

VTER TECHNICAL PAPER, CSS 98, 39th Corrosion Science Symposium, 8th Sept. 98,  
University of Northumbria at Newcastle, U.K.

## **ON-LINE MONITORING OF FURNACE WALL AND SUPERHEATER**

### **CORROSION IN POWER GENERATION BOILERS**

D.M. Farrell, B. Robbins  
ROWAN TECHNOLOGIES LTD  
Tel: +44 (0) 161 748 3644  
Email: [mail@rowantechnologies.co.uk](mailto:mail@rowantechnologies.co.uk)  
[www.rowantechnologies.co.uk](http://www.rowantechnologies.co.uk)

#### **ABSTRACT**

The major power producers are moving towards increasing the efficiency of fossil fuel fired power plant. Conventional and ageing pulverised fuel (PF) plant are now expected to compete with new gas-fired plant in the UK. The government are now pushing the electricity producers to use more UK coal to support the local mining communities. Coal fired boilers are increasingly being operated at higher efficiencies with excess oxygen levels minimized and intervals between scheduled maintenance shutdowns maximized. Typical maintenance intervals are currently 3 years, however the utilities are attempting to increase this towards 6 years.

Corrosion, erosion, fouling and sometimes failure of heat exchanger tubing in furnace wall, superheater and reheater locations is a major obstacle to this aim. Furnace wall corrosion and fouling tend to increase with decreasing oxygen concentration, ie under reducing conditions, whereas superheater corrosion, attack by condensed molten salts, is more likely at high oxygen concentrations where a higher proportion of the sulphur dioxide is oxidised to sulphur trioxide. This, in conjunction with molten salts condensed on the tubes, may lead to significant corrosion normally in a specific temperature band associated with the melting points of the salts. Unscheduled outages for tube repairs are currently around 2 to 3 per year in a typical 500MW boiler; the unit remaining off-line for periods of the order of 2 to 3 days to effect repairs.

Inspection of the condition of heat exchanger tubes has, to date, only been carried out off-line during scheduled maintenance outages. An established corrosion monitoring (CM) system has now become available for the on-line evaluation of these high-temperature corrosion reactions. The system is based on a modification of the well-established electrical resistance (ER) technique. Probes and instrumentation have been developed and proven and these systems are currently operating in a number of steam boilers in the power generation and paper industries around the world. An accurate measure of a low corrosion rate may be made in periods as short as 2 days. RTL currently have an EPRI R&D contract to further improve the sensitivity of the instrumentation and probes to obtain an accurate corrosion rate within a typical shift, ie 8 hour period.

## **INTRODUCTION**

Corrosion of metals exposed to high-temperature gaseous environments, frequently in the presence of deposits, has long been a problem in industrial process plants and furnaces [1]. The corrosion may be caused by gas-phase oxidation, sulphidation, molten salt attack, carburization or other types of mechanism. In boilers, furnace wall corrosion is generally considered to result from low excess oxygen levels leading to high concentrations of carbon monoxide around the furnace tubes. The attack is reported to be exacerbated in the presence of high chloride concentrations and under reducing conditions [2].

In coal fired boilers, severe corrosion of superheaters and reheaters can arise because of ash build-up on the tube surface facing the gas flow. Potassium, sodium and magnesium sulphates formed earlier in the furnace gradually accumulate by condensation at the base of the porous ash deposit [3]. This mixed sulphate deposit remains molten at tube metal temperatures above 600°C and forms a thin layer of highly corrosive liquid next to the protective oxide scale.

Currently, the only available condition monitors installed in some of the furnace zones of power generation boilers are heat flux probes comprising thermocouples embedded in the furnace wall tubes. Gas composition analyses are sometimes carried out on an occasional basis. Gas temperatures are not routinely monitored prior to the superheater outlet when the temperature has decreased to below 800°C.

Methods for on-line monitoring of the corrosion rate in high-temperature systems have not previously been available. The ability to monitor corrosion is useful to link increases in the severity of the corrosion environment with changes in the unit operation, combustion conditions, fuel composition and additive performance. In the case of furnace wall and superheaters, the combustion conditions may be optimised to improve the efficiency of a boiler without causing undue fireside corrosion. Alternatively, a low and known rate of corrosion may be acceptable so long as the tubes last between outages.

Conventional low-temperature corrosion monitoring probes do not have a cooling capability and, when exposed in a gas stream, normally take up a temperature similar to that of the gas. However, in a furnace, gas temperatures are typically in the range 1200°C to 1500°C whereas the waterwall and steam tube temperatures are much lower than that at around 400°C to 700°C. During the past few years, conventional corrosion monitoring techniques have been adapted for use in high-temperature plant using suitable ceramic probe sections and air-cooling systems to accurately control the probe element temperature to that of the heat transfer surface.

## **CORROSION INSPECTION TECHNIQUES**

At major overhauls of boilers, a full scaffold is erected in the furnace to allow access for inspection of all wall tubes. The fireside scales and corrosion deposits are first removed by grit blasting. This mechanical cleaning tends to result in removal of metal from the tubes.

Typically, a visual examination of the tube surfaces is made; then remaining thickness measurements are established on every tube in the boiler at height intervals of 2 to 3 metres and at a total of 9 levels in the furnace. This results in approximately 10,000 remaining thickness readings. Thickness measurements are determined using an ultrasonic thickness gauge. The remaining thickness data are processed by a computer spreadsheet program to calculate simple linear corrosion rates. The corrosion rate data may then be output as contour maps. Tubes, or sections of furnace wall, with a measured wall thickness below a minimum value are removed and new tubes inserted. A contour map of remaining thickness of the tubes on the sidewall of a 660MW boiler is shown in Figure 1. The coal fired boiler is opposed fired by a 60 burner array. Maximum corrosion rates of 60 and 70nm/hr were established around tube numbers 55 to 100 at a height of 23 to 25 metres, ie around the burner level. Contour maps are produced at all major outages.

Occasionally, radiography or other crack detection techniques may be employed for the examination of wall tubes in-situ.

## **ELECTRICAL RESISTANCE CORROSION MONITORING