosion rate and the level of hoop stress.



Coal ash corrosion

All fossil fuels, with the possible exception of natural gas, contain constituents that will promote corrosion on the fire side of boiler components. The "bad actors" are compounds of sulfur, vanadium and sodium; but in the case of municipal-refuse boilers, chlorine is an increasing concern. There are three temperature regimes where fire-side corrosion occurs:

Less than 300oF. Dew-point corrosion occurs when sulfuric acid condenses.

Temperatures from 500o-750oF. Waterwall-tube corrosion occurs in coal-fired units by the formation of pyrosulfates of sodium and potassium. In refuse-fired boilers, mixtures of chlorides of zinc, lead, iron and sodium are the likely causes of corrosion.



Temperatures greater than 1000oF. The cause of superheater and reheater ash corrosion depends on the fuel. The corrosive species are different for coal and oil-fired boilers. Mixtures of vanadium pentoxide and sodium oxide or vanadium pentoxide and sodium sulfate are the principal offensive compounds in oil ash. For coal-fired boilers, sodium and potassium iron trisulfates are the liquid species blamed for high-temperature corrosion.

ASH CORROSION

Carbon and alloy steels develop corrosion resistance from the formation of protective oxide scales. The more dense and tightly bound the oxides are, the more corrosion resistant the material will be. Any process that removes the oxide will promote more rapid corrosion wastage. Any process that prevents the formation of these oxides will also promote more rapid corrosion. Fly-ash and soot-blower are not by themselves corrosive, but both remove the protective iron-oxide layer. The cleaned steel is then exposed to the high temperature flue-gas environment, and an oxide film reforms. The oxide forms by converting steel to scale, and a little metal is lost. Each cycle of scale formation and removal reduces the wall thickness until the boiler tube is too thin to contain the fluid pressure, and failure occurs. The actual cause of the wastage is the rapid oxidation of clean, unprotected steel.

Whether the fuel burned is oil or coal, and whether the corrosion location is in the furnace (at temperatures of 500o-700oF) or the high-temperature components (at a metal temperature above 1,000oF), the corrosion mechanisms are similar. Constituents within the ash form a low-melting-point species or a mixture of several compounds that has the required low melting point. These low-melting-point species dissolve the protective iron oxide on the surface of the boiler tube and bring the bare metal in contact with oxygen.

Two observations: a) the melting point discussed here is not the ash fusion temperature, and b) the action of these liquids is like a brazing flux; it dissolves and prevents the formation of a protective oxide film. In the case of furnace-wall corrosion, mixtures of sodium and potassium pyrosulfates are the suspected liquid species. Melting points between 635o and 770oF have been reported for ash constituents on furnace walls under severe coal-ash corrosion. For corrosion of Superheaters and Reheaters at temperatures above 1000oF in coal-fired boilers, sodium- and potassium-iron trisulfates are the culprits. The exact melting point depends on the relative amounts of sodium and potassium, but the minimum melting point can be as low as 1030oF.



In oil-fired boilers, mixtures of vanadium pentoxide and sodium oxide or vanadium pentoxide and sodium sulfate are the problem. Again, the precise composition will dictate the particular melting point, but these compounds can melt at temperatures as low as 950oF.

In municipal-refuse burners where appreciable chlorine, from polyvinyl chloride, is part of the fuel, various chlorides or mixtures of chlorides will serve the same purpose. Mixtures of iron, sodium, zinc, lead, and perhaps calcium chlorides will form low-melting-point

species. There are many combinations of chlorides that have melting points below 600oF and some less than 350oF.

Reducing conditions will exacerbate fuel-ash corrosion. The presence of carbon monoxide and/or unburned carbon and hydrogen sulfide promote the formation of metallic sulfides. Iron sulfide, for example, is inherently less protective than iron oxide. Sulfides tend to be less protective because they are porous and less firmly attached to the steel. Alternate oxidizing and reducing conditions are no help either. The oxide that forms during oxygen-rich cycles is reduced or made less sound during the reducing

part of the cycle. In fact, it is not unusual in municipal-refuse burners to find a strong smell of hydrogen sulfide (a rotten-egg aroma) on a freshly broken ash sample. The presence of hydrogen sulfide is positive proof of a reducing furnace atmosphere.

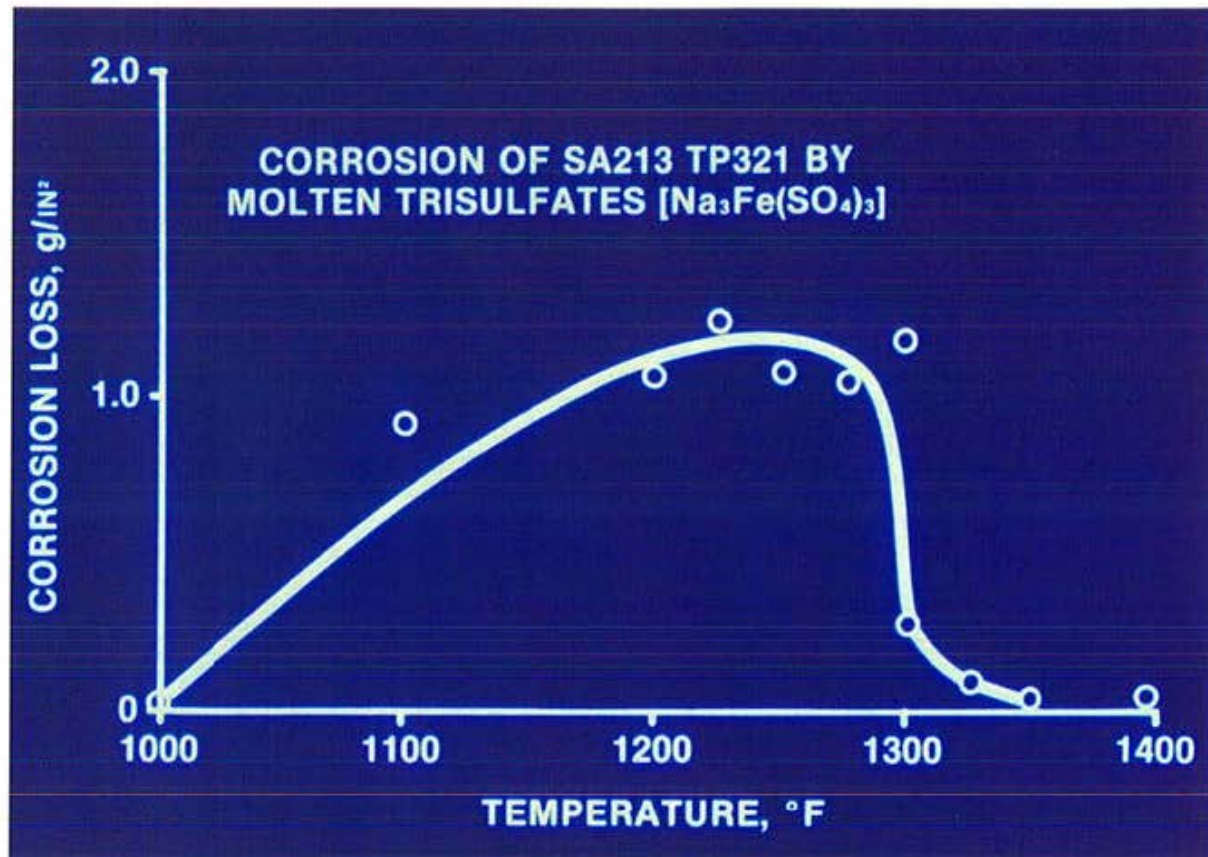
The morphology or appearance of fuel-ash corrosion is variable. For superheater or reheater tubes in an oil-fired boiler, the corrosion pattern depends on the volume of liquid and the aerodynamics of the flue-gas flow over the tube. In coal-fired boilers, the appearance takes the form of a series of grooves and is sometimes referred to as "alligator hide."

For waterwall tubes, especially in super-critical units burning coal, the appearance is a series of circumferential grooves or cracks. In cross section, again, the appearance is a series of shallow grooves. A micrometer measurement would show that the gross fire-side wall thickness is not substantially different from the cold or casing side. The wall thickness at the tip of the crack can, of course, be thin enough to form a steam leak.

In the case of a refuse burner, the appearance is one of a smooth and uniform wastage that reduces the wall thickness. Corrosion rates can be exceedingly high. Carbon-steel wastage rates of about 1/2 inch per year (failure in less than 2,000 hours of operation) are known.

The formation of "alligator-hide" appearance in Superheaters and the circumferential grooving in furnace-wall tubes are related and develop by the same kind of mechanism. A liquid phase forms from constituents within the coal ash. The strength of the liquid layer between the ash and the tube is weak. When the ash layer builds to a particular thickness, the film of liquid can no longer support the weight, the ash layer falls off exposing the bare tube to the fire, and the local heat flux jumps. This sudden rise in heat flux means a sudden rise in temperature and creates a locally high stress. As the ash layer reforms, the insulating effect of the ash reduces the metal temperature.

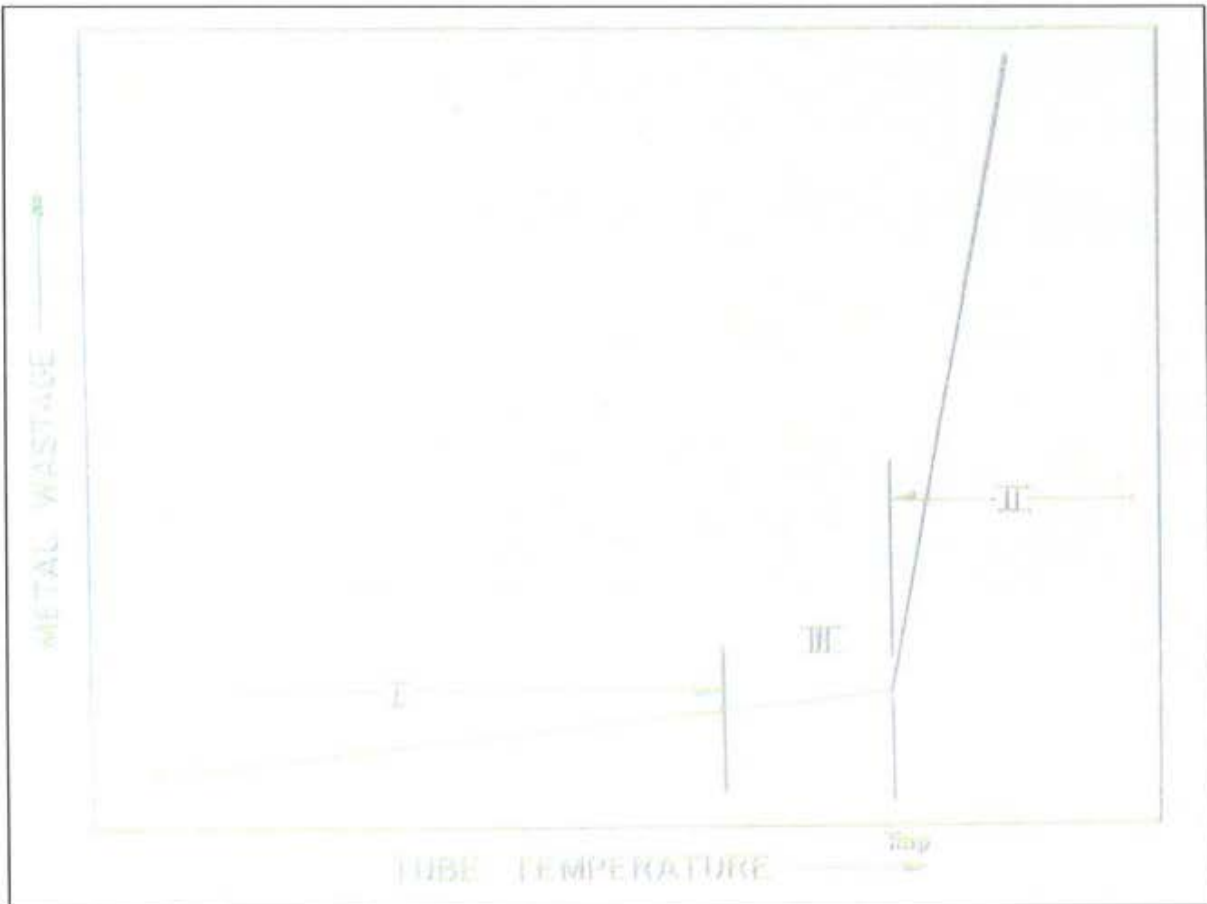




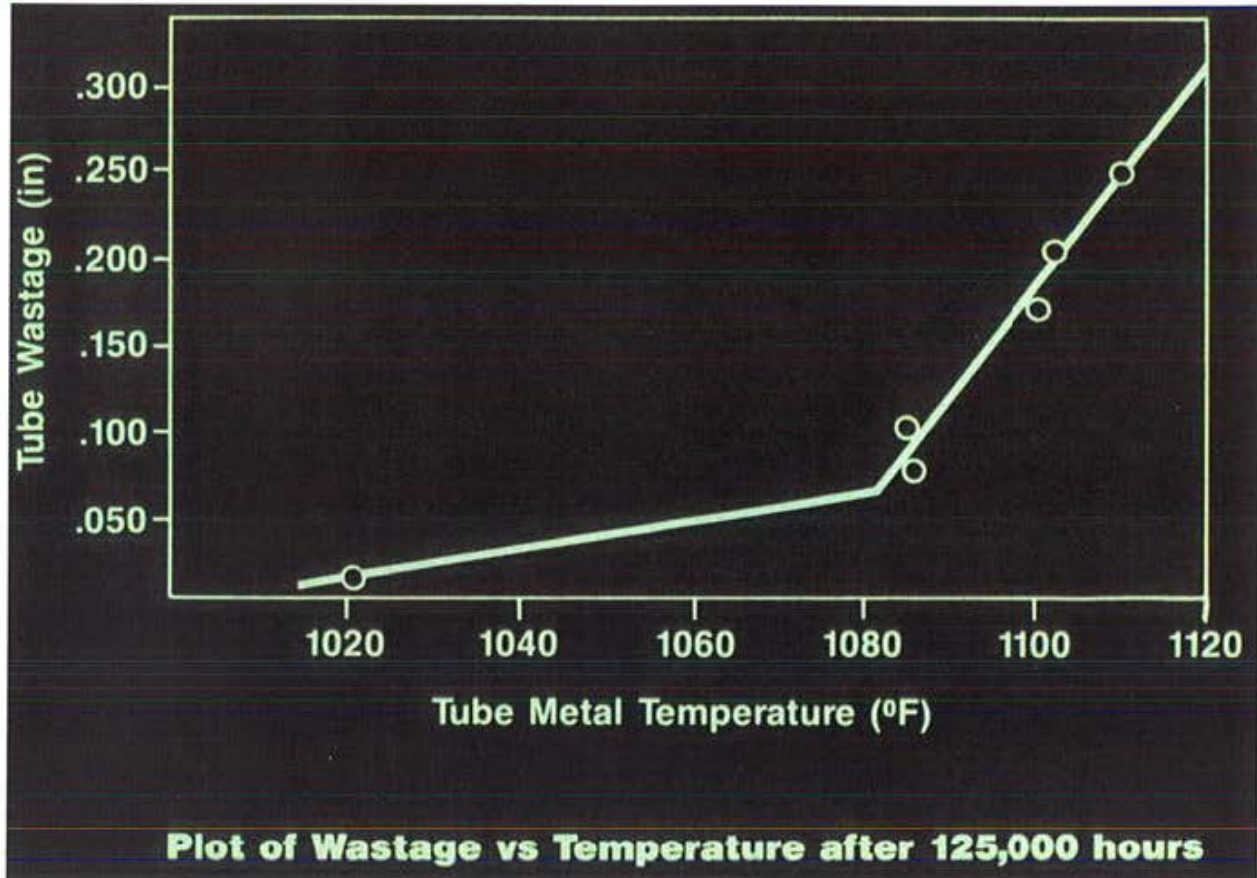
Corrosion as a function of temperature for a 321 stainless steel in molten trisulfates. Note rate changes for the better at approximately 1300° F when the sulfates decompose.

Over several (or many) such cycles, corrosion-fatigue cracks form. The difference between the "alligator-hide" appearance on superheater tubes and circumferential grooving on waterwall tubes is the magnitude of the heat flux and temperature spike. For Superheaters, the peak heat flux is perhaps 1/4 -1/3 that of a furnace wall in the highest heat-release regions. In the case of a stoker-fired, municipal-refuse boiler, the heat flux is not high enough to lead to a temperature spike, so the corrosion proceeds in a uniform fashion. In summary, the three temperature regimes of fire-side corrosion are: less than about 300oF, where sulfuric acid dew-point corrosion occurs, 500o - 750oF on furnace walls, and greater than 1000oF on superheater and reheater tubes. Even though the temperature regimes are quite different, the mode of corrosion is similar for furnace walls and Superheaters.

A liquid phase forms on the surface of the tube from constituents within the fuel, dissolves the protective iron oxide (similar to a brazing flux), and leads to more rapid corrosion. Under reducing conditions, protective iron oxides do not form as readily, and the result is the formation of a porous iron sulfide that is inherently less protective.



Schematic presentation of material wastage vs. metal temperature. At T_{mp} the melting point of the trisulfates in the ash, liquid ash corrosion begins. In a steam cooled tube (either SH or RH) there may be three distinct regions; a portion always above the melting point (III), a portion that is always below (I), and a portion that goes from below to above as the scale forms on the steam side (II).



Corrosion wastage of a superheater tube after 125,000 hours (about 16 years of "normal" operation)

Coal ash corrosion is caused by the formation of complex alkali-iron trisulfates in the ash deposits when the tube metal temperature is between 1000F(593C) and 1300F (704C). Certain coals contain constituents,



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which form ash deposits that are corrosive in the molten form. The corrosion becomes a significant concern when the wall thickness reduces rapidly

LOCATION:

High temperature coal ash corrosion can occur at locations in Superheaters and Reheaters that:

(1) Have tube surface metal temperatures between 1000F (593C) and 1300F (704C).

Maximum corrosion rates occur at 1200F (649C).] High metal temperatures are likely to occur in tubes that surround a radiant cavity, are exposed to radiant heat, or contain the hottest steam prior to leaving the flue gas enclosure.

(2) Have slag type corrosive ash deposits that are strongly bonded to the tube.

EXTERNAL APPEARANCE:

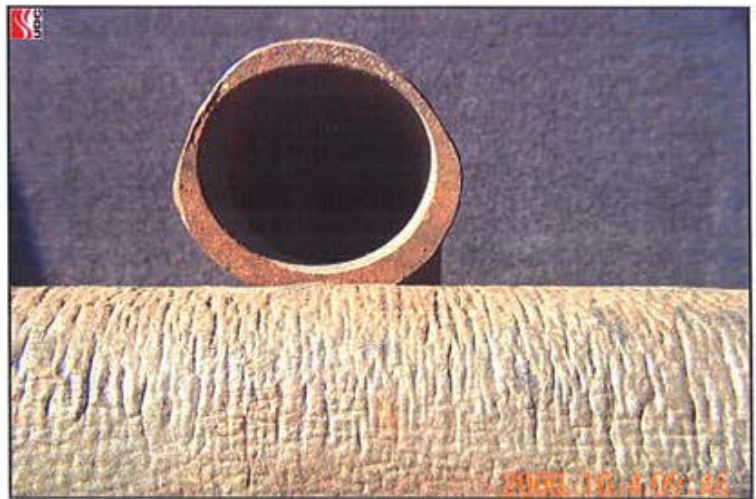
High temperature coal ash corrosion produces tube wall thinning that eventually results in stress rupture of the steel. The greatest metal loss occurs along the interfaces between the ash-covered portion of the tube and the uncovered portion. Flat spots on the tube surface occur at the 2 o'clock and 10 o'clock positions (30 to 45 degrees off the direction of gas flow). Fractures are longitudinal and the outside surface may have an alligator hide texture.

INTERNAL APPEARANCE: None



PROBABLE CAUSE:

The root causes of coal ash corrosion can be verified by determining the corrosiveness of the coal ash and by measuring the tube metal temperature under the ash deposit. Coals with chloride content of less than 0.2% and sulfur content of less than 3.0% have not produced significant corrosion rates. Temporary thermocouples on the tube surface can show whether the metal temperatures are within the range to produce a molten form of deposit. Combustion ash deposits should be removed for chemical and melting point analyses.



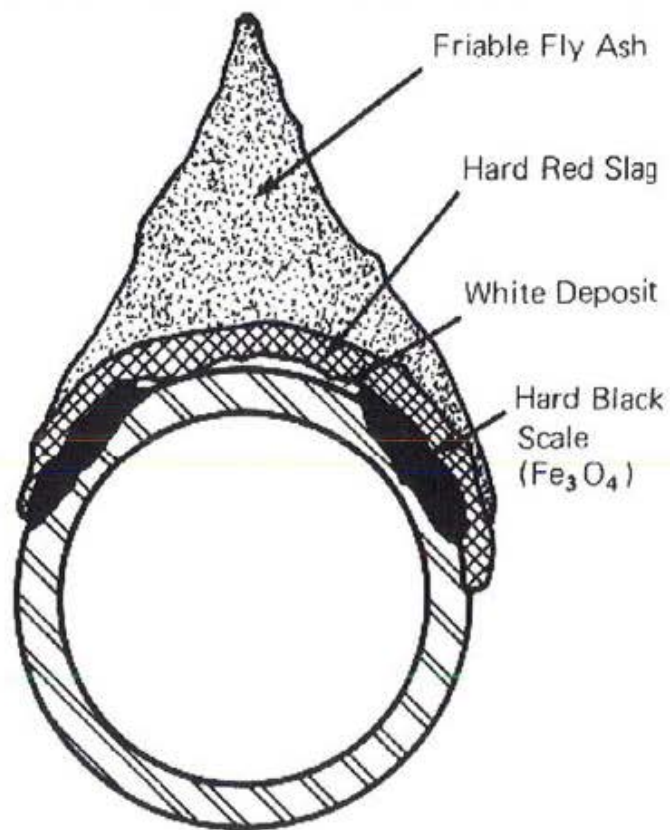
CORRECTIVE ACTION:

Ultrasonic (UT) tube wall thickness measurements and tube metal temperature measurements are taken to establish the corrosion rate and extent and to calculate the effect of the corrosion on the service life of the tube steel.

Inspection over the length of a lead tube in one or more of the assemblies with the highest element steam temperature can show whether there is corrosion and the elevations where it is greatest. Removal of ash deposits by wire brushing or sandblasting is performed prior to UT measurement. The measurement is taken at the area of greatest metal loss, which usually is at 30 to 45 degrees off the gas flow direction.

Corrective actions depend on the severity of the corrosion problem. An estimate of tube remaining service life should be performed on non-failed tubes several short-term actions involve using thicker tubes, shielding the tubes, or coating with a thermal sprayed corrosion-resistant material.

REPAIR PROCEDURES: Long term actions include replacing the tubes with a higher grade alloy, co-extruded tube steel or other surface treated tube steel; blending the coal to reduce the corrosive constituents in the ash; or lowering the metal temperature by modification of the final steam outlet temperature or redesign of the tubing circuits.



Typical ash deposits on a superheater tube from a pulverized coal-fired boiler.

COAL PARTICLE EROSION

COMMENT:

Coal particle erosion occurs in cyclone units as well as on wall fired and "T" fired where the burners are impinging the furnace water walls. This also occurs if coal is bypassing the burners.

LOCATION:

Coal particle erosion occurs in cyclone type coal burners where the introduction of combustion air at high velocity and tangent to the tube surface imparts a whirling motion to the incoming coal.

Coal particle erosion also occurs adjacent to tangent burner corners.

On water walls where flame and coal are impinging the walls.

EXTERNAL APPEARANCE:

Coal particle erosion produces thinning of the tube wall. A thin-edged fracture results when the wall thickness is reduced to a point beyond its ability to contain the internal water pressure.

INTERNAL APPEARANCE:

PROBABLE CAUSE:

Coal particle erosion is caused when the wear protective devices inside the cyclone burner no longer are able to perform their function.





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The root cause of coal particle erosion can be verified through observation of the condition of the wear-resistant liners and refractory coatings that have been installed to protect the boiler tubing. Observation of the flow patterns that are established in the burner from the introduction of secondary and tertiary air may reveal where significant erosion will occur. Visual examinations and ultrasonic (UT) tube wall thickness measurements are used to detect and monitor coal particle erosion. Small diameter UT transducers are used to obtain tube wall thickness measurements since the cylindrical studs welded onto the tube limit access to the tube surface. UT measurements provide data to determine the appropriate extent of immediate repairs after a failure and to plan for tubing replacement during a boiler overhaul outage.

CORRECTIVE ACTION:

Corrective actions involve surveillance and replacement of the wear-resistant liners and refractory coatings so that their protective function is not lost during boiler operation. Adjustments of secondary and tertiary air.

Coal connections if leaking should be repaired.

Flame impingement should be corrected.

REPAIR PROCEDURES:

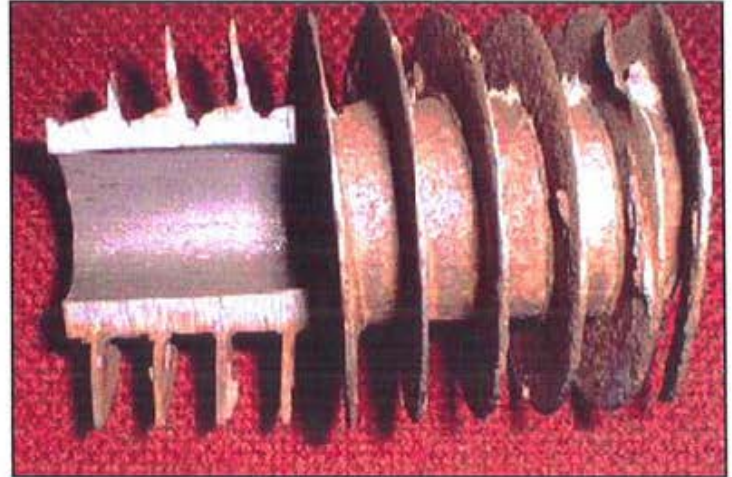
Replacement or pad welding, depending of the remaining thickness of thin tubes.

FLY ASH EROSION

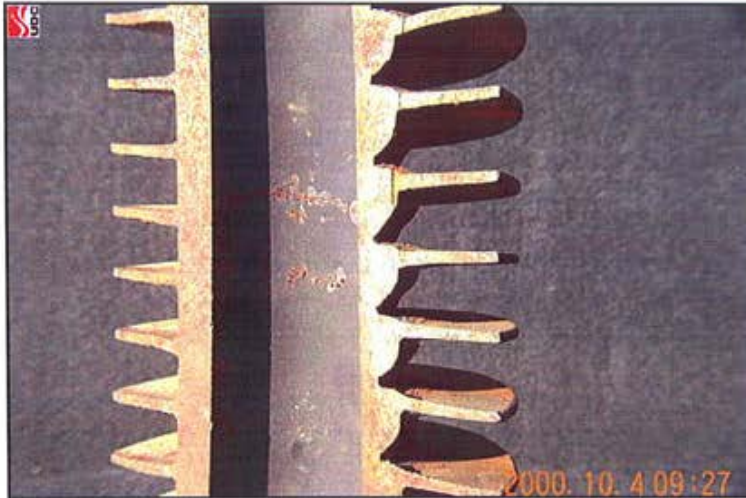
LOCATION:

Fly ash erosion can occur at locations that:

- (1) Have gaps between the tube bank and the duct walls.
- (2) Have gas by-pass channels where the velocity of the flue gas can be much higher than that of the main flow.
- (3) Have protrusions or misalignment of tubing rows.
- (4) Are adjacent to areas with large accumulations of ash.



PHYSICAL DESCRIPTION:



Fly ash erosion is caused by non-uniform or excessive gas flow, which accelerates a large volume of fly ash particles and directs them onto the tube surface. Tube erosion is enhanced by distortion or misalignment of tubing rows; misalignment or loss of gas flow guides and baffles; operation above the maximum continuous design rating, above design excess air flow, or with non uniform flow of flue gas; and fouling or plugging of gas passages by ash buildups. Changing fuel to one with higher ash content can result in more erosion and failures.

PROBABLE CAUSE:



The root causes of fly ash erosion can be verified by determining the reason for the non-uniform or excessive gas flow at the location of erosion. Misalignment of tubing or flow guides and buildup of ash can be seen and corrected without any further testing requirements. Verification of excessive gas flow requires reviewing operating practices and conditions and possibly conducting gas velocity tests. "Cold air" velocity tests have achieved good correlations between areas of high velocity and locations of failures.

Fly ash erosion produces polished flat spots from removal of the oxide and reduction in

wall thickness.

A longitudinal, thin-edged fracture results when the erosion rate is high but if the erosion occurs gradually over time; the fracture may be thick-edged due to long-term creep effects. Erosion damage is usually limited to a small area.

Visual examinations and ultrasonic (UT) tube wall thickness measurements are listed to detect and monitor fly ash erosion.

UT surveys should be conducted after a change in fuel supply or after a failure occurrence to determine the extent of erosion and to prevent a subsequent failure within a short time.

Periodic UT surveys can provide data for predicting remaining useful service life and planning corrective actions.

An estimate of remaining service life should be made on un failed tubes

Corrective actions involved either reducing the amount and velocity of ash striking the tube or increasing the amount of wear resistance of the tube.

Changing boiler operation conditions such as reducing load, lowering excess air levels, balancing airflows, modifying soot blowers, and preventing ash accumulations are possible actions to reduce the velocity of the ash. Structural changes such as baffles, fences, shields, and plates may also be made but care must be taken to prevent transfer of the erosion problem to another location.

Cold air tests should be conducted after such changes. Pad welding and spray are short-term actions which increase the amount of wear resistance of the tube. Staggered tubes arrangements replaced with in-line tube geometry.



Tubes may have a distinct flat area from the fly ash erosion. In the absence of a "UT" thickness meter, this flat can be measured and the thickness calculated from the cord of the tube wall.



The photo at the left shows fly ash erosion located on a convection pass sidewall. Any tube that sticks out will be impacted by the fly ash crowding the side wall areas.



Any shields that are miss matched will create a focused area of accelerated fly ash erosion.

In the back pass area it is likely that fly ash will ricochet between tubes. Use of a mirror will required to see the results of this ricocheting fly ash.



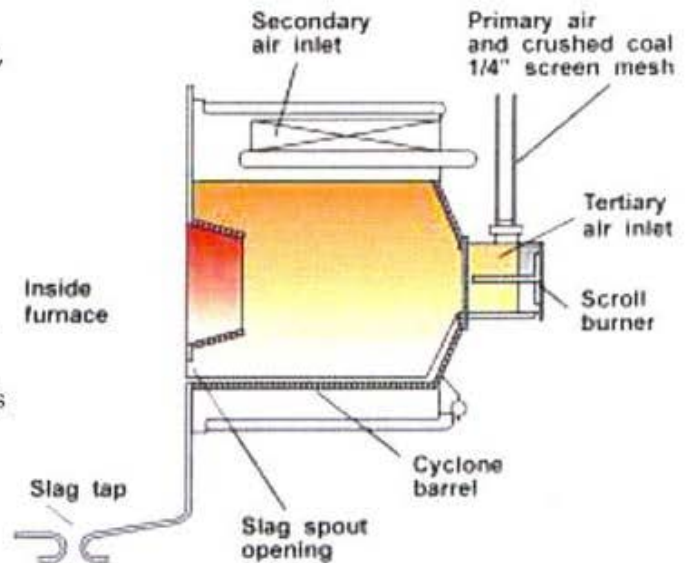
Fly ash can ricochet around spacer, hanger or offset tubes.



PRB Coal Fuel

PRB fuel used in Cyclone fired boilers

Cyclone boilers, which were built in the 50s and 60s, are an efficient, compact way to burn high-ash, high-sulfur coals to produce steam for power generation. The design coals produce a thick molten slag layer on the walls of each cyclone barrel. The slag coating catches the incoming coal and holds it until combustion is completed. When burning Powder River Basin (PRB) coal, however, the slag layer is too thin and watery to capture the coal, so the coal must burn in flight. Even though PRB coal burns faster than bituminous coal, there is just not enough time for combustion to be completed within the main furnace fire-box. The result is usually unacceptable amounts of unburned carbon in the flyash (fires in the ash collection system have occurred at some plants) as well as increased ash deposition, higher stack opacity, and reduced unit heat rate.



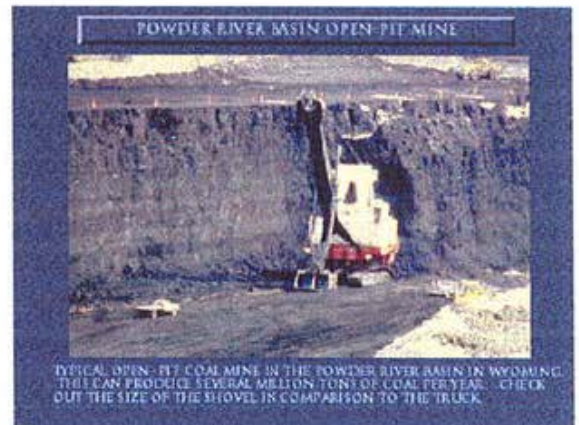
Another problem with PRB coal slag in a cyclone furnace is that it solidifies (freezes) abruptly during Low-load operation when the cyclone temperature drops. Since these boilers rely on keeping the slag molten all the way to the slag tap (a drain on the furnace floor) in order to operate, the freezing problem can cause unplanned shutdowns and lost revenues. In order to keep the PRB molten, these units must be operated at high loads even during periods of low demand which adversely effects power revenues. Finally, bottom ash is a more valuable commodity for sale to ash brokers than fly ash.



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Impact of PRB coal with pressure parts

PRB is not considered to be a high slagging coal in the traditional sense of the word. Unlike high slagging eastern coals, the ash accumulation caused by burning PRB is thin. However, the impact on surface effectiveness is generally the same as that of high slagging coals. The ash in PRB coal contains high amounts of calcium oxide (CaO). Because the calcium oxide is white, it causes the ash to be light colored and to have a reflective quality. When fired, a thin layer of light-colored ash quickly builds on the furnace water walls and any other radiant heat transfer surface. The reduction in surface effectiveness causes less heat to be absorbed in the water walls, roof and radiant superheater. The suppressed absorption in the furnace results in a high furnace exit gas temperature. PRB also has a relatively high fouling potential which must be considered. Due to the high gas temperatures, the hemispherical softening temperature of the ash can be exceeded at the furnace exit and into the convection surface, causing the ash to be "sticky". As a result, a layer of ash forms on the convection surfaces, and reacts chemically with the tubes and the hot flue gas to form a tenacious deposit which is difficult to remove. Fouling in the convection surfaces (HRA) generally begins as the ash accumulates in the back spacing between the tubes. This is known as "profiling".



Profiling with PRB coals is not uncommon in the primary superheater and the reheater. Over time, the backspace can become completely closed. This not only insulates a significant area of the heat transfer surface, but it changes the gas flow around the tubes and thus reduces the effectiveness of the surface.

Experience has indicated that fouling in the HRA is more significant in the primary superheater and the upper banks of the reheater. The severity of the fouling appears to be reduced in the lower HRA. Consequently, from a design standpoint, it is desirable to have ample clear space between elements in the upper HRA. If ample space between coils is not maintained, the ash accumulation may bridge the space between tubes. The higher gas temperature also helps drive the transfer of heat in spite of the decreased surface effectiveness. This is due to the higher log mean temperature differential (LMTD) between the gas and the steam. Even with the higher LMTD, heat transfer to the fouled tubes can not be maintained at the rate achieved with the clean tubes. The elevated flue gas temperature is then carried through the entire boiler. The result is a higher gas temperature leaving the economizer. If significant, this can potentially weaken the structural supports and the flue plate in the area above and below the lower economizer.

All structural equipment must be carefully examined for the gas temperatures experienced when burning PRB. The high gas temperatures combined with the high moisture content of PRB together results in lower boiler efficiency. In some cases, as much as a 5% reduction in boiler efficiency has been noted when switching to PRB coal firing.

Sandblasting whole boiler example



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PRB System design considerations

Highlights from the 2002 PRB Coal Users Group meeting included;

A major boiler manufacturer's representative expressed some opinions including a comparison of various PRB coals. The source of fuel observations were that: Wyoming/Montana border-not so good; southern Montana/Colstrip good; and eastern Wyoming-very good. A plant's analysis should begin, he emphasized, with an overall heat balance, fuel analysis, and study of emissions requirements, to understand how these factors affect furnace selection, surface arrangement, and tube spacing.

The specific coal will determine the size of the furnace. For example, a typical furnace burning a Gillette (Wyo) coal will require a ratio of net heat input per furnace cross-sectional area between 0.75 and 2.0. The specific coal also will determine the potential for ash fouling based on the Na₂O and CaO found in the fuel. An Na₂O concentration below 1 % indicates no fouling, while 2.5-5% indicates high ash fouling potential. The fuel further defines the tube layout configuration to minimize plugging and fouling, especially in the convective back pass.

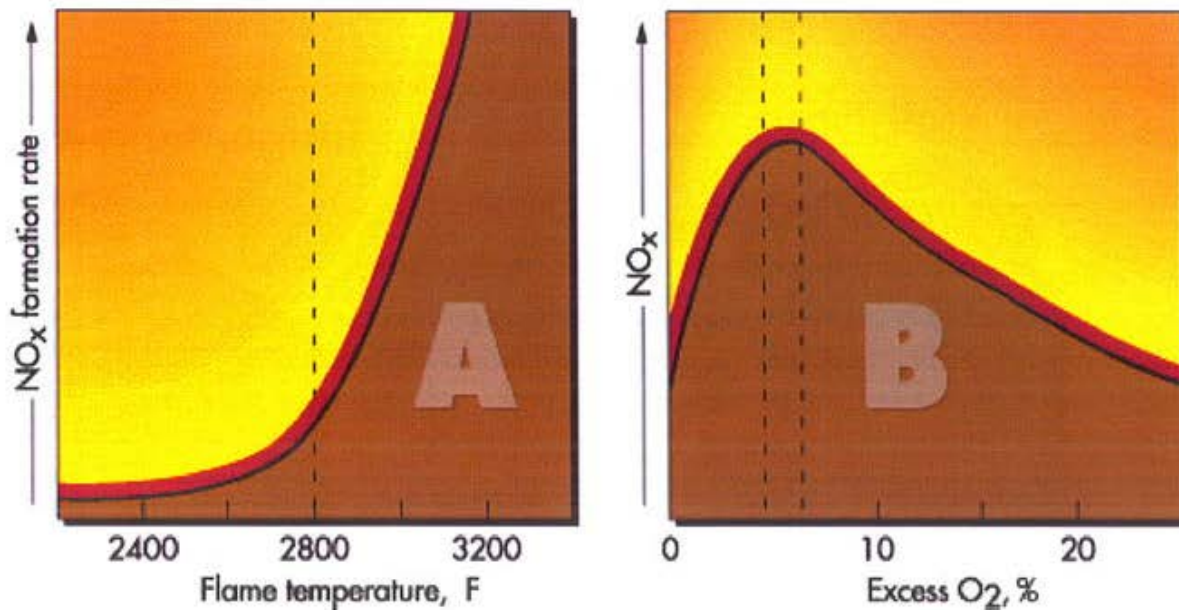
Another point expressed: While PRB coal is not erosive at gas velocities up to 80 ft/sec, significant tube erosion can and does come from improper soot blowing.

