



# Effects of fuel composition and temperature on fireside corrosion resistance of materials for advanced ultrasupercritical coal fired power plants

Horst Hack  
Greg Stanko  
Foster Wheeler North America Corp., USA

**Published in**  
Energy Materials, © 2008 Institute of Materials,  
Minerals and Mining and W. S. Maney & Son Ltd  
[www.ingentaconnect.com/content/maney/ema](http://www.ingentaconnect.com/content/maney/ema)

**Citation**  
Hack,H., and Stanko, G. (2007). Effects of fuel composition and temperature on fireside corrosion resistance of materials for advanced ultrasupercritical coal fired power plants. *Energy Materials*, 2 (4), 241-248.

# Effects of fuel composition and temperature on fireside corrosion resistance of materials for advanced ultrasupercritical coal fired power plants

**H. Hack\* and G. Stanko**

The fireside corrosion resistance of candidate materials for the waterwalls and superheater/reheater sections of ultrasupercritical coal fired boilers have been evaluated through field testing as part of a programme cosponsored by the US Department of Energy and the Ohio Coal Development Office. The materials tested include high strength ferritic steels (SAVE12, P92, HCM12A), austenitic stainless steels (Super304H, 347HFG, HR3C), and high nickel alloys (Haynes 230, CCA617, INCONEL 740, HR6W). Protective coatings (weld overlays, diffusion coatings, laser claddings) that may be required to mitigate corrosion were also evaluated. The trials were based on previous laboratory evaluations under synthesised coal ash and flue gas conditions typical of three North American coals at temperatures ranging from 455 to 595°C for waterwall materials, while superheat/reheat materials were tested at 650–870°C. Promising materials from the laboratory tests were assembled on air cooled, retractable corrosion probes for testing in utility boilers. The probes were designed to maintain metal temperatures using multiple zones, ranging from 650 to 870°C. Three utility boilers, equipped with low NO<sub>x</sub> burners, were identified that have adequate flue gas temperatures and represent each of the three coal types. New fireside corrosion probe results are presented for mid-western and western coal types, after approximately one year of exposure in the field. Visual examination of samples from the mid-western utility site indicated minimal evidence of significant wall loss for any of the tested materials. Samples removed from the western utility site indicated evidence of wall loss for some tested materials. Further evaluation and quantification of total metal wastage through wall thickness measurements and metallographic examination of subsurface penetration is being undertaken.

**Keywords:** Ultrasupercritical power plant, Fireside corrosion, High strength ferritic steels, Austenitic stainless steels, High nickel alloys, Diffusion coating

## Introduction

Power plants in the USA are under increasing pressures to improve efficiency and reduce emissions. The efficiency of conventional pulverised coal power plant cycles is strongly related to operating temperature and pressure. The need to improve efficiency has been a driving force to advance materials suitable for these higher boiler operating temperatures and pressures. The US Department of Energy (DOE) and the Ohio Coal Development Office (OCDO) are cosponsoring a project, managed by Energy Industries of Ohio (EIO), to evaluate candidate materials for coal fired boilers

operating under ultrasupercritical (USC) steam conditions. The objective of this programme is to allow boiler operation at much higher temperatures and pressures than are presently used in conventional power plants.

Power plants incorporating USC technology will deliver higher cycle efficiency, and lower emissions of carbon dioxide (CO<sub>2</sub>) and other pollutants than current coal fired plants. Turbine throttle steam conditions for USC boilers will approach 732°C (1350°F), at 35 MPa (5000 psi). The materials used in current boilers typically operate at temperatures below 600°C (1112°F) and do not have the high temperature strength and corrosion resistance required for USC operation. These higher operating conditions will enable the use of advanced, more efficient USC steam cycles in coal fired power generation, which offers the added advantage of reducing carbon dioxide emissions.

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Foster Wheeler North America Corp., 12 Peach Tree Hill Road, Livingston, NJ 07039, USA

\*Corresponding author, email horst\_hack@fwc.com

The existing fleet of pulverised coal power plants is typically 35% (higher heating value) efficient, and operates at steam temperatures below 600°C (1112°F). The materials used in these existing plants do not have the high temperature strength and corrosion properties required for USC operation. By developing improved materials systems that can withstand higher temperatures, pulverised coal power plant efficiencies of up to 47% (higher heating value) are possible. These efficiency gains, alone, would cut the release of carbon dioxide and other emissions by nearly 30%. Additionally, USC cycles can be combined with oxycombustion technology to facilitate carbon dioxide capture.