While much of the presentation focused on boiler design, he emphasized that when switching to PRB coal, desired changes aren't limited to the furnace. Pulverizer requirements, for instance, may increase 20% compared to bituminous coal firing, so you may need new motors, dynamic classifiers, and high-efficiency exhaustor wheels, and the hot-air temperature required for pulverizers will increase to as high as 750F. You also may need to update your air heater with loose pack surfaces, soot blowers, and off-line water washing. Your fans may need changing because gas flow increases approximately 5% by weight; and low excess air operation usually causes an increase in furnace-outlet temperatures and makes furnaces dirtier and harder to clean, especially in the upper furnace area.

A soot blower manufacturer picked up the theme of proper cleaning of a furnace. Pointing out that PRB coal ash can vary from thin to up to several inches thick. Thin deposits are typically white, while thicker coatings appear glossy. Both types are highly reflective, reducing furnace heat absorption and thus increasing furnace outlet and back pass temperatures.

A soot blower, therefore, should provide two features for removing deposits: a high level of nozzle impact pressure, and sufficient nozzle dwell time on the deposits for adequate removal without excessive tube erosion. Special offset nozzles have been developed that balance the performance between the two jets that can double the impact energy of a typical nozzle. The simplest system uses slag-rate mapping with infrared imaging systems or furnace-exit gas-temperature monitoring. State-of-the-art designs include heat-flux sensors in the furnace, and a furnace optimization system to control all the soot blowers.

Dwell time can be controlled by a programmable logic controller that slows down the carriage travel speed, and by variable-speed controls with nozzle-position feedback.

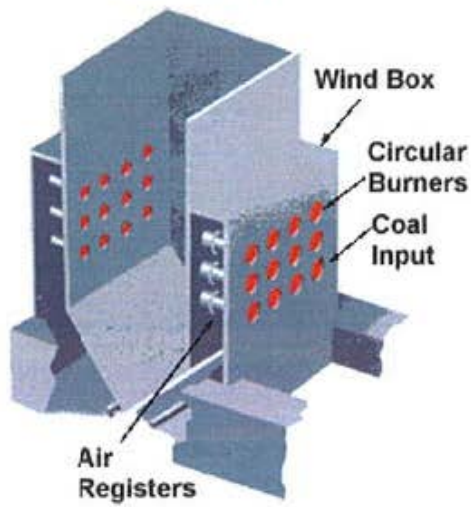


NO_x emissions have been linked to acid rain, photochemical smog, and tropospheric ozone destruction. This has led to establishment of regulatory measures and to development of technologies to reduce NO_x emissions from both existing and new power plants. Two general techniques are used to reduce NO_x emissions. The first type involves modification of the combustion process (staged combustion) and includes low-NO_x burners (with and without overfire air [OFA]) and gas or coal reburning; these methodologies are described in this section. The second type of NO_x reduction strategy involves post combustion removal and includes selective non catalytic NO_x reduction (SNCR), selective catalytic reduction (SCR), and combined SO₂/NO_x removal.

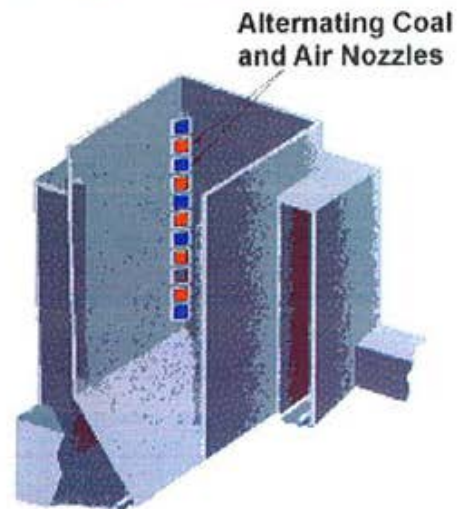
Wall-fired boilers can be fired either from opposed walls (as shown) or from a single wall. Each burner nozzle is surrounded by water tubes.

Before low-NO_x burners were developed, conventional wall-fired burners produced an intense, turbulent flame, which produces high levels of NO_x.

Wall-Fired



Tangentially-Fired



Tangentially-fired, or T-fired, boilers have a column of alternating coal and air nozzles mounted in each corner of the boiler.

The resulting lower temperature and diminished turbulence lead to inherently lower NO_x formation than is the case in wall-fired burners.

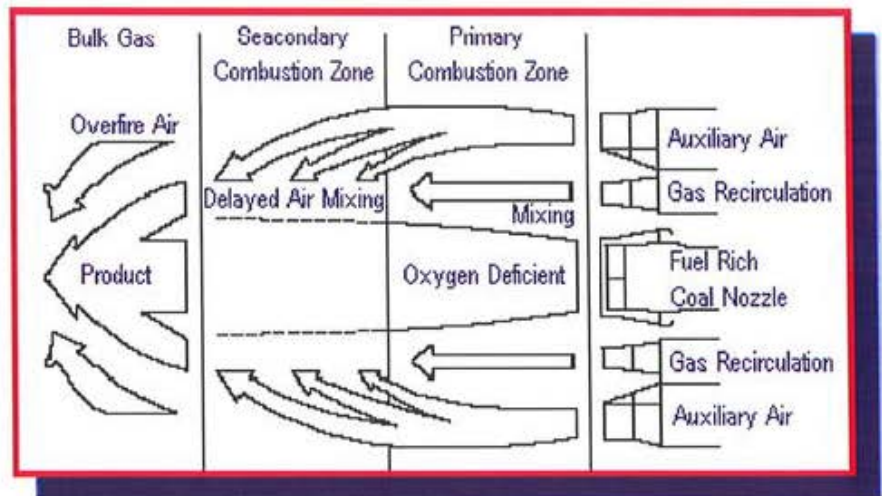
The Clean Coal Technology Program brought new low-polluting burner technology to hundreds of boilers designed and built before the New Source Performance Standards (NSPS) were established in 1971 (these boilers are referred to as pre-NSPS boilers).

Most of these units produced levels of NO_x well above the current Title IV (Acid Rain) emission regulations established by the Clean Air Act Amendments of 1990. Differences in boiler design were important for retrofitting clean coal technology because a majority of the 192,000 megawatts of pre-NSPS coal capacity consisted of boilers that produce the highest levels of NO_x (e.g., wall fired, cyclone, and cell burners).

T-fired boilers constituted 43%, wall-fired 26%, cyclone 15%, and cell burners 13% of the pre-NSPS boiler population in the United States. The remaining 5% consisted of other boiler types.

In addition, more than 70,000 megawatts of U.S. boiler capacity was subject to New Source Performance Standards.

Low-NO_x burners (LNBs) are designed to "stage" combustion (see Figure 2). In this technology, a fuel-rich combustion zone is created by forcing additional air to the outside of the firing zone (auxiliary air) and by delaying the combustion of coal. Reduction of 30 to 55 percent of NO_x can be achieved with low-NO_x burners. Advanced stage combustion technologies use overfire air and gas or coal reburning to achieve even greater reductions of NO_x.



The figure shows the introduction of auxiliary air outside the coal nozzle (right side of figure), which creates an oxygen-deficient region and delayed combustion in the primary and secondary combustion zones (center). Overfire air (left) completes the combustion.

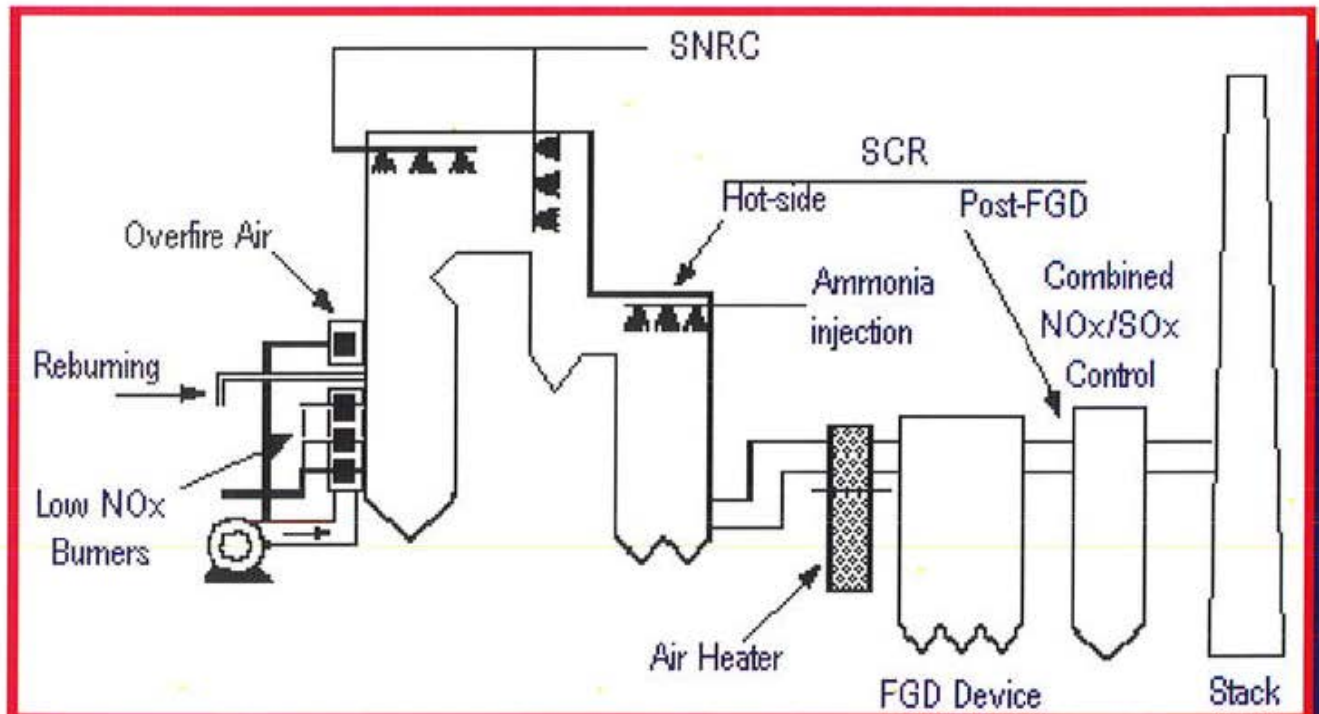
OFA systems introduce 10 to 25 percent of the combustion air above the main combustion zone, creating a fuel-rich combustion. LNB plus OFA can reduce NO_x by 40 to 60 percent, and gas or coal reburning can reduce NO_x by up to 60 to 70 percent.

Note: SCR = selective catalytic reduction

SNCR = selective non catalytic reduction

FGD = flue gas desulphurization

The figure shows both combustion and post combustion NO_x controls. The left side of the figure shows technologies used in the burner low-NO_x burners, overfire air, and reburning. The top and right sides of the figure show technologies used downstream of the boiler - SNCR, SCR (hot-side and post-FGD), and combined NO_x /SO_x technologies.





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In reburning, the rate of flow of coal into the main combustion zone is reduced by up to 20 percent; it is replaced by an equal heat input of natural gas or coal introduced above the main combustion zone (see Figure 2.1). The NO_x reduction potential of these three low-NO_x burner systems, as well as the associated capital costs, operating and maintenance impacts, and required outage for retrofit are summarized in Table 2.4 below.

2.4.

Key Characteristics of Low-NO _x Burner Technologies						
	Costs (US\$/kW)			O&M Impacts (mill/kWh)		
Technology	Retrofit	New Boiler	NO _x Reduction %	Retrofit	New Boiler	Retrofit Outage
LNB	5-10	1-3	30-55	<1 ¹	None	3-5
LNB + OFA	10-25	3-10	40-60	<1 ¹	None	4-9
Reburning	20-50	10-30	50-70	1-4	1-4	5-10

Note:

LNB = low-NO_x burner

OFA = overfire air

LNB and LNB plus OFA are being used commercially in Europe, Japan, and the United States. New boilers in industrialized countries all use low-NO_x burners, and retrofits of old boilers are being legislated in many cases. In the United States, more than 280 plants with a total of 100,000 MW of generating capacity were retrofitted with low-NO_x burners during 1992-94. Reburning has been installed in 15 boilers in the US and another 15 in Europe (mostly in Italy).

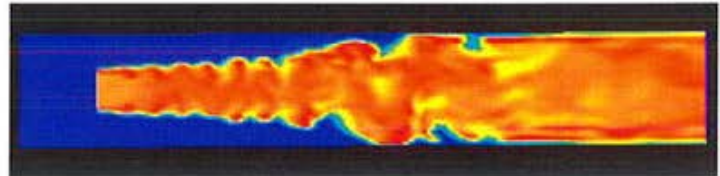
The costs of retrofitting existing boilers with low-NO_x burners range from US\$5/kW for LNB to US\$50/kW for reburning. The capital costs of incorporating such systems into new boilers are a fraction of the costs for retrofitting existing boilers. For example, incorporating a LNB + OFA into a new boiler adds only US\$3 to 10/kW, whereas retrofitting an existing boiler may cost up to US\$25/kW. The cost-effectiveness (in terms of US\$/ton of NO_x removed) depends on the capital costs, O&M impact, and required NO_x reduction. Typical ranges of cost-effectiveness are as follows:

- LNB: 100 to 400 US\$/ton NO_x removed
- LNB + OFA: 200 to 400 US\$/ton NO_x removed
- Reburning: 500 to 1,200 US\$/ton NO_x removed.

Cyclone and cell units represent more than 50% of the NO_x generated by pre-NSPS coal-fired boilers.

The effect of combustion on water wall corrosion

The presence of reducing gases implies that insufficient oxygen is supplied to the combustion zone by improper air/coal mixing, and a high heat flux dictates the existence of a high metal temperature on the furnace-wall. Under insufficient oxygen



conditions, sulfur in coal is primarily converted to sulfide (H_2S) instead of sulfur oxide (SO_x). The H_2S gas is very corrosive and readily sulfidizes the conventional furnace-wall alloys. The sulfidation of the furnace-wall alloys is further escalated by high metal temperature. Therefore, when a large H_2S concentration and a high metal temperature coexist, accelerated corrosion wastage on the furnace-wall is expected.

A combination of these conditions could have accounted for the majority of the corrosion wastage.

It has been suggested that the accelerated corrosion took place mainly on the furnace-wall where substoichiometric combustion and high heat flux coexisted. Accelerated corrosion wastage has been experienced by some US utilities in the past few years after the implementation of low- NO_x burners. By design, the low- NO_x burners create a substoichiometric combustion zone to reduce NO_x formation. While NO_x reduction is achieved, the substoichiometric combustion mechanism also generates a significant amount of H_2S in the flue gases, which can be very corrosive, and through sulfidation, it affects boiler performance.

British researchers generally believe that the presence of chlorine in the substoichiometric combustion condition would further elevate the flue gas corrosivity.



The mechanism of waterwall fireside corrosion is generally found at the crown of the tube facing the fire of the furnace and can encompass the tube circumferentially. Damage is usually found beneath the loosely bonded ash attached to a hard fired inner-layer deposit that usually contains unburned carbon, iron oxide and iron sulfides (FeS). This deposit is usually indicative of poor combustion, flame impingement, local reducing conditions and corrosive producing fuels (high sulfur, high chlorine, etc.)

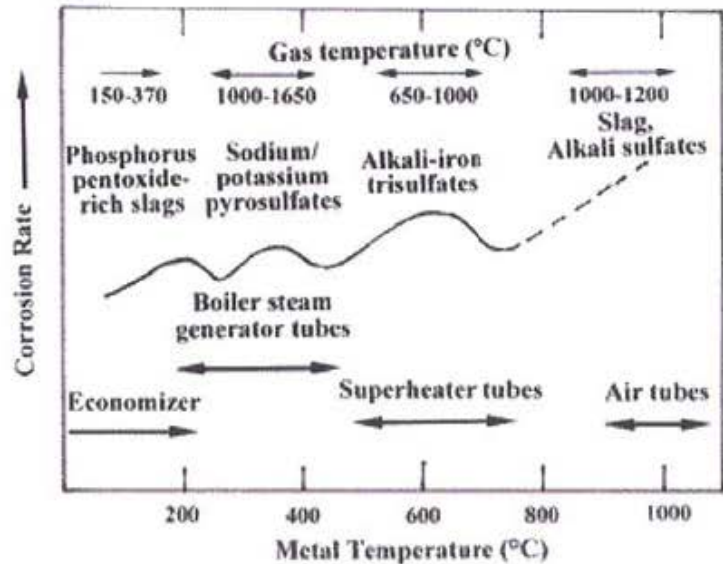
General Conclusions on the Conditions that affect Furnace Corrosion are:

In areas of high waterwall wastage, the characteristics of the solids deposited are more important than the gaseous reducing conditions on the wall. There is a high possibility that the most aggressive conditions are created when the deposits are rich in unburned carbon and iron sulfide and the gas phrase fluctuates between the oxidizing and reducing.

Deposition of unburned carbon and iron sulfides in fuel rich regions produce less, but still very significant, aggressive conditions.

Significant but less waterwall wastage rates can occur under the combination of circumstances, which involve gaseous reducing conditions on the wall, deposition of unburned carbon material and high incident heat fluxes.

Various Solution Options include:
 Weld Overlay in the Field
 Weld Overlaid Replacement Panels
 Chromized Replacement Panels
 Thermal Sprayed Coating



7. Component Replacements

Economic justification tips

The decision to replace a component is usually the result of inspection activities and component failures, which, left unchecked, will result in unacceptable availability. Management has a low tolerance for this condition as it adversely affects the business model of the plant. However, one must exercise caution when recommending wholesale component replacement.

Chronic tube leaks do not necessarily warrant component replacement. The root cause condition of the failures must be assessed prior to making the determination that no other action will yield the required results short of replacement. Often interim steps can be taken that will extend the useful life of a component such as shielding and pad welding. Partial replacements are often most appropriate when extending the useful life without total replacement.

Only use total replacement as a last resort measure, not an interim measure. Use your inspections, life extension or assessment reports, and your tube sampling and analysis all in concert to establish your replacement strategy. Sometimes management will wait until failures become a regular occurrence before they will take appropriate steps in this area. It behooves the team leader to justify his recommendation for replacement with an intelligent, well-articulated cost benefit analysis. Illustrating the cost of a tube leak is an essential step in this process.



The decision to replace boiler components is 100% determined by economics. When the results or consequences are more expensive than the cost to replace the component are reached, management will easily approve the capital outlay.

Never forget that we are not in the power business we are in the money business. Our job is to be timely with the replacement as a project. You can't pick up a new Superheater on the way to work. Pressure part replacements require planning engineering and scheduling considerations. We must be three to five years ahead of the required replacement. Based on the justifications discussed above we must be careful to hit the window of opportunity right on the bull's eye.

Information is our only weapon in this process. We must know operating conditions, previous outages when where and why. We must have samples analyzed and projections drawn from those samples. We must rely on NDE examinations and assessment information. Most of all we must inspect track and analyze data. There will be telling signs of problems to come.



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Networking is very important as other plants have similar equipment. This can be on an intra company as well as industry network of consultants, manufactures and user groups.

Once all of this data is digested and it is determined that the component is at risk, management should be alerted that it is likely that there will be some financial impact. Management needs to be advised of the entire risk. Remember the consequences will have to out weigh the capital costs.

Risk management is a concept we all need to be very familiar with. Our basic job description as boiler specialist is that of boiler risk management.



It is possible and even likely that we can keep an old deteriorated component viable long after its normal demise. We can upgrade materials; partially replace sections or areas and other proactive repairs short of total replacement.

Component Replacements \ Replace versus Repair the How's and Whys

What information should a plant use to determine whether to repair, replace or refurbish a boiler component? Most plants would use Budgets, Unit Value to Plant and System, Failure History, Repair History, Change in boiler operations due to fuel changes and or Low NOX equipment, Replications, Boiler Inspection Team recommendations, remaining unit service life, and Tube samples to justify their decisions. Do we always make the most economical and best business decisions?

Budgets

Corporate Accountants classified through the Unit Retirement Book whether the Boiler Component is a Capital Expenditure or O&M Expenditure. This clarification will define what portion of the equipment must be replaced in order for the replacement to be classified as a capital expenditure. A capital expenditure goes toward the company's rate base expensed out over thirty years. O&M expenditures are part of the company's expenses and are expensed out during the current year. However, a dollar is a dollar whether it is O&M or Capital.



Unit Value to Plant and System

The value of the unit to the plant and system depends on the unit position in dispatch. The value of the unit is based on heat rate, response time in regulating, generation capability, fuel cost, variable O&M, maintenance cost and system integrity.

We must take into account the short term and long term cost and value of the units. These decisions will assist the plant in providing the information that would allow them to make "educated and informed" decisions that are cost driven. Even with these tools the plants must step back and determine if the "calculated risk" provided by these tools are realistic. For an example: a unit has a small Superheater leak on Tuesday, and the cost to bring the unit off line is double the cost if the unit is held on line to Friday night. However, if the unit remains on line, the maintenance cost to repair the damage could be many times more than if the unit had been removed from service on Tuesday. Justification of boiler capital projects will almost always be justified by EFOR.

Failure History

Failure history of the unit can assist in determining the predicted remaining life of the unit based on the current frequency of leaks. This information can also assist in determining the root cause problem of the failures.

Documented localized failures may indicate only a localized problem and could be repaired rather than total replacement. Localized problems could be flow initiated steam or gas side. Problems with the same



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tube within each panel could be a material problem. Failures in tube panels could be related to operational, fuel, and/or environmental changes within the unit.

Repair History

Repair history just like failure history is important information in determining the extent of damage in existing pressure parts. The repair history can also help determining the root cause of the failures.

Change in Operations

Changes in operations due to fuel and/or environmental changes could greatly reduce the remaining life of boiler components. Fuel changes that increase the amount of fly ash flow, fuel changes involving additional chlorine and/or sulphur content, and fuel changes that change the staging characteristics of the boiler could all reduce the life of the boiler components. Operator changes that are required due to some of the above problems (like running gas fan continuously, running with burner tilts in the + tilt direction, firing the boiler for Low NO_x by reducing furnace O₂) can also reduce the life of the boiler.

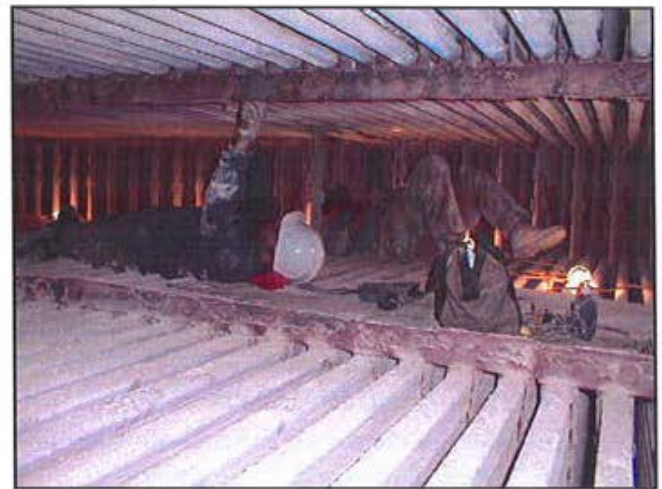


Replications, Tube Samples, etc.

Replications, Tube samples, UT data, radiography, etc. are testing and sampling methods that are valuable tools that can assist in determining the existing damage and remaining life of the boiler components. This metallurgical information is essential in the assessment of the boiler components.

Boiler Inspection Team Findings

The inspection findings provided by the boiler inspection teams have allowed the plants to identify boiler component problems and have enabled the management at the plants to prioritize boiler repairs.



Replacements versus Repairing

Should we repair or replace the boiler component in question? Many of the assessment tools above should provide the information required to make this decision. Is the damage localized to a few panels at the center of the boiler, is the damage on tube 5 -8, is the damage in the T22 material, is the damage at a weld line or tube tie, are all questions that must be addressed? Should the new boiler component be fabricated in loose pieces or provided in a modular form? Can quality of the new boiler component be guaranteed if installed as the loose option from the manufacturer? Can the new boiler component be installed as fabricated? Can the boiler component be fabricated with more details such that the installation will be a lower cost? Due to the current operations, does the effective surface area of the boiler component require changing? Should the material used in the fabrication require upgrading due to maintenance or corrosion concerns? Should the new boiler components be provided with orifices in order to balance the steam/water flow through the tube circuits? How does the replacement of this boiler section affect the operation/maintenance of the rest of the boiler?

7"Sell" The Concept by Measuring The Dollar Impact

Steam, and energy efficiency programs, can be moved up the list of corporate priorities if their presentation responds to specific corporate needs. Study past corporate challenges to similar schemes, and identify opportunities to "sell" energy efficiency related programs as a solution. Hire a specialized [consultant](#) in order to assist you, both with the technical aspects of your proposal, and to quantify the potential savings.

Life Cycle Costs

The first step is to identify and quantify the total dollar impact of your steam, or energy efficiency proposal. A typical framework for such a task is known as "life-cycle cost analysis". This analysis captures the sum total of expenses and benefits associated with the project. This will result in either a net gain, or loss on balance, and can be compared to other investment options, or to the anticipated outcome if no investment is made. Typically, a life-cycle cost analysis for our hypothetical steam project would include projections of:

- Contractual fees for implementing the project
- Initial capital costs, and the cost of borrowing.
- Maintenance costs.
- Supply and consumable costs.
- Energy costs over the economic life of the equipment.
- Depreciation and tax impacts.
- Scrap value, and the cost of disposal.
- Impact on production, such as downtime, and product quality.

Concerning boiler and steam utilities, one revelation that typically emerges from such an analysis, is that fuel costs may represent as much as 96% of the life-cycle costs, while the initial capital expenditure is only 3%, and maintenance costs, a mere 1%.

These figures are true for boilers and steam installations with a 20-year life, operating at high rates of capacity utilization. Then clearly, any measure that contributes to reduced fuel consumption, (while not impacting on reliability and productivity) will certainly yield positive financial benefits for the company.



Beware Of the "Simple Payback" Trap

As with all corporate investments, there are many ways to assess the economic impact of energy efficiency programs. Some may be more complex than others. Generally speaking, the choice of analyses employed will depend upon the sophistication of the presenter and the audience.

In dealing with the unsophisticated plant director, or engineering manager, the corporate comptroller will probably be tempted to employ a simple, (yet widely used) measure of a project economics called the payback period. Simply put, this is defined as the period of time required for a project to "break even". It is the time for the net benefits of the investment to accrue to the point where they are equal to the initial capital outlay.

For any project that returns financial benefits in consistent, annual increments, the simple payback is equal to the initial investment divided by the annual benefit. However, simple payback does not take into account the time value of money, no distinction is made between the value of "today's" dollar earned, versus a dollar of future (and uncertain) earnings. Still, the simple payback, is simple to understand, and it is used to effect by many corporate financial comptrollers, as a simple "go/no-go" decision on a project. However, you need to remember five important factors when discussing, and calculating simple payback, with your corporate comptroller:-

- Simple payback is an approximation, not an exact analysis.
- All benefits are considered without considering their timing.
- All economic consequences beyond the payback are ignored.
- Payback calculations will not always find the best solution (for the above two reasons) when choosing between several options.
- Payback does not consider the time value of money or tax consequences.

Another commonly used calculation for determining the economic feasibility of a project is internal rate of return, which is defined as the discount rate that equates future net benefits (cash) to an initial investment outlay. This discount rate can be compared to the corporation's interest rate at which it borrows capital. Many companies will set a threshold (or hurdle) rate for a project to be considered viable. Future benefits are discounted at the threshold rate, and the net present worth of the project must be positive for the project to be considered a "doer".

Get The Plant Finance Group On-Board

During the study and preparation of your energy related project, and prior to presentation, it is critical that you include the plant financial staff as part of your project team. Many benefits will come from this strategy. Generally, plant financial staff are in direct contact with the corporate financial comptroller at regular intervals, normally during the generation of monthly "flash reports". Intelligence gathered by plant financial staff from their corporate brethren will enable you to assess which of the above approaches is best suited for the current corporate climate.

The Presentation...Avoid the "One Man Band" Approach

The initial presentation should last no longer than 45 minutes, and should include three speakers, and a question and answer period. The presentation would normally include, the plant director, the plant financial comptroller, and the plant engineering manager. This will convey the impression of a team effort, and a well rounded presentation. You should be aware that the financial benefits of a project alone, may not be enough for some corporate observers. The plant directors position may be strengthened by relating a positive life-cycle cost outcome to corporate needs. Some suggestions for your presentation are as follows:

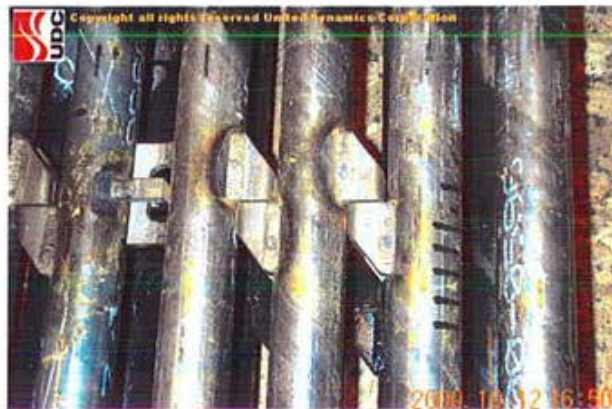
Equipment replacement and or modifications

Whenever a systemic change is made we must consider the potential impact those changes may have through out the boiler system. The entire system will be affected with change of any kind. For example if we replace a reheater with a new stainless steel reheater we must:

Consider thermal expansion since the reheater will expand at a higher rate than the previous hybrid reheater.

The stainless steel will have different heat absorption profile than the hybrid. How will this affect the spray water desuperheaters, downstream temperatures to other components? Also the stainless steel version will have different support and flexible alignment design than the original.

What is the condition of the terminal tubes from the DMW just above the penthouse floor to the header. In many cases we will replace the major component and miss the terminal tubes or the header itself in our assessment.



The above is just one partial example of the compound affect of making a change in the system.



8. Selection and installation of pressure part components

STRENGTH BASIS OF MATERIAL SELECTION OF BOILER PRESSURE PARTS

A) The ASME Boiler Code assigns allowable stresses for each grade of steel at temperature intervals of 100° F or 50° F.

B) Further, the code provides a basis for determining the thickness of pressure part components based on the design temperature using these assigned allowable stresses.

C) Time Independent vs. Time Dependent

(1) At temperatures exceeding about 650° F, most steel suffers a gradual decrease in tensile and yield strength. At still higher temperatures, the strain in a material is a function of the applied stress and the time under stress at temperature. In this high temperature range the metal will deform (creep) continuously even at stresses much lower than the short time yield strength. If held for sufficient time under these conditions, the material will stress rupture.

(2) The behavior in the creep range is called the time dependent temperature regime (time at temperature and stress is important to the rate of deformation and rupture life).

(3) The behavior at temperature below the creep range is called the time independent temperature regime (time has no effect on deformation or rupture at constant stress).

D) To determine these allowable stresses, the code reviews tensile and stress rupture property data obtained over the temperature range of usage and applies the following criteria listed in paragraph A-150 of section 1 (POWER BOILERS) of the code.

(1) 1/4 of the specified minimum tensile strength at room temperature.

(2) 1/4 of the tensile strength at elevated temperatures.

(3) 2/3 of the specified minimum yields strength at room temperature.

(4) 2/3 of the yield strength at elevated temperatures.

(5) One hundred percent of the stress to produce a creep rate of 0.01 percent in 1,000 hr.

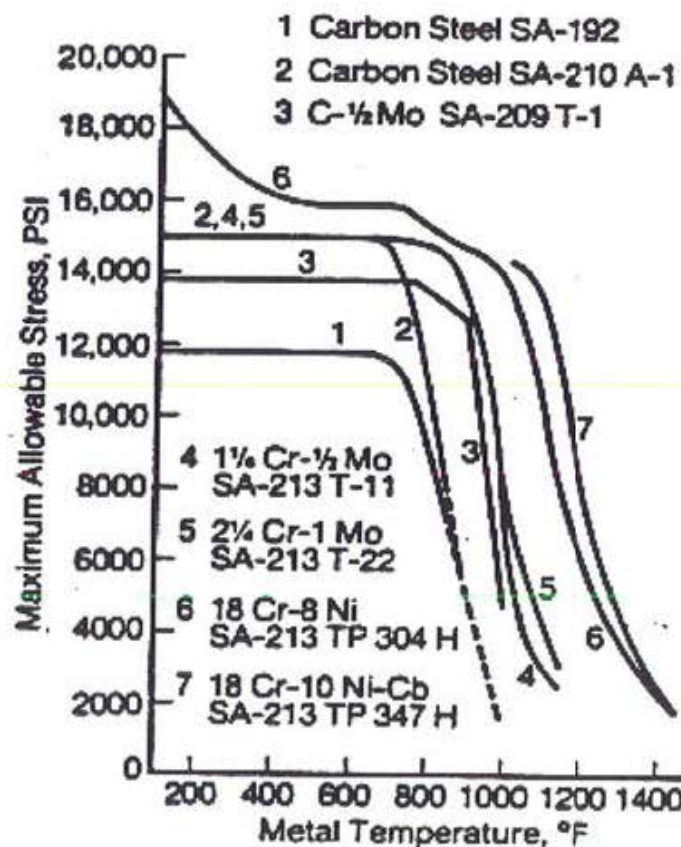
Sixty seven percent of the average stress to produce rupture at the end of 100,000 hours or eighty percent of the minimum stress for rupture at the end of 100,000 hours and be determined from the extrapolated data, whichever is lower.

E) Note that the code assesses in a conservative manner the rupture (tensile strength) and deformation (yield strength) behavior in the time independent regime (1-4). Further the rupture (stress rupture strength) and deformation (creep strength) behavior in the time dependent regime (5 and 6) is also assessed. The lowest strength value after application of these criteria to the material test data is the allowable stress assigned for each temperature increment evaluated.

F) Illustrates how creep and rupture strengths for 2-1/4 Cr-1 Mo steel are established from test data. Creep-rate data for 1000°, 1100° and 1200° F are plotted versus stress. The intersection of these data lines with that for 0.01 percent in 1,000 hours sets the respective creep strengths of 7,800 psi, 5,000 psi and 2,400 psi. The other curves show rupture life versus stress for the same three temperatures. Lines through these data are extrapolated to 100,000 hours to establish rupture strengths of 13,000 psi, 7,000 psi and 3,300 psi, respectively.

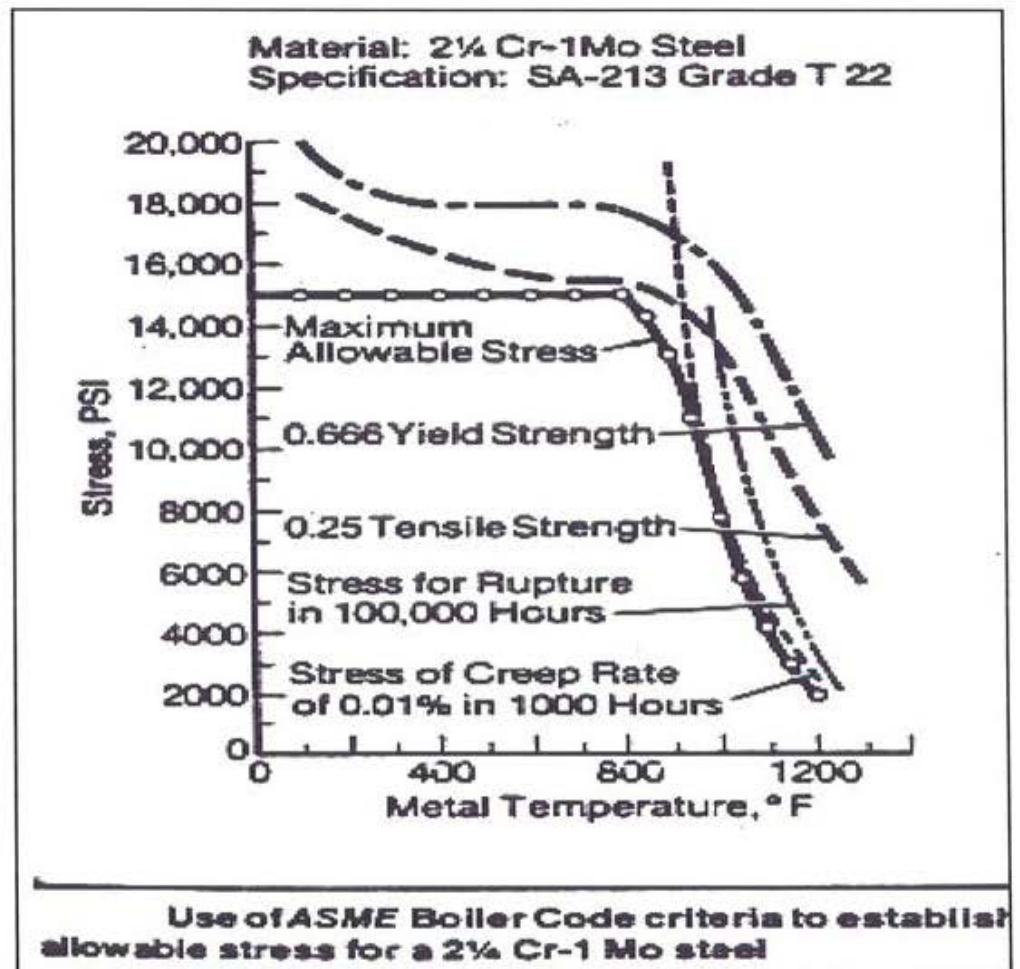
G) Note that because of the percentage factors applied to the 100,000 hour intercept of minimum and maximum rupture strength, there is a considerable life span expected for materials operating at the code allowable stresses. However, the "expected" life is not predictable. The code has no specific life span in mind when setting allowable stresses. A long useful life is the intent.

H) (Figure 3) shows how the Figure 2 data is applied to establish allowable stresses for T-22 tubing. The criteria of 1/4 of specified minimum tensile strength at room temperature controls for this material up to 800° F. At 950° F and above, the creep and rupture strength criteria require a rather sharp decrease in the allowable stress.



Effect of temperature on ASME Boiler Code allowable stresses for grades of steel tubing

I) The relative influence of the different criteria varies with materials as well as with temperature. The carbon steels begin to lose strength above 700° F and by 850° F are down to about one half their room temperature values. The low chromium ferritic alloys start to lose strength above 800° F. At this point, the alloys are decreased to half strength at about 1000° F because of a reduction in yield strength. Above 1000° F, creep and rupture strength cause a rapid decrease to half strength or less by 1200° F.



OTHER CONSIDERATIONS IN MATERIALS SELECTION AND USE

A). Graphitization

(1) The carbon normally present in the steel in the form of carbides may transform over a long period to graphite.

(2) This transformation may take place preferentially along heat affected zones of welds, or along stress lines, to form chain type graphitization.

(3) Carbon steel pipe and carbon molybdenum pipe in long-time service, particularly when generated at temperatures well above 800° F and 875° F, respectively, have experienced numerous instances of chain-type graphitization resulting in failure or requiring repair or replacement.

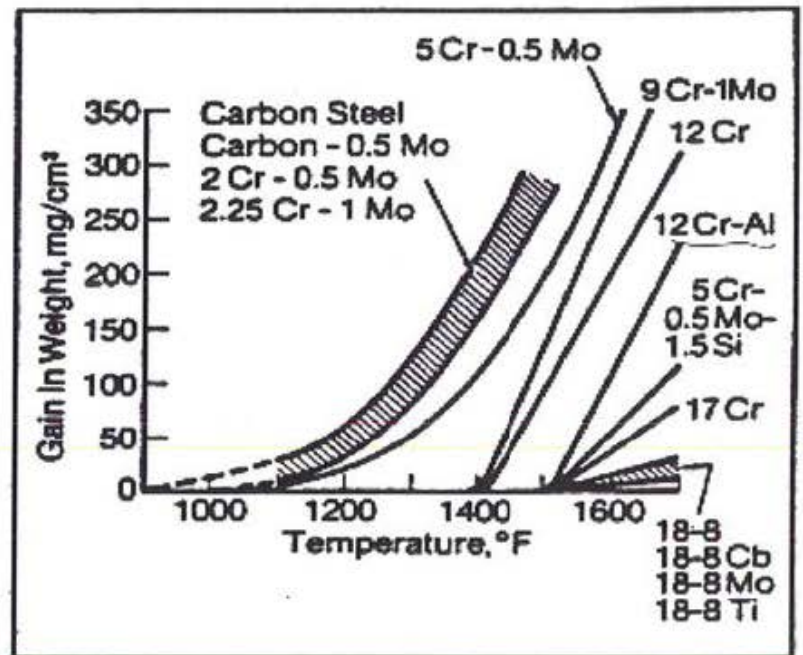
(4) Because of these problems, OEMs have for many years avoided the use of carbon molybdenum for piping components and has limited the use of carbon steel pipe to 800° F.

(5) For higher temperature service, the use of steels containing one half percent or more chromium eliminates the danger of graphitization.

(6) Carbon steel and carbon molybdenum tubing has not shown a similar tendency to graphitize as has piping.

(7) The graphitization occasionally found in tubing is usually in the form of well-dispersed nodules that do not weaken the steel.

(8) Carbon steel and carbon molybdenum tubing may be used in applications when the temperatures reach 850° F and 900° F, respectively.



Amount of oxidation (scaling) of carbon, low-alloy, and stainless steels in 1000 hours in air at temperatures from 1100° to 1700° F



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B. Oxidation and Corrosion Resistance

- (1) Chromium is the most useful alloying element for imparting oxidation and corrosion resistance to steel. (Figure 4) shows the degree of oxidation sealing versus temperature for a number of steels with a range of chromium from 0 to 18 percent. Note that silicon and aluminum also improve resistance to oxidation scaling.
- (2) Similarly, chromium additions improve resistance of steel to molten ash corrosion.
- (3) Low levels of chromium, in the range of 1/2 to 2-1/4 percent, provide a useful improvement in high temperature and corrosion resistance. Within this chromium range, high temperature strength accompanies the trend of somewhat improved corrosion resistance.
- (4) For these reasons, there is widespread use of the family of low chromium alloys, up to 2-1/4, Cr, for intermediate temperature range applications, where carbon steel and carbon molybdenum are not used because of their low high-temperature strength and their tendencies to graphitize.
- (5) The temperatures at which these low-chromium alloy grades are used involve considerations of high-temperature strength and corrosion /oxidation resistance.
- (6) For superheater and reheater tubes in the boiler gas pass, alloy grades SA-213 T-11 1-1/4% CO and T-22, 2-1/4% CO are limited by C-E to gas side surface temperatures of 1025° F and 1075° F, respectively.
- (7) These temperatures, well below the point at which oxidation scaling is significant, were established based on review of data detailing the external wastage rate from units in service experiencing coal-ash corrosion.
- (8) With these limits, excessive external corrosion leading to metal loss is not expected even when coals with a corrosive tendency are burned.
- (9) Generally the 2-1/4 Cr-1 Mo steel is the highest alloy used for pressure part components outside of the gas pass because the metal has good strength and is oxidation resistant at outlet steam temperatures between 1005° and 1055° F. Because some gas touched portions of the superheater and reheater are exposed to skin metal temperatures in excess of 1075° F, alloys with high temperature strength and oxidation / corrosion resistance are needed.
- (10) There has been some past use of tubing with 5 percent chromium, but oddly these alloys did not provide a significant improvement in corrosion resistance and have lower high temperature strength than the T-22 grade.
- (11) 1) SA-213 T-9 (9 Cr-1 Mo) has been and continues to be used in some reheaters. The material has good oxidation/corrosion resistance and may be used to outside surface temperatures as high as 1175° F. At these temperatures the high temperature strength (ASME allowable mid wall stresses) is quite low, less than that for the T-22 (2-1/4 Cr - 1 Mo) grade.



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(12) AUSTENITIC stainless steels (grades grade 304H and TP 347H) are used for most of the tubing operating at surface metal temperatures above 1075° F. Not only do these materials have excellent high strength properties, which are characteristic of austenite, but they also have excellent oxidation resistance because of their 18 percent (nominal composition) chromium content.

(13) However, it is important to recognize that no tube alloy operating above 1,000° F is immune to oil or coal ash corrosion. By virtue of their higher operating temperatures, the austenitic stainless steels will experience metal loss if there are molten ash deposits.

(14) Chromium is also important to the selection of non-pressure part materials such as shields, baffles, and spacer attachments that will operate at elevated temperatures approaching gas temperature. In a coal fired environment where corrosive ash cannot exist above 1350 ° F, the flue gas oxidation rate is similar to that in air; therefore, data is useful for selecting these components. Type 309 is commonly used for these applications.



9. Commercial issues of procurement of new pressure parts

There are two different types of pressure part component replacements:

"Replaced in kind" is the most common as this is the easiest project type to engineer, specify and procure. This type of project will have the least impact from a "new source review" standpoint. This type of project requires a minimum of engineering and no input required from the original OEM. In this mode most tube benders can provide a suitable quality product for the replacement. You should require field measurements from vendors to place the responsibility of fit and suitability squarely on them.

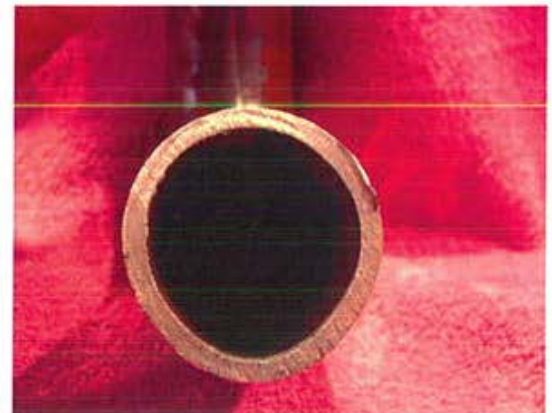
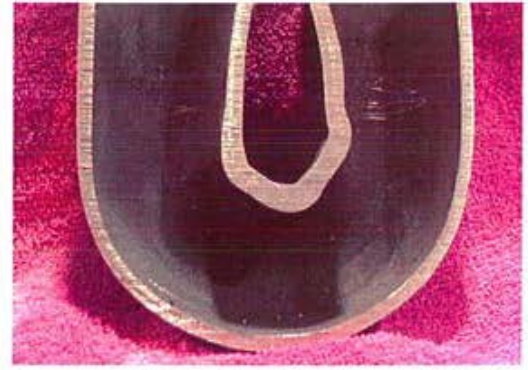
"New design" would include a change in material like a hybrid reheater with a stainless steel reheater. Another example would be a scenario of increasing or reducing the heating surface in a component. This category of replacement will require legal review to determine suitability with environmental regulations concerning new source review. We suggest that if this type of replacement is anticipated then engineering, the OEM, and your legal department be consulted in this process. Proceed with caution!

We have provided a general outline of a UDC specification for component replacements. This is illustrating some of the general topics that should be covered in your purchasing requirements. Never call the OEM and order a replacement in kind as the OEM will surely take financial advantage of your circumstances. We have seen this to be true historically time after time.

Inspection of new fabrications in the assembly shop QA/QC

It is important to have qualified inspection and surveillance of any new fabrications you may order. This will keep the fabricator honest. Remember you will have to live with this pressure part for a very long time to come. The photographs below are actual new parts that were rejected for poor quality. This type of fabrication can get into your boiler very easily if you do not monitor this process carefully. Many failure conditions are a result of this type of poor craftsmanship or inadequate procedures.

These types of fabrication errors cause flow disruptions as well as hoop stress issues all of which will likely result in tube failures.



Ovality and crushing are a prime concern especially in tight bends like hair pins.



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There are complex procedures in the proper fabrication of boiler tubing. The stress introduced into the assembly can set up a future failure.



Failures due to material or fabrication error

CREEP, LOW TEMPERATURE

COMMENT:

Low temperature creep occurs from a relatively continuous extended period of slight overheating 570° - 790° well above the design metal temperature, from a slowly increasing level of temperature or stress, or from the accumulation of periods of excessive overheating. This is usually complicated by stresses from other sources.

LOCATION:

Occur primarily in medium temperature locations such as primary superheat, low temperature reheat and economizer tubes. It is usually found in high residual stress locations imitated by the tube bending process.

EXTERNAL APPEARANCE:

This condition usually manifests itself as a crack on the outside surface of a tube bend.

INTERNAL APPEARANCE:

The tube internal surface may also have a thick hard oxide scale with oxide, which have an alligator hide appearance.

PROBABLE CAUSE:

Creep low temperature is often confused with stress corrosion or fatigue cracking. The difference is that only creep low temperature will exhibit evidence of grain boundary creep cavitations and creep voids.

High stress areas from the tube bending (forming) process. Cold working is the most stressed.

High mismatch in ovality of the tubing greater than 8%

High hardness in material usually due to the forming process greater than 220-240 HV

Hammer blows or shot gun dents can create stress areas that are of concern

CORRECTIVE ACTION:





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Replace the failed tube bend and plan to replace all other similar tube bends during the next most convenient time. If you have this condition in one element you probably have it in all like loops.

REPAIR PROCEDURES:

Tube replacement is the preferred method of repair. Pad welding is not recommended even in forced outage conditions. Complete removal of all stress is unlikely and a repeat failure is likely in the same general site.



10. BOILER CHEMISTRY

Boiler Cycle chemistry

Why water chemistry is important.

Water, one of the building blocks of life, is rarely ever "pure" -- except, maybe, in a lab. Most water contains different impurities and compounds, and hence has different characteristics.

Dissolved minerals, acidity or alkalinity balance, dissolved gases -- they all can affect the longevity of equipment. But even pure water is not enough to prevent equipment deterioration and possible failure.

Particularly with today's high-pressure boilers, water must be chemically treated to assure long-term performance.

Understanding the issues related to water chemistry can give you a clearer picture on equipment problems. And, most important, this knowledge will provide you with valuable insights on ways to guard against system failure.



Common water chemistry problems and their consequences.

Most people have experienced water chemistry problems in their everyday lives. Scale in coffee makers. Pitted cooking pots. Dingy laundry. "Hard water" deposits inside showers and bath tubs. Most water-related problems in the home are generally just an inconvenience. But some can be costly. For instance, it's not uncommon for scale to accumulate in home water heaters and lead to a major repair or replacement. In commercial equipment found in business, industry, and public institutions, water-associated problems almost always lead to a significant expense. Boilers and water heaters, Steam generators, Water cooling towers, Chillers, Heat exchangers. Even seemingly insignificant water problems can destroy major components in these systems.

The environment inside the equipment. For instance, improperly treated water in a boiler can cause scale or corrosion and result in serious damage surprisingly fast. In the cooling towers of commercial air conditioning systems, mold, algae and other organisms can rapidly grow and clog the system.



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What condition might increase the chance of a water chemistry problem?

Do you need to frequently add water to make up for steam leaking? Do your processes use up a lot of water in the form of steam, requiring frequent replenishment or "make-up" water? If either of these are the case, your odds of a problem are greater. The more water with improper chemistry that passes through the boiler, the more scaling and corrosion can occur.

Untrained or under-trained operators can also contribute to the chance a problem. Maintaining proper water chemistry requires regular attention from someone who knows what to check and when. Frequent turnover in maintenance staff can compound this problem.

More than just capital equipment losses. Depending upon the type of business or organization, these types of problems can add up to business interruption losses. Loss of energy efficiency and loss of product quality -- such as a dry cleaner whose clothing becomes stained, or a food processor whose product becomes compromised.



The elements of a good water chemistry program.

A good water chemistry program should be designed to minimize the failures caused by corrosion. Under the conditions present in most boilers and steam generators, corrosion can destroy components or complete systems within a short period of time.

A good water chemistry program should minimize the amount of scale-forming deposits that enter the equipment. The buildup of scale on the waterside surfaces causes many problems, the least of which is a decrease in the operating efficiency of the unit. A variety of water treatment techniques are available to control scale, corrosion, and steam quality.

A good water chemistry program should include regular water-quality monitoring. The quality of water coming from any particular source can change significantly, even day to day. For instance, a municipality routinely alters the chemicals it adds to its water distribution network. And construction or repair in a municipal network can stir up particulates that can affect the water you count on. The bottom line: A regular water-quality monitoring program is essential to effective, long-term equipment performance and safety.

And, finally, a good water chemistry program should include regular periodic maintenance. Proper "blow down" is important to remove particulate matter and sludge. Surface "blowdown" is used to remove surface particulates while bottom "blow down" eliminates the sludge that accumulates as a byproduct of chemical treatment.

External water treatments.

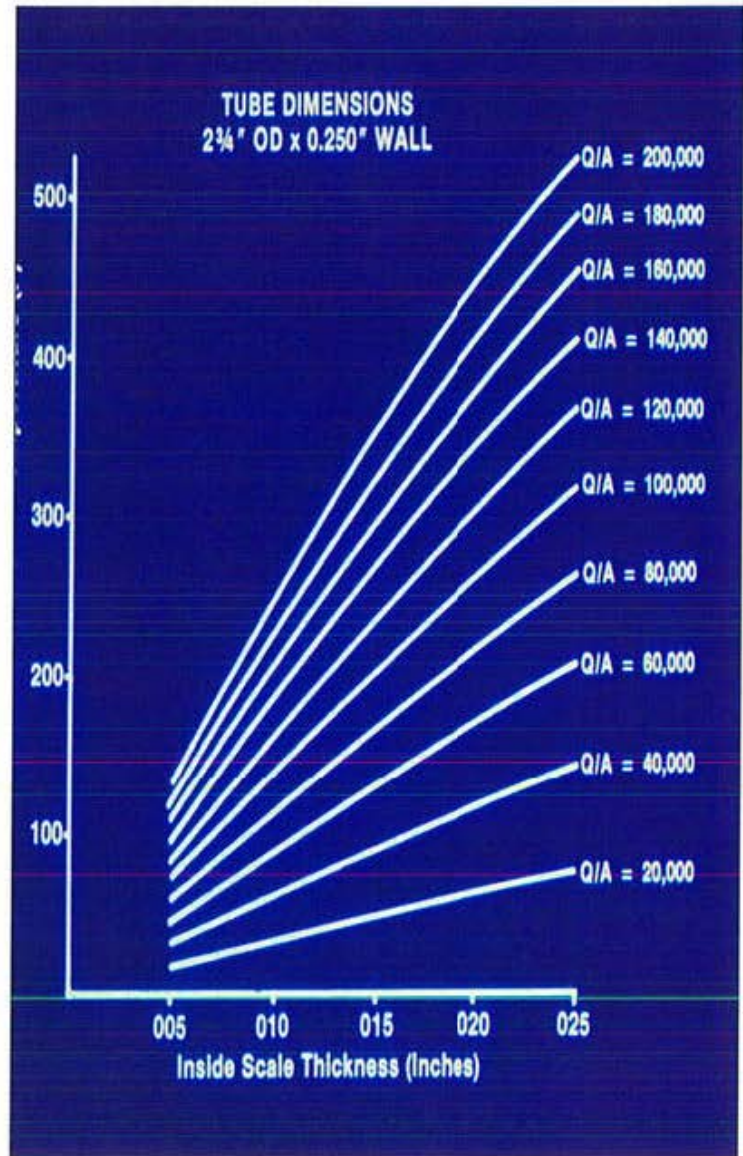
Depending upon the quality of the incoming water, a variety of purification processes are available. Most of these processes are performed prior to the water reaching your boiler.

Particulate and gas removal processes. For heavily contaminated and polluted water, it is necessary to remove coarse suspended solids, colloids, turbidity, and silt.

Typically, a chemical is added that causes these coarse organic contaminants to "agglomerate" and settle to the bottom of the storage tank.

The effluent from this process is then filtered to remove any remaining coarse material. This filter bed is normally made up of graded stone, gravel, or coarse anthracite coal. After being filtered, the water is sent through an aerator, allowing oxygen and nitrogen to replace gaseous compounds (such as carbon dioxide and hydrogen sulfide).

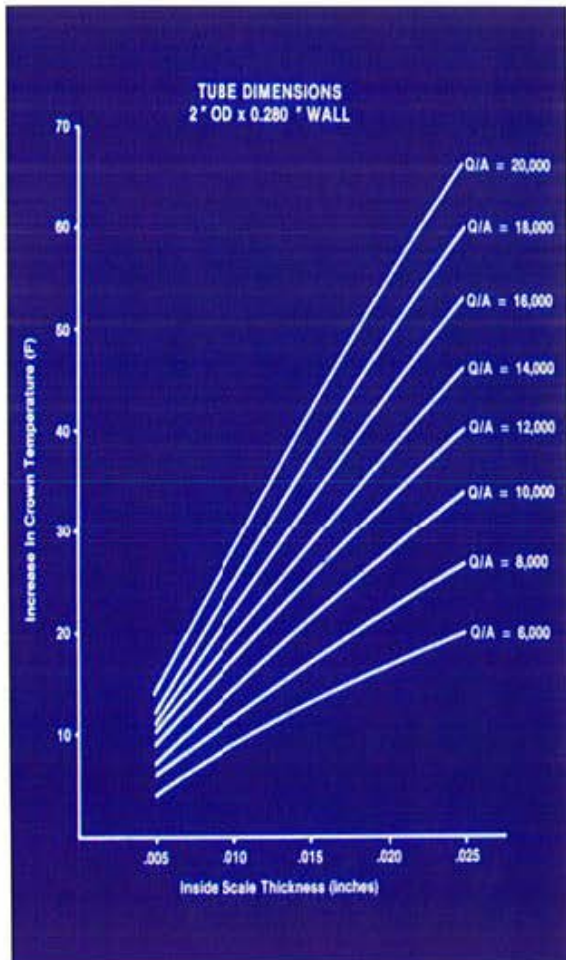
Chemical softening processes. Calcium, magnesium, and silica are the major scale-forming impurities found in raw-water supplies. The concentrations of these impurities are measured in parts per million (PPM) of hardness. To remove these impurities, it is necessary to apply one or more chemical softening processes. The lime-soda softening process reduces the hardness concentration of the raw makeup water by precipitating out the calcium and magnesium impurities as insoluble compounds. In the "cold" lime-soda softening process, relative hardness is significantly reduced. If the technique is heated up, this "hot" lime-soda process can reduce relative hardness even further.



Effects of steam side scale formation on the tube metal temperature in a water wall tube where fluid side cooling is by boiling heat transfer to the water.

Zeolite softening is an ion-exchange process that uses chemically synthesized compounds to remove calcium and magnesium compounds, and replace them with sodium. Zeolite softening can be used directly on raw water supplies that have an initial low hardness; it can also be used in tandem with the hot lime-soda process on very hard water to produce an effluent with a hardness of 0 to 2 PPM.

Finally, the demineralization process also operates on the principle of ion exchange. In this process, positively charged ions (such as calcium, magnesium, and sodium) and negatively charged ions (such as bicarbonates, sulfates, chlorides, and silica) are removed by specially developed resins. These resins can be used either in separate exchangers or together in what is called a mixed-bed ion exchanger. Demineralization is the only chemical process capable of removing chloride and sulfate from the water.



Effects of steam side scale formation on the tube metal temperature in a superheater or reheater tube where fluid

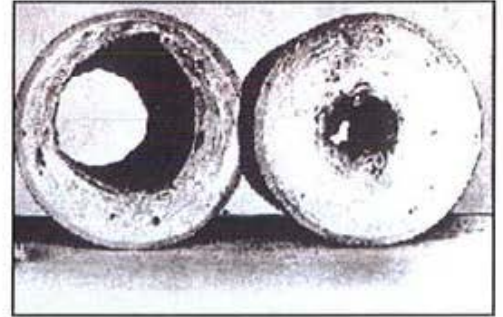
Mechanical softening processes. There are three major physical processes for removing scale-forming impurities from raw water.

The first two, evaporation and distillation, are very well known and widely used. Both provide pure water by condensing steam vapors that have been cleansed of all their chemical impurities. However, high operation expense is a major drawback to both of these mechanical processes.

The third mechanical softening process is called reverse osmosis (RO). It produces pure water by placing the contaminated raw water on one side of an artificial membrane called a permeator. Because this permeator primarily allows water molecules to pass through it, most of the chemical and organic impurities in the raw water supply are left on one side of the membrane while relatively pure water is produced on the other side.

Deposit Control

Deposits in boilers may result from hardness contamination of feedwater, and corrosion products from the condensate and feedwater system. Hardness contamination of the feedwater may result from either deficient softener systems or raw water in leakage of the condensate. Deposits act as insulators and slow heat transfer. The insulating effect of deposits causes the boiler metal temperature to rise and may lead to tube-failure by overheating. Large amounts of deposits throughout the boiler could reduce the heat transfer enough to reduce the boiler efficiency. The graph demonstrates that different types of deposits will affect boiler efficiency differently. This is why it is important to have an analysis of deposit characteristics.



When feed water enters the boiler, the elevated temperatures and pressures cause the components of water to take on dramatic changes. Most of the components in the feedwater are soluble; they are dissolved in the water. However, under heat and pressure most of the soluble components come-out of solution as particulate solids, sometimes in crystallized forms and other times as amorphous particles. The coming-out of solution is referred to as retrograde solubility, and means that as temperature increases, ability to stay in solution decreases. When solubility of a specific component in water is exceeded, scale or deposits develop.

Internal chemical treatment for deposit control is achieved either by adding a treatment to prevent the contaminants from depositing or by adding a treatment chemical that will allow for easy removal by blow down. Hardness can be kept from depositing in boiler water by treatment with chelating agents.

When phosphate treatment is preferred over chelant treatment, the boiler water is conditioned to form a fluid sludge which can be removed by bottom blow down. Formation of this sludge requires that alkalinity from caustic be present in the boiler water. If sufficient alkalinity is not maintained in the boiler water, a sticky precipitate will form and reduce heat transfer.

Even when the precipitates formed in the boiler water are in the form most desired, they are often difficult to remove completely by blow down. This is especially true when the precipitates also contain iron and copper corrosion products from the pre boiler system and organic contaminants from condensate returns. Sludge conditioners enhance the removal of precipitates from industrial boilers. Sludge conditioners are organic polymers which combine with the precipitates to permit the particles to be dispersed. This makes removal by blow down easier.



Conventional phosphate treatment:

Conventional phosphate control involves maintaining a phosphate residual and a hydroxide alkalinity residual in the boiler water. Phosphate residuals are typically maintained in the range of 20-40 ppm PO_4 . Hydroxide alkalinity, if controllable without excess blow down, are maintained in the range of 300 -500 ppm OH. This treatment provides the ideal conditions for formation of calcium and magnesium precipitates in the preferred states. It also provides a residual of alkalinity to neutralize any acid contamination, such as organic acids. It may, however, promote foaming, especially if organic contaminants enter the boiler.

Chelant treatment:

A chelant is a compound which is capable of "grabbing onto" calcium, magnesium and iron. Chelant treatment of boiler water is attractive because the chelates of calcium and magnesium are soluble. The undesirable scales of calcium carbonate and calcium sulfate are successfully eliminated by chelant treatment.

While the chelates of the hardness and iron contaminants are soluble, some chemistry precautions need to be mentioned. Phosphate will compete with the chelant for calcium, and if present in significant amounts, will result in undesirable calcium-phosphate deposits. Phosphate can enter the boiler water where city water makeup supplies phosphate. Both hydroxide alkalinity and silica compete with the chelant for magnesium. Depending on the concentration of all the boiler water chemistry, magnesium silicate deposits may result.

Chelants should be fed to the feedwater downstream of any copper alloys, after the deaerator and before the boiler drum. The preferred feed location is down-stream of the boiler feedwater pump. A stainless steel injection quill is required.

Feed to the Deaerator storage is not recommended since copper alloys in the boiler feed pump may be attacked. Proper feed of chelant will result in a chelant residual in the boiler water.

A chelant residual in the boiler water, however, is not in itself proof of adequate feed control. A chelant residual should be maintained in the feedwater at all times. Chelant treatment is not a solution for highly variable and excessive concentrations of hardness in the makeup and condensate returns.

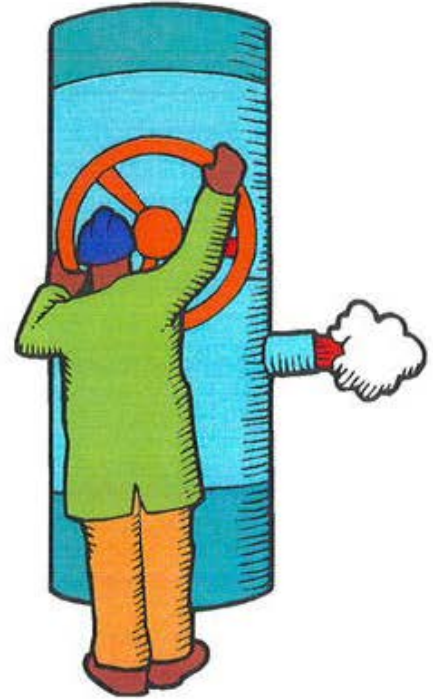
Boiler off line lay up procedures

The best program for preventing scale and corrosion during the operation of the boilers can be wasted by improper shut down, improper lay-up, and improper maintenance on the boilers during downtime.

Continued maintenance of the entire boiler systems, even during downtime, is essential in protecting the boilers against corrosion. General Preparation

Prior to the shutdown, the blowdown rate should be gradually increased, both via continuous and bottom blowdown. Chemical feed rate may have to be increased to offset the additional chemical loss through higher blowdown rate.

The solids level must be reduced to prevent potential precipitation. As water cools while shutting down the boiler, the solubility of most solids decreases...thus, increasing the potential for precipitation. During operation, the solids are dispersed both chemically and mechanically (by natural circulation of water). As circulation slows down during shut-down, excessive solids can settle onto the waterside surfaces, and then dry to become adherent deposits.



If a boiler is drained while hot, the continued evaporation of water will cause the excess solids to concentrate and precipitate on the waterside surfaces...and possibly bake on the hot surfaces too. When boilers are removed from service, they can be laid up either WET or DRY. The choice depends on how long a boiler would be laid up.

WET Lay-up

WET lay-up entails keeping a boiler filled with treated water. It allows the boiler to be returned to service within a short notice. Under this method, the boiler water chemistry must be prepared before shutting down.

The oxygen scavenger level must be increased significantly to protect boilers against higher oxygen level during shutdown. As water cools down, it will absorb more oxygen.

The boiler water pH must be maintained at the high end to ensure against any acidic conditions.

The polymer level must also be maintained at the high end. The additional dispersion properties of the polymer will assist in preventing the minerals from becoming insoluble at the lower temperature.

The boiler must be filled to the top with the above treated water to force out as much air as possible.

Otherwise, trapped air will consume the oxygen scavenger in the water. Excessive trapped oxygen may consume the entire available oxygen scavenger, causing the boiler to corrode.

It is important that the chemicals are well distributed in the boiler water. It is desirable to fire up the boilers lightly to provide some circulation of the chemicals.

It is also important that the analytical tests on the boiler water be conducted regularly to ensure the maintenance of the above chemistry.



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DRY Lay-up

Dry lay-up entails draining the water out of the boiler completely. This method is used for longer outages. Under this method, the boiler metal surfaces must be kept dry or the air must be kept out.

Idle boilers are vulnerable to attack when air contacts moist metal surfaces. To prevent corrosion, either the boiler metals must be dried completely or air must be forced out by nitrogen blanketing.

To dry the boiler metals, circulate warm air through the boiler. Adding desiccants would also help. Seal and blanket off all openings to the boiler to prevent air, or steam incursion.

For nitrogen blanketing, pressurize the boiler with nitrogen while draining. The nitrogen will force all the air out. Pressurize all system to prevent air incursion.

It is also important that inspection be done regularly for evidence of corrosion and to replace the desiccants if necessary. Reseal and restore to proper conditions.

At a recent seminar a participant suggested use of Protecsol as a material they have used for long lay up periods with good results. The following is a brief description. We do not endorse any particular product or service this is provided as a potential source of information that may be useful to you.

PROTECSOL 770P & PROTECSOL 700P From Ashland / Drew chemicals

Introducing PROTECSOL 700P and PROTECSOL 770P - two innovative, water-soluble corrosion inhibitors designed to help you and your ship win the war against corrosion. Unlike inferior substitutes, these non-toxic, non-polluting additions to Drew's already potent arsenal of corrosion inhibitors protect a variety of metals in inaccessible areas, such as boilers and exchanger equipment.

Efficient, economical, and non-polluting to the environment, PROTECSOL 770P is a unique blend of self-vaporizing corrosion inhibitors, specifically formulated for ferrous metals and aluminum. PROTECSOL 700P multi-metal powdered corrosion inhibitor provides effective, long-lasting protection for both ferrous and non-ferrous metals, including copper and brass. Both powders are unique in providing a mono-molecular inhibitor layer at THREE distinct phases - the water phase, the vapor phase, and the water/vapor interface.

Versatile Protection

If you've already taken steps to combat corrosion, that's good. You realize the seriousness of the problem, and the importance of protection. But if you're using competitive products, you may be lulled into a false sense of security - and that's not good.

PROTECSOL 770P ferrous powdered corrosion inhibitor and PROTECSOL 700P multi-metal powdered corrosion inhibitor protect both long-term lay up of heat exchangers, boilers, and related piping and equipment that is used intermittently, such as auxiliary boilers and cargo pumps. And because both powders provide up to two years protection with a single application, they are ideally suited for those instances which require equipment to be completely removed from service - including seasonal lay ups of fishing fleets, long-term storage of decommissioned military vessels, and dry docking for ships for brief or extended repairs.

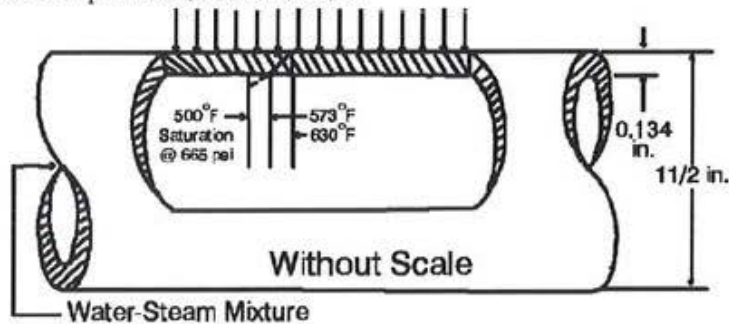
Chemical cleaning?

Removing Deposits

Chemical cleaning has been considered a necessary part of boiler maintenance for years. The objective of a chemical cleaning is to safely remove all the deposits from the inside of the boiler tubes. In higher-pressure boilers, the major deposit removed is magnetite and some copper. Chemical cleaning can improve the boiler heat rate and reduce the number of tube failures. It typically improves the stability of boiler chemistry. However, there also are down sides to chemical cleaning.



Heat Input -120,000 Btu/ft²/hr



Temp Drop across Water Film = 73°F
Temp Drop across Tube Wall = 57°F

Heat Input = 120,000 Btu/ft²/hr

0



Temp Drop across Water Film = 76°F
Temp Drop across Internal Scale = 362°F
Temp Drop across Tube Wall = 66°F
Assumed CaSO₄ Scale (0.024 in. thick)
Thermal Conductivity 10 Btu/ft²/hr.-°F/in.
Maximum Tube Temp (1004°F) is above Allowable Oxidation Temp Limit for SA-210 Carbon Steel

Chemical Cleaning May Be Hazardous

The chemical cleaning of a boiler is a project fraught with danger and horror stories abound. For example, a few years ago a power boiler was cleaned with ammoniated EDTA (ethylenediaminetetraacetic acid). The plant operators were unaware that chemical cleaning solution had found its way into the superheater and was not flushed out. When the unit went back on line, the chemical cleaning solution evaporated in the Superheater and caused it to fail. Complete replacement of the Superheater was required.



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Disposal of the chemical cleaning solution also can be a problem. Recently during evaporation of the spent chemical cleaning solution in a utility boiler, the vendor allowed the solution to impinge on a riser tube, causing it to fail catastrophically. The resulting repair cost the utility more than \$1 million.

Another utility experienced a rash of catastrophic tube failures due to hydrogen embrittlement. The failures followed an incomplete chemical cleaning with inhibited hydrochloric acid.

When to Clean

In the past, utilities and others who operate steam generators have considered a number of factors when determining the need to use chemical cleaning. The most common criteria are:

- Deposit loading on tube samples

- Time-based cleanings (operating hours or calendar months since last chemical cleaning)

- A major contamination incident (condenser tube leak)

We will review each of these briefly.

Deposit Loading

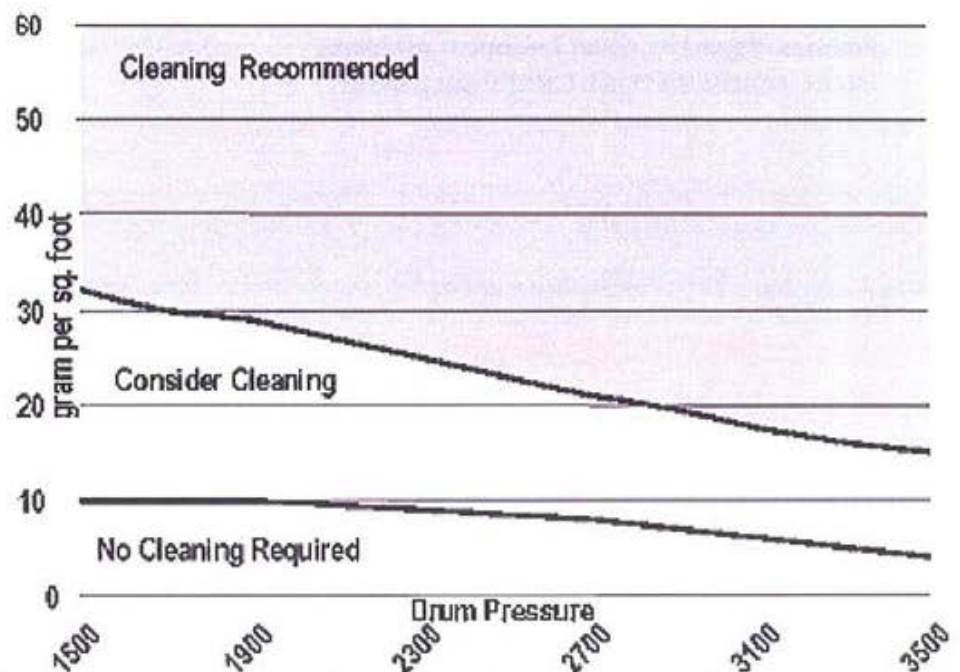
One of the most common criteria is the deposit loading on the inside of the water wall tube. The plant will take two or three boiler tube samples from the high heat areas of the boiler and have the deposit loading analyzed on each. An average of the hot-side loading on the tubes is compared against a chart similar to the one in Figure 1. This is still the best way to determine the need to use chemical cleaning, assuming that there have been no major contamination incidents since the last chemical cleaning.

Deposit Loading

Time-Based Cleanings

In the past, some boiler operators cleaned based on time — either the number of operating hours or the number of years since the last chemical cleaning. This is probably the worst way to determine the need to use chemical cleaning. Deposits do not form on boiler tube walls at a uniform rate over time. Immediately after a chemical cleaning, the boiler tubes create a protective film of magnetite that limits further corrosion of the base metal.

This quickly adds 3 to 5 or so grams/ft.² of deposits to the boiler. Over time, new deposits collect on top of this protective layer. These deposits typically come from the boiler feedwater. Boiler start-ups and shutdowns can add a tremendous amount of deposit to the boiler tube wall. The number of start-ups is a better predictor of tube deposit density than operating hours.



Time-based cleanings do not consider water chemistry (good or bad) or the amount of deposits since the last cleaning. It may be that the water chemistry control has been particularly poor and the deposit



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loading is high. In that case, the frequency should be increased. The opposite also might be true, and the chemical cleaning can be put off for years.

Contamination-Required Cleanings

This criterion is often overlooked, particularly by those who clean on a set time schedule. If there is a major contamination of the boiler water, a chemical cleaning must be performed at the next opportunity, preferably before the unit is restarted.

The most common contamination incidents are calcium hardness in the boiler from a condenser tube leak or demineralizer / softener malfunction. Corrosion cells are created during this contamination that lead to caustic gouging and hydrogen embrittlement. In these cases, the high risk of major water wall damage outweighs the risks associated with chemical cleaning.

How to minimize Chemical Cleaning

The need to use chemical cleaning is the result of corrosion products building up on the boiler tube walls. The more corrosion products generated in the boiler and feedwater system, the more often the unit will require chemical cleaning. Reducing corrosion in these areas can improve overall boiler chemistry and extend the time between cleanings.

A large percentage of the corrosion products on boiler tube walls come in from the feedwater system during start-up. Improving lay-up and start-up practices can mean the difference between needing to clean with chemicals every three years and every 12 years. Find a knowledgeable consultant or chemical vendor that will help you develop better lay-up and start-up practices and get out of the chemical cleaning cycle.

Failures caused by water treatment problems

HIGH TEMPERATURE CREEP see page 87

STRESS CORROSION CRACKING

LOCATION:

Stress corrosion cracking can be found in areas such as Superheaters, Reheaters and water tubes.

Superheaters and reheater tubing can experience stress corrosion cracking at locations that.

- (1) Have been exposed to concentrations of chlorides, sulfates, or hydroxides.
- (2) Have been stressed to high levels by service conditions or fabrication and assembly processes such as at bends or at attachment welds and at supports.

PHYSICAL DESCRIPTION:

Most areas suffering from corrosion attack appear pitted and creviced.

Often times stress corrosion cracking will be hard to identify with the naked eye unless a failure has occurred.

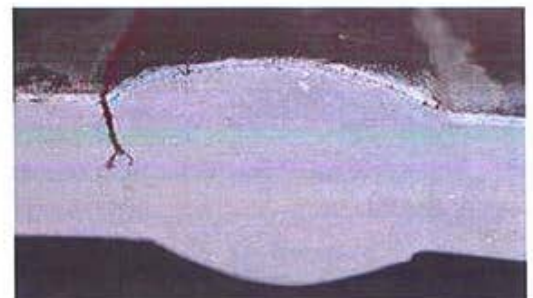
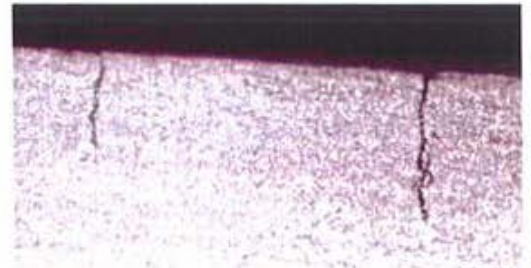
Stress corrosion cracking is caused by the concentration of corrosive materials at a tube location that has high tensile stress and susceptible tube material.