The multiyear programme is funded by DOE through the National Energy Technology Laboratory (NETL), cofunded by OCDO, and managed by EIO. A consortium of industry members are cost sharing the project (Alstom Power, Riley Power, Babcock and Wilcox and Foster Wheeler), along with the direct participation of NETL and Oak Ridge National Laboratory, and are responsible for the technical aspects of the project. The Electric Power Research Institute (EPRI) provides technical management and direction. The programme has been divided into eight tasks, with responsibilities distributed among the consortium members, as described by Viswanathan *et al.*<sup>1</sup> The focus of the present paper is the work being conducted by Foster Wheeler on fireside corrosion resistance.

## Fireside corrosion

In the first half of the twentieth century, the development of pulverised coal boilers evolved gradually, setting the groundwork for the explosion of technology that occurred in the second half. Steam temperatures rose an average of 3.7°C (6.6°F)/year from 173°C (343°F) in 1903 to about 621°C (1150°F) in 1955. However, the excursion above 538°C (1005°F) was short lived; by 1960 most steam generators were designed for 565°C (1049°F), and by 1970 they were back to 538°C (1005°F). There were several reasons for this retreat, one being a materials problem that, at that time, defied a technical or economic solution. Materials that exhibited strength to withstand the higher temperatures and pressures present in the superheaters of these supercritical advanced boilers were available; but they proved to be especially susceptible to corrosion by certain coals, most notably high sulphur bituminous coals.

The cause of this type of corrosion, referred to as coal ash corrosion, was discovered in the late 1950s and is now generally accepted to be the presence of liquid alkali iron trisulphates on the surface of the superheater and reheater tubes beneath an overlying ash deposit.<sup>2</sup> Approaches to solving this problem have included changing the fuel or providing protective baffling with sheaths of corrosion resistant material around selected tubes. Coal ash corrosion is a widespread problem for superheater and reheater tubes, especially where high sulphur, high alkali, and high chlorine coals are used, and is a critical problem that needs to be resolved before advanced USC boilers can be deployed. The installation of low NO<sub>x</sub> burners in boilers in the 1980s has, in some cases, resulted in conditions in the superheater and reheater sections that have exacerbated the coal ash corrosion problem. Tube samples obtained from the superheater section in units operating with low NO<sub>x</sub>

burners contained evidence of carbon carryover and less oxidising flue gases. This environment has resulted in carburisation of the tube surfaces. Carburisation ties up the chromium in the alloy, which is the element that provides the most benefit to coal ash corrosion resistance and, as a result, promotes higher wastage rates. In a somewhat related matter, Powder River Basin fuels that were previously thought to be non-corrosive have been found to cause very high wastage rates under certain less oxidising operating conditions.<sup>3</sup> There have been a number of literature reviews and recent updates discussing the variables affecting the corrosion mechanism.<sup>4-8</sup>

As part of the project 'Boiler R&D for improved coal fired power plants', sponsored by the EPRI, Foster Wheeler Development Corp. (FWDC), and Ishikawajima Harima Heavy Industries Co. Inc. performed both laboratory and field testing to assess coal ash corrosion mechanisms.<sup>3,8</sup> The results of the laboratory tests for 22 materials, three alkali sulphate levels, three levels of SO<sub>2</sub>, and four temperatures, indicated that the alkali and sulphur content, along with the metal operating temperature, can have a significant effect on coal ash corrosion. The loss from corrosion increased with higher levels of SO<sub>2</sub>, alkali sulphates, and temperature. The corrosion rate-temperature plot is a bell curve, the form of which shifts and varies in width as a function of alloy composition, SO<sub>2</sub> level in gas, alkali content, and CaO concentration in the coal. Pitting did not occur at low levels of SO<sub>2</sub> and alkali, but became an active mechanisms, especially on stainless steels and chromised coatings, at very high levels of SO<sub>2</sub> and alkali sulphate concentrations. Also, chromium was found to be the most beneficial alloying element for enhanced corrosion resistance. The corrosion resistance was greatly improved as the chromium levels approached and exceeded 25%. Laboratory tests also indicated that standard Type 347 tube material is adequate for mildly corrosive environments, but type 310 or type 310 HCbN (Sumitomo HR3C, ASME code case 2115) is required for more corrosive conditions.

The second phase of the 'Boiler R&D for improved coal fired power plants' project included field tests exposing eight alloys on air cooled, retractable corrosion probes for up to 16 000 h. FWDC and EPRI chose three boilers: two burning eastern high sulphur coal and one burning western low sulphur subbituminous coal, for test probe exposures. The air cooled, retractable corrosion probes were designed and installed; they exposed eight metal samples for 4000, 12 000 and 16 000 h at temperatures generally in the range 650–700°C (1200–1300°F). In both units burning the high sulphur eastern coal, classical alkali iron trisulphate attack occurred. As expected, chromium was the most beneficial element that improved coal ash corrosion resistance in these tests. Alloys with 25% or more chromium generally showed satisfactory corrosion resistance. The boiler burning the low sulphur western coal produced atypical reducing conditions on the backside of the corrosion probes. This resulted in high corrosion rates, from sulphidation in the presence of calcium sulphate, on the backside of the tube, rather than at the 2 and 10 o'clock positions on the front of the tube, which are typical for coal ash corrosion. The results from these field corrosion probe exposures confirmed the performance of alloys in the laboratory

corrosion tests. The combination of the laboratory screening and parameter testing and field test results under complex realistic conditions provided a database for alloy selection.

A similar field test, at temperatures typical of an advanced cycle plant, exposed 10 alloys (including developmental and clad compositions) on air cooled retractable corrosion probes for up to 16 000 h at temperatures in the range 620–730°C (1150–1340°F).<sup>9</sup> The results of that Oak Ridge National Laboratory programme showed that some of the developmental alloys and claddings had wastage rates that were one-fourth of the wastage typical for a 347 superheater tube. In a separate study for EPRI, samples of 304, 347, 800H, NF709 HR3C, CR30A and chromised T22 were exposed for over 45 000 h at temperatures from 521 to 685°C (970–1265°F), which covers the first part of the first target for the expected tube metal temperatures for a USC steam plant.<sup>2</sup> The active corrosion mechanism was found to be molten salt attack by potassium iron trisulphate. Additionally, the tube location in the boiler was found to be very important, and in some areas this variable overshadowed the effect of temperature and alloy content.

Under the USC conditions, maximum steam temperatures will approach 760°C (1400°F), which means that metal temperatures will be 815°C (1500°F) or higher. As a result of these metal temperatures, high strength, high nickel alloys and advanced austenitic stainless steels have initially been selected for the superheater and reheater sections of the boiler. An insidious form of corrosion that could be problematic in the high strength Ni base superalloys that will be necessary in USC boilers is known as type II hot corrosion. A temperature of 815°C (1500°F) is high enough that the ashes, even with the fuel and low NO<sub>x</sub> burner conditions discussed above, should not result in the classic coal ash corrosion. Rather, the corrosion mechanisms that will be operative are oxidation and sulphidation from the gas and solid deposits. In much of the previous work cited, fireside corrosion data were measured that were generally in the temperature range 620–727°C (1148–1340°F). More importantly, no field data were obtained on the high nickel alloys that have been selected for the high temperature tubular components of the USC plant. Thus, the absence of fireside corrosion data for many alloys above temperatures of 727°C (1340°F) where type II hot corrosion could be a problem, and particularly for the high nickel alloys over the full temperature range expected for the USC plant, requires additional laboratory and field testing.

The waterwalls located in the furnace also have fireside exposure, but the operating conditions, deposits and resulting corrosion mechanisms differ from those in the superheater and reheater. In the area of the waterwalls, the introduction of new combustion systems to reduce NO<sub>x</sub> emissions has led to severe waterwall corrosion for some fuels, especially eastern bituminous coals. The active fireside corrosion mechanism is expected to be sulphidation from a substoichiometric gas with H<sub>2</sub>S and deposits containing carbon and iron sulphide. The higher waterwall temperatures of the USC plant will significantly increase corrosion rates vis-à-vis existing plants. Future, more stringent NO<sub>x</sub> emission regulations will further increase the risk of waterwall corrosion. The utility industry is studying

and implementing combustion system modifications to reduce waterwall corrosion, but it is likely that waterwall corrosion will persist in core areas. This will require protective coatings or claddings applied by various means, such as weld overlaying, laser cladding, and various forms of thermal spraying. In response to present waterwall corrosion problems, various promising coating compositions and application techniques are under development, but need thorough evaluation and possibly some more development.

Fireside corrosion evaluation involves a three task approach. First, laboratory testing is necessary to screen the different alloys in controlled environments where the different variables of alloy content, temperature, fuel/ash and sulphur in the flue gas can be evaluated. Second, the best performing alloys in the laboratory tests can be evaluated on air cooled retractable corrosion probes inserted in the superheater and reheater areas of actual operating boilers burning distinctly different fuels. Third is a test of the best performing alloys under pressure in actual boiler operating conditions, e.g. steam loop, inline probes. Since the temperature at any given location in an operating boiler is usually not isothermal, because of unit cycling, multiple test locations must be utilised to cover multiple temperatures and different deposit formations. This third task requires some boiler modification because no existing boilers are operating at the advanced USC conditions. Some limited higher temperatures can be obtained by the use of flow restricting orifices in the tubes, but the highest temperatures will require a separate steam circuit. That steam circuit will be at the needed higher temperature but not at a higher pressure than the operating boiler. In the waterwalls the outer diameter metal temperature can be increased by the use of a greater wall thickness.