Corrosive materials are introduced by "carry-over" from the drum or Injection with de superheater spray water. These materials concentrate at flow disturbances or bends on the internal surface. Fireside deposits can contain high levels of nitrates, sulfates, or polythionic acid. These conditions can become "sensitized" to stress corrosion when exposed to normal boiler operating temperatures.

PROBABLE CAUSE:

For stress corrosion cracking to occur a synergistic interaction of a tensile stress and a specific corrosive to which the metal is sensitive must be present. When this phenomenon occurs the strength in the metal is diminished and if not corrected a thick-walled fracture will occur.

The root causes of stress corrosion cracking can be verified by determining the source of the corrosive materials and the reason for the high tensile stress. Internal surface corrosive materials are usually chlorides or hydroxides. Internal surface corrosive materials include polythionic acid or sulfates. The stress level in the tube can be estimated by stress analysis, while the susceptibility of the tube material can be established by testing the material according to ASTM Standard practices. Residual stresses in bends introduced during the forming operation are sometimes involved.



Stress corrosion cracking produces a thick-edged fracture since the corrosion results in propagation of a crack through the material instead of reduction in wall thickness. Crack orientation can be circumferential or longitudinal depending on the direction of the tensile stress. Most cracks initiate on the internal surface, but some cracks have been initiated from the outside diameter due to exposure to nitrates, sulfates, or polythionic acid in fireside deposits.

Fluorescent dye penetrant examination of austenitic stainless steel tubing and fluorescent magnetic particle examination of ferritic steel tubing are used for detection of cracks that initiate from the external surface. It is necessary to increase the dwell time of the penetrant because of the closeness or hairline type nature of the cracks. Multiple cracks may be present and hydrostatic testing can be used if a boiler stop valve has been installed. NDE methods are not used to inspect for cracks that originate on the internal surface since failure typically occurs within 100 hours after crack.

CORRECTIVE ACTION:

Fluorescent dye penetrant examination of austenitic stainless steel tubing and fluorescent magnetic particle examination of ferritic steel tubing are used for detection of cracks that initiate from the external surface. It is necessary to increase the dwell time of the penetrant because of the closeness or hairline type nature of the cracks. Multiple cracks may be present and hydrostatic testing can be used if a boiler stop valve has been installed. NDE methods are not used to inspect for cracks that originate on the internal surface since failure typically occurs within 100 hours after crack.



Corrective actions depend on the severity of the stress corrosion cracking damage. Whole sections of super-heater tubing have been replaced when corrosive chemicals were introduced during a Waterwall chemical cleaning project. Surveillance for carryover from the boiler drum and observation of the source of the de superheater spray water can prevent the introduction of corrosive chemicals during boiler operation. Heat treatment of bends and control of installation welding can reduce the tensile stresses. Usage of stabilized grades of austenitic steels can eliminate the sensitization effect.

Reducing the stress on cold side tube attachments.

Reinforcement of the attachment will exacerbate the condition.

Reduce sub cooling in natural circulation boilers. (Top to bottom temperature differential) on start ups.

Control and improve water chemistry and chemical cleaning

Utilize non hydrochloric acid cleaning schemes

REPAIR PROCEDURES:

Tube replacement is the preferred method of repair. Pad welding is not recommended even in forced outage conditions. Complete removal of all cracks is unlikely and a repeat failure is likely in the same general site.

CORROSION FATIGUE

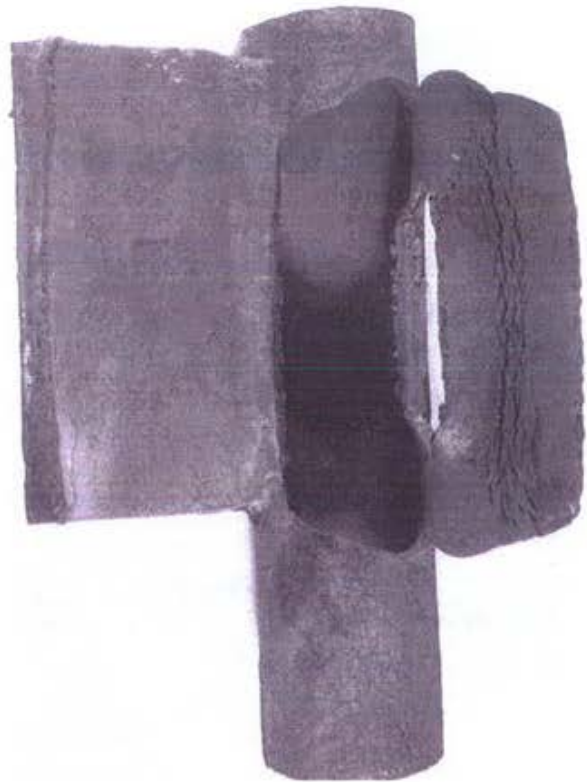
COMMENT:

This condition is a result of the cyclic loading externally (OD) combined with corrosive environment internally (ID). These cracks can have their origin in surface imperfections or pits. This condition should not be confused with cracks that are initiated on the outside of the tubing. The physical description of these cracks are usually transgranular, wide and oxide filled.

LOCATION:

Water side of water wall and economizer tubes. This occurs specifically at attachments and restraints. Specifically this occurs at:

- Windbox casing attachments
- Backstay connections
- Sidewall to slope connections
- Division wall at slope penetration
- Burner elevations
- Boiler water seals (weir box)
- Boiler ash hopper seal plates
- Gas recirculation duct attachments
- End of membrane connections
- Economizer fin welds
- Fin welded tubes
- Scallop tie bars
- Waterwall gusset plates
- Penthouse floor attachments
- Rear wall arch



EXTERNAL APPEARANCE:

INTERNAL APPEARANCE:

The cracking usually occurs on the inside diameter of the water touched tubes on the cold side of the tubing. It is unusual but not uncommon that this also occurs on the hot side of a tube. These cracks are usually orientated longitudinally in relation to the stress region. Cracks can also be circumferential or in any orientation that is consistent with the stress region.

PROBABLE CAUSE:

Carbon steel is usually protected by a layer of magnetite. When this layer is damaged then Corrosion fatigue may form. This layer of magnetite can be compromised by either a mechanical (stress) or from a chemical (corrosion). Most importantly the problem is exaggerated by the combination of both of these conditions. The factors which directly affect this condition are:

Mechanically

Boiler pressure

- Thermal gradient through tube
- Heat flux BTU/SF
- Restraint during thermal expansion
- Weight of restraint.
- Start up and shut down ramp acceleration
- Sub cooling on start ups in natural circulation

boilers

Chemically

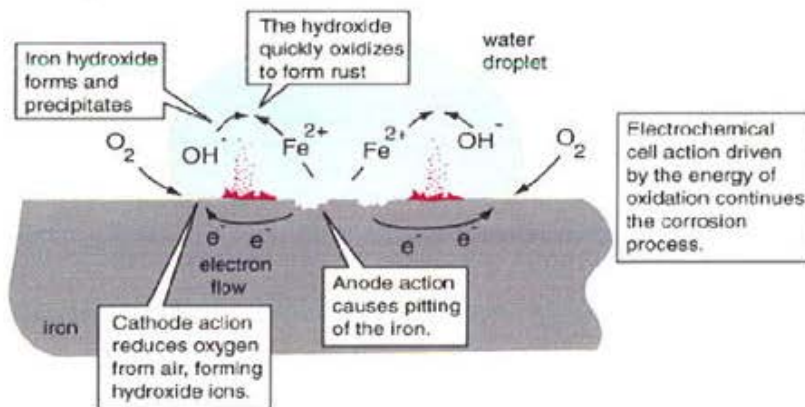
- PH excursions in boiler water
- High levels of oxygen in boiler water
- Phosphate hide out



Close up of failure area O.D. cold side

Operating environment of the boiler can be a major factor to this condition.

Some specifics:



This condition would be more likely in peaking units where many thermal cycles are experienced.

Chemical cleaning with hydrochloric acid will aggravate corrosion fatigue.

A piece of bare iron left outside where it is exposed to moisture will rust quickly. It will do so even more quickly if the moisture is salt water. The corrosion rate



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Other factors which may contribute to corrosion fatigue

Phosphate hide out

Hydrogen damage

Caustic gouging incidents

Low PH in boiler blow down

High dissolved oxygen in feed water

CORRECTIVE ACTION:

Reducing the stress on cold side tube attachments.

Reinforcement of the attachment will exacerbate the condition

Reduce sub cooling in natural circulation boilers. (Top to bottom temperature differential) on start ups.

Control and improve water chemistry and chemical cleaning

Utilize non hydrochloric acid cleaning schemes

REPAIR PROCEDURES:

Tube replacement is the preferred method of repair. Pad welding is not recommended even in forced outage conditions. Complete removal of all cracks is unlikely and a repeat failure is likely in the same general site.

Corrosion fatigue metallurgical considerations:



As the name implies, corrosion fatigue is failure by repeated or cyclic stresses in a corrosive environment. There is a stress level for steels, called the endurance limit, below which failure will not occur, regardless of the number of cycles. In a corrosive environment, no true endurance limit or safe working stress may exist. Corrosion-fatigue cracks are typically transgranular; they may be branched, but usually are not; and several minor cracks may be visible at the metal surface in the vicinity of the major crack that accounted for final failure. Fatigue cracks, on the other hand, while they are similarly transgranular, have rarely more than major crack. On occasion, the fatigue crack may originate at an oxygen pit, in effect a stress-concentration factor, but oxygen pits are not necessary. -e 6.10 shows



an example of a corrosion-fatigue crack. An oxide wedge forms once a fatigue crack occurs. Since the volume occupied by the oxide is greater than the volume of metal from which it forms, the wedge adds stress to



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the crack tip and prevents the crack from closing. On the next cycle, the crack moves further and propagates faster than without the formation of the wedge and the corroding media in which it formed.

Mild case of intergranular oxide penetration, normally not a severe problem for ferritic steels below about 1250-1300°F (680-700°C) (Magnification 100x, nital etch).

Corrosion fatigue; a single spear-shaped oxide wedge is typical of failure (Magnification 500x, nital etch).

Inspection techniques

The unit failure and inspection history will dictate the inspection scope. It is not practical to uncover the entire boiler on the cold side in search of these types of cracks. Visual inspection, Magnetic particle and dye penetrant Ultrasonic shear wave and borescope are acceptable methods for this condition.

Ultrasonic Circumferential Shear Wave Inspection

In the circumferential wave technique, ultrasonic waves are introduced and detected from the process side of the boiler tubing. To develop adequate coupling, adherent accumulations of oxide as well as any loose rust/ash and debris must be removed, most typically with a power wire brush or sand blasting. The technique detects longitudinally oriented discontinuities. The approximate size/penetration depth of the flaw is estimated by comparing the signal fraction that is reflected from discontinuities with that which travels the entire circumference, and the relative position of the discontinuities it detects longitudinally oriented flaws best (because they are perpendicular to the direction of wave travel), which is consistent with the predominant orientation of stress corrosion cracking discontinuities in boiler tubes.



This shows a seal box on the cold side of waterwall tubes. They are restrained by this box and have failed due to corrosion fatigue

A possible disadvantage of the technique is that, due to the limited inspected area, it is inefficient for examination of an entire boiler. As a result, analysis using this technique typically must focus on particular "suspect" areas based on history as mentioned above.

Also, the technique works best from the process side of the boiler opposite the external attachment locations because this position places the expected stress corrosion cracking location in the center of the detection range (halfway around the tube from the transducer). This means the boiler can most practically be inspected with this technique only at outage.

- Ultrasonic Longitudinal Shear Wave Inspection

In this technique, known as the guided wave method, ultrasonic waves are introduced on the cold side of boiler tubes with a transducer array. The waves travel longitudinally down a length of tubing to be detected by a separate receiver or, alternatively, reflected from circumferentially oriented flaws and detected with the same unit as the input transducer. Like the circumferential wave technique, discontinuities can be located and sized by analysis of the pitch/catch time for reflected waves and the fraction of the input energy collected at the receiver. Similar to the circumferential wave technique, appropriate surface preparation and coupling is required.

Advantages of this technique include that it can be used from the cold side of the boiler. In addition, the technique is not necessarily a localized technique.

Disadvantages of the technique are that circumferentially oriented indications are not particularly common for stress corrosion cracking, which limits the general usefulness of this method.

- Borescope/Visual Inspection

The borescope should have an adjustable power light at the tip and an optics system capable of approximately 5x magnification. This process is slow and tedious but very accurate with virtually no false positives.

- Magnetic Particle Inspection

Magnetic particle inspection on the cold side of the tube can be effective in locating Stress corrosion cracking. Magnetic particle will examine an area below the surface of the tube. This does however require removal of obstructions such as insulation and lagging and in some cases buck stays.

- Dye penetrant Inspection

Dye penetrant **can** be effective if the crack extends thru wall. It will not locate cracks below the surface. These tests are conducted on the cold side of the tube. This does however require removal of obstructions such as insulation and lagging and in some cases buck stays.

- "RT" x-RAY could be used if the source can be located in such a way to develop a meaningful picture of the affected area.

Inspection case history

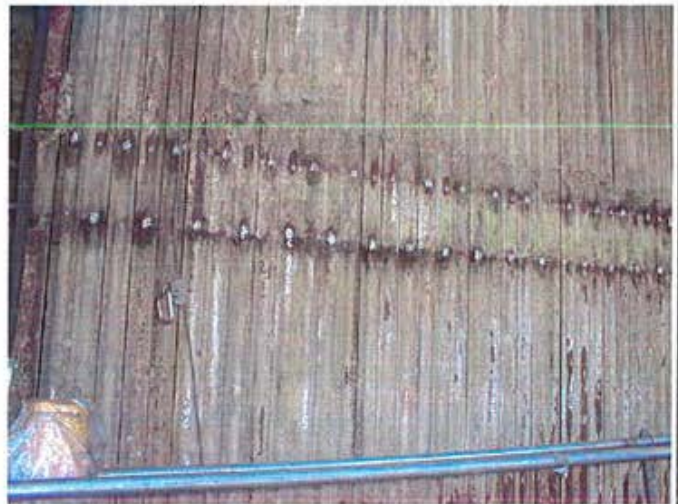
Repair #: 130-b >>Record:# 132>> (REPLACE TUBE).

Priority #: 1

Location of repair is Steam Cooled Wall Rear Cold side, elevation 103.2'
This appears as cracked

Material specification = SA-209T1A X OD =2.0" X MWT =0.203" Weld rod = 7018-Al.

UDC has performed a Magnetic particle test by means of GLO-NETICS spray solution. This record is for all crack indications found at the second buck stay elevation down from the top, at all support clip locations. UDC recommends that all tubes that show crack indications be replaced. Replacement should range from one foot below the hanger supports @ roof line, down to the nipple welds at the rear Primary Superheat inlet header. The following tubes showed indications of cracks: 19 / 20 / 22 / 23 / 25 / 89 / 90.





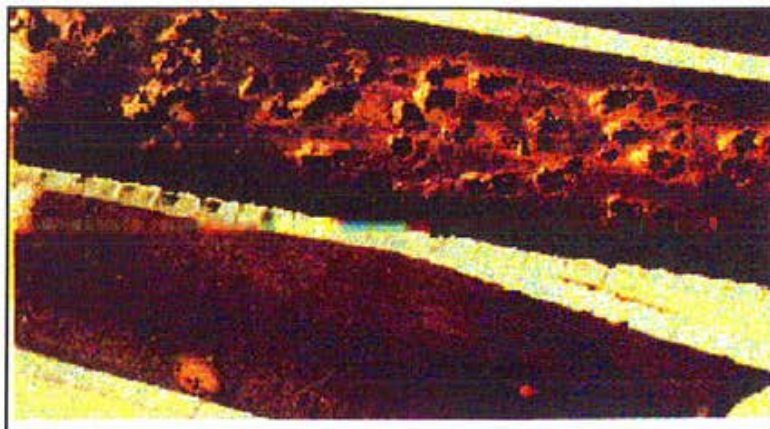
PITTING

LOCATION:

Pitting can occur anywhere in the boiler including economizers, superheaters, reheaters, and the non-heated portion of waterwall tubes.

Locations where high levels of oxygen can be present are most likely to experience pitting. Inlet tubing in economizers and low points in reheater tubing where condensate can collect during outages are locations, which have frequent pitting problems.

Horizontal reheater tubing is most susceptible due to the relatively thin wall thickness of the tube and to the direct exposure of the internal surface to the atmosphere during unit outages.



PHYSICAL DESCRIPTION:

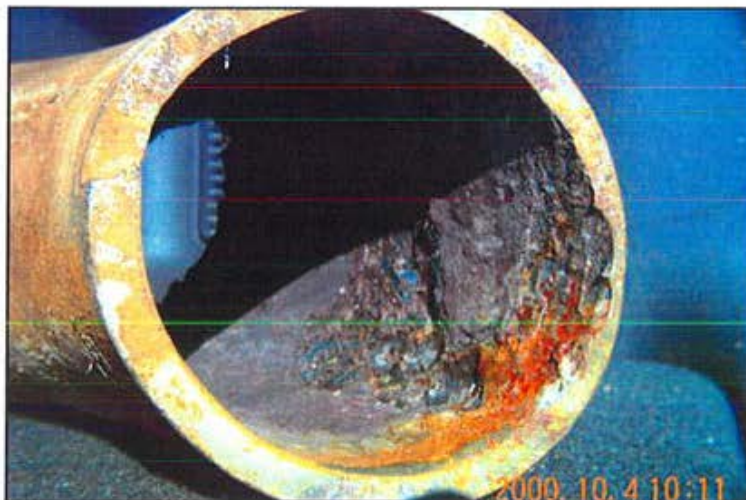
Pitting produces perforations of the tube wall through localized corrosion on the internal surface. Crater-like corrosion sites develop from galvanic activity and may have a red, rusty appearance due to the production of Fe_2O_3 (hematite) corrosion products.

PROBABLE CAUSE:

Pitting is caused by exposure of the tube to water with a high concentration of oxygen.

In economizer tubing, the cause of pitting is likely to be high levels of oxygen in the feed water entering the economizers during boiler startups and low load operation periods.

In reheater tubing, the cause of pitting is likely to be the collection or pooling of condensate in bends and low points in horizontal sections during start up.



The root causes of pitting can be verified by monitoring the level of oxygen entering the economizer, especially during startups and low load operation periods. The cause of the high oxygen concentration may be mal-function of the de aerating heater, inadequate injection of oxygen scavenger chemicals, or excessive air in leakage in low pressure heaters, condensate piping, and the main condenser. During boiler outages, inadequate draining and standby protection methods can be verified by tube sampling to reveal the formation of any localized corrosion cells.

Ultrasonic (UT) tube wall thickness measurements are used to detect wall thinning that results from localized corrosion. Access to the tube surface for a complete wall thickness survey is limited in some



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cases. External surface preparation is necessary since the UT transducer must traverse this surface in search of wall penetrations.

Corrective actions involve control of the oxygen level in the economizer feed water and protection of the tubing during non-operating periods. When oxygen levels exceed 10 ppb in the feed water, steps must be taken to immediately locate and isolate the source of the problem.

CAUSTIC CORROSION / GOUGING

COMMENT:

Caustic corrosion produces thin-edged ruptures or pinhole leaks in tubing where the corrosion on the waterside has reduced the wall thickness. Caustic gouging and ductile gouging are other names for this mechanism, since the tube fails in a ductile manner after the wall thickness has been significantly corroded through.

LOCATION:

Water-cooled tubes can experience caustic corrosion at locations that:

- (1) Have flow disruptions such as welded joints with backing rings or protrusions, bends, or deposits.
- (2) Have horizontal or inclined tubing.
- (3) Have high heat flux or flame impingement.

EXTERNAL APPEARANCE:

None

INTERNAL APPEARANCE:

The cracking usually occurs on the inside diameter of the tubing. A thick deposit on the internal surface is usually present.

PROBABLE CAUSE:

Caustic corrosion is caused by concentration of sodium hydroxide from boiler water high heat flux and deposits. Deposits are formed from feed water system corrosion products or from condenser in-leakage constituents. As porous deposits build up in high heat input areas, sodium hydroxide can concentrate within the deposit to a locally corrosive level. An increase in the tube metal temperature due to the heat transfer resistance of the deposit supports the concentrating mechanism.

The root causes of caustic corrosion can be verified by an investigation into the water chemistry practices and the amount of feed water corrosion product deposition on the boiler tubes. Condenser leakage from fresh water-cooling bodies can be monitored. Tube sampling can be performed to measure the relative thickness and amounts of deposit buildup on the heated side of the internal surface.





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Tube sampling practices and test methods are detailed in ASTM Standards D 887-82 and D 3483-78. Upsets in water chemistry from malfunctions and operating errors can be verified by review of the chemical control logs, on-line water chemistry records, and instrumentation alarms. Radiographic and ultrasonic (UT) techniques have been used to detect wall thinning that results from caustic corrosion. Since deposit buildups are likely to occur at tube joints the surface when using the UT technique at the welds. The weld crown on the external surface needs to be ground flush with the surface to allow access for the UT transducer. The tube end preparation on the internal surface must be known to differentiate any reduction in wall thickness due to weld fit-up requirements from wall thinning that is caused by caustic corrosion. Tube metal temperature monitoring by cordial thermocouples can be used to indicate when deposition of feed water corrosion products has reached a significant level; however, corrosion damage can occur without any measurable increase in tube metal temperature.

CORRECTIVE ACTION:

Corrective actions involve control of boiler water chemistry, minimization of ingress of feed water corrosion products and condenser leakage products into the boiler, and removal of corrosion product deposits by periodic chemical cleaning. Elimination of welds with backing rings or other welded joint surface contour irregularities can be beneficial. Low chromium ferritic steel (such as ASME SA 213 Grade T-11) and rifled or ribbed tubing are less susceptible but not immune to caustic corrosion damage.

Reducing flow disruptions in tubing, reducing burner impingement, and reducing steam blanketing will all help reduce this condition.

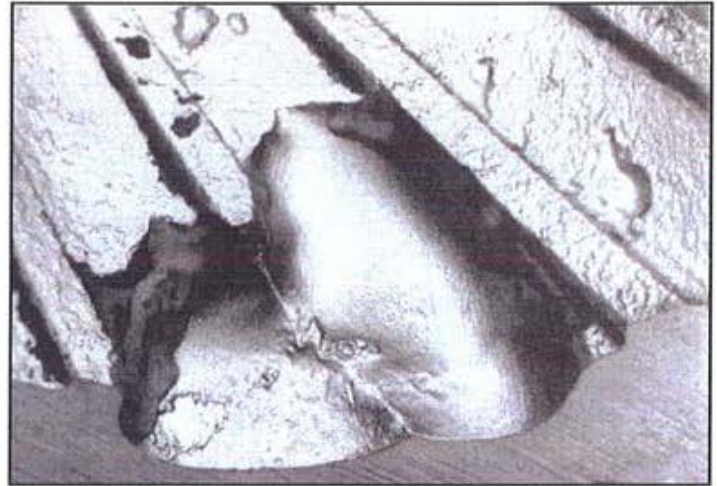
REPAIR PROCEDURES:

Tube replacement is the preferred method of repair. Pad welding is not recommended even in forced outage conditions. Complete removal of all thin areas is unlikely and a repeat failure is likely in the same general site.

ACID PHOSPHATE CORROSION

COMMENT:

Acid phosphate corrosion occurs when tube deposits form from feed water corrosion components allow phosphate salts to concentrate. This concentration leads to under deposit corrosion. This condition is in a family, which includes hydrogen damage, and caustic gouging. It is easy to confuse all of these conditions since they are similar in appearance.



LOCATION:

- Locations of high heat flux (BTU /SF)
- Locations where water turns to steam in the water wall tubes
- Locations where disruptions in flow
- Flame impingement (burner mis alignment)
- Welded joints
- Backing rings
- Poor quality welds
- Window welds
- Canoe welds
- Internal deposits

EXTERNAL APPEARANCE:

On failure, the tube will be typically thin edged due to ductile overload.

INTERNAL APPEARANCE:

Tube gouging is the trademark for acid phosphate corrosion. See photo above. This condition is usually identified because of the sharp edge between the gouge and adjacent metal. Multiple layers exist which will be white and gray with red speckled throughout.

Acid phosphate corrosion differs from hydrogen damage is that hydrogen damage is typically thick edged upon failure. Acid phosphate corrosion differs from caustic gouging is that caustic gouging damage is represented by the deposits found on the ID of the tubing. Maricite forms instead of crystals of sodium ferroate, which would be the case for caustic gouging.

PROBABLE CAUSE:

A breakdown of the protective layer of magnetite by a fluxing action causes acid phosphate corrosion. Unlike hydrogen damage where growth of an oxide layer occurs on the tube internal surfaces which results a layer that is internally stressed. With acid phosphate corrosion, the feed water corrosion



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products accumulate at areas where there are disruptions in flow. Disruptions in flow can also include steam blanketing. This can be exaggerated by increased heat of the area affected. The compounding of an initial deposit coupled with the addition of mono and di sodium phosphate in an area where heat concentration is high causes this corrosive condition. A area prime for this condition is where the water in the Waterwall tube is converted to steam (steam phase). This varies from boiler to boiler but it is usually just above the burners.

Chasing phosphate hide out with mono sodium phosphate or excess use of di sodium phosphate in your chemical program is usually a source

Maricite is the key to determining whether acid phosphate corrosion is your problem. Maricite is produced only when magnetite and mono di sodium phosphate are reacted. If this is the case then you have acid phosphate corrosion.

CORRECTIVE ACTION:

Keeping the boiler clean on the water side is paramount. The prevention of the ingress of boiler water contaminates will help prevent this condition.

Reducing flow disruptions in tubing, reducing burner impingement, and reducing steam blanketing will all help reduce this condition.

REPAIR PROCEDURES:

Tube replacement is the preferred method of repair. Pad welding is not recommended even in forced outage conditions. Complete removal of all thin areas is unlikely and a repeat failure is likely in the same general site.

HYDROGEN DAMAGE

COMMENT:

Hydrogen damage is caused by operation with low pH water chemistry from ingress of acidic salts through condenser leakage, contamination from chemical cleaning or malfunction of the chemical control components, and concentration of the corrosive contaminants within deposits on the internal tube wall. Deposits are formed from feed water system corrosion products or from condenser in-leakage constituents.

LOCATION:

Typical Locations

Water-cooled carbon steel tubes can experience hydrogen damage at locations that:

- (1) Have flow disruptions such as welded joints with backing rings or protrusions, bends, or deposits.
- (2) Have horizontal or inclined tubing.
- (3) Have high heat flux.

EXTERNAL APPEARANCE:

Hydrogen damage can produce a "window opening" and thick-edged split" fracture appearance. The thick-edged fracture surface will outline the region of hydrogen damage. A thick internal surface scale may be present.



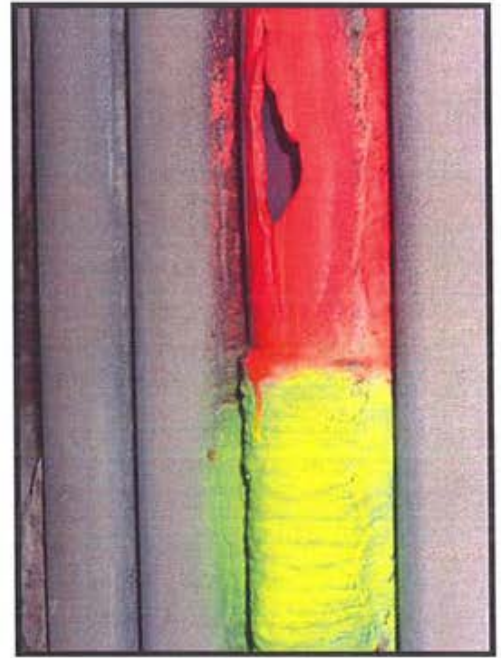


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INTERNAL APPEARANCE:

PROBABLE CAUSE:

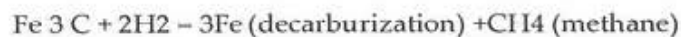
The root cause of hydrogen damage can be verified by chemicals in the boiler and into the amount of deposition on the boiler tubes.. Tube sampling is performed to measure the relative thickness and amounts of deposit buildup on the heated side of the internal surface. Tube sampling practices and test methods are detailed in ASTM Standards D 887-82 and D 3483-78. Potential sources of corrosive chemicals include in-leakage from the condenser, malfunction of the boiler water conditioning facilities) and errors in the boiler chemical cleaning process. In-depth review of chemical control logs, on-line water chemistry records, and instrumentation alarms can be performed.



Radiographic and ultrasonic (UT) techniques have been used to detect hydrogen damage. UT methods include detection of wall thinning and attenuation of sound energy in the damaged steel. Properly calibrated UT instruments can indicate an increase in sound attenuation that is caused by degradation at the grain boundaries. Care must be taken to assure good contact between the UT transducer and the tube surface. A clean fireside surface is essential when using this technique. Tube metal temperatures can be measured and monitored by cordial thermocouples to indicate the deposition of feed water corrosion products on the tube internal surface; however, corrosion damage can occur without any measurable increase in tube metal temperature.

Hydrogen damage a more in depth technical discussion

Hydrogen damage or hydrogen attack is produced in steel from the seepage of hydrogen that reacts with carbides to form methane gas. This gas decarburizes the steel, produces microcracks, and lowers the toughness of steel without necessarily a loss of thickness. Detection of hydrogen attack is important to assure safe operation of pressure vessels and piping susceptible to such damage.



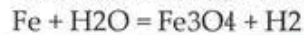
The type of damage caused by hydrogen attack depends on the source. The source of hydrogen in boiler tubes is from a reaction of steam and steel. Hydrogen damage in boiler tubes is, therefore, always associated with ID corrosion.



Boiler Tube

Hydrogen attack, The dark area on the Boiler Tube ID represents hydrogen damage.

Hydrogen damage in boiler tubes is caused by a corrosive reaction between steam and steel as follows:



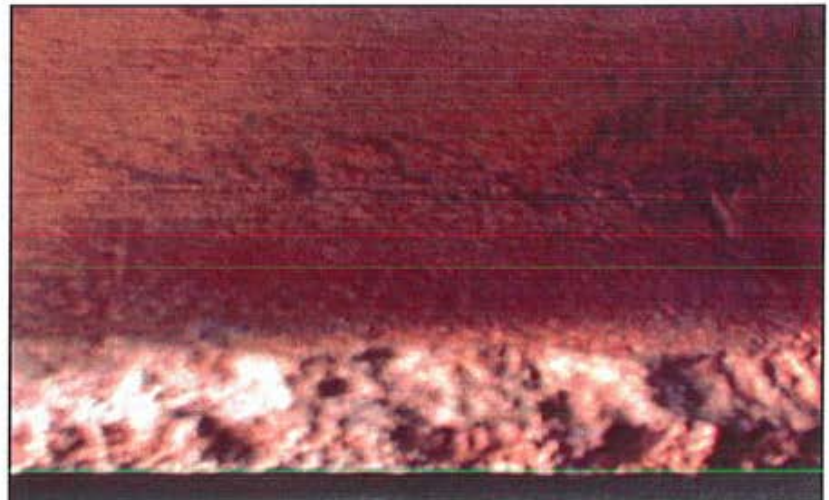
The hydrogen available from the above reaction reacts with carbides to decarburize the steel and forms methane gas at the grain boundaries. Hydrogen damage results in wall loss due to corrosion and a loss of strength in the material attacked by hydrogen.

Hydrogen damage occurs in waterwall tubes when the pH level drops below the normal level. The damage usually occurs in areas of high heat flux and flow disturbances. These include circumferential welds, tubes opposite to burners and tube bends.

Technique "A": Inspection for hydrogen damage in boiler tubes is accomplished in a two-step procedure. The first step is locating areas with ID surface corrosion. This

is done with an ultrasonic scanning method that detects areas with ID surface corrosion.

The second step is to determine whether the corrosion was a result of hydrogen attack or some other mechanism. Ultrasonic velocity measurements are taken in the material under the corroded area. A loss of ultrasonic velocity is an indication of hydrogen damage. This velocity loss is measured by a pitch catch method. The loss of ultrasonic velocity is related to hydrogen damage.



Hydrogen Attack can occur both in the base metal and the weld HAZ. The attack in the base metal is wide spread and distributed uniformly. Weld attack is very localized and grows along the HAZ. The susceptibility of attack in the weld HAZ depends on the heat treatment. Post-weld heat-treated welds are less susceptible to hydrogen attack compared to the welds that are not heat-treated. There have been several cases where the depth of the attack in the HAZ is greater than the depth in the base metal. It is therefore imperative that both the base metal and the weld HAZ be inspected for presence of hydrogen attack.

Technique "B": Base metal attack as shown in then is detected by using a combination of ultrasonic backscatter and velocity measurements (1,5). Hydrogen attack increases the ultrasonic backscatter and reduces the ultrasonic velocity in the material.

These two measurements are applied to detect hydrogen attack. Details of the techniques are given in the references. Weld HAZ attack is detected using the ultrasonic shear wave technique. Since the cracking caused by hydrogen attack in the weld HAZ is extremely fine, the shear wave inspection is done at a very high sensitivity. Both the base metal and weld HAZ should be inspected for hydrogen attack. Further verification of attack can be done by surface replication.



CORRECTIVE ACTION:

Corrective actions involve the restoration of boiler water chemistry to the proper values and the consideration of boiler chemical cleaning. Chemical cleaning should be considered when the boiler water pH has been below 7 for more than one hour due to the ingress of saline condenser cooling water or acidic chemicals into the boiler from breakdown of boiler water conditioning facilities. Chemical cleaning is performed to remove the internal deposits and to stop further generation of hydrogen on the tube surface. If significant wall thinning has occurred, the tube will have to be replaced to prevent a ductile type fracture later in service.

REPAIR PROCEDURES:

Replacement is mandatory. No other action is recommended.

11. STEEL APPLICATIONS AND USE

Metallurgy

Metallurgy can be defined as the science and technology of metals. It is a technology that combines different chemical elements (chemical composition) and processes that optimized blend (to obtain given microstructure) to produce desired properties. The major types of metallurgy are process metallurgy, defined as the reduction of ores, refining metals, alloying, casting, and shaping metals (i.e. steel production companies) and physical metallurgy which includes application, design, testing, and inspection (i.e. steel tube manufacturing). We will address the latter in this section.

Some simple descriptions of the elements of steel may be useful here. These are some general rules, Nickel increases low temperature toughness, molybdenum increases high temperature strength, and chromium increases corrosion resistance. The following represents a discussion of how all of these elements fit together.

6 During the 1980s considerable attention was focused on preventing and understanding boiler-tube failures, which are the principal cause of forced outages in power plants. Understanding boiler-tube failures may lead to substantially improved performance, availability, and reliability of steam generating equipment. The explanation of the root cause of the failure may lead to reduced frequency of future failures, since appropriate corrections may be made in a timely fashion.



Thermal degradation of the microstructure occurs at elevated temperatures and weakens the steel. The onset of this change is temperatures above about 850°F for carbon steels and above about 1000°F for chromium-molybdenum steels. Microstructural changes precede creep failures. Occasional short-term, high-temperature excursions hasten the process. Excursions to very high metal temperatures will, by themselves, cause instantaneous failure. Examination of the microstructure will indicate its temperature at the moment of rupture.



Metal wastage reduces the thickness of the pressure part and increases the operational stress that hastens the onset of failures. Erosion by fly ash, soot blowers, or coal particles leads to metal loss. Usually erosion patterns are well known and may be repaired as a part of an annual outage. Fire-side corrosion comes from liquid-ash attack in the superheater and reheater at temperatures above 1000°F (540°C), on furnace walls at temperatures below 750°F (400°C), and dew-point corrosion by condensing sulfuric acid occurs at temperatures below 300°F (150°C). Ordinary high-temperature oxidation consumes steel also. Metal loss from oxidation is 1-2 mils per operating year, while liquid-ash corrosion rates may be as high as 15-25 mils per operating year, although they usually are 2-4 mils per operating year. Water- or steam-side corrosion comes from impurities, most often oxygen, or excursions in boiler-feed water chemistry that are outside of the normal control range.

Welds are a continuing source of trouble, especially in high-temperature components. When a superheater and Reheater support or alignment clip breaks, oxidizes, or corrodes, or slip spacers do not slip because of fly-ash pluggage, welds break. These failures cause bundles to fall out of alignment, and improper flue-gas distribution through the pendant sections results. Poor flue-gas distribution then puts added thermal stress on these high-temperature components. Weld backing rings are a source of corrosion, hideout, and fatigue cracks. Chemical cleaning may lead to preferential corrosion of the heat-affected zone of welds in drums, headers, and downcomers. Rolled tube ends are also subject to more rapid corrosion during chemical cleaning. Dissimilar-metal welds between ferritic and austenitic alloys have local high - temperature stresses that lead to premature failure.

Fatigue, thermal fatigue, and corrosion fatigue are causes of failures that are difficult to identify before actual failure occurs. Thermal-fatigue cracks can form on the insides of headers and drums that suffer temperature excursions. Superheater and Reheater outlet headers may have large tube-to-tube differentials in steam temperature that accentuate and promote thermal fatigue or creep-fatigue failures. Waterwall tubes suffer corrosion fatigue, especially at welded attachments or buck stays, when there is insufficient allowance for differential thermal expansion.

Failures caused by human error or poor overall quality can occur in any manufactured item. However, within a boiler, human error can be operator error (e.g., a low-water upset) design error, or poor choice of material. Material defects, laps, seams, or poor-quality welds are amenable to prevention by appropriate inspection techniques. For the most part, these kinds of mistakes have been well identified and are not a principal focus here.

A variety of steel materials are applied to fabricate the tubes used throughout a boiler. As much as 300 miles of tube ranging from 0.75 to 3.0 inches outside diameter may be required to generate, superheat, and reheat in a large unit. The design coolant temperature and thus the tube metal temperature vary from as low as 350° F at the economizer inlet to over 1050° F at the final superheater / reheater outlet.

Engineering choices based on economics are made to place the appropriate tube steel at any one location in the boiler. Temperature is one of two considerations, the other being pressure. The units operate at several thousand pounds of pressure.