The objectives of the present fireside corrosion resistance programme are:

- (i) to determine the fireside corrosion and type II hot corrosion resistance of the alloys which have the strength for USC tubing applications, and to select the optimum tubing alloy or coating for superheaters and reheater tubes
- (ii) to determine the fireside corrosion resistance of alloys, overlays and coatings which have the strength for USC waterwall applications and to select the optimum alloy and protection system for the waterwalls.

## Field testing

During the laboratory testing phase of the fireside corrosion resistance task, experiments were performed on a variety of developmental and commercial alloys and coatings by exposing them to simulated USC superheater and reheater environments.<sup>10–12</sup> While these laboratory tests are a valuable screening tool for down selecting candidate materials for use in advanced USC power plant applications, there are a variety of variables that cannot be addressed in laboratory tests. Field exposures allow the evaluation of important environmental parameters that cannot be fully simulated in the laboratory tests, for example:

- (i) the actual composition of the deposits formed on the tubes is more complex than the composition of the simulated ash in laboratory tests



**1 Corrosion probe installed at mid-western utility**

- (ii) the  $\text{SO}_3$  concentration formed by heterogeneous reaction on cooled surfaces is variable
- (iii) the temperature gradients that occur within the ash deposits are very large
- (iv) the ash and flue gas move past tubes at high velocity; the rate varies with design
- (v) the composition of the corrosive deposits changes over time
- (vi) the temperatures are not constant
- (vii) the effect of fly ash erosion results in the removal of the protective oxides from the tube and replenishes the metal surface with fresh corrosive, molten sulphate ash.

The alloys and coating materials that gave the most promising results in laboratory testing were selected for field testing. Some materials tested in the laboratory were not available in tubular form, and/or in sizes compatible with the probe design. Therefore, the materials selected for testing in the field were a subset of those tested in the laboratory (Table 1). The weld overlays and laser claddings were applied to 230 tubing

**Table 1 Materials and coatings selected for field testing**

Wrought	Weld overlays	Diffusion coated	Laser clad
Super 304H	622	FeCr	50/50
347HFG	52	SiCr	–
800HT	72	–	–
617	33	–	–
230	–	–	–
HR6W	–	–	–
HR3C	–	–	–
740	–	–	–

**Table 2 Specimen layout and target temperatures for mid-western utility site**

Time	Zone 5 – 1200°F (650°C)	Zone 4 – 1300°F (704°C)	Zone 3 – 1400°F (760°C)	Zone 2 – 1500°F (815°C)	Zone 1 – 1600°F (871°C)
2 years	HR6W	740	50/50 LC	740	50/50 LC
	HR3C	617	230	HR3C	HR6W
	S304H	230	740	72WO/230	52WO/230
	33WO/230	50/50 LC	SiCr/S304H	52WO/230	HR3C
	622WO/230	HR6W	33WO/230	HR6W	72WO/230
1 year	800HT	HR3C	HR6W	740	72WO/230
	740	S304H	230	800HT	740
	617	800HT	740	50/50 LC	52WO/230
	347HFG	622WO/230	52WO/230	SiCr/S304H	HR6W
	230	347HFG	800HT	230	50/50 LC

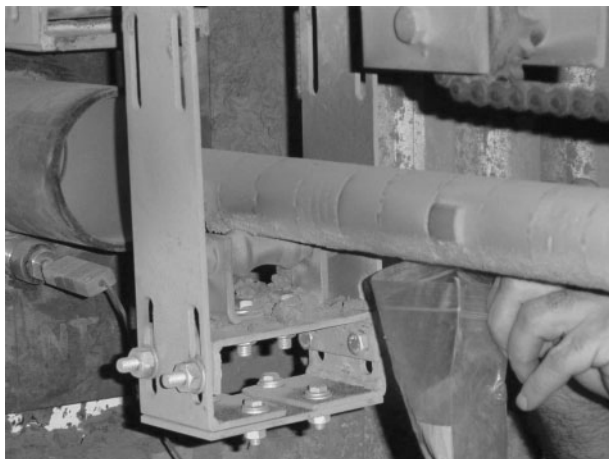
material. The diffusion coatings were applied to Super 304H tubing material.

Three utility boilers were selected for use as host sites for installation of the field corrosion probes. Two air cooled, retractable, corrosion probes have been installed at each utility plant. Each of these boilers was equipped with low  $\text{NO}_x$  burners and one each was expected to be burning eastern, mid-west and western coal for the duration of the testing. Promising alloys from the laboratory testing were assembled on air cooled retractable corrosion probes for testing in the superheater or reheater areas of these three utility boilers. At each site two corrosion probes were intended to be exposed for one and two years respectively, at each site. The corrosion probes included material samples intended to be exposed at controlled metal temperatures of 650, 704, 760, 815, and 871°C, (1200, 1300, 1400, 1500 and 1600°F), representing the range of temperatures expected in the superheater and reheater components of the USC plant.

The layout of the material specimens on each probe was based upon knowledge of the fuels burned at the host site, combined with the results of the laboratory testing. For example, the first of the three installations is burning a high sulphur mid-western coal. The specimen layout for this site is shown in Table 2.

The selected materials were machined into uniform tubular specimens, and assembled into probes, each containing 25 specimens. Figure 1 shows one of the corrosion probes, in the extended position, mounted to the retraction mechanism. The probes are instrumented with thermocouples to monitor and control the zone temperatures. Figure 2 shows a close-up view of the same probe, in the retracted position, in which the sample segments are visible. The completed probe extends approximately five feet (1.5 m) into the furnace.

The first set of corrosion probes was successfully installed and tested at a mid-western host utility site in January 2006. Installations at the western and eastern utility sites followed thereafter. The corrosion probe system was designed to be independent from the main boiler, to be installed and removed without a boiler outage, and to be fail safe, retracting the probe in the event of a malfunction. With these safety features, years of testing would not be compromised by a sudden overheating event. Each assembled and instrumented probe is attached to a retraction mechanism that allows automatic removal of the probe in the event of a malfunction. A blower supplies cooling air to maintain the temperatures of each of the five zones within each probe. A control system monitors selected thermocouples for each temperature zone, and modulates the airflow to maintain the desired average metal temperature for each



2 Close-up view of corrosion probe in Fig. 1

zone. The probes will retract automatically upon failure of the cooling air supply system, loss of data signal, power failure, computer failure, and thermocouple failure. Probe status and temperature data are being continuously monitored and collected remotely. Periodic onsite inspections are performed to remove the probes and visually assess the deposits, corrosion rates, and wall thickness loss of the specimens.

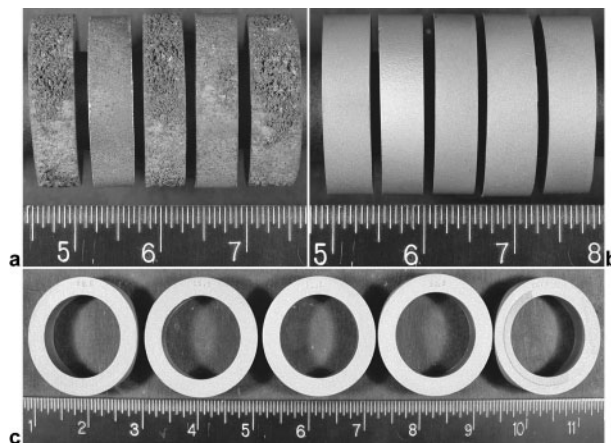
The field corrosion probe testing is an ongoing part of this programme. At the end of the testing period, post-exposure metallurgical evaluation will be performed on each probe. All the samples from each probe will be disassembled and will be evaluated for thickness loss and subsurface penetration of the corrosive species. The samples and deposits will be evaluated to determine what corrosion mechanisms are operative at each test condition.

### Mid-western site exposure results

The first probe to complete the field exposure was the one year corrosion probe at the mid-western site. This probe was removed for metallurgical evaluation during April 2007, with approximately 5200 h of exposure to boiler operating temperatures. The initial metallurgical evaluation focused on zone 2, which had a target temperature of 816°C (1500°F). The median temperature for the exposure time was approximately 732°C (1350°F), with short term exposures to temperatures as high as 927°C (1700°F). The external surface was mostly covered with relatively thin, hard, dark coloured ash deposits that were non-uniformly distributed across the length of the probe and around the circumference, as seen in Fig. 3. The heaviest deposit build-up was generally located between the 3 and 5 o'clock positions (as viewed from the probe tip) where the flue gas was impinging on the probe surface. In several locations along the probe length, however, entire coupon specimens were free of ash deposits, and covered with only