Table 1 -- Most Frequently Used Steels

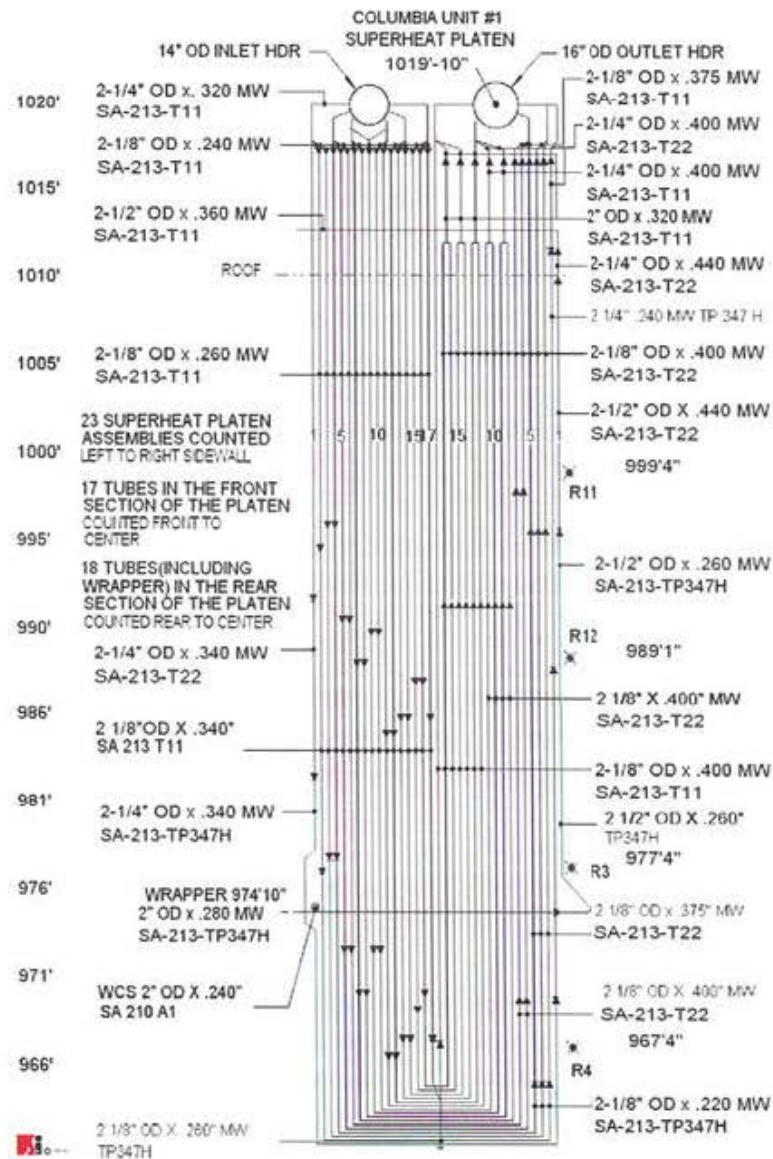
ALLOY	SPECIFICATION	MAXIMUM USEFUL TEMPERATURE
Carbon-steel	SA178, SA192, SA210, SA106, SA515, SA516	850°
Carbon-1/2 Molybdenum	SA209	900°
1 1/4 Chromium-1/2 Molybdenum	SA213 T-11 SA335 P-11	1025°
2 1/4 Chromium-1 Molybdenum	SA213 T-22 SA335 P-22	1075°
18 Chromium-10 Nickel	SA213 TP304(H), 321(H), 347(H)	1500°

These five alloys cover probably 85% to 90% of the steels used of the many acceptable grades listed in the Code. There are others that may find specific applications, for example 1/2 Chromium-1/2 Molybdenum alloy SA213 T-2, 9 Chromium-1 Molybdenum alloy SA213 T-9, and corrosion-resistant, high-temperature alloys of nickel and chromium, SB-407.

The maximum useful temperature is determined either by corrosion or oxidation concerns that limit the useful life before premature failure or changes within the microstructure occur that weaken the steel too much for elevated-temperature service.

Exotic materials are required to perform reliably and safely for the life of the unit, which can be more than forty years. A primary function of the boiler inspection team is to manage these exotic materials by replacing and repairing them before degraded performance and subsequent failure occur.

An accurate record of the locations where material and size transitions occur is essential to assure the proper replacement steel and welding procedure is used when failure repairs are performed. Tubing circuit diagrams of Superheaters and Reheaters are essential reference documents for each boiler in a power station. These diagrams must be updated when changes are made during the service life of the boiler. There are occasions when materials must be substituted due to lack of availability of the design material. This section on metals is designed to empower you with the knowledge necessary to properly select substitute materials.



Since the steam temperature in a superheater tube can vary from below 800° F (427° C) to over 1050° F (566° C), the material and minimum wall thickness (MWT) of a tube will vary at different locations within the circuit. The tube material varies from plain carbon steel (SA-192) at the superheater inlet header to austenitic stainless steel (SA-213 TP347H) just before the rear pendant superheater outlet header. Usually a material transition from austenitic steel to ferritic steel will occur in the final leg because the tubing is outside the boiler gas passage and inside the boiler header enclosure or penthouse.

See the drawing above to appreciate the complexity of tube materials in a typical superheater or reheater. The American Society of Mechanical Engineers (ASME) has approved certain steel materials for use as tubes in boilers designed according to the ASME Boiler and Pressure Vessel (B&PV) Code. The ASME specification number is commonly





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used to identify the tube steel type allowed at different sections of the boiler. The ASME specifications are essentially the same as the American Society for Testing and Materials (ASTM) standard specifications for steel tubular products. The ASME specification is normally used to purchase replacement tubes.

The ASME Boiler and Pressure Vessel Code govern all boiler pressure part materials. The ASME B&PV Code have established criteria for the allowable stresses that may be placed on all tube steel as a function of temperature. Allowable stresses are reduced for operation in the high temperature regions of the superheater and reheater. These criteria have been set to allow for considerable tube life, provided design conditions are not exceeded and corrosion or erosion does not appreciably reduce the tube wall thickness. Experience shows that virtually all boilers frequently operate outside design conditions. This is the sole reason boiler inspection teams exist. It is the responsibility of all involved with boiler inspections and maintenance to manage the variations in design and performance of these exotic materials.

One important factor in the selection of a tube material is its oxidation resistance at high temperature. While the ASME B&PV Code provides allowable stress values at high metal temperatures, the boiler manufacturers have placed maximum allowable temperature values that are lower than the highest ASME temperature values.

The limits take into consideration the heat transfer design analysis and the oxidation resistance properties of the actual tube materials used by the manufacturer. A direct comparison of maximum tube metal temperature cannot be made without information on design calculations and on actual material properties.

Tube metal temperature will increase throughout the steam path in both superheater and reheater circuits and requires the use of more oxidation resistant material when the temperature exceeds these limits.

Overheat is the creep (time-dependent strain that occurs under stress) resistance of the metal must be considered. Chromium is added to the steel to enhance its oxidation resistance and to improve its high temperature strength. Ferritic and austenitic stainless steel alloy tube products, such as made in accordance with ASME specifications SA-213 and SA-249, are employed to provide the high temperature strength, oxidation resistance, and ductility required.

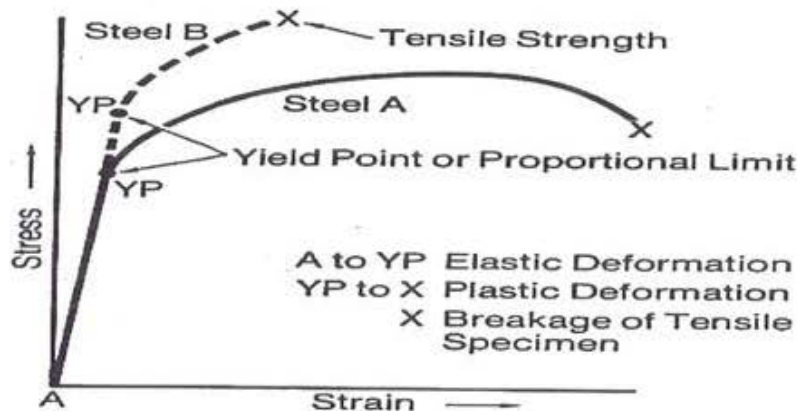
Technical Discussion of the Properties of Steel

A. Tensile Properties

1) When metals are pulled (stressed) with a uniaxial increasing load, the material stretches (strains).

Figure 1 shows the relationship between stress and strain for specific materials. With increasing load, the material strains elastically until it reaches the yield point. During this period of elastic behavior, there is

no permanent deformation; strain is directly proportional to the stress.



2) Continuing to increase the loading beyond the yield point results in plastic strains and eventually breakage of the component material. Ductility is a measure of the amount of plastic deformation the steel will sustain before breaking. It is usually expressed as a percentage elongation or reduction in cross sectional area of the specimen. How much plastic

strain steel will exhibit is quite variable and is generally inversely related to the tensile strength of the material.

(3) The effects of carbon (carbides) in tensile properties are that with increasing carbon content, tensile and yield strength increases in the carbon steels, while elongation values (ductility) decrease with increasing carbon.

(4) Greater strength could be realized by using steels with higher carbon, but ductility and weld ability would suffer. Pressure part steels have a specification requirement of 0.35 percentage carbon or less due to this limitation.

B) Hardness

(1) The hardness of a material is a measure of resistance to plastic deformation and is related to the tensile strength of the steel. It is also used as an indicator of the machinability and abrasion resistance of steel.

C) Fatigue

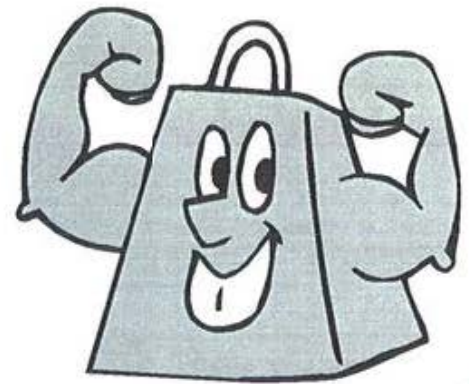
(1) The stress a material can withstand under repeated application and removal of load is less than that it can withstand under static conditions. Dynamic, cyclic loading causes slip and cold working in minute areas localized at grain boundaries and at stress concentrating notches of various types.

(2) Fatigue strength is the magnitude of a cyclic stress, which a material can resist for a specified number of cycles before failure.

- (3) The endurance limit is the stress level at which a material can tolerate an almost infinite number of cycles.
- (4) There are not specification requirements for measuring fatigue strength or endurance limit.
- (5) Fatigue failures in boilers are the result of excessive or unexpected cycling strains and are not attributable to in any deficiency of the steel.

D) Toughness

Under most circumstances, ductile steel can tolerate localized stresses above the yield point by plastically absorbing and redistributing these stresses. However, under certain circumstances of geometry or impact, when this redistribution is not possible, steels with considerable ductility area subject to a brittle cleavage mode of failure. The property of toughness is the ability to resist this type of failure.



Impact tests are the means of assessing toughness, but such tests are not required for boiler steels.

- (3) Temperature is important to determine whether cleavage type failure can occur at a temperature decrease below 70 degrees F. As such, the only concern for this type of failure in boilers is during hydrostatic test.

E) High Temperature Properties

- (1) Creep- At elevated temperatures, steels will continue to elongate under constant load below the yield strength of the material. Creep rate is used to measure this property.
- (2) Stress Rupture- At elevated temperatures steels will fail under constant load below the yield strength of the material. Stress rupture strength is used to measures this property.
- (3) Creep-fatigue interaction- when metals are exposed to cyclic loading while operating at temperatures within their creep range, the effects can reduce fatigue life. The introduction of periods of hold time at temperature, while under maximum strain, causes the slope of fatigue curves to change considerably.
- (4) There are not specification requirements for assessing any of these properties important to high temperature properties. Room temperature tensile properties do not provide a basis for determining behavior at elevated temperature, i.e., behavior in the creep range.

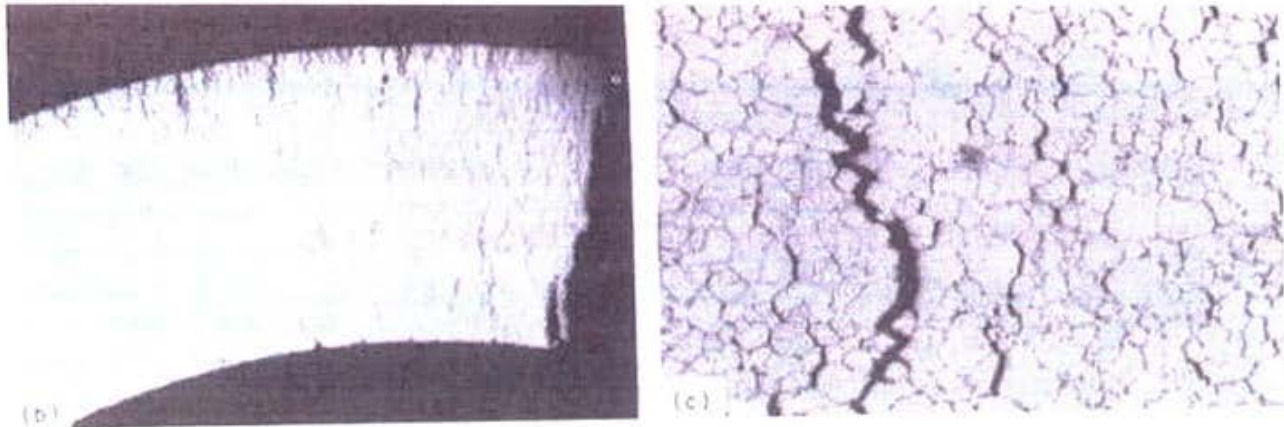


Fig. 10-26 Type 321 stainless steel superheater tube that failed by thick-lip stress rupture

Table D-1

IMPORTANT MICROSTRUCTURAL CONSTITUENTS OF BOILER TUBE STEELS

Constituent	Appearance in Etched Section	Composition	Hardness and Strength	Ductility	Comments
Ferrite (α -iron)	Bright	Iron with dissolved carbon and other elements	Low	Ductile	
Austenite (γ -iron)	Bright	Iron with dissolved carbon and other elements	Low	Ductile	Nonmagnetic; main constituent of many 300 series stainless steels and a few others
Cementite	Particles, rods, plates, usually small	Iron carbide, Fe_3C	High	Very brittle	
Other carbides	Particles, rods, plates, usually small	Carbides of molybdenum, vanadium, chromium, etc.	High	Very brittle	In alloy steels
Graphite	Dark gray nodules or flakes	Carbon	Low	Brittle	Generally undesirable in steels; may form by decomposition of carbides
Sigma phase	Must be identified by special staining etchants or by X-ray diffraction	Variable; nominally FeCr	High	Very brittle	May form in high chromium boiler tube steels during service
Pearlite	Lamellar (layered) combination of ferrite + cementite		Moderate	Ductile	
Martensite (untempered)	Bright, acicular (needle-like)	Iron with dissolved carbon	High	Brittle	Not found in tube steel unless tube has been rapidly quenched from high temperature after overheating failure
Tempered martensite	Dark-etching, acicular	Iron with dissolved carbon + carbides	Lower than untempered martensite	Less brittle than untempered martensite	
Bainite	Highly variable: feathery, blocky, or similar to tempered martensite	Ferrite plates + fine carbide particles	Intermediate between ferrite and martensite	Ductile	

The figure at the right shows a schematic of a time-temperature-transformation diagram for low-carbon steel, similar to SA-192. Three cooling curves are superimposed to indicate the cooling rates needed to form three types of HAZ microstructures. Cooling rate "c", the slowest, forms ferrite and pearlite. From a practical viewpoint these HAZ structures are seldom seen. Cooling rate b leaves a mixture of ferrite and a quenched structure from the austenite, often a Widmanstatten structure. This intermediate cooling rate is most often found. Cooling rate "a" forms a martensitic HAZ and is to be avoided, especially in the higher-chromium alloys.

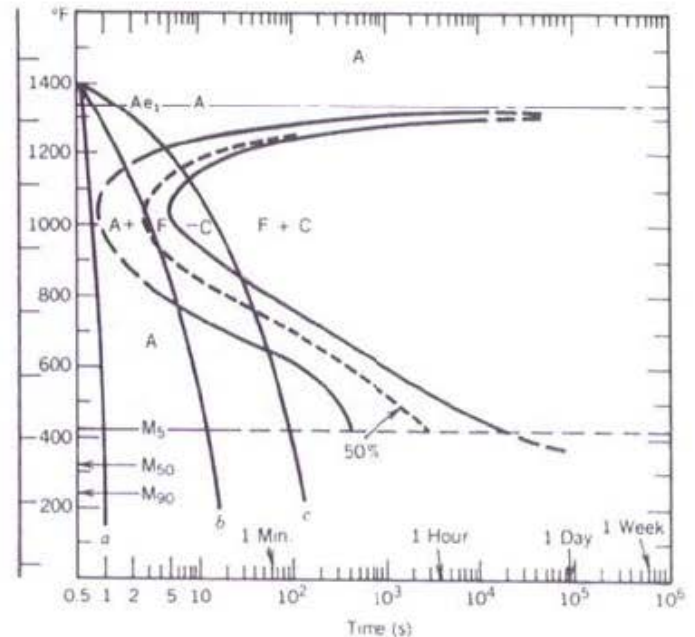


FIGURE 7.4. T-T-T curve for a low-carbon steel with three cooling rates superimposed.

The cooling rate from the all-austenite region determines the final microstructure. Under equilibrium conditions, cooling rate c and slower, ferrite begins to appear at the upper critical transformation temperature. The relative amounts of austenite and pearlite change, as does the composition of austenite. At the lower critical transformation temperature, the austenite transforms to pearlite. At a more rapid cooling rate, b, the transformation of austenite is suppressed and ferrite only begins to form at temperatures below the upper critical transformation temperature. The dashed line in Fig. 7.4 indicates the formation of ferrite, which forms preferentially along the austenite grain boundaries and along particular crystallographic planes in the austenite. The cooling rate is now fast enough to prevent the formation of pearlite, and the austenite transforms to bainite or, perhaps, martensite. Extremely rapid cooling rates, "a", prevent formation of ferrite, pearlite, and bainite, and the final microstructure is martensite. In low- and medium carbon steels (SA-192 and SA-210 A-1), cooling rates are seldom quick enough to form martensite, and the usual HAZ structure is ferrite and bainite.

Figure at the right shows the expansion and contraction characteristics when heated to and cooled from about 1800°F. The body-centered-cubic arrangement of atoms in ferrite is not as densely packed as the face-centered-cubic arrangement of atoms in austenite. Thus, at about 1350°F, the lower critical transformation temperature, as ferrite transforms to austenite, the denser atomic packing appears as a contraction of the length of a sample. The lower critical transformation temperature depends on the alloy content. Table XV in the appendix gives the approximate temperatures for the more common ferritic boiler steels. At about 1550°F, the upper critical transformation temperature, the ferrite-to-austenite transformation is complete. The slope of heating curve below 1350°F is in the thermal-expansion coefficient of ferrite and pearlite; the slope of the heating curve above 1550°F is the thermal expansion coefficient of austenite. During welding the base-metal heat affected zone will follow a heating curve similar to that in Fig. 7.5. The slope ferrite and pearlite is not as steep as the slope for austenite; that is, coefficient of expansion for austenite is greater than that of ferrite and pearlite.



Schematic presentation of the expansion of a low-carbon steel during heating and

When welding is complete, the HAZ begins to cool. When the cooling rate very slow, the transformation back to ferrite and iron carbide or pearlite follows the heating curve, and the final transformation product in the HAZ be ferrite and pearlite. For more rapid cooling rates, the transformation ferrite and carbide is suppressed, and martensite begins to form at a temperature of about 400°F; see Fig. 7.4. For carbon steels, the cooling rate prevent the formation of ferrite and iron carbide is very rapid, and, for the A part, the heat-affected zones show structures that are free of martensite.

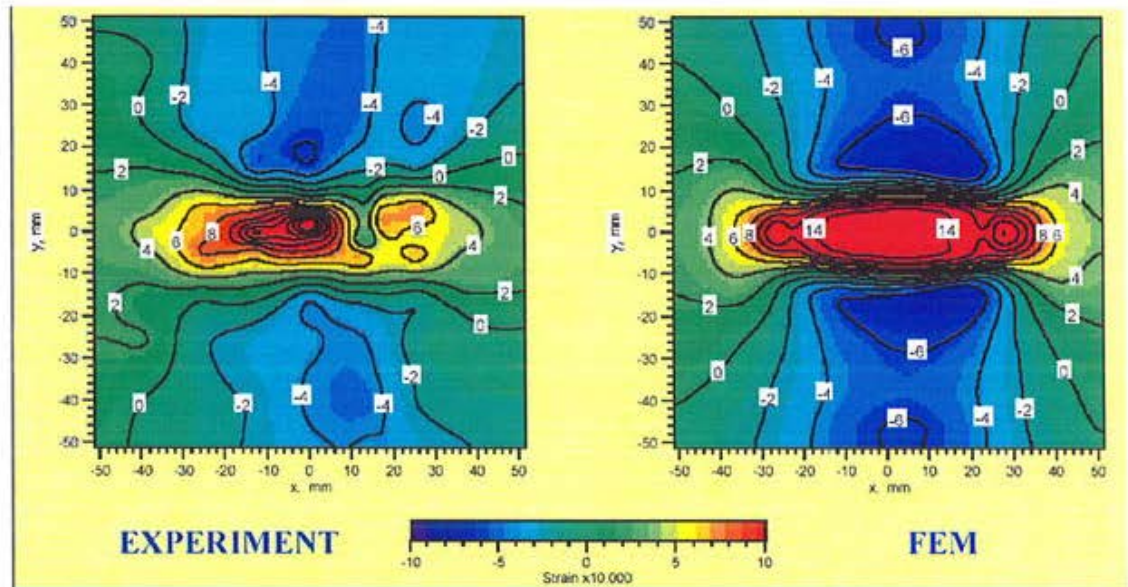
Another consideration in carbon steels is the cooling rate through the two phase region of ferrite and austenite. Again, if the cooling rate is slow enough to allow ferrite to form, the initiation sites for ferrite formation are in the austenite grain boundaries and along particular crystallographic planes in the austenite. Under these cooling rates, the microstructure just prior to austenite transformation is a mixture of austenite and ferrite with h austenite grain nearly surrounded by ferrite. The final microstructure is a Widmanstatten structure.

The second effect of the cooling of the heat-affected zone is the residual stress that remains following the austenite transformation. The change from BCC ferrite to FCC austenite involves a rearrangement of the iron atoms > a more densely packed structure. The discontinuous change in length at 1350°F in Fig. 7.5 reflects the closer spacing in the atomic alignment.

The change in volume of the HAZ must be accommodated by the surrounding metal. Stresses, or more accurately strains, within this material leave both HAZ and adjacent material with locked-in residual stresses. Such strains lead to distortion or, perhaps, cracking.

Figure 7.5 shows that when the transformation occurs at an elevated temperature, the volume change (shown in Fig. 7.5 as a change in length) is smaller than when the transformation occurs at a low temperature.

Extrapolation of the cooling of the austenite line to 500°F, for example, leads to a bigger change in length because the coefficient of expansion of austenite is larger than that of ferrite. When the



transformation of austenite occurs at high temperature, the surrounding material is both more ductile and weaker than at low temperatures. When the transformation of austenite occurs at a low temperature, the volume change is greater and the surrounding material is stronger and less ductile. The net result is a greater strain and residual stress within the heat-affected zone when the transformation occurs to martensite rather than to ferrite and iron carbide.

The effect of alloying elements on the T-T-T curve of Fig. 7.4 is to shift the nose of the pearlite transformation to the right. Slower cooling at SA-213 T-11 or SA-213 T-22 than in SA-192 will form martensite, for example. The transformation to ferrite and carbide is suppressed, and martensite will form at slower cooling rates. Cooling rates for the formation of satisfactory heat-affected zones in low-carbon steel will form unsatisfactory, martensite, heat-affected zones in alloy steels. Thus, for low-alloy, ferritic steels, cooling rates need to be reduced to prevent excessive residual stresses. The easiest way to accomplish this is to preheat the area surrounding the weld. Depending on the alloy content, higher preheat temperature will be needed to retard HAZ cooling rates enough to prevent damage



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How much preheat depends on the composition. ASME suggest the following.

Material	Preheat, °F
Carbon steel (<1 in and <0.30% C)	50
Carbon steel (>1 in and >0.30% C)	175
Carbon + 1/2Mo (>5/8 in)	175
Carbon + 1/2Mo (<5/8 in)	50
1-1/4Cr-1/2Mo (>2 in)	250
1/4 Cr-1/2Mo (<2 in)	50
2 1/4 Cr-1Mo	300

The heat-affected zones of austenitic stainless steels are different in the sense that there is no transformation between ferrite and austenite on heating and cooling during welding. The heat-affected zones of the austenitic stainless steels reflect only the peak temperature during welding. As temperature is increased, residual-stress relief, recrystallization of cold-worked structures, and grain growth occur. In those regions immediately adjacent to centerline of the weld, there will be fairly large austenite grains, and the grain size will decrease until the cold-worked structures are not altered by heating and cooling cycle of welding.

The long and the short of all of this is that no pad weld or overlay should be installed in carbon steels below 50° F. Any T-22 pad weld should be preheated to 300 ° F. This will help reduce stress in the materials. As discussed in other sections of this manual the cooler the application of the weld the better.

Last but not least the pad welds should be TIG re melted at the edges of the pad area to reduce the notch at the toe of the welds all the way around the area. Grinding or smoothing the transition would be a second choice although not as effective.

12. Hydrostatic testing yes or no?

The use of hydrostatic testing has become a commercial issue rather than the diagnostic it was designed for. The issue to many is the rapid return to service after a boiler repair. If we don't hydro then the thinking is that we can reduce the overall time that we are not commercial. This is strictly a gamble assuming that no other leaks or conditions present themselves during the after repair hydro.

The following is some guidelines for doing a hydrostatic test. In North America then the NBIC will give the guidelines on hydrostatic testing.

Hydrostatic test duration of boilers is placed in to four categories;

- 1-Proof [British developed this many decades ago]
- 2-Integrity [Brand new units get this]
- 3-Repair
- 4-Leaks.

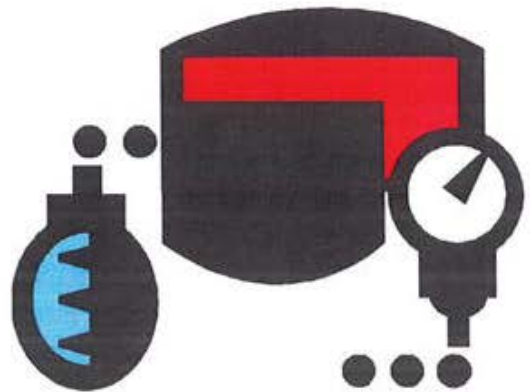
Hydrostatic tests can be at 1.5 times MAWP. This is an integrity test.

The repair hydrostatic test is done just below the lowest safety valve setting. There are some folks who believe that inspection cannot be carried out at 100% MAWP and should be lowered after holding for 30-minutes then the boiler entered for inspection. Now, hydrostatic tests are not going to create any serious hazard if inspected at that pressure. You will have to make that determination.

The leak test is less or equal to the pressure just below safety valve settings. It should be at least at 90% of operating pressure. The problem is very tight cracks will not leak at low pressure so do the leak test near the safety valve setting for the best success.

Finally the temperature of the water and metal surfaces has to be such that at the lower temperatures condensation or dew point will not occur and at the higher temperature the tinniest of leak will not evaporate from heat. ASME wants not less than 70F and NBIC wants not less than 60F and not greater than 120F. I would work with in the NBIC but follow what I said before about condensation and evaporation. Everyone should buy in to this.

The purpose of the hydrostatic test is to find leaks and it is not a proof test where deformations are the criteria. Although, while you are inspecting the boiler during a hydrostatic test you should inspect for leaks and if you notice a deformation then take appropriate action. Some folks take the safety precaution that there maybe weld repairs that have not proven themselves under a hydro and deformation may occur or the repair may blow out. This has happened although rare.





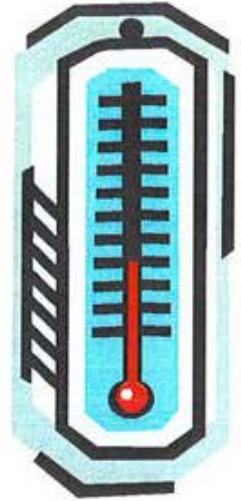
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The duration should be at least 30-minutes or longer [this time frame is determined by the ability for a leak to manifest. Drop the pressure to less than MAWP or to a safe agreed upon pressure that will still attribute to a leak and enter the boiler firesides and inspect.

BOILER FILL WATER TEMPERATURE REQUIREMENTS

Items 1 and 2 are recommended boiler water and metal temperature limitations for filling the boiler during normal unit start up and operation. Items 3 and 4 define ASME code temperature limitations prior to applying pressure for a hydrostatic test and before close examination, respectively.

1. The temperature differential between the fill water being introduced and the boiler metal temperatures shall not exceed 200°F. The boiler metal is defined as the highest temperature component that will be wetted by water for, and for hydrostatic test filling it is defined as drum shell and superheater outlet header(s). The intent of this limitation is to reduce stresses within thicker walled components that can be exacerbated by thermal gradients.
2. If the boiler metal temperature is less than 100°F and the fill water temperature is greater than 100° a low fill rate shall be used, i.e. a single condensate pump or a feed pump at minimum flow rate. The intent of this limitation is to reduce the risk of brittle fracture. The risk for brittle fracture increases if external surface cracks exist.
3. * 1992 ASME Power Boiler Code, Section 1, PG-99 Hydrostatic Testing states: "After a boiler has been completed, it shall be subjected to pressure tests using water at no less than ambient temperature, but in no case less than 70°F." The intent of this limitation is to reduce the risk of brittle fracture. When metal temperatures are below the transition temperature, steel is more prone to brittle fracture. We further qualifies ASME by recommending both water temperature and metal temperature to be no less than ambient, but in no case less than 70°F. The 70°F temperature limit must be observed on all pressure parts subjected to the hydrostatic pressure. The water and metal temperature limitation can be found in the Hydrostatic Test Procedure tab of the Unit Instruction Manual.
4. * ASME Code, PG 99.2, further states that prior to examination of the pressure parts when the boiler pressure is at maximum allowable working pressure (MAWP) or less, "The metal temperature shall not exceed 120°F during the close examination." The intent of this limitation is to reduce the risk of injury to personnel during close examination.





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NOTE: * Depending on the condition of a component to be hydrostatic pressure tested, it may be our recommendation to maintain a metal temperature greater than 120°F. The 120°F maximum temperature limit is applicable in most cases, however, if the component is sampled and assessed to have reduced fracture toughness (a metal's resistance to brittle fracture) the transition temperature will increase. The transition temperature range is the range at which a particular grade of steel shifts from having ductile properties to becoming more prone to brittle fracture.

NOTE: The ASME code applies to new boilers. Hydrostatic Tests performed after the successful completion of the unit's initial hydrostatic test are guided by the National Board Inspection Code (NBIC) and the owner's Insurance carrier. The NBIC states the following: "The temperature of the water used to apply a hydrostatic test should not be less than 70°F (21°C), and the maximum temperature during inspection should not exceed 120°F (49°C). If a test is conducted at 1-1/2 times the MAWP and the owner specifies a temperature higher than 120°F (49°C) for this test, the pressure should be reduced to the MAWP and the temperature to 120°F (49°C) for the close examination."

For further information on Hydrostatic Testing refer to Hydrostatic Testing or ASME Code requirements for Hydrostatic Test - New Boiler Construction.

13. Repairs

Tube replacement vs. repair

Welding

There are about 25 welding processes. We will only discuss three of these as they apply to welding in and around the boiler. Shielded metal arc (SMAW) (rod or stick), gas metal arc (GMAW) (MIG), and gas tungsten arc (GTAW) (TIG).



For SMAW use 3/32" diameter electrodes for tubes over 0.125" thick. Before using this process a minimum thickness of 0.150" is required. Follow the weld layer sequence and general techniques of the aforementioned instructions. The E7010-A1 electrode may be used for hard to weld areas and where the electrode may not be kept within 20° of perpendicular to the tube. Otherwise use the E7015-A1 or E8015-B2L electrode. Always use the lower half of the recommended amperage range. Maintain the stringer bead technique to minimize penetration.



For GMAW use only the short-circuiting type of arc. This process may be used on tubes 0.90" or heavier wall. The thickness is based upon using 75% argon - 25% carbon dioxide shielding gas. Carbon dioxide (100%) may be used for the shielding gas with the advantage of less penetration but more spatters would be present. Voltage and amperage values should be in the lower half of the range specified, but carefully balanced for good weld ability.

This may be used after depositing one bead layer on thin tubes with the gas tungsten arc process. Less heat input is used when compared to manual metal arc allowing for thinner sections to be welded.

Arc welding a metal with a low melting point or low solidus requires less heat input and more accurate control of the process to prevent melting through, especially if the metal is thin. Melting points of some common metals and other temperatures of interest are shown in Fig. 1-31.

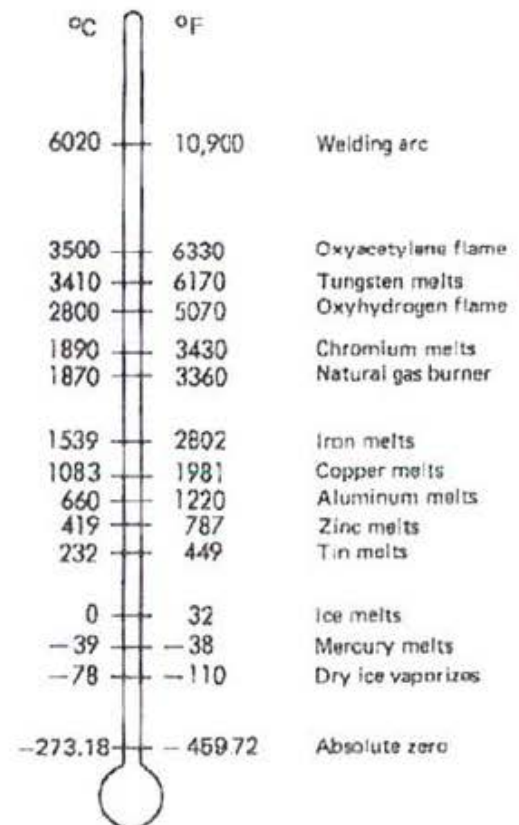


Fig. 1-31. Melting points of some metals and other temperatures of interest



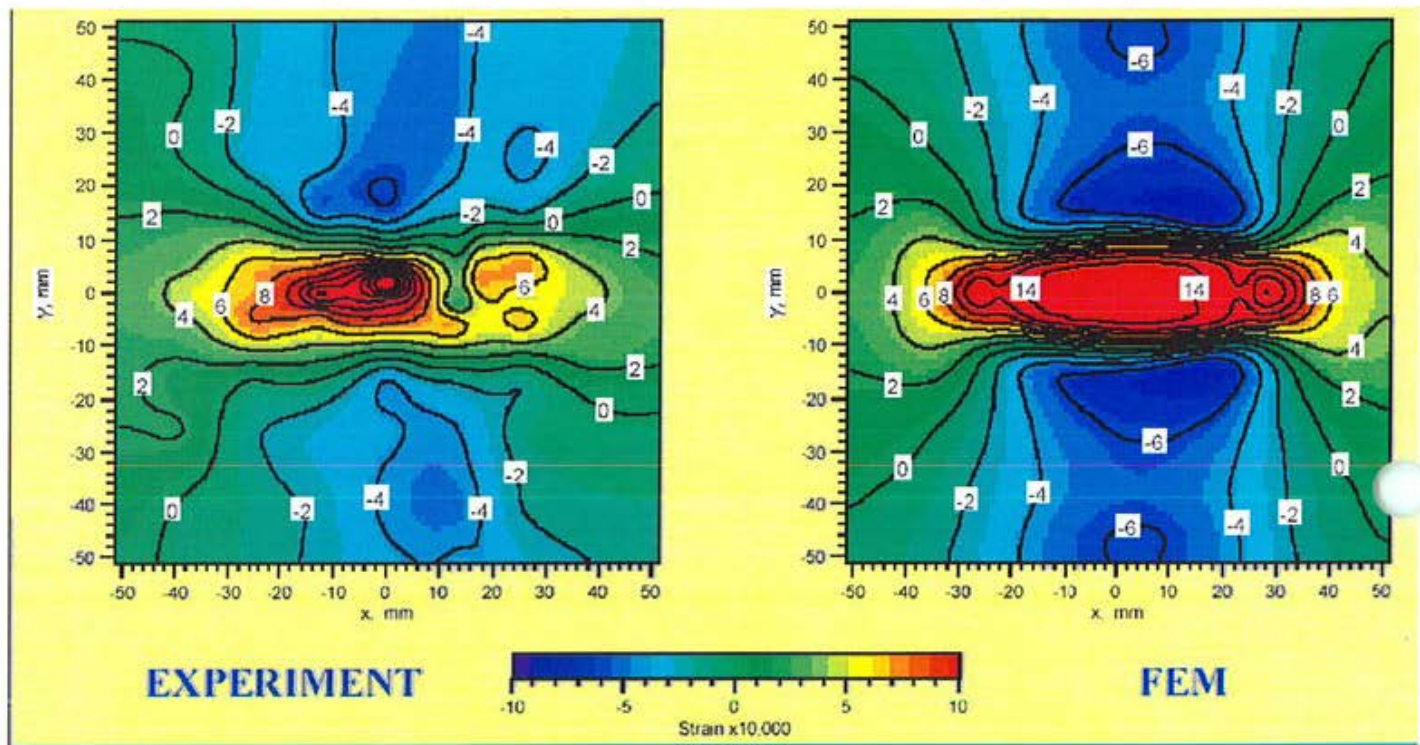
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For fill welds this is best suited for use on thin sections or holes. Filler metal should be added for all passes unless a bead is not completely fused. A pass without adding filler metal may be used, but is not recommended. By starting on the heavier section of tube, a puddle is established before entering a thin area. Once a weld puddle has been established, begin adding filler wire to the front of the puddle. By laying the wire on the surface and passing over it, the filler wire absorbs some of the heat reducing penetration and the change of burn through. Repair of holes, leakage points, and severe notches or dislocations are best repaired by this method.

Pad Weld / Overlay Applications

There is much discussion about replacements as repairs and their proper application. In a utopian world, replacements are the desired repair for anything threatening the pressure boundary. There are, however, constraints such as access, time, length of repair, and material availability, which force alternatives. In these cases we must make other repairs that may not include replacements. Pad welding and tube shielding are common alternatives to tube replacements.



The extremes of compressive (blue) and tensile (red) strains in steel carrying a pad weld / weld overlay are shown by neutron diffraction mapping. Undesired welding process variations cause irregularities in the strain distribution.



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When considering repairs, a well-defined repair criteria must be considered. As previously discussed, action levels need to be established based on prior set criteria. To determine criteria we must follow some rules.

You can calculate your own thresholds by calculating hoop stress based on ASME specifications and applying that information to your MWT of each component.

You can adopt a recognized criteria used by most OEM's and UDC. These suggestions are based on item one above.



<65% of MWT for replacements
<75% >65% of MWT for pad welds
<85% >75% of MWT for shielding

3. Thinning rates must be established before proper application of the rules.

4. The scheduled run time must be considered in applying the rules. You must effect a repair that will not be compromised within the scheduled operations time. You may have to implement a more conservative criteria to achieve the desired result. Depending on the circumstances, you may need to increase the MWT above design or to apply heavy shielding. When increasing MWT, consult your engineering department for their interaction, as this will affect performance of the boiler. Always consult engineering when considering a design change in the boiler.

It has been our experience over the last 30 years that a properly installed pad weld can be an effective long-term repair. This is some contrast to the formal recommendations suggesting replacement. We do not support pad welding in lieu of replacement; however, we do suggest that the pad weld will be more survivable if installed properly. It is common practice to install pad welds as a compromise to replacement.