3 One year corrosion probe from zone 2, mid-western utility: post-exposure (before cleaning)



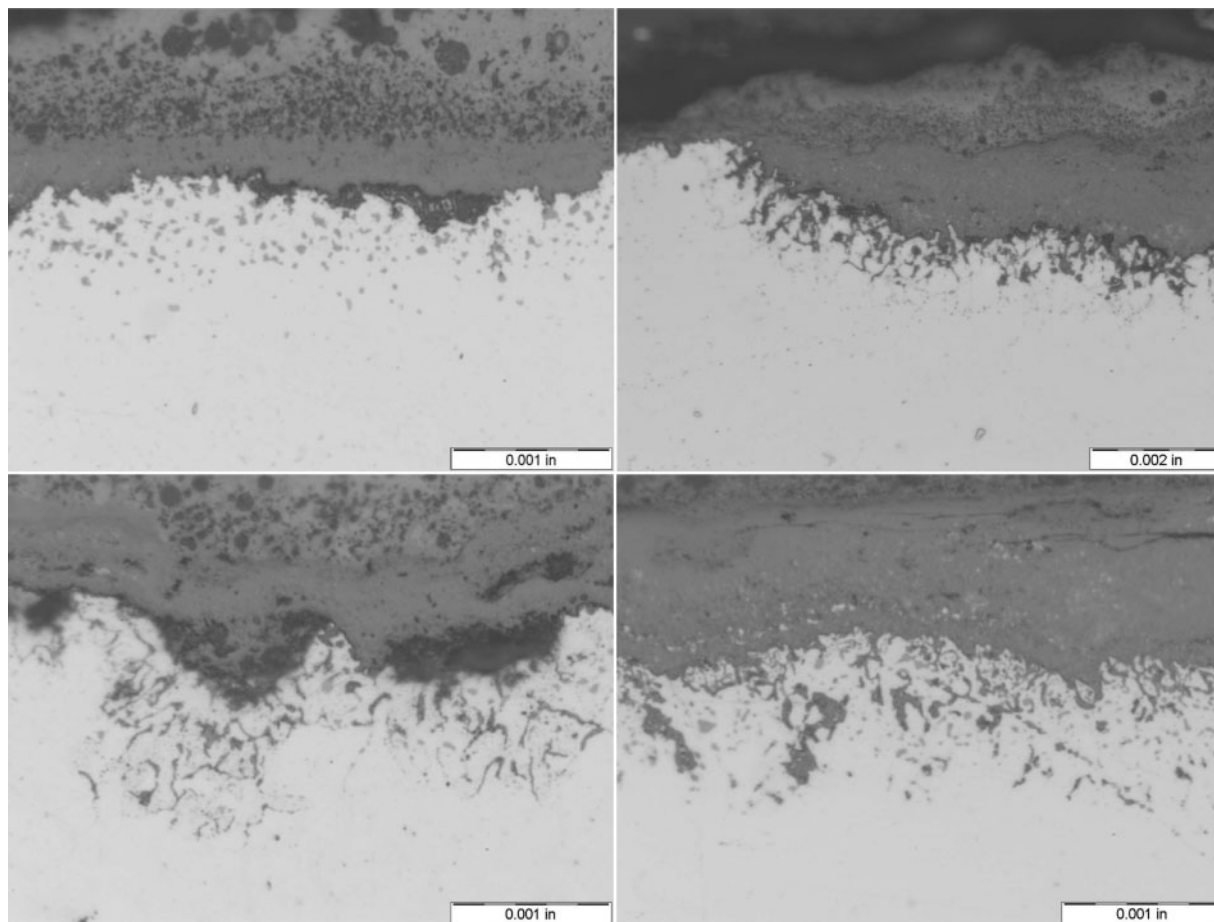
4 One year corrosion probe rings from zone 2, mid-western utility, showing post-exposure a before cleaning and b,c after cleaning

thin, black and red oxide layers. The specimens located near the back (coolest) portion of the probe were also covered with streaks of light coloured residue.

Following post-exposure evaluation and documentation, the probe was sectioned into five zones, each representing the different temperature regimes that the probe specimens were expected to maintain during testing. Ring sections for the five materials residing within each zone were cut from the coupons samples and lightly grit blasted for macroscopic and physical evaluation of wall loss, as shown in Fig. 4. Visual examination of the samples removed from zones 1–4 revealed little to no evidence of significant wall loss for any of the proposed materials. Scattered pits were observed on a few of the sections removed from zones 3 and 4, but the extent of wall loss was relatively shallow. The wall thickness loss on the zone 2 material samples ranged from 0.4 to 1.2% of the original wall thickness. Photomicrographs of the typical subsurface penetration noted in the samples are presented in Fig. 5. Further evaluation and quantification of total metal wastage through wall thickness measurements and metallographic examination of subsurface penetration is required before any definitive statements can be made concerning the condition of the probe samples, and relative ranking of candidate material alloys.