To continue this discussion we must consider the physical risks of other repairs. Pad welding is the most popular repair method for thinned tubes. A pad weld is nothing more than a large heat affected zone on the tubing. In all heat affected zones there is a modification to the grain structure, which affects the strength of the modified material.



The number one suggested repair for pressure boundary thinning is replacement; however, there exists several conditions when pad welding is more practical:

If the thin area is small (less than 25% of the surface of the tube outside diameter vertically and horizontally), then pad welding is acceptable. This would also apply to crack removal as well as tube wall thickness restoration.

If acceptable replacement material is not available.

If access is not practical.

You should never pad weld under the following conditions.

If a copper deposition on the waterside of the tubing is likely.

If a hole or crack breaches the tube inside diameter.

If the remaining wall of the tubing is very thin ($<0.0625"$ $1/16"$).

If the lengths of the pad weld exceeds 18".

If the work quality of available welders is questionable.





Copper (Weld Repair Caution)

- a. Molten copper can penetrate the grain boundaries of steel causing failure.
- b. Weld repairs of either the butt weld or pad weld type can readily melt any copper present on the ED surface. This can result in failures.
- c. Copper can be locally removed when preparing the ends of tubes for butt-welding.
- d. When considering making weld build up pad welds, samples should be checked for the presence of copper.
- e. If present, it would be prudent not to weld the tubes until the copper is removed by chemical cleaning.





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Problems associated with the use of Pad welding and Overlay welding

The failure conditions listed below should be considered before any pad welding or overlay welding are administered. If you have any of these underlying conditions then you should not overlay or pad weld.

HYDROGEN DAMAGE see page 165

PITTING see page 159

CAUSTIC CORROSION see page 161

STRESS CORROSION CRACKING see page 153

THERMAL FATIGUE see page 79

Corrosion Fatigue see page 155

Dissimilar metal welds see page 67

CREEP see page 87

ACID PHOSPHATE CORROSION see page 163



Repair procedures

Caution with stainless steels

A presentation was made by Mr. R. Schueler on the use of austenitic stainless steel on October 28, 1999 during the Annual Chiefs' Technical Seminar held at Columbus, Ohio is quite relevant to the discussion of stress corrosion cracking. The presentation can be summarized as follows:

Type 300 series stainless steel has been used in boiler and pressure vessel applications for quite some time. Typically it is used where contamination and/or corrosion may be considered a problem. Some typical applications include food processing vessels and boiler Superheaters.

However, it is important to consider that there may be downsides with the use of these materials. For many years, the oldest code of the ASME, Section I, Power Boilers, has made a number of precautionary statements for the use of austenitic stainless steel. However, because not all people took notice of the provisions, a number of revisions in Section I have been added in the last few years.

In particular, a new paragraph PG-5.5 was added in the 1998 Addenda which states that "The use of austenitic stainless steel is permitted for boiler pressure parts which are steam touched (sic) in normal operation. However, the use of such steel for boiler pressure parts which are water wetted in normal service is prohibited except as specifically provided in PG-12 and PEB-5.3.1"

The added footnote (1) of the paragraph noted that "Austenitic alloys are susceptible to intergranular corrosion and stress corrosion cracking when used in boiler applications in water wetted service. Factors which affected the sensitivity to these metallurgical phenomena are applied or residual stress and water chemistry. Susceptibility to attack is usually enhanced by using the material in a stressed condition with a concentration of corrosion agents (e.g. chlorides, caustic or reduced sulfur species).

For successful operation in water environments, residual and applied stresses must be minimized and careful attention must be paid to continuous control of water chemistry."

The 1999 Addenda of the ASME Section I Code introduced a new set of rules under paragraph PG-19 which requires the calculation of percentage strain in the forming of the various shapes used and items exceeding the limits will have to be heat treated at a temperature over 1800°F (982°C) and in some cases over 2050°F (1121°C).

Although not having the statements because the Section is less product specific, ASME Section VIII Division 1 provides for guidance under paragraph UHA-6 that "Specific chemical compositions, heat treatment procedures, fabrication requirements and supplementary tests may be required to assure that the material will be in its most favorable condition for the intended service. It goes on to note that "This is particularly true for vessels subject to severe corrosion. These rules do not indicate the selection of an alloy suitable for the intended service or the amount of corrosion allowance to be provided".

For the National Board Inspection Code, NBIC-23, paragraph RB-3240(g) also provides for specific guidance on this matter. It should be noted that stress corrosion cracking introduced by chlorides could actually occur in such simple instances as a hydrostatic test using city water.

The three factors which promote Stress Corrosion Cracking in this case are a) Stress which could be induced by pressure or weight, b) chemistry of contents, such as a very small amount of chloride and c) a liquid, normally water, in contact with the metal. Removal of any one of the three factors will help to prevent this form of corrosion.

Other possible problem areas with the use of stainless steel in conjunction with carbon steel include the different heat treatment temperatures and differential expansion. P-1 material is typically heat treated in



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1100°F range while P-8 in the 1900°F range. Also, stainless steel typically has an expansion rate 1.5 times that of carbon steel. Special attention must be paid when the materials are used together.

Codes and standards provide for good guidance but purchasers, designers, manufacturers and users need to become more aware of the properties of stainless steel for the actual intended services to allow for safe pressure equipment applications."

Coming after the alert we issued in the last issue of the Pressure News concerning the mistaken substitution of stainless steel for carbon steel in a mechanical clamp that caused a catastrophic failure, Mr. Schueler's presentation again alerted our industry to the importance of cautions that must be exercised in the selection and use of materials for pressure equipment.

ABSA wishes to acknowledge the support of the National Board in all matters related to pressure equipment safety in general and in the publication of this article in particular.



ADVANCED BOILER INSPECTION TECHNIQUES 2011



The National Board Inspection Code (NBIC) provides guidelines and rules for repairs and alterations to boilers and pressure vessels after they have been placed into service. Any welding should be done accordance with your local rules and codes. This jurisdiction may be under the authorized inspector. Jurisdictional requirements involving the AI vary widely. Most jurisdictions require the owner to obtain the AI's ACCEPTANCE BEFORE REPAIR OR ALTERATION. However, the NBI Code places the responsibility of coordinating the acceptance inspection on the contractor. Anyone that is required to do pressure part welding owner, contractor or manufacturer must use approved welding procedures done by qualified and certified welders.

What are the functions of the National Board?

The National Board is comprised of Chief Boiler Inspectors representing government agencies from across North America. functions include:

- Helping to maintain quality within the boiler and pressure vessel industry through the process of third-party inspection during the manufacturing process as well as promoting the establishment of manufacturing, maintenance, and repair standards for boilers and pressure vessels.
- Offering an extensive training program for inspectors and other industry professionals, involving continuing education in various disciplines of the boiler and pressure vessel industry.
- The commissioning of inspectors who pass an extensive examination administered by the National Board, enabling the qualified inspection of boilers and pressure vessels.
- Maintaining a pressure relief testing laboratory -- setting the industry standard for testing pressure relief devices and other appurtenances.
- Maintaining detailed records of all National Board registered boilers and pressure vessels.
- Accrediting qualified repair organizations and owner/user inspection organizations for repair and alteration of pressure-retaining items and pressure relief devices.
- Investigating accidents and code compliance problems involving boilers and pressure vessels.
- Educating the general public and government representation on the need for safety standards.
- Developing inspection, repair, and alteration standards (*National Board Inspection Code*).

What is the *National Board Inspection Code*?

It is the only standard recognized worldwide for in-service inspection repairs and alterations of boilers and pressure vessels. This American National Standard has been adopted by a number of states and jurisdictions, as well as by federal regulatory agencies including the U.S. Department of Transportation.

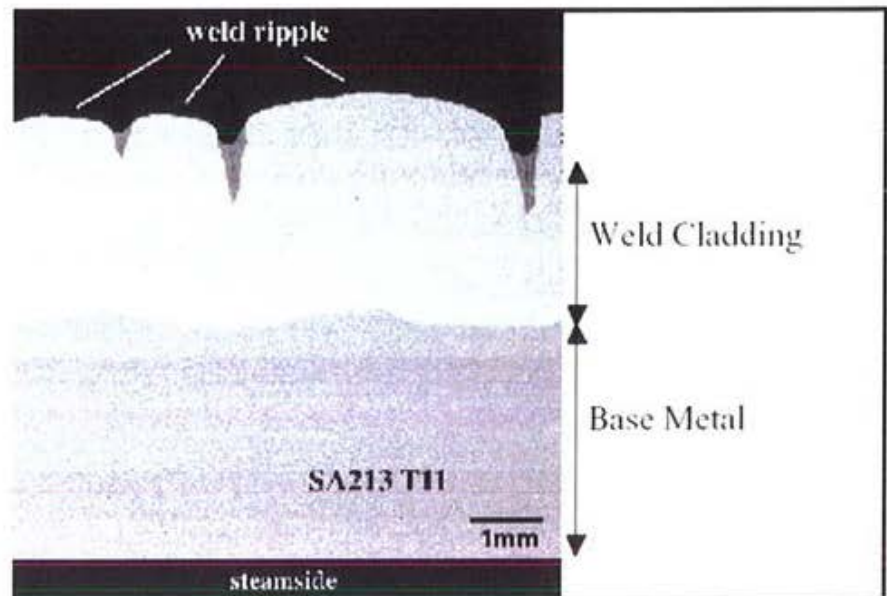
The use of overlay welding on tubes (*pad welding by a different name*)

The use of overlay welding on tubes

(1) Since the early 1990's, U.S. utilities have been making major modifications to their fleets of coal fired boilers to comply with NO_x regulations. In many cases, this involved installation of low NO_x burners and overfire air registers, often resulting in oxygen deficient regions in the vicinity of the burners. Some of the coal-fired utility boilers, which were converted to low NO_x operating conditions, subsequently experienced increased rates of waterwall corrosion. In response, some utilities turned to weld overlay coatings for corrosion protection. In 1998, reports began drifting back to the ERC that some boilers with weld overlay coatings were experiencing circumferential cracking of coated waterwall tubes. Since then, researchers at the Center have been working to determine why these coating failures are occurring.

The materials research team, led by Drs. Arnold Marder and John DuPont has been studying coatings for boiler tubes for more than a decade. Their work has included investigations into the mechanisms of waterwall corrosion and the effects of furnace conditions and alloy composition on corrosion rate. They have looked at different types of coatings, including weld overlay, thermal spray and chromized. Their research has included laboratory experimentation, laboratory evaluation of tube specimens obtained from the field, and computer simulations.

As part of this activity, they recently completed a research program that evaluated the corrosion resistance of commercial weld overlay coatings in a range of oxidizing/sulfidizing environments and various slag compositions. With these results they were able to better define the corrosion mechanism in low NO_x boilers through accelerated tests that included cyclic gas experiments. They have also looked at the stresses and strains which arise during the application of weld overlay coatings. Teaming with Dr. Herman Nied, a specialist in stress analysis and fracture mechanics, they investigated the effects of welding procedures on the quality of the weld overlay coating and on the

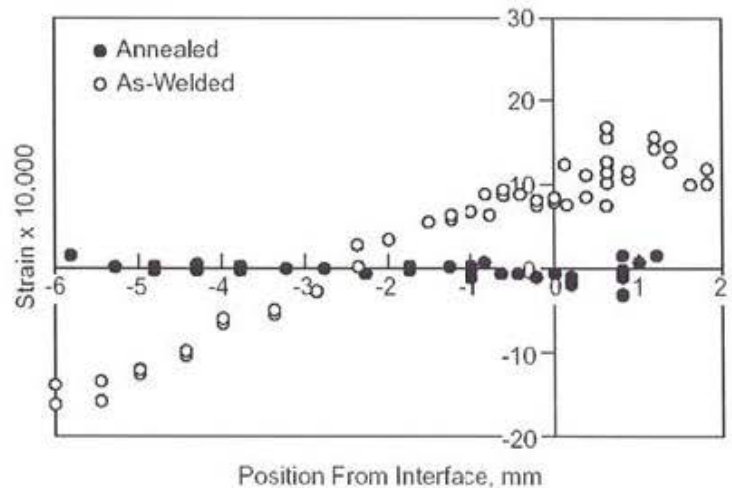


Cross Section View of Circumferential Cracks in a Weld Cladding

In 1998, the group obtained five tube samples from three utilities, all with Inconel 625 weld cladding. Laboratory analysis showed the weld clad coatings were not visibly thinned, but they did contain longitudinal and circumferential cracks which were quite severe on four of the five tubes.

The cause of the longitudinal cracks was attributed to improper welding procedures and recommendations were made on ways of avoiding these types of cracks.

The circumferential cracks found across the weld cladding are of greater concern since they are related to boiler operating environment. These ranged from minor to very severe, with almost half the circumferential cracks having fully penetrated the cladding, and in some cases, into the tube material beneath the cladding. Detailed chemical analysis showed each circumferential crack contained a sulfur "spine" which extended all the way down to the crack tip.



Residual stresses in Inconel 625 weld overlay tubing

Comparison of cracks to those found in an earlier study of chrome moly low-alloy boiler tube steels showed a striking similarity. In the 1989 study, the materials group characterized circumferentially cracked low alloy steel tubes retrieved from service in several pulverized coal boilers. There were approximately 20 to 25 circumferential cracks per inch. Just as with the cracks recently found in weld overlay claddings, each crack was filled primarily with an iron oxide corrosion product, but each also possessed an iron sulfide "spine" running down to the crack tip.

According to Marder, "Our research suggests the circumferential cracks are caused by a combined process of corrosion and thermal fatigue. Stresses in the tube walls can be caused by temperature gradients, resulting from fluctuations due to slag falls, sootblower operation and changes in the flame. These stresses are magnified, in some cases, due to a thermal expansion mismatch between the cladding material and the base metal. In general, corrosion can be caused by both oxidation and sulfidation mechanisms. However, sulfidation is a more severe factor in coal-fired boilers because of the role which the sulfur plays in the crack propagation process. Susceptible locations on the cladding surface act as thermal stress concentrators and are potential sites for crack initiation and propagation. Corrosive sulfur species diffuse to the crack tip and react with the steel alloy at the tip. This weakens the alloy and permits continued growth of the crack with time."

DuPont adds, "Now that we think we know the causes of cracking of weld clad coatings, we are continuing our studies to determine why some weld overlay coatings experience circumferential cracking and others don't. Some coating alloys are obviously more susceptible to corrosion attack. There may also be some features of the weld overlay process which lead to initiation of corrosion induced cracking. Our goal is to be able to specify which alloys to use and how to perform the welding process to minimize the potential for failure."

Marder adds, "Based on discussions with our utility sponsors, we've developed proposals for two new research projects that we think will help power companies cope with waterwall degradation in low NOx boilers. One project, "Development of Low Cost Weld Overlay Coatings for Low NOx Waterwall Tubes,"

will apply material design principles to develop low cost core wire compositions for weld overlay coatings. The other project, "Remaining Life Assessment of Circumferentially Cracked Weld Overlay Coatings" will estimate remaining life of circumferentially cracked tubes as a function of stress level, coating composition and corrosion environment. Together, these two programs will enable utility companies to overcome the circumferential cracking problem found in certain existing weld overlay coatings and apply a new generation of low cost weld overlay coatings for the more stringent requirements expected in the future."

(1) LEHIGH research project Lehigh University.



Waterwall panels have been weld overlaid in the field utilizing both 309 stainless steel and Inconel Alloy 625. Typical weld thickness has been to .100". The weld procedures were developed to minimize the hardness of the heat-affected zone (HAZ) of the base metal. The concerns caused by this process include residual stresses introduced into the panels due to the heat input during the welding and the different coefficient of expansion of the overlay. The welding process may also introduce panel distortion, which could initiate problems at the buckstay connections. The overlay could be applied on the tubes with the panels filled water to minimize the panel distortion. However, this practice can limit other work planned on the waterwall circuit. The boiler will require scaffolding to these areas with the proper clearances for the applicator's equipment. Power supply and access are also important.

Weld Overlay Replacement Panels

The same material has been used on the shop-applied panels. The same concerns apply on shop-applied panels as far as residual stresses and heat input. Some of the supplier has mechanically straightened the panels by inserting the panels in roll mills.

Cost of Various Solutions

The cost per square foot for new waterwall panels for supercritical boilers without attachments and installations are:

Carbon steel	\$100 - 125
T2	\$125 - 150
T11	\$150 - 175

Installation cost is estimated to be \$300 - 350/square feet

Similar waterwall panels (material only) for sub critical boilers can be as low as \$501ft.

Overlay Costs

Their "all-inclusive" prices usually range from \$200 - \$500 per square foot.

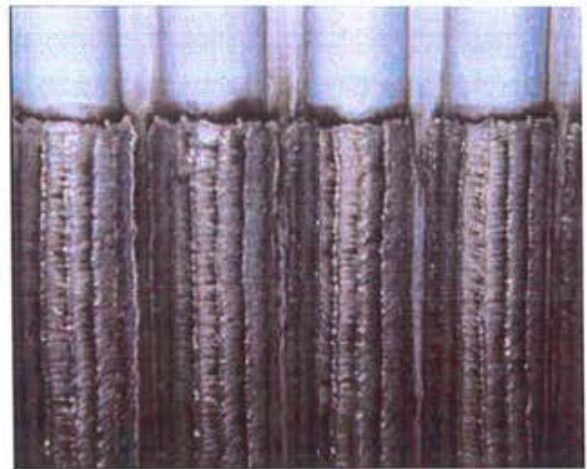


Table 1
Material Property Comparison Chart

Property	Carbon Steel	Type 304L	Incoloy 825	Inconel 625
Expansion Coefficient Mean to 700 F (370C) x 10 ⁻⁶ , in./in. F	7.59	9.69	8.3	7.5
Thermal Conductivity @ 700F (370C), Btu/h ft ² F	320	142	115	117
Ultimate Tensile Strength, Ksi @1000F (540C)	—	56	86	132

Information on Inconel 622

9 INCONEL Filler Metal 622 overlays have been used successfully for more than four years in low-NO_x boilers. In side-by-side testing, where Alloy 625 overlays have cracked in as little as 18 months, 622 overlays have performed with no cracking at very low corrosion rates for more than four years.

In laboratory testing in waste-to-energy boiler simulated environments, INCONEL Filler Metal 622 overlays exhibit about half of the weight loss and depth of penetration of that exhibited by 625 overlays.

In low-NO_x boiler survey results, INCONEL Filler Metal 622 overlays have shown about 300% lower attack rate than 625 and type 309 stainless steel. INCONEL Filler Metal 622 exhibited no cracking or preferential attack, while 625 is subject to circumferential cracking and 309 suffers preferential attack.

In a 2765-hour low-NO_x boiler field test type, 312 stainless steel overlays were attacked at a rate 1.5 times (0.21 mm) faster than INCONEL Filler Metal 622 (0.14 mm). INCONEL Filler Metal 622 welds have minimum tendency for cracking and have nearly two times more active ingredients than 625.





Thinning weld repair guidelines



When to apply

1. Most of the wear is general erosion of a localized area.
2. Notches and dislocations are present in a random manner. These may penetrate deeply into the wall, possibly extending through the wall (leakage).
3. Repairs may have to be made in all positions.
4. Tubing to be repaired will be some form of carbon steel.
5. Wall thickness to consider: Must be above 65% of design MWT.
6. An aluminum or stainless steel coating may have been applied to various areas of the tubes by metallizing.

Base Metal Preparation

Prior to cleaning, the tubing has been exposed to service environment and is covered with grease, oil, paint, dirt, coal dust, and/or slag. For areas requiring repair, and six inches around the area, all loose material must be removed. For one inch around the defective area, the tube shall be cleaned to base metal, removing all foreign matter.

The above requirements are valid whether or not any metallizing is present. If either the aluminum or stainless steel has been applied, this must be removed. These coatings are not compatible to the parent base metals if diluted with weld metal. Due to the very thin nature of the remaining base metal in the defective area, grinding in this area is not recommended. Either a power steel brush or a flexible flap wheel will clean the defective areas properly. Grinding may be used to complete cleaning to white metal around the weld joint.

After cleaning the defective area to sound parent metal etching the surface will reveal any remaining foreign materials. This is left to the discretion of the individual. If it is felt that no metallizing, other coatings, or foreign material remains, the etching is not required.

Bi metal tubing INCOCLAD® 625/Steel

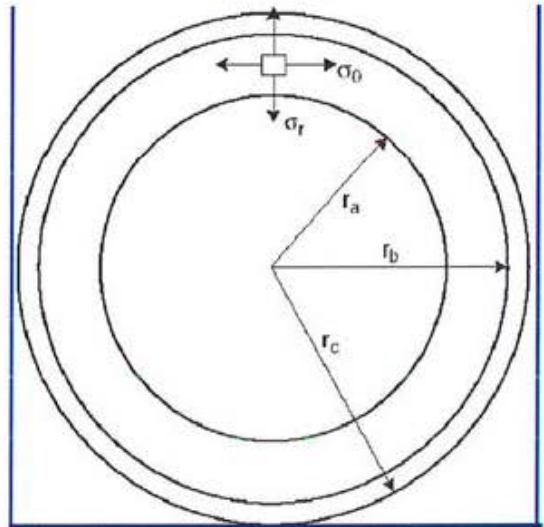
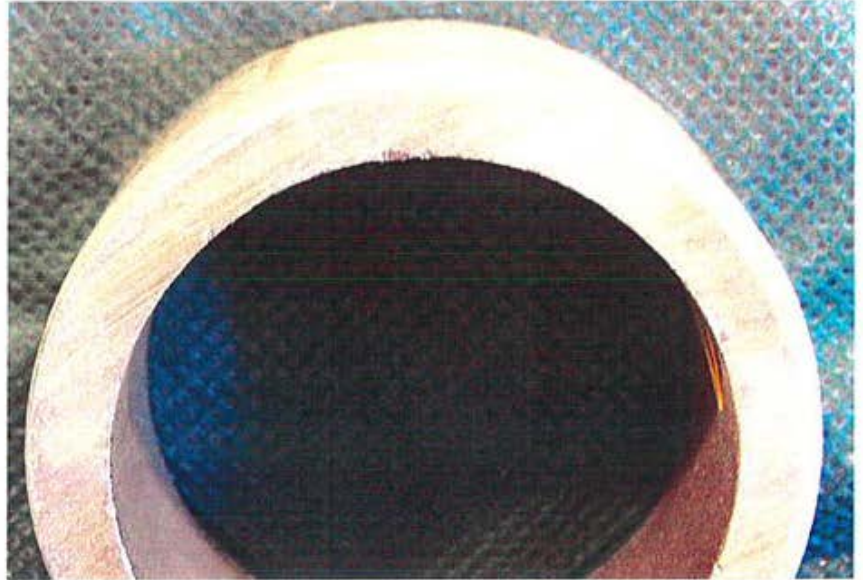
Tubes comprised of a ferritic boiler steel core with an austenitic, corrosion-resistant cladding of INCONEL® alloy 625 offer a unique combination of properties for service in aggressive elevated temperature conditions such as those encountered in many power and process boilers. Ferritic steels are favored for steam service because they are essentially immune to chloride stress corrosion cracking (SCC). Unfortunately, such steels have very marginal resistance to the aggressive corrodents in boiler environments. INCONEL alloy 625, however, offers excellent resistance to corrosive attack. Thus, ferritic steel tubes clad with INCONEL alloy 625 are ideal for steam service in boilers, especially those exhibiting very corrosive conditions.

The composition range of the alloy 625 cladding of the INCOCLAD tubes is the same as that of conventional alloy 625 tubes and is specified by ASTM B 444 - UNS N06625.

The grade and composition of the steel substrate are dependent on the steel specified. Some of the common boiler steel grades used for the tube core are ASTM A 210 - grade A-1, ASTM A 213 - grade T-2, and DIN 17175 - grade 15Mo3.

Welding Applications

INCOCLAD 625/Steel clad tubes may be joined by procedures essentially identical to those used for welding conventional INCONEL alloy 625 tubes. Recommended welding products are INCONEL Filler Metal 625 for GMAW and GTAW and INCONEL Welding Electrode 112 for SMAW. The included angle of the weld joint should be as steep as practical to minimize iron dilution of the weldment.





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Production and Testing of Clad Tubes

INCOCLAD tubes are produced by means of co-extrusion. The metallurgical bond between the two alloys is achieved by the high temperature and pressure required in this process. The tube shell is then cold worked to the required diameter and wall thickness by standard tube reducing/pilgering techniques. Tubing is ultrasonically tested to ensure a good metallurgical bond between the two alloy layers. This is essential in service for effective heat transfer. The inner tube material is mechanically tested to ensure conformance to the normal pressure vessel standards.

INCOCLAD® alloy 625/Steel bimetallic clad tubes are designed for service as boiler tubes for steam generation and heating in utility, municipal solid waste (MSW) fired boilers in waste-to-energy (WTE) incineration systems. Boiler tubes in these environments are exposed to corrosion by halogens such as chlorine and fluorine generated during the incineration of plastics. Steels and iron-base alloys are rapidly attacked by these elements because iron forms stable compounds with the halogens at elevated temperatures. Alloy 625, however, by virtue of its high nickel content and low iron content offers excellent resistance to attack by halogens as nickel does not form stable compounds with these elements at elevated temperatures. Alloy 625 also offers excellent resistance to oxidation, sulfidation, and carburization due to its content of chromium. INCONEL Filler Metal 625 has been successfully used for many years for weld overlay of boiler components for increased resistance to corrosion in WTE boilers in MSW incineration systems. Production of alloy 625 clad tubes is an extension of that proven technology. The black liquor recovery boilers used in pulp processing for paper production should also benefit from the use of INCOCLAD alloy 625/Steel boiler tubes. These boilers burn the concentrate left from de-watering the spent liquor from the pulp digestion process. Consequently, the boiler tubes are exposed to a very corrosive environment that contains significant concentrations of halides and sulfur. As in WTE boilers, INCONEL Filler Metal 625 weld overlays have been widely used for protection of the boiler components against corrosion. Thus, alloy 625 clad tubes offer proven corrosion resistance to the exterior environment and SCC resistance to the steam in the interior in a fully wrought tube. INCOCLAD and INCONEL are trademarks of the Special Metals Corporation group of companies.

Chromizing

Chromizing is the diffusion-controlled enrichment of component surfaces with chromium to impart superior levels of corrosion and/or erosion resistance. As noted above, ATC pioneered the development of the chromium-enhanced studs for use in both the Pulp and Paper and Utility industries. You can also chromize larger pressure parts, such as waterwall tubing panels for installation in Recovery and Utility type boilers.



Chromized Replacement Panels

This process was developed by primarily ABB-CE, however, B&W also offers chromized replacement panels. Chromized replacement panels have limited use since this process requires shop application. The process used by ABB-CE involves a pack cementation process in which the panel is packed in a mixture of chromium, halide activators and inert materials and placed in a retort, and raised to a temperature below 1400°F to allow the chromium to diff-use into the material. B&W uses a blanketing process which results in less dense material and a shorter time at temperature, which reduces the thickness of the decarburized layer between the chromium coating and the tubing material. Both of these processes applied between 10 - 15 mils of protection that is metallurgical bonded and have been used successfully by other utilities.



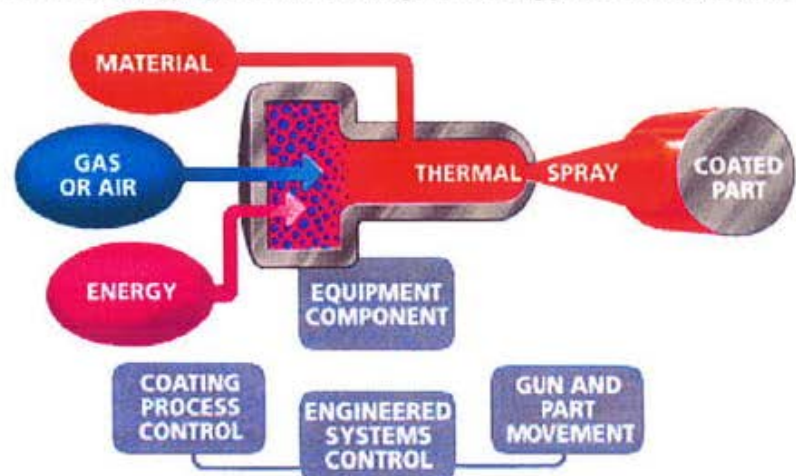
14. Thermal Spray Coating and when to use it?

Thermal Spray coatings that have been used by the utility industry include arc and plasma spray and high velocity oxygen fuel (HVOF). Wire Arc spray coating is a mechanically bonded coating that has a bond strength of 5000 psi while the HVOF applied spray coating has a bond strength of 10,000 psi or more. The other significant difference is in the porosity of the finished product. This is important, since the denser the material, the less likely that the corrosive byproducts of combustion (H_2S) can penetrate the coating layer. When the coating is breached, the mechanical bond is broken and the coating will spall. Once the coating is gone, the base metal is exposed once again to the corrosive environment. All of these products have been successful and unsuccessful. The major drawbacks to field applied coatings is the criticality of the tube cleaning procedure and operator competence resulting in problems caused during field applications are the grit blasting process delaying other critical boiler repairs and the combustion products of the process themselves.

In the simplest terms possible, thermal spray coating involves heating a material, in powder or wire form, to a molten or semi-molten state. The material is propelled using a stream of gas or compressed air to deposit it, creating a surface structure on a given substrate. The coating material may consist of a single element, but is often an alloy or composite with unique physical properties that are only achievable through the thermal spray process.

Generally speaking, thermal coatings are a highly cost-effective way to add superior performance qualities to a given substrate. The variations on this technical theme are virtually limitless. Coatings can be metallic, ceramic, plastic, or any combination desired to meet a broad range of physical criteria.

The coating materials can be applied using several different processes. Thermal coating methods utilize fuel combustion, plasma spray and electric arc delivery systems. Coatings can be applied under standard atmospheric conditions or in specialized, highly controlled atmospheric environments — even under water! Coatings can be applied manually or with the automated precision of software-driven robotics. Thermal sprayed coatings can be the most cost-effective means of protecting substrate surfaces from wear or corrosion.



- Wear Resistance to reduce the effects of:
 - Fretting
 - Adhesive or Galling Wear

- Impact Resistance
- Abrasion
- Erosion
- Cavitation
- Sliding Wear
- Corrosion Resistance to:
 - Chemical Attack
 - Oxidation
 - Sulfidation
 - Galvanic Corrosion
- Chrome nickel spray coatings

Large power boilers that are exposed to highly corrosive sulfur gases and have water-wall temperatures from 700 to 800°F (300 to 425°C) are prone to wall failure due to corrosion. Thermal spraying the wall with a metallized coating of Cr-Ni alloy can extend the wall life five years or more, reducing downtime and saving hundreds of thousands of dollars per boiler each year. In the power industry, high-chromium alloys extend the life of power plants that burn high sulfur coal. Tests have shown that chromium contents have the largest influence in determining resistance of an alloy to coal ash corrosion. Metallized coatings are also used to prevent erosion in slag-collection systems and Superheaters.



Application of high-chromium alloys using the thermal spray process instead of weld metal cladding will save both money and down time. Thermal spray application involves grit blasting to a "clean white metal" (SSP -SP-5). The metallized coating is then applied in multiple layers to about 10 to 15 mils total thickness (this thickness varies according to specifications) with a bond-strength of greater than 5000 lb/in². Being a "low heat" process shrinkage and thermal distortion is minimal so the coating can be applied quickly and downtime kept to a minimum.



Metallizing is generally 3 to 4 times less expensive than metal cladding and about 10 times as fast. See appendix page 253 for specifications of nickel spray materials



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HVOF (High Velocity Oxy-Fuel) Spray

High-Velocity 7200 FPS

The coatings have low residual internal stresses and can be sprayed to thicknesses not normally associated with dense, thermal sprayed coatings.

The process uses an oxygen-fuel mixture. Depending on user requirements,

propylene, propane or hydrogen may be used as the fuel gas.

The coating

material, in powdered form, is fed axially through the gun using

nitrogen as a carrier gas. The thoroughly mixed gases are then

ejected from a nozzle and ignited externally of the gun. The

ignited gases form a circular flame

configuration which surrounds and uniformly heats the powdered spray

material at it, also, exits the gun and is propelled to the work piece

surface.

As a result of the high kinetic energy transferred to the particles by the HVOF process, the coating material generally does not need to be fully melted. Instead, the powder particles are in a molten state and flatten plastically as they impact the work piece surface. The result are coatings with more predictable chemistries that are very homogeneous with a fine granular structure.

This adds up to coatings that can survive harsher service conditions, particularly in wear and many corrosion applications, greatly increasing service life. The smooth as-sprayed surface finishes; uniform chemistry and low porosity of the coating can be machined to very high surface finishes.



Air Plasma Spray

Plasma Spray is perhaps the most flexible of all of the thermal spray processes as it can develop sufficient energy to melt any material.

Since it uses powder as the coating feedstock, the number of coating materials that can be used in the plasma spray process is almost unlimited. The plasma gun incorporates a cathode (electrode) and an anode (nozzle) separated by a small gap forming a chamber between the two. DC power is applied to the cathode and arcs across to the anode. At the same time, gases are passed through the chamber. The powerful arc is sufficient to strip the gases of their electrons and the state of matter known as plasma is formed. As the unstable plasma recombines back to the gaseous state thermal energy is released. Because of the inherent instability of plasma, the ions in the plasma plume rapidly recombine to the gaseous state and cool. At the point of recombination, temperatures can be 12,000 °F to 30,000 °F (6,600 °C to 16,600 °C), which exceeds surface temperatures of the sun. By injecting the coating material into the gas plume, it is melted and propelled towards the target component.



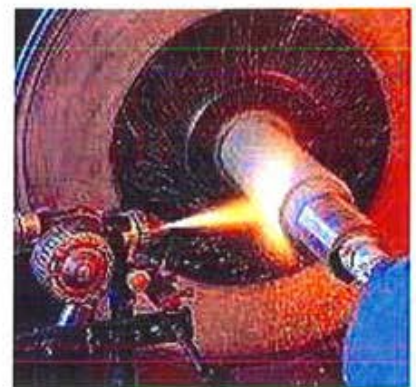
Arc Wire Spray

Arc Wire Spray uses two metallic wires as the coating feedstock. The two wires are electrically charged with opposing polarity and are fed into the arc gun at matched, controlled speeds. When the wires are brought together at the nozzle of the, the opposing charges on the wires create enough heat to continuously melt the tips of the wires. Compressed air is used to atomize the now molten material and accelerate it onto the work piece surface to form the coating. In arc wire spray, the weight of coating that can be deposited per unit of time is a function of the electrical power (amperage) of the system and the density and melting point of the wire.



Wire Flame Spray

Wire Flame Spray is the earliest thermal spray processes to be developed, with its usefulness enduring even today. The spray material in wire form is fed continually into a fuel gas-oxygen flame where it is melted by the heat of that combustion. Compressed air surrounds the flame and atomizes the molten tip of the wire. This accelerates the spray of molten particles towards the prepared work piece surface. Typical choices for fuel gases are acetylene, propane, hydrogen or MAPP.





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Powder Flame Spray

The Powder Flame Spray process is similar to the Wire Flame Spray process except that it has the advantage of using powdered materials as the coating feedstock. This offers a much wider range of coating material options than the Wire Flame Spray process. In addition, the use of powder allows for a greater degree of freedom for spray gun manipulation. The spray material in powdered form is fed continually into a fuel gas-oxygen flame where it is typically melted by the heat of combustion. A powder feed carrier gas transports the powder particles into the combustion flame, and the mixed gases transport the material towards the prepared work piece surface. Typical choices for fuel gases are acetylene or hydrogen.



Many Utilities have experienced high corrosion rates in boiler components primarily waterwalls since the retrofit of Low NO_x Burners with over-fire air (SOFA) ports. To protect against the effects of the corrosive environment caused by the new burners, many utilities are applying protective surface coatings. This protective coating will range from mechanically bonded spray coating, to metallurgical bonded weld overlays and chromized layers. All of the currently applied solutions should introduce at least 20% chrome between the tube and the corrosive furnace environment.

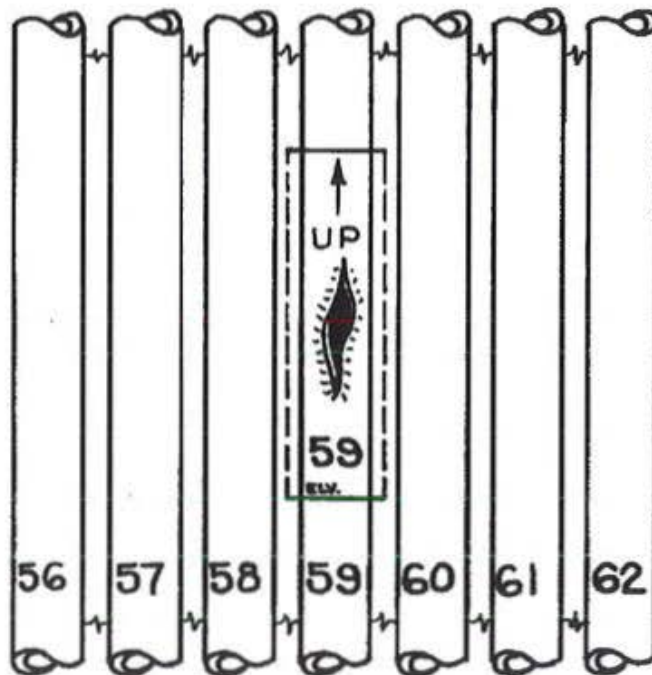
The life of the coatings or weld overlay varies. Theoretically, the mechanically applied spray coating (Wire Arc) should have the shortest life span. The HVOF (High Velocity Oxygenated Fuel) Spray Coating should have the next longest life span. Both of these processes are only as reliable as the success of the preparation and application.

The most reliable and most expensive coatings are weld overlay and chromized tubing. Both of these processes are metallurgical bonded into the subsurface of the base metal.

15. How to handle a tube sample

It sometimes becomes necessary to remove a tube sample from the furnace for a waterside inspection, or to be sent out for analysis. Certain procedures should be followed to insure that the sample is removed intact, and that it is documented as to its exact location.

A boiler becomes dirtier as operating time increases, making it more prone to tube failures caused by deposit build up.



2.) Tube sampling and deposit analysis after a failure occurs, serve only to confirm that the boiler is dirty and that deposits promoted the failure.

3. Forced outages caused by these types of failures can be avoided by establishing a planned sampling and analysis program for waterwall tubes.

4. The basic purpose of such a program is to monitor the boiler cleanliness. Periodically, all factors influencing boiler cleanliness are reviewed to determine the quantity of internal deposits and to predict when a chemical cleaning will be necessary.

5. Tube samples are generally taken from the waterwalls of Controlled Circulation units at a location approximately 10 feet above the upper most elevation of fuel

nozzles. This is found to be an area of potentially high deposition.

6. On natural circulation units tube samples are removed from the same location as well as the arch and bottom slope tubes.



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When removing a tube sample:

- a. Dry cut the sample out
- b. Seal the sample from the atmosphere
- c. Wrap the sample in packing material to prevent damage.

When submitting the sample for Analysis State the specific information needed from the analysis. Also include:

- a. Sample location

Which unit did the sample come from.

Where on the unit was the sample taken.

Include a marked cross-sectional drawing

State the elevation and tube count to an adjacent wall. b. Sample material (1) Type

Diameter.

Age

Was the tube original to the unit.

Was the tube part of a replacement section.