### Western site exposure results

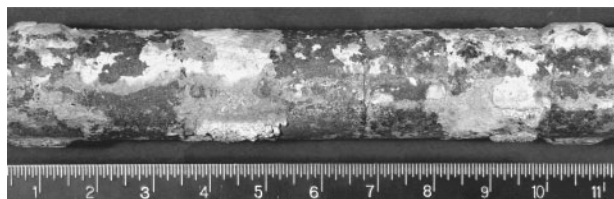
The second probe to complete the field exposure was the one year corrosion probe at the western site. This probe was removed for metallurgical evaluation during July 2007, with approximately 5800 h of exposure time to boiler operating temperatures. The initial metallurgical evaluation focused on zone 2, which had a target temperature of 816°C (1500°F). This zone exhibited surface attack that was representative for the probe materials exposed at this site. The median temperature for the exposure time was approximately 749°C (1380°F), with short term exposures to temperatures as high as 893°C (1640°F). The external surface was generally covered with relatively thick, nodular, yellow and orange deposits (and/or corrosion products) that overlaid a dense, black oxide layer, as seen in Fig. 6. Locally heavier deposition was noted at the 1 and 5



5 Photomicrographs of one year mid-western probe

o'clock positions (as viewed from the probe tip) along the periphery of where the flue gas was impinging on the probe surface. In several locations along the probe length, however, entire coupon specimens were free of ash deposits, and were only covered with a thin, brownish black oxide layer.

Again, following post-exposure evaluation and documentation, the probe was sectioned into five zones. Ring sections for the five materials within each zone, prepared as described above, are shown in Fig. 7. Visual examination of the samples removed from zones 1–5 revealed some general wall loss and scattered pitting on many of the materials. The average wall thickness loss on the zone 2 material samples ranged from 0.6 to 2.0% of the original wall thickness; however, localised pitting of up to 10% of original wall thickness was noted. The microscopic morphology of subsurface attack in the samples that exhibited notable wastage is illustrated in Fig. 8. This preliminary data after one year of exposure suggests that the wall loss under Western coal samples was significantly greater than for the mid-western coal conditions. This is clearly a departure

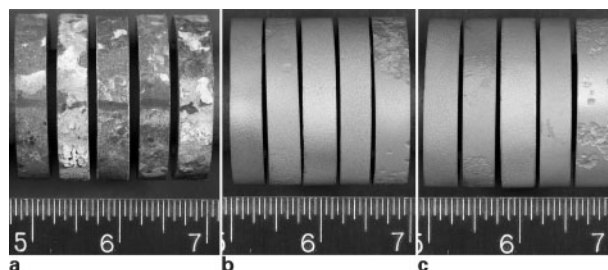


6 One year corrosion probe from zone 2, western utility: post-exposure (before cleaning)

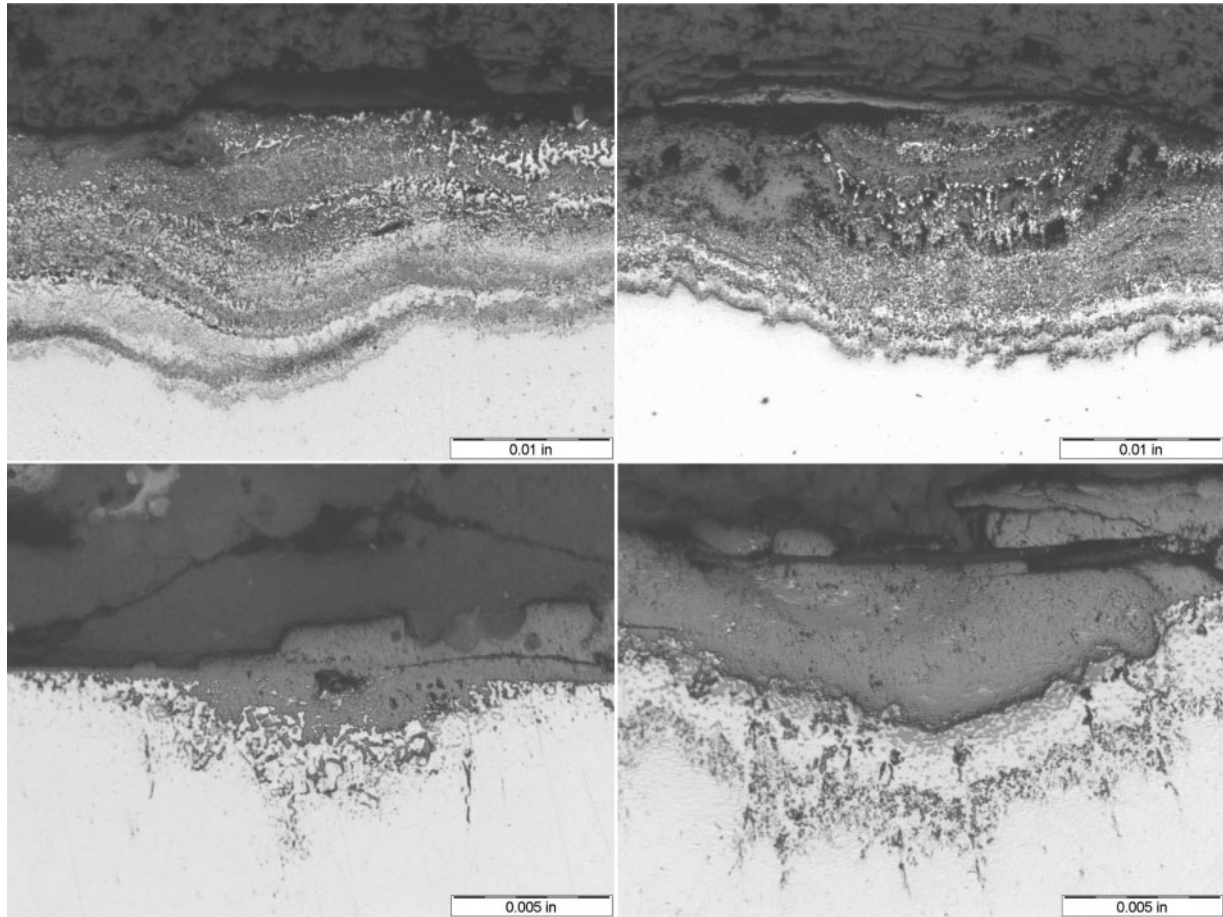
from the results obtained in the laboratory testing, in which the western coal samples showed the least wall loss. Further evaluation and quantification of total metal wastage is required before definitive statements can be made concerning the overall condition of the probe samples, and relative ranking of candidate material alloys.

## Conclusions

Preliminary results of field trial evaluation of fireside corrosion resistance of candidate materials, with and without surface coatings, for use in USC boilers have been presented. The candidate materials were selected on the basis of prior laboratory tests under synthesised coal ash and flue gas conditions typical of three North American coals, representing eastern (mid-sulphur



7 One year corrosion probe rings from zone 2, western utility, showing post-exposure *a* before cleaning at 12 o'clock position, *b* after cleaning at 12 o'clock and *c* after cleaning at 4 o'clock position



**8 Photomicrographs of one year western probe**

bituminous), mid-western (high sulphur bituminous) and western (low sulphur subbituminous) coal types.

Promising materials from the laboratory tests, assembled on probes, are being exposed in three utility boilers for one and two year durations. These air cooled, retractable corrosion probes were designed to maintain metal temperatures using multiple zones, ranging from 650°C (1200°F) to 870°C (1600°F).

Visual examination of the samples removed from the mid-western utility site indicated minimal evidence of significant wall loss for any of the tested materials, and the extent of wall loss, especially in zone 2, was relatively shallow. Visual examination of the samples removed from the western utility site indicated evidence of wall loss for some of the tested materials, and the extent of wall loss, as presented for zone 2, was more severe than for the mid-western samples. Further evaluation and quantification of total metal wastage through wall thickness measurements and metallographic examination of subsurface penetration is required before any definitive statements can be made concerning the condition of the probe samples.

### Acknowledgements

The authors wish to thank Dr Robert Romanosky (NETL), Robert Purgert (EIO), and Dr R. Viswanathan (EPRI) for support and guidance during this project.

This work was prepared with the support of the US Department of Energy, under Award DE-FG26-01NT41175 and the Ohio Coal Development Office/Ohio Department of Development (OCDO/ODOD)

under Grant Agreement Number CDO/D-00-20. However, any opinions, findings, conclusions, or recommendations expressed herein are those of the authors and do not necessarily reflect the views of the DOE and/or the OCDO/ODOD.

This paper is based on a presentation at the 5th International Conference on Advances in Materials Technology for Fossil Power Plants, held at Marco Island, FL, on 3–5 October 2007, sponsored by EPRI and ASM International.

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This report was prepared by Foster Wheeler North America Corp. pursuant to a grant partially funded by the US Department of Energy (DOE) under Instrument Number DE-FG26-01NT41175 and the Ohio Coal Development Office/Ohio Department of Development (OCDO/ODOD) under Grant Agreement Number CDO/D-00-20.

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