Date the sample was removed.

Unit operating history

Date of last chemical cleaning

Number of start-ups

Boiler water chemistry log.



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DC TUBE SAMPLE REPORT

Date_____

Customer_____ Plant_____

Unit No._____ Location_____

Initial Firing Date_____

Commercial Operation_____ Design Capacity_____ Main Fuel_____

Alternate Fuel_____ %_____ Drum Pressure_____ PSI

Superheater Outlet Pressure_____ PSI Reheater Outlet Pressure_____ PSI

Superheater Outlet Temperature____OF Reheater Outlet Temperature____OF

Sample 1 Sample 2 Sample 3

Estimated In-Service Hours Of Sample _____

Tube Sample Source Element Row _____

Tube Size _____

OD _____

MWT _____

Elevation _____

Material _____

Surface Condition _____

Comments. _____



16. What Are Refractories Used For?

In general, refractories are used to build structures subjected to high temperatures, ranging from the simple to sophisticated, e.g. fireplace brick linings to reentry heat shields for the space shuttle. In industry, they are used to line boilers and furnaces of all types--reactors, ladles, stills, kilns--and so forth.

Depending upon the application, refractories must resist chemical attack, withstand molten metal and slag erosion, thermal shock, physical impact, catalytic heat and similar adverse conditions. Since the various ingredients of refractories impart a variety of performance characteristics and properties, many refractories have been developed for specific purposes. It is a tribute to the refractory engineers, scientists and technicians, and plant personnel that more than 5000 brand name products are listed in the latest Product Directory of the Refractories Industry in the United States.

Refractory basic specifications

3400° Refractory Castable / Plastic

A very high purity, high alumina castable manufactured from selected grains of tabular alumina and pure calcium aluminate cement. It has a very low iron content making it resistant to carbon disintegration and reducing atmospheres. The maximum use limit is 3400F.

3300° Refractory Castable / Plastic

An 80% plus alumina castable designed for areas where resistance to abrasion and hot load strengths are desired. Has excellent resistance to slag and molten metal. The maximum use limit is 3300F.

3200° Refractory Castable / Plastic

A 70% alumina castable containing a blend of high alumina grogs and high alumina hydraulic binders. It was designed for quick cast, cure, and firing (when properly placed and cured) thus eliminating excessive delays in preheating schedules. Has good volume stability and exceptional strengths at intermediate temperatures. The maximum use limit is 3200F.



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3100° Refractory Castable / Plastic

A high alumina castable with an alumina content of 65%. This mix is designed with good volume stability and a minimum of shrinkage at high temperatures. The maximum use limit is 31000F.

3000° Refractory Castable / Plastic

A low iron, high purity, 60% alumina castable. It is designed to successfully withstand high sulphur fuel, reducing atmospheres, carbon deposition, erosion and abrasion. This can be used for casting or troweling. The maximum use limit is 30000F.

2800° Refractory Castable / Plastic

A 28000F castable used extensively for blast furnace repair. The material has been designed to give a low iron content to resist the effects of CO disintegration. It possesses excellent strength to resist abrasion. Able Cast BF is also useful in repairing tread-wells, open top iron ladles, hot metal mixers and other similar applications. The maximum use limit is 28000F.

2700° Castable

A specially formulated low iron, high duty refractory castable designed to withstand loads exceptionally well and resist normal abrasion and erosion at moderate temperatures. This material is ideal for use in Seal Tanks of Fluid Catalytic Crackers. The maximum use limit is 27000E

2600° Castable

A general purpose refractory castable. It has been specifically formulated to resist erosion and abrasion at moderate temperatures. Able Cast 2600 is also available as a gunning mix. The maximum use limit is 26000F.

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Mortar	Super 3000	2700	High temp/abrasion
2700 Plastic	Super Moldit	2800	High temp/abrasion
	Moldit S	2400	High temp/abrasion
2700 Castable	Ricast	2700	High temp/abrasion
	Moldit D	2400	High temp/abrasion
Ceramic blanket	Fiberfrax	3000	Extreme temp/no abrasion

[illegible]

Mortar	Super 3000	3000	Extreme temp/abrasion
3000 Plastic	Moldit chrome	2900	Extreme temp/abrasion
	Wasp 60	2900	
	Ramtit 25	2900	
	Blu-Ram HS	3100	
	Ramtite 25	2900	
	Emerald Ram HS	3400	
3000 Castable	Cercastm 70	3000	Extreme tem/abrasion
	Cerca M HT	2900	Extreme tem/abrasion
Ceramic blanket	Fiberfrax	3000	Extreme temp/no abrasion

Furnace walls not in line of sight to fire (fireside) >>>>>>>>>>>>>>>>

Mortar	Super 3000	2700	High temp/abrasion
2700 Plastic	Super Moldit	2800	High temp/abrasion
	Moldit S	2400	High temp/abrasion
2700 Castable	Ricast	2700	High temp/abrasion
	Moldit D	2400	High temp/abrasion
Ceramic blanket	Fiberfrax	3000	Extreme temp/no abrasion

[illegible]

Ceramic blanket	Fiberfrax	3000	Extreme temp/no abrasion
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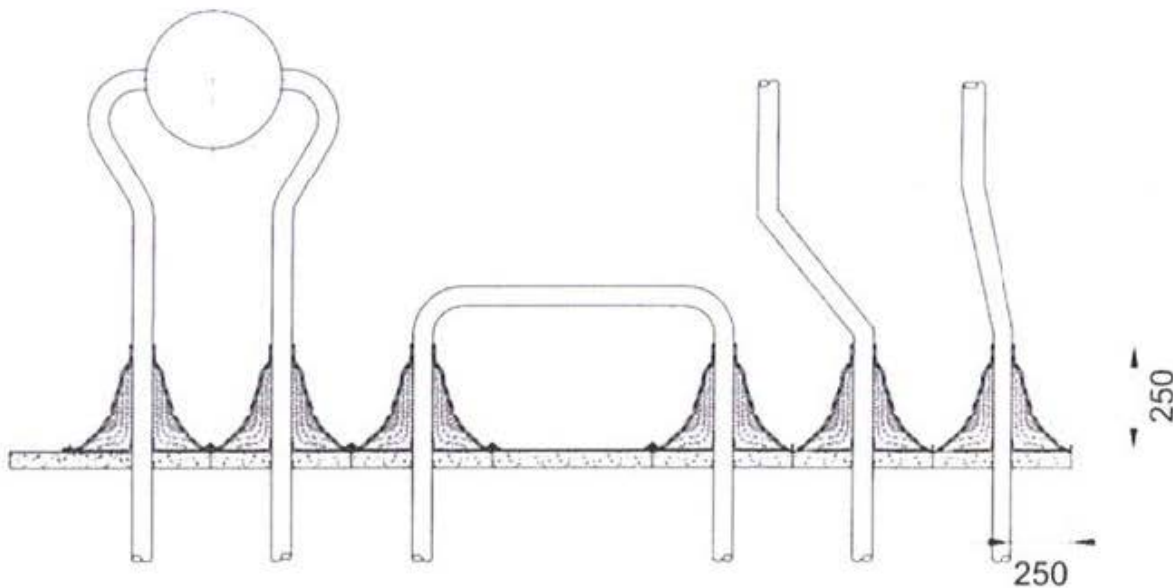
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Pourable insulation	CER-Lite 18	1800	Med-Hi Temp/low abrasion
Mineral Fiber blanket	CER-Wool Blanket	1200	Med temp no abraision.Tubes headers and nipples.

17. Isomembrane and its usefulness:

What is ISOMEMBRANE?

- The ISOMEMBRANE is a flexible, elastic, ash- and gas tight sealing, based on a special combination of mainly refractory materials.
- The ISOMEMBRANE is a sandwich-type construction. It consists of an ISOMASK made by layers of specially designed high density ceramic fibre, a special metal lattice, or mesh. Between the layers High Temperature Adhesive is applied. To finish off of the top layer it is covered with a high temperature castable.



The ISOMEMBRANE can be installed in many shapes according to the actual need of the different sealing areas. It can be fixed to any clean surface by welding, casting or gluing.



Penthouse floor conditions that isomembrane might be considered for repair.



Actual in-field application of Isomembrane located just above the fire box.



An Inspection Note Primer

If inspection notes are to be hand written, data sheets can help simplify and clarify the task. Some items are universal regardless of the method of note taking.

Clearly identify where your inspection is taking place. An example would be: The economizer top of bank one in the forward crawl space starting on the left side wall and working to the right side wall. Be specific about the exact configuration such as dogleg, hanger tube, or bent tube. Proactively simplify future report generation. Be sure to include changes in your notes to delineate a change in location.

Identify each problem by a specific element (assembly) and tube number. Also identify element, tube, and bank counts. Element #34 as counted from the left side wall tube #5 from the top five feet from the front steam cooled wall.

If relevant, identify the elevation. This need not be the elevation above sea level. You can reference a landmark such as a soot blower or access door. This is located 3' below the center line of retractable soot blower IK-2.

Almost all repair items in the boiler have a length. Include the length of the item in your notes. The tube is eroded for a total length of 6".

Also include the length of the required repair. A 12" long straight shield will be required to cover the eroded area.

Describe the required repair. A 24" straight shield and inside radius bend shield will be required.

If you are using a digital camera then you should record the photograph numbers so that you can easily match them when you are preparing your inspection report.



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Non code documentation

c:\Network\JTracker\DeseretUnit1\DESERET1.MDB

File Edit Table Reports Attachment Tools Help >>Edit "OFF" >>Error "OFF"

Workorder: [] Report: [] Leak Date: 11/27/1999

? Area: WATERWALL FRONT Specific: [] Detail: []

F-Elem 0 L-Elem 0 ? FTube 1 LTube 0 ? Elev 5200 Dist [] Config [] Post Off []

Material: ? SA210C OD 3.00 ? Thick 0.28 Red +

Cause: [] Outage: []

Appear []

Repair: + Monitor closely Length []

Repair Comment: []

General Comment: This will require further monitoring, no action is required at this time.

Status: Inspected

User: [] By: UDC

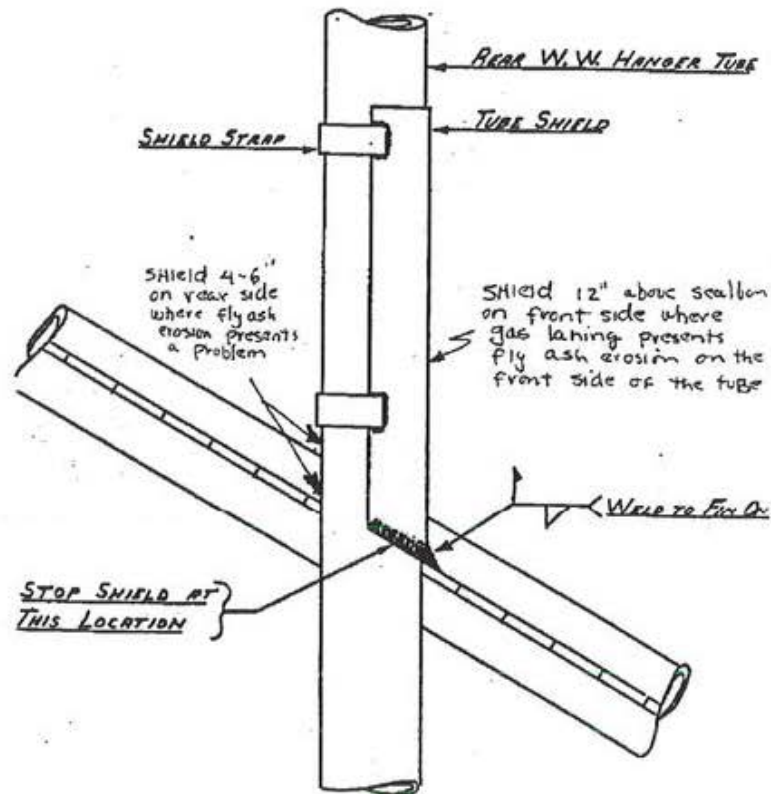
Priority: 3 Photo Off [x] Photo-1 ^

Zoom Clear Import Filter Sort New Edit Del Exit Update Goto Rec 1



Effective applications of protective shielding

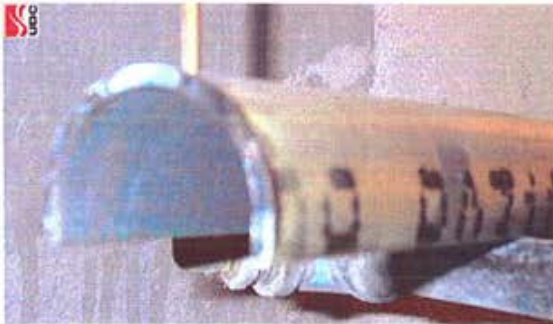
In many cases blocking the medium that is causing the erosion can arrest thinning. This is true only if the pressure boundary has not been reduced to an action level more severe such as replacement or pad welding. You should utilize clear and concise criteria for established this action level.



TYPICAL ARRANGEMENT OF SHIELDS FOR REAR WATERWALL HANGER TUBES



- a. Tube shields should be 210' to 225' circumferentially instead of 180' to allow the shield to actually clamp onto the tube helping it to remain in place longer. (Figure 1)
- b. Tube thickness and material should be:
(1) Up to 1750° F. inclusive 14 gauge SS AISI type 304 (2) Over 1750°F. 10 gauge SS AISI type 309 or 310
- c. Tube shields should be limited in length to 18" to 24". Longer shields tend to warp and distort and will break away from the tube. If longer sections are needed they should overlap approximately 1" starting from the bottom and working up.
- d. Tube shields should only be attached to clean tubes. Clean tubes actually help to cool the shield while a tube with slag may cause the shield to overheat sooner.



stitch weld on each side.

- e. Tube shields should be attached to the tube by 1" wide straps on 6" - 8" centers. Through experience we have found that the durability of the shield is improved if the clips were attached with a GTA weld using bare filler wire. Each shield should then be welded to the tube in one spot to secure it and to allow for thermal expansion the attachment at the bottom is perforated.

- f. In cooler areas of the boiler tube shields can be attached using straps less than 1" or no strap at all and use a 1-1/2"

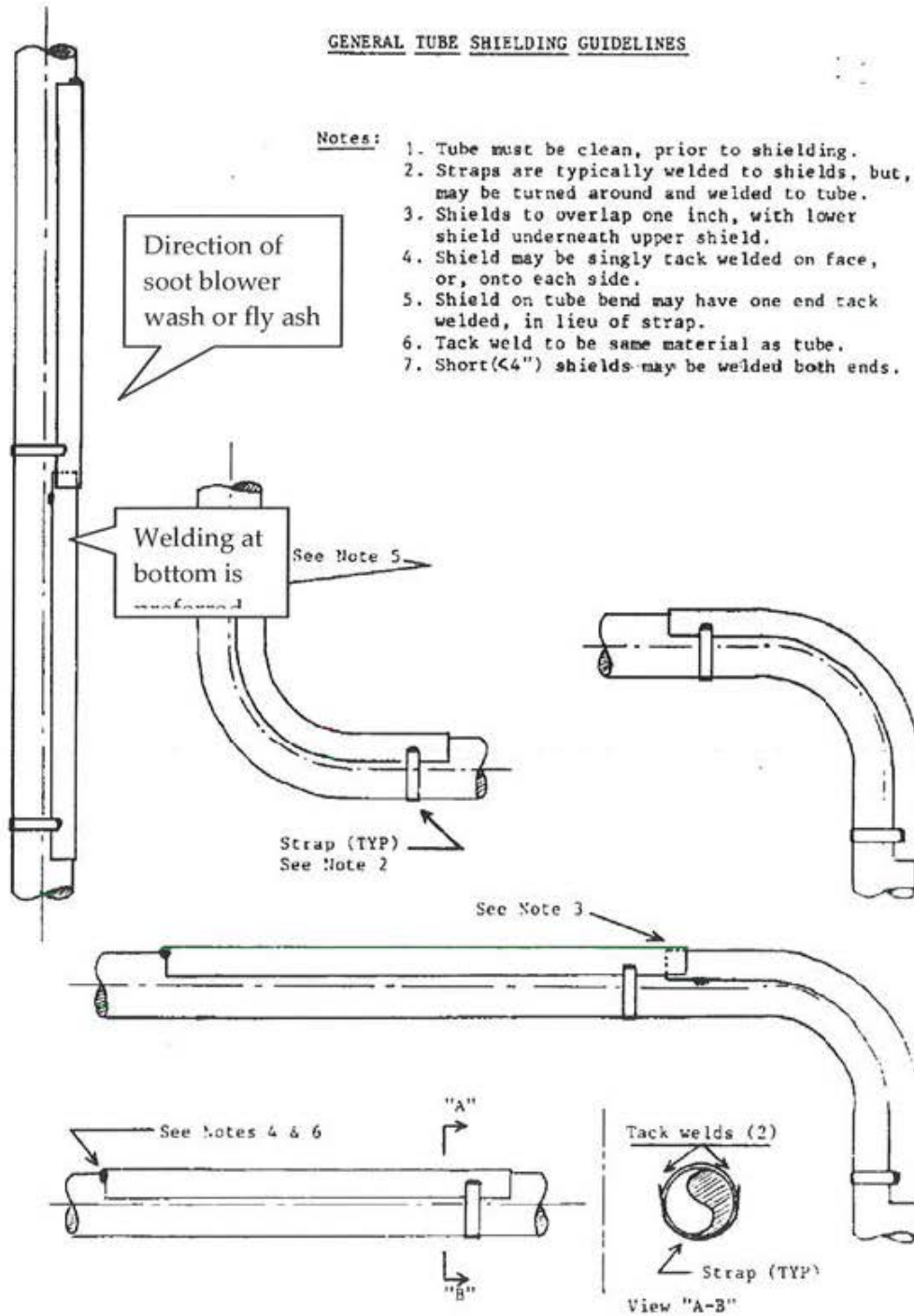
- g. In some cases, tube shields may not be the best solution. Lowering soot blower pressures, repairing traps, or installing baffles may be more appropriate. Remember, tube shields treat problems, not cure them.



GENERAL TUBE SHIELDING GUIDELINES

Notes:

1. Tube must be clean, prior to shielding.
2. Straps are typically welded to shields, but, may be turned around and welded to tube.
3. Shields to overlap one inch, with lower shield underneath upper shield.
4. Shield may be singly tack welded on face, or, onto each side.
5. Shield on tube bend may have one end tack welded, in lieu of strap.
6. Tack weld to be same material as tube.
7. Short (<4") shields may be welded both ends.





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This is a chart of nickel powders available for spray coatings.

<http://www.powderalloy.com/spray/nickel.asp>

5871 Creek Rd. Cincinnati, OH 45242



(p) 513-984-4016 (f) 513-984-4017

Nickel 98C	Chemically similar to PAC 98F. However, a coarser cut of powder is utilized to permit build-up of coatings as thick as 0.050 to 0.100 inches. Coatings are bright and resistant to oxidation and corrosion. Useful for heat resistance.	RB 90-95	3000 PSI MIN	Easily machined with all grades of cutting tools.	
Nickel 98C-1	Same as PAC 98C except certifiable to industrial specifications at as listed below. INDUSTRIAL SPECIFICATIONS: US Naval Specifications, OS 8293 and OS 10602. Also GE B50TF40 Class A; PWA 1315; Boeing Co. BMS10-67 (Type 6); and General Motors Co. EMS 56760, RR9507/8.	RB90-95	3000 PSI MIN	Easily machined with all grades of cutting tools.	
Nickel 98F	A fine nickel chromium alloy developed to produce dense, clean bright coatings resistant to oxidation and corrosive gases at temperatures to 1800 degrees F. Coatings of PAC 98F are readily machinable.	RC90-95	2500 PSI MIN.	Easily machined with all grades of cutting tools	PWA 1317; GE B50TF40 Class B RR9507/27
Nickel 98F-1	Same chemistry as PAC 98F except screened for compliance to industrial specification at right.	RB 90-95	2500 PSI MIN.	Easily machined with all grades of cutting tools.	PWA 1319
Nickel 99	A highly machinable nickel base chromium alloy useful for salvage and build-up applications on corrosion resistant steels or nickel base alloys where high hardness is not required; but good wear and corrosion resistance are needed.	RB75-85	2500 PSI MIN	Easily machined with all grade tools	
Nickel 625	Is identical in chemistry to wrought alloy IN 625. Can be used for build-up of mismatched or damaged parts. Is also the most versatile corrosion resistant alloy for use in chemical, petrochemical, flue gas desulfurization and sea water environments.	RB92	5500 PSI TYP	Machines ready with Silicon-Carbide tools.	Industrial

Nickel 718B	Is identical in chemistry to wrought super-alloy IN718 and thus designed for dimensional build up of damaged or mismatched IN718 parts. Produces coatings that can be built in excess of .030" with porosity less than 0.5%.	RB90		Machines with Silicon-Carbide tools.	GE B50TF202 CL. B
Nickel 718F	Identical to chemistry PAC 718B, but precision sized for HVOF applications. Coatings have been sprayed to thickness up to .200" with porosity less than 0.5%.	RB 94	12,000PSI	Machines readily with Silicon-Carbide tools.	GE B50TF202 CL.D
Nickel 900	A high purity nickel powder used to produce dense, hard coatings recommended for the salvage and build-up of nickel and nickel alloy parts. Coatings are smooth, low in porosity and bond well.	RB 50-70	2600 PSI MIN	Machines with most grades of cutting tools.	PWA 1324; GE B50TF17
Nickel 9620AM 9630AM 9640AM	Are Nickel-Chromium-Aluminum-Yttrium alloys that provides outstanding resistance to oxidation and corrosion resistance in environments up to 1800 degrees Fahrenheit. These materials are primarily used for bond-coats on Thermal Barrier Coatings but also show promising results in protecting boiler tube walls from corrosion and sulfidation/oxidation.	RB 85	5500 PSI TYP	Wet grind with Silicon-Carbide wheels.	GE B50TF192 CL.A GE B50TF162 CL. A MSRR 9507/48 Garrett 52432 XXI
Nickel 93652 AM	A ductile, Nickel-Cobalt-Chromium-Aluminum-Yttrium Alloy that provides increased resistance to hot corrosion and oxidation at temperatures up to 2000 degrees Fahrenheit. Also, provides a rough as-sprayed surface for ceramic, top-coat applications.				

Summary of Typical Boiler Tube Materials of Construction

Class of Material	Typical Alloy Designations	General Properties
Carbon steel	SA-178: Welded carbon steel SA-192: Seamless carbon-silicon steel SA-210: Seamless carbon-manganese-silicon steel	Hypoeutectoid steels. Mild corrosion resistance. Moderate strength up to 538°C (1000°F). Susceptible to graphitization above 427°C (800°F).
Carbon - molybdenum steel	SA-209-T1, T1a and T1b: Seamless carbon-½ molybdenum steel SA-250-T1: Welded carbon-½ molybdenum steel	Greater creep strength than carbon steels. Susceptible to graphitization with prolonged exposure above 468°C (875°F).
Chromium-molybdenum steel	SA-213-T2: Seamless ½ chromium - ½ molybdenum steel. SA-213-T12: Seamless 1Cr-½Mo steel SA-213-T11: Seamless 1½Cr-½Mo steel SA-213-T22: Seamless 2½Cr-1Mo steel SA-213-T21: Seamless 3Cr-1Mo steel SA-213-T5: Seamless 5Cr-½Mo steel SA-213-T5b: Seamless 5Cr-½Mo-Si steel SA-213-T5c: Seamless 5Cr-½Mo-Ti steel SA-213-T7: Seamless 7Cr-½Mo steel SA-213-T9: Seamless 9Cr-1Mo steel SA-213-T91: Seamless 9Cr-1Mo-½V-X (Cb/Ni/Al) steel	Most common boiler tube materials (particularly T22 and T11). Each increase in Cr content yields improved properties, particularly higher strength, creep properties, and improved corrosion resistance. Resistant to graphitization.
Austenitic stainless steel	SA-213-TP304/304H: Seamless 18Cr-8Ni austenitic stainless SA-213-TP316/316H: Seamless 16Cr-12Ni-2Mo austenitic stainless SA-213-TP321/321H: Seamless 17Cr-11Ni-Ti austenitic stainless SA-213-TP347/347H: Seamless 18Cr-10Ni-Cb austenitic stainless	Excellent oxidation resistance and good elevated temperature strength. "H" following designation indicates higher carbon content and slightly higher solution heat treat temperature.
Ferritic stainless steel		For use in highly aggressive or high temperature environment.
Martensitic stainless steel		For use in highly aggressive or high temperature environment.
Nonferrous alloys	Nickel-chromium (Alloy 800)	For use in highly aggressive or high temperature environment.
Nickel-chromium-iron	Alloy 800 or 800 H	For use in highly aggressive or high temperature environment.



ADVANCED BOILER INSPECTION TECHNIQUES 2011

Tube Steel Type	ASME Specification ^a	Grade	Minimum Tensile Strength (ksi)	<u>200m in</u> eld Strength (ksi)
Carbon Steel				
Electric resistance welded	SA-178	A	47 ^b	26 ^b
		C	60	37
Seamless	SA-192	—	47 ^b	26 ^b
Seamless	SA-210	A1	60	37
		C	70	40
Electric resistance welded	SA-226	—	47 ^b	26 ^b
Ferritic Alloy				
Electric resistance welded	SA-250	T1	55	30
Seamless	SA-209	T1	55	30
		T1a	55	30
	SA-213	T1b	55	30
		T2	60	30
Seamless		T5 ^c	60	30
		T9 ^c	60	30
		T11	60	30
		T12	60	30
		T22	60	30
		T91 ^d	85	60
Austenitic Stainless Steel				
Seamless	SA-213	TP304H	75	30
		TP316H	75	30
		TP321	75	30
		TP347	75	30
		TP347H	75	30



ADVANCED BOILER INSPECTION TECHNIQUES 2011

MAXIMUM TUBE METAL TEMPERATURES

Tube Steel Type No.	ASME Spec.	ASME Max	B&W Max.	C-E Max.	Riley Max.
Carbon Steel	SA-178C	1000(538)	950 (510)	850 (454)	850 (454)
Carbon Steel	SA-192	1000(538)	950 (510)	850 (454)	850 (454)
Carbon Steel	SA-210 A1	1000(538)	950 (510)	850 (454)	850 (454)
Carbon Moly	SA-209 T1	1000(538)		900 (482)	900 (482)
Carbon Moly	SA-209 T1a	1000(538)	975 (524)	--	--
Chrome Moly	SA-213 T11	1200(649)	1050 (566)	1025 (552)	1025 (552)
Chrome Moly	SA-213 T22	1200 649)	1115 (602)	1075 (580)	1075 (580)
Stainless	SA-213 321	1500 (816)	1400 (760)	--	1500 (816)
Stainless	SA-213 347	1500 (816)	--		1300 (704) --
Stainless	SA-213 304	1500 (816)	1400 (760)	1300 (704)	

Upon prolonged exposure to temperatures above about 800 degrees Fahrenheit (427 degrees C), the carbide phase of carbon steel may be converted to graphite.

Only killed steels shall be used above 850 degrees Fahrenheit (454 degrees C).

Upon prolonged exposure to temperatures above about 875 degrees F (468 degrees C,) the carbide phase of carbon steel molybdenum steel may be converted into graphite.

18. ASME APPROVED BOILER TUBING STEELS

Mechanical Properties of Steel

NOTE: Certain mechanical properties of steel affect its fabrication and performance in service. Among these are tensile properties, hardness, toughness, fatigue strength, and high temperature characteristics.

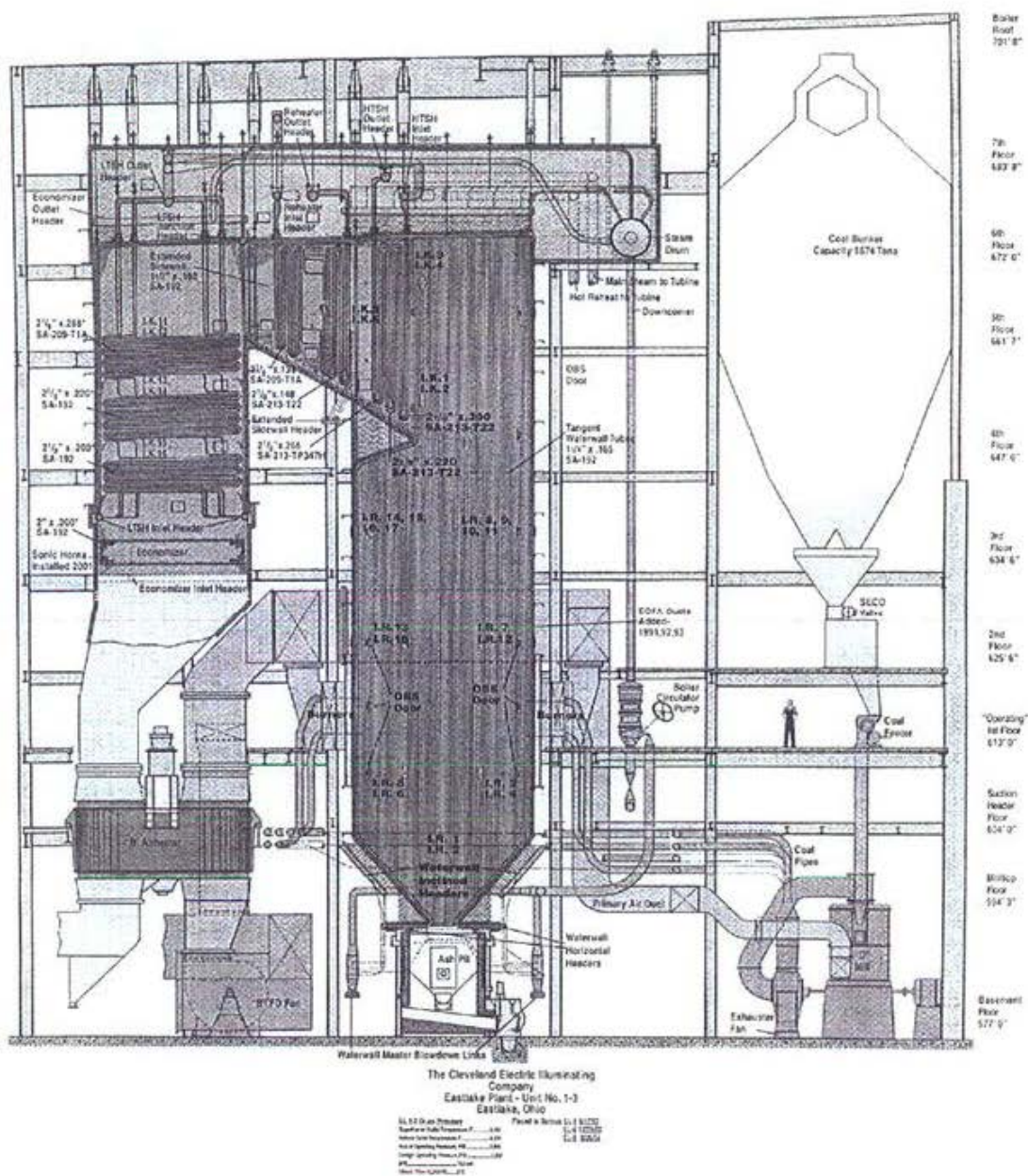
ASME* APPROVED BOILER TUBING STEELS

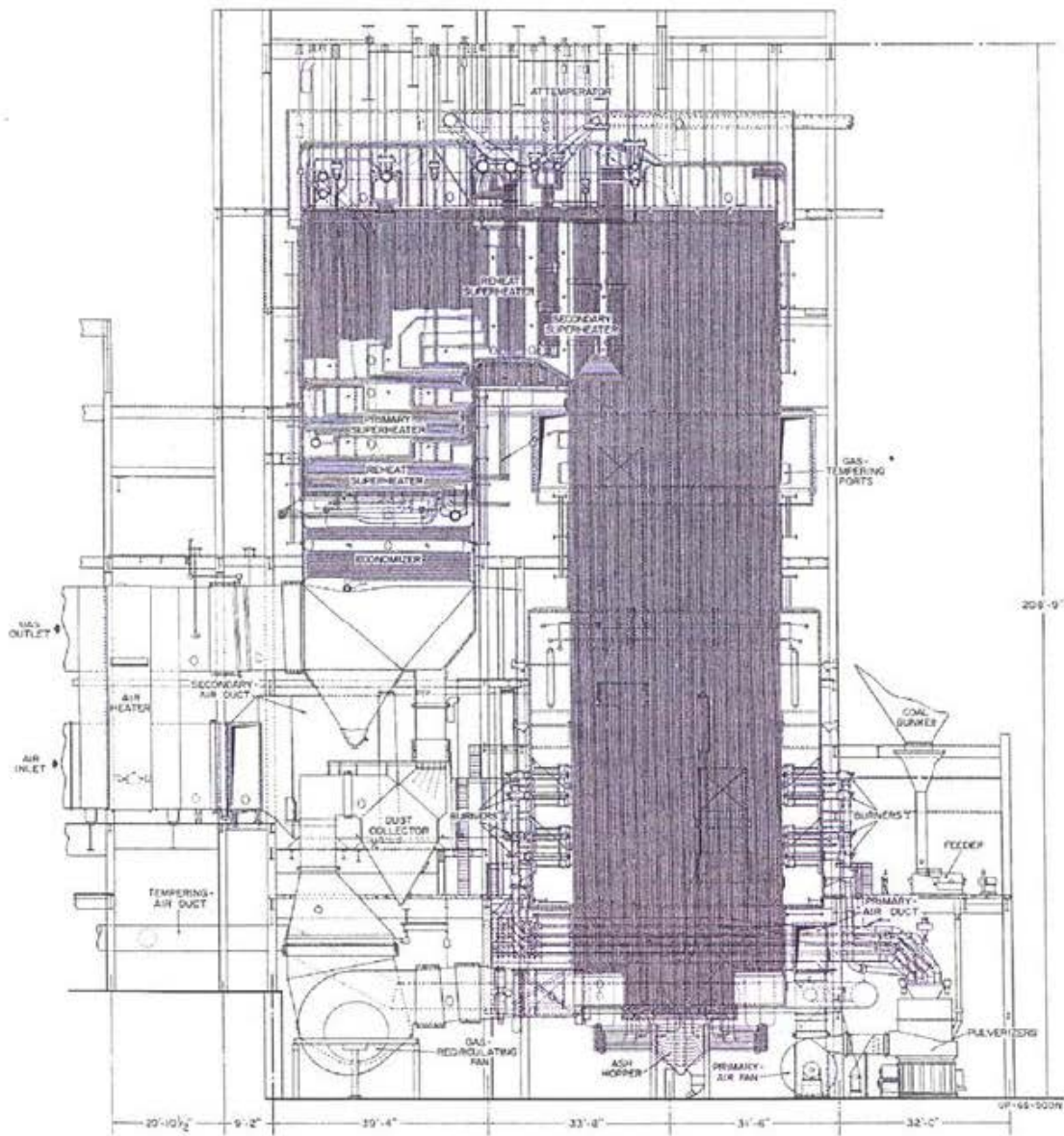
Number	Title of ASME Specification
SA-178	Electric-Resistance-Welded Carbon Steel Boiler Tubes
SA-192	Seamless Carbon Steel Boiler Tubes for High Pressure Service
SA-209	Seamless Carbon-Molybdenum Alloy-Steel Boiler and Superheater Tubes
SA-210	Seamless Medium Carbon Steel Boiler and Superheater Tubes
SA-213	Seamless Ferritic and Austenitic Alloy-Steel Boiler, Superheater, and Heat Exchanger Tubes
SA-226	Electric-Resistance-Welded Carbon Steel Boiler and Superheater Tubes for High Pressure Service
SA-249	Welded Austenitic Steel Boiler, Superheater Heat-Exchanger and Condenser Tubes
SA-250	Electric-Resistance-Welded Carbon-Molybdenum Alloy-Steel Boiler and Superheater Tubes
SA-268	Seamless and Welded Ferritic Stainless Steel Tubing for General Service
SA-423	Seamless and Electric Welded Low Alloy Steel Tubes
SA-450	General Requirements for Carbon, Ferritic Alloy, and Austenitic Alloy Steel Tubes



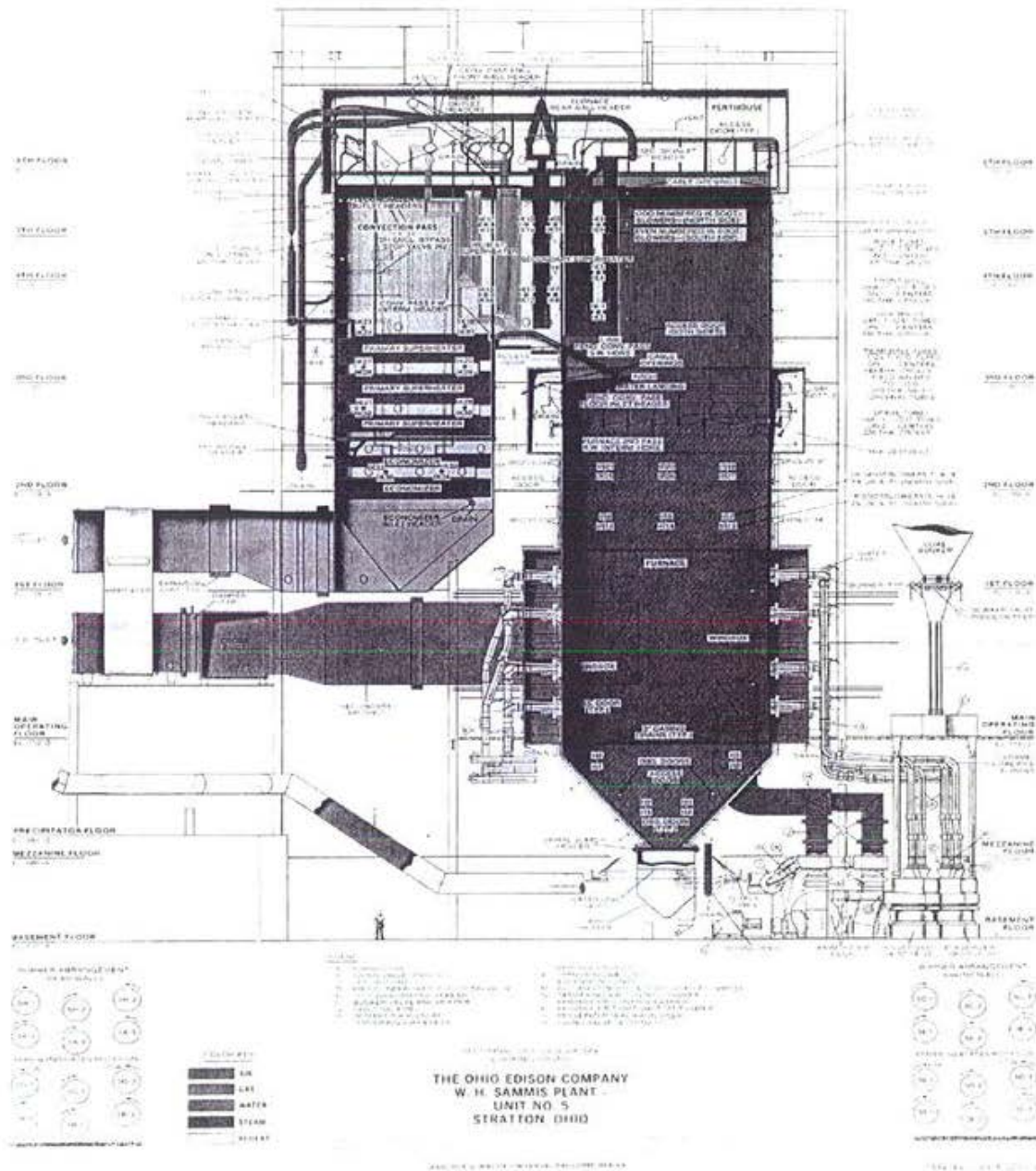
ADVANCED BOILER INSPECTION TECHNIQUES 2011

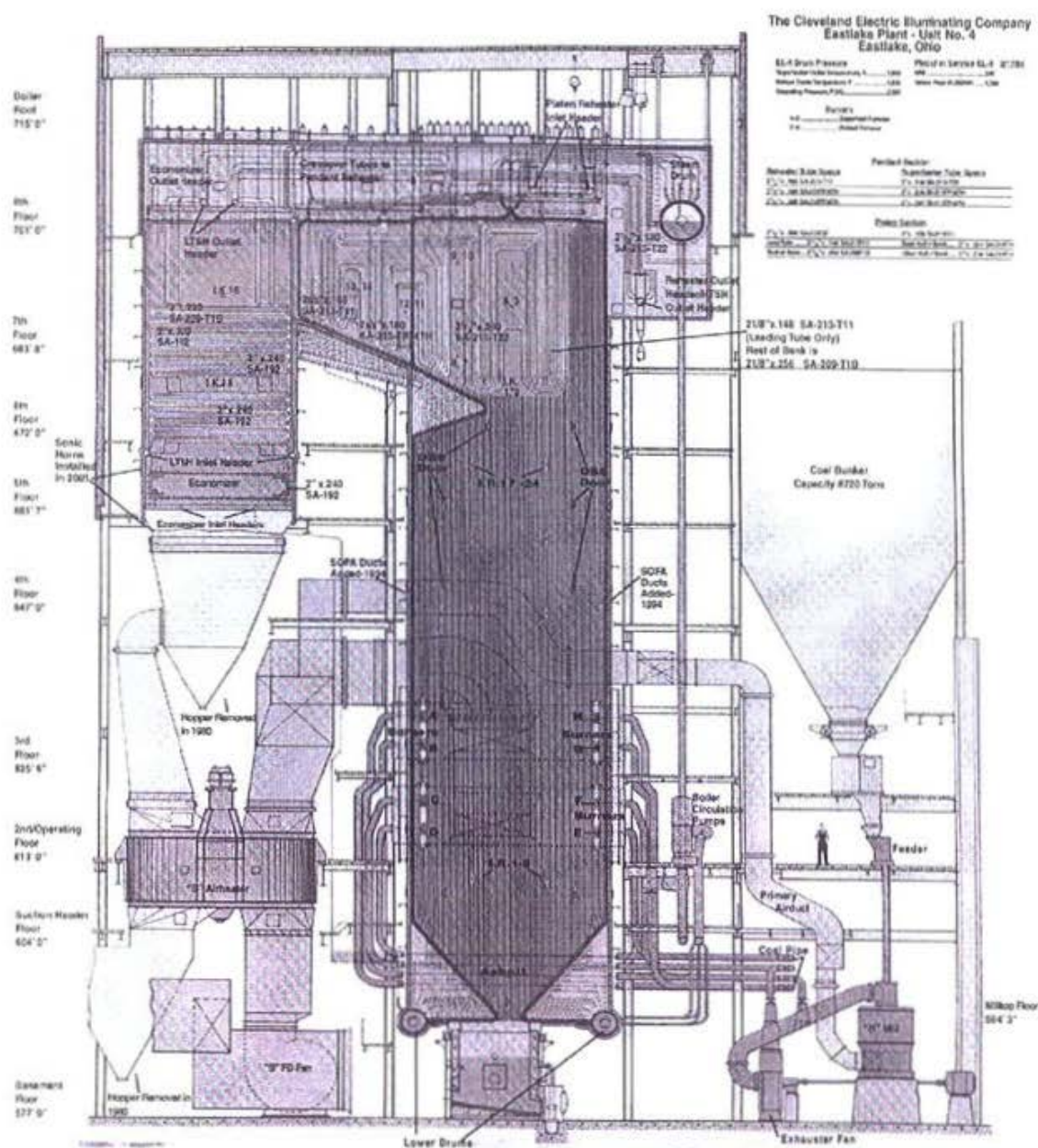
Materials Used in Boiler Construction														
ASME or ASTM Specs.	Grade	Alloy	Temp. ASME F (C)	Product Form	Minimum Tensile Strength ksi	Minimum yield strength ksi	Composition (a),%							
							C	Mn	P	S	Si	Ni	Cr	Mo
Carbon Steel														
SA-192	----	Low strength	1000 (538)	Tubes	47	26	0.06-0.18	0.27-0.63	0.048	0.058	0.25	----	----	----
SA-192	A		1000 (538)	Tubes (ERW)	----	----	0.06-0.18	0.27-0.63	0.05	0.06	----	----	----	----
SA-226	----		1000 (538)	Tubes (ERW)	47	26	0.06-0.18	0.27-0.63	0.05	0.06	----	----	----	----
SA-210	A-1	Intermediate	1000 (538)	Tubes	60	37	0.27	0.93	0.048	0.058	0.10 Min	----	----	----
SA-178	C	Strength	1000 (538)	Tubes (ERW)	60	37	0.35	0.3	0.05	0.06	----	----	----	----
SA-106	B		1000 (538)	Pipe	60	35	0.3	0.29-1.06	0.048	0.058	0.10 Min	----	----	----
SA-216	WCA		1000 (538)	Castings (b)	60	30	0.25	0.7	0.04	0.045	0.6	----	----	----
			1000 (538)	Structural shapes	58	36	0.26	----	0.04	0.05	----	----	----	----
SA-106	C	High Strength	1000 (538)	Pipe	70	40	0.35	0.29-1.06	0.048	0.058	0.10 Min	----	----	----
SA-299	----		1000 (538)	Plate	75	40	0.3	0.86-1.55	0.035	0.04	0.13-0.33	----	----	----
SA-515	70		1000 (538)	Plate	70	38	0.35	0.9	0.035	0.04	0.13-0.33	----	----	----
SA-105	----		1000 (538)	Forgings	70	36	0.35	0.60-1.05	0.04	0.05	0.35	----	----	----
SA-216	WCB		1000 (538)	Castings (b)	70	36	0.3	1	0.04	0.045	0.6	----	----	----
Ferritic alloys														
SA-209	T1	C-0.5Mo	1000 (538)	Tubes	55	30	0.10-0.20	0.30-0.80	0.045	0.045	0.10-0.50	----	----	0.44-0.65
SA-336	F12	1Cr-0.5Mo	1200 (649)	Forgings	70	40	0.10-0.20	0.30-0.80	0.04	0.04	0.10-0.50	----	0.80-1.10	0.45-0.65
SA-213	T12		1200 (649)	Tubes	60	30	0.15	0.30-0.61	0.045	0.045	0.5	----	0.80-1.25	0.44-0.65
SA-335	P12		1200 (649)	Pipe	60	30	0.15	0.30-0.61	0.045	0.045	0.5	----	0.80-1.25	0.44-0.65
SA-387	12C12		1200 (649)	Plate	65	40	0.17	0.36-0.69	0.035	0.035	0.13-0.32	----	0.74-1.21	0.40-0.65
SA-182	F12		1200 (649)	Forgings	70	40	0.10-0.20	0.30-0.80	0.04	0.04	0.10-0.60	----	0.80-1.25	0.44-0.65
SA-213	T11	1.25Cr-0.5Mo	1200 (649)	Tubes	60	30	0.16	0.30-0.60	0.03	0.03	0.60-1.00	----	1.00-1.60	0.44-0.65
SA-335	P11		1200 (649)	Pipe	60	30	0.15	0.30-0.60	0.03	0.03	0.50-1.00	----	1.00-1.50	0.44-0.65
SA-387	11C12		1200 (649)	Plate	75	45	0.17	0.36-0.69	0.035	0.04	0.44-0.86	----	0.94-1.56	0.40-0.70
SA-182	F11		1200 (649)	Forgings	70	40	0.10-0.20	0.30-0.80	0.04	0.04	0.50-1.00	----	1.00-1.50	0.44-0.65
SA-217	WC6		1200 (649)	Castings(b)	70	40	0.2	0.50-0.80	0.045	0.045	0.6	----	1.00-1.50	0.45-0.65
SA-213	T22	2.25Cr-1Mo	1200 (649)	Tube	60	30	0.15	0.30-0.60	0.03	0.03	0.5	----	1.90-2.60	0.87-1.13
SA-335	P22		1200 (649)	Pipe	60	30	0.15	0.30-0.60	0.03	0.03	0.5	----	1.90-2.60	0.87-1.13
SA-387	22C11		1200 (649)	Plate	60(c)	30(c)	0.17	0.27-0.63	0.035	0.035	0.5	----	1.88-2.62	0.85-1.15
SA-387	C12		1200 (649)		75(d)	45(d)								
SA-182	F22		1200 (649)	Forgings	75	45	0.15	0.30-0.60	0.04	0.04	0.5	----	2.00-2.50	0.87-1.13
SA-217	WC(9)		1200 (649)	Castings(b)	70	40	0.18	0.40-0.70	0.04	0.045	0.6	----	2.00-2.75	0.90-1.20
SA-213	T5	5Cr-0.5Mo	1200 (649)	Tubes	60	30	0.15	0.30-0.60	0.03	0.03	0.5	----	4.00-6.00	0.45-0.65
SA-213	T9	9Cr-1Mo	1200 (649)	Tubes	60	30	0.15	0.30-0.60	0.03	0.03	0.25-1.00	----	8.00-10.00	0.90-1.10
Austenitic stainless alloys														
SA-213	TP304H	18Cr-8Ni	1500 (816)	Tubes	60	30	0.15	0.30-0.60	0.03	0.03	0.5	----	1.90-2.60	0.87-1.13
SA-376	TP304H		1500 (816)	Pipes	60	30	0.15	0.30-0.60	0.03	0.03	0.5	----	1.90-2.60	0.87-1.13
SA-240	304		1500 (816)	Plate	75	30	0.08	2	0.045	0.035	1	8.00-10.50	18.00-20.00	----
SA-240	304H		1500 (816)		75	30	0.04-0.10	2	0.045	0.03	1	8.00-12.00	18.00-20.00	----
SA-182	F304H		1500 (816)	Forgings	75	30	0.04-0.10	2	0.04	0.03	1	8.00-11.00	18.00-20.00	----
SA-213	TP321H	18Cr-10Ni-Ti	1500 (816)	Tubes(e)	75	30	0.04-0.10	2	0.04	0.03	0.75	9.00-13.00	17.00-20.00	----
SA-213	TP347H	18Cr-10Ni-Ti	1500 (816)	Tubes(f)	75	30	0.04-0.10	2	0.04	0.03	0.75	9.00-13.00	17.00-20.00	----
SA-213	TP316H	16Cr-12Ni-2Mo	1500 (816)	Tubes	75	30	0.04-0.10	2	0.04	0.03	0.75	11.00-14.00	16.00-18.00	2.00-3.00
SA-376	TP316H		1500 (816)	Pipe	75	30	0.04-0.10	2	0.04	0.03	0.75	11.00-14.00	16.00-18.00	2.00-3.00
SA-182	F316H		1500 (816)	Forgings	75	30	0.40-0.10	2	0.4	0.03	1	10.00-14.00	16.00-18.00	----
SA-240	316H		1500 (816)	Plate	75	30	0.04-0.10	2	0.045	0.03	1	10.00-14.00	16.00-18.00	2.00-3.00
				Structural sheet	70	25	0.03	2	0.045	0.03	1	10.00-14.00	16.00-18.00	2.00-3.00
A167	316i		1500 (816)											
SA-351	CH20	25Cr-12Ni		Castings	70	30	0.2	1.5	0.04	0.04	2	12.00-15.00	22.00-26.00	----





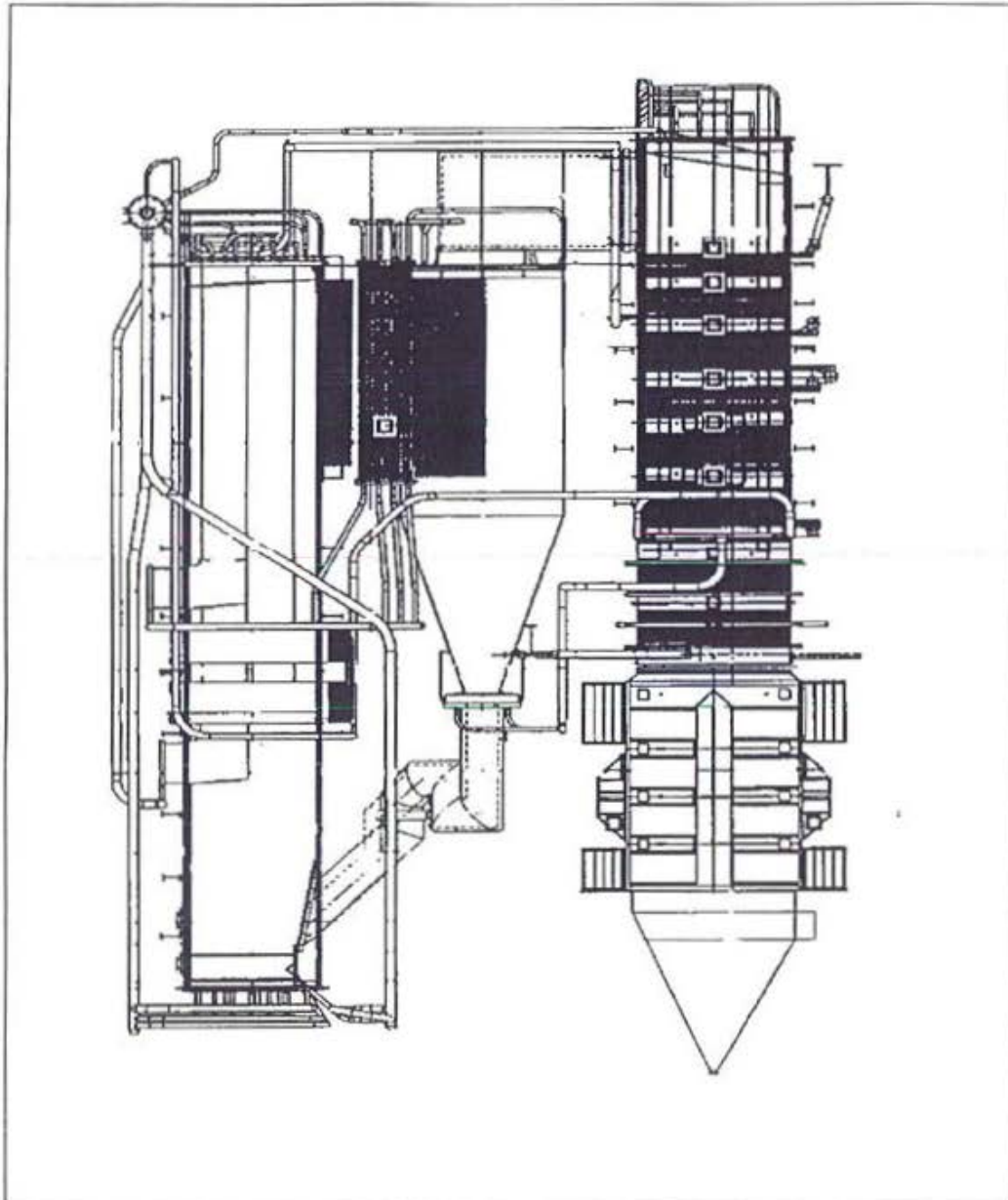
OHIO EDISON COMPANY
W. H. SAMMIS PLANT - UNIT NO 7
STRATTON, OHIO
B & W CONTRACT NO. UP-66



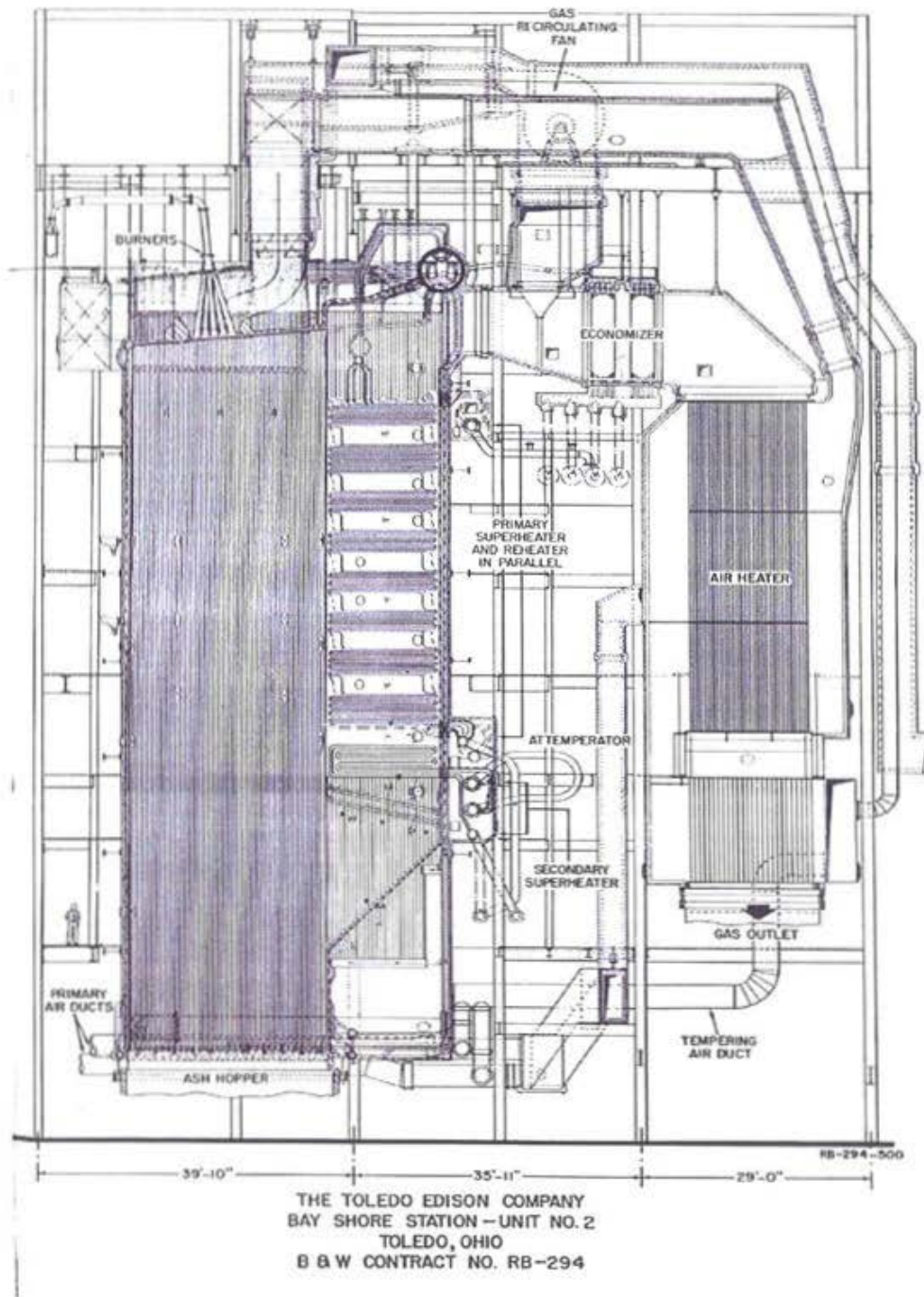


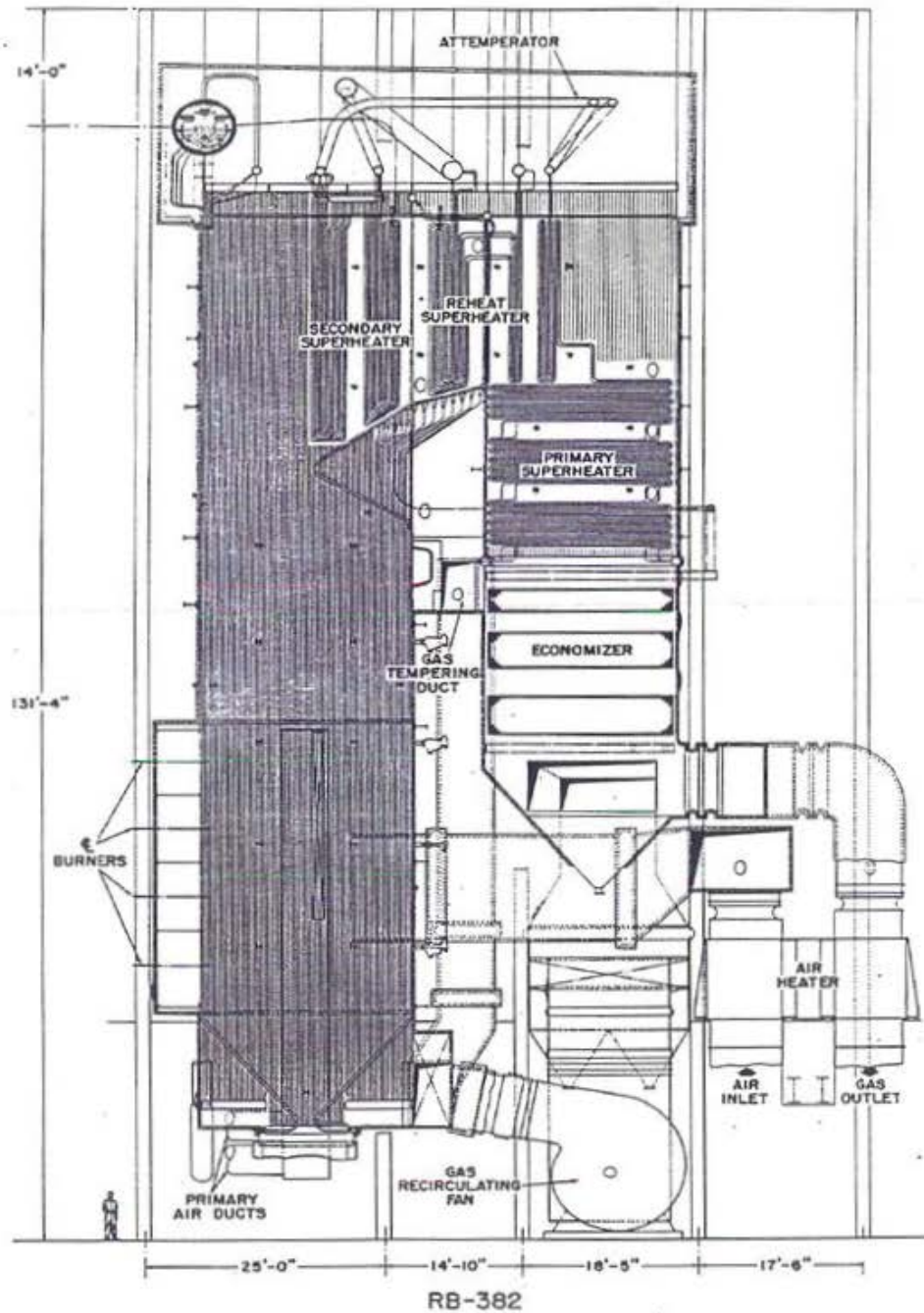
Foster Wheeler

Bay Shore Power Project Operations & Maintenance Manual

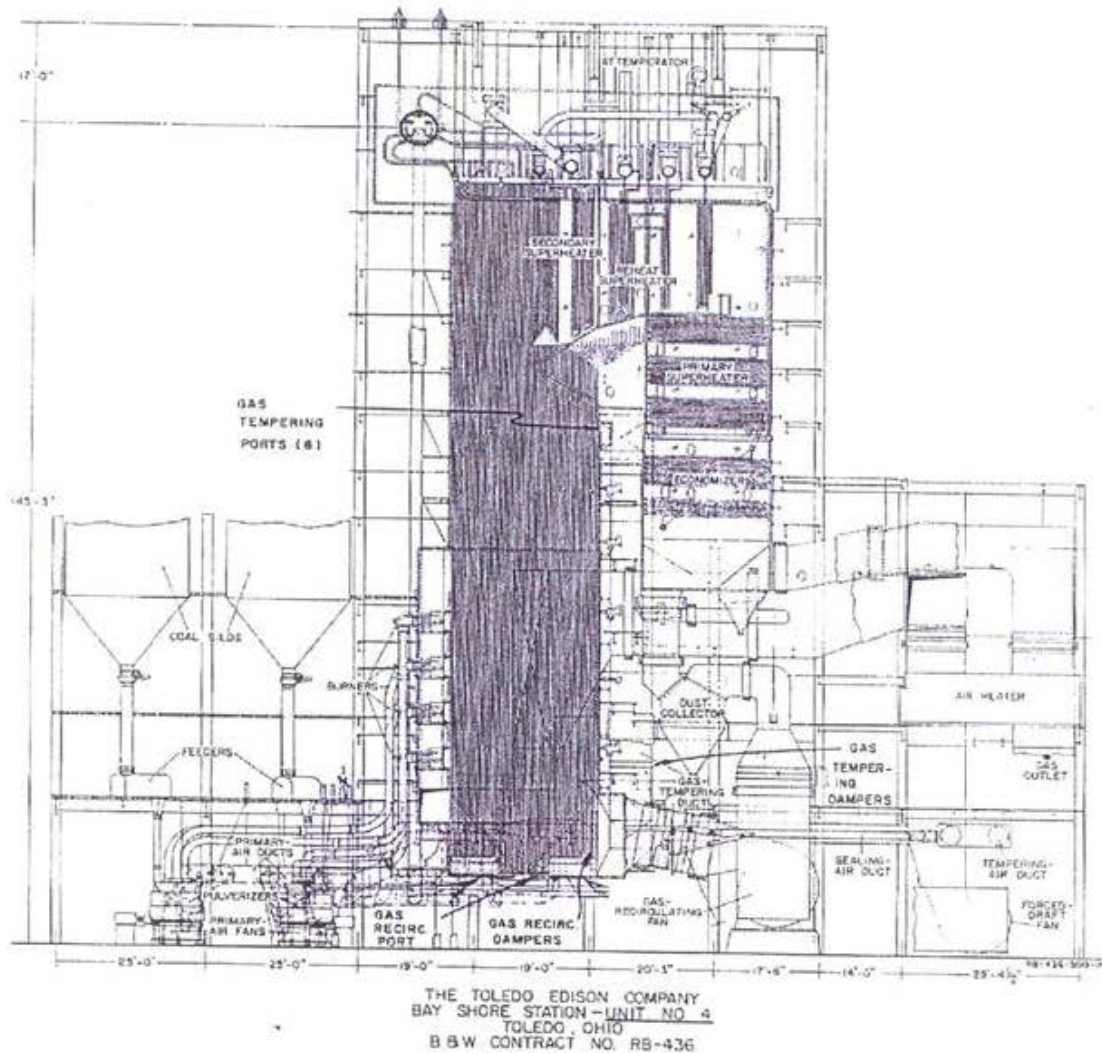


Side View of Bay Shore Power Project CFB Boiler





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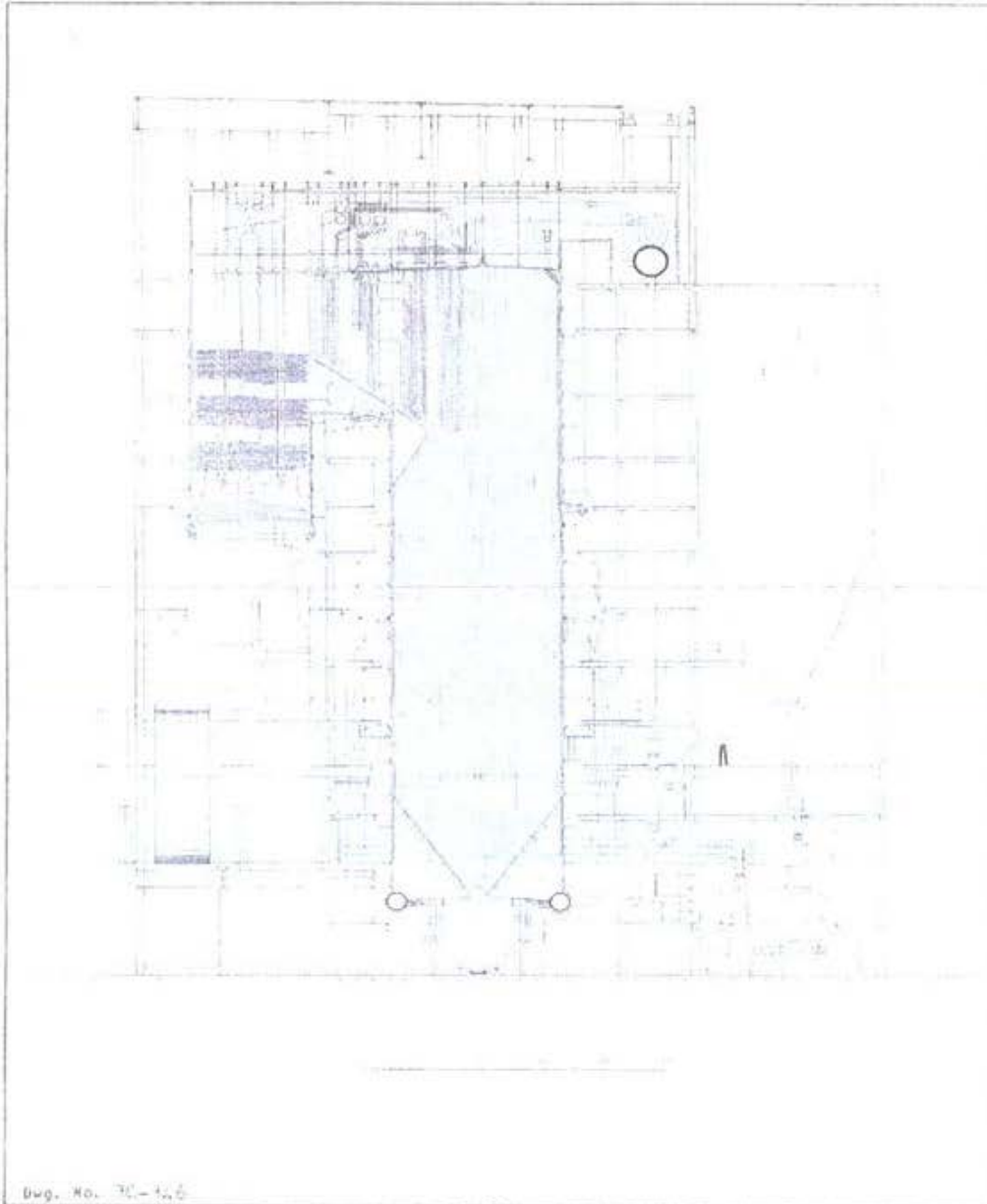


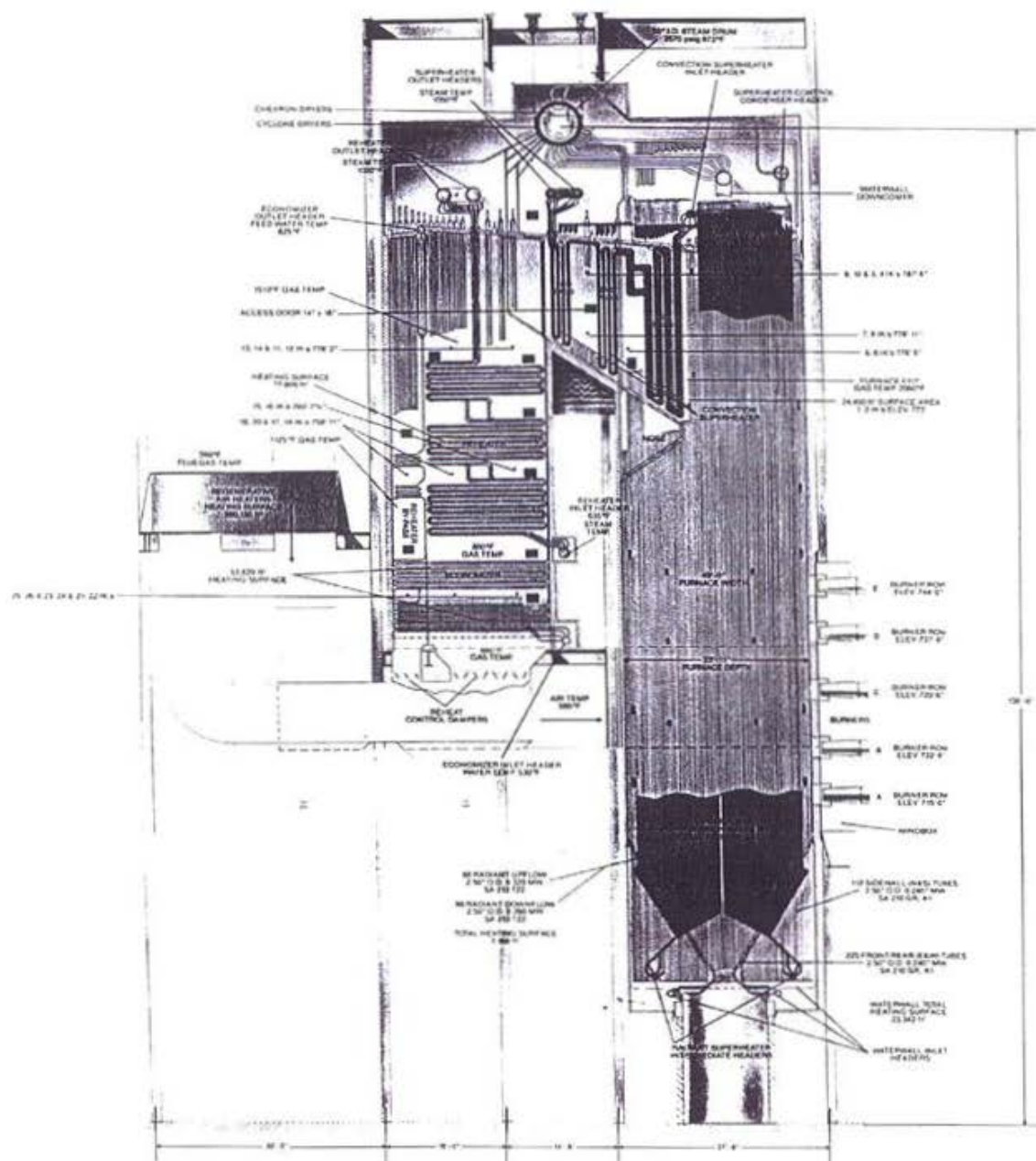
CAPACITY, LB STEAM / HOUR	1,505,000
SUPERHEATER OUTLET PRESSURE, PSI	2540
HIGH PRESSURE STEAM TEMPERATURE, F	1060
REHEAT STEAM TEMPERATURE, F	1010

LAKESHORE #18



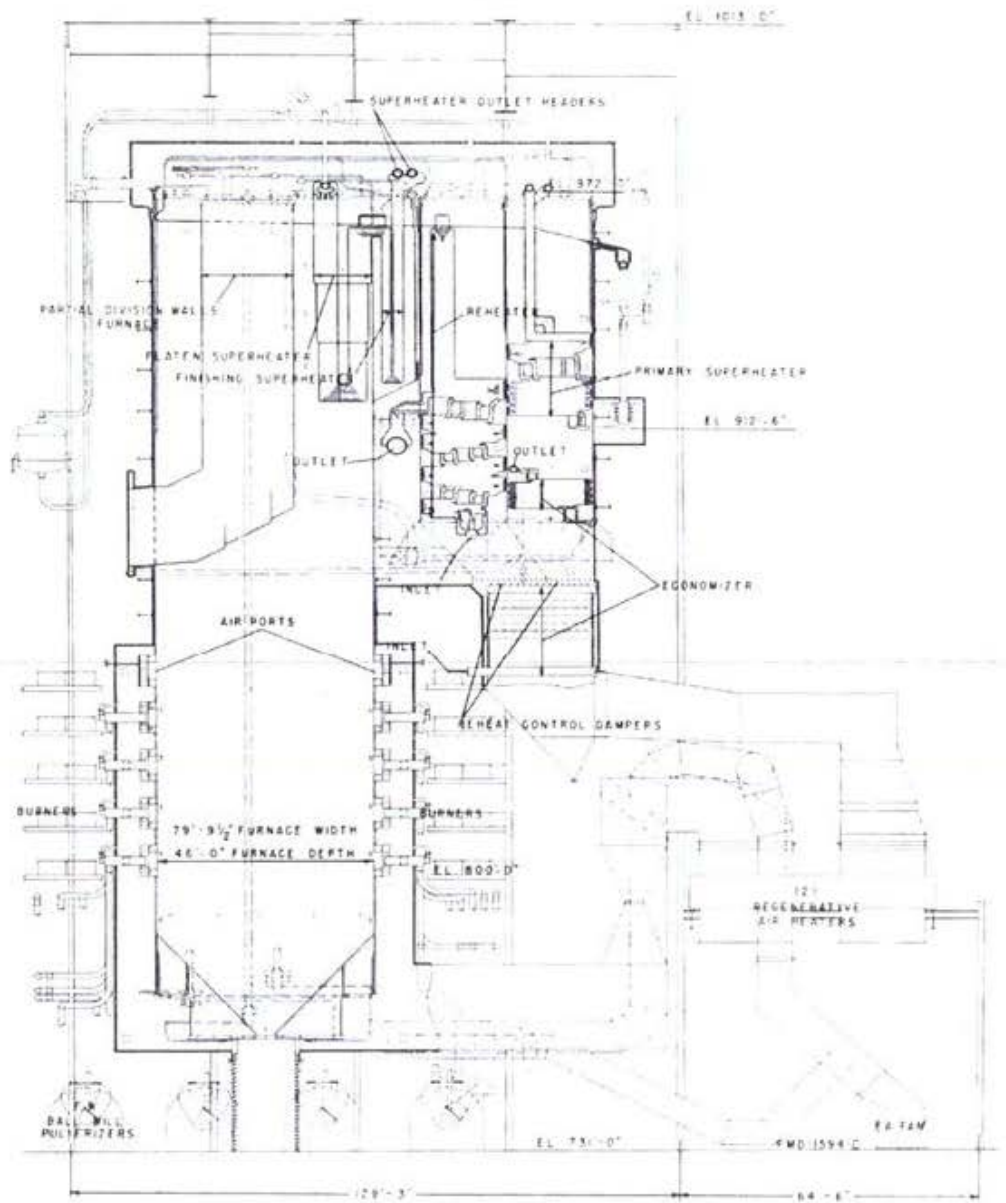
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FOSTER WHEELER STEAM GENERATOR
THE OHIO EDISON COMPANY
W. H. SAMMIS PLANT UNITS 1, 2, 3, 4

FOSTER W WHEELER



Name Bruce Mansfield Station - Unit No. 3	Design Pressure 4000/825
Location Shippingport, Pennsylvania	Final Steam Temperature 1005/1005
No. of Units 1	Capacity 6,415M lb/hr Type 8 heat O.T.U.
Contract No. 2-85-2233	Date August 1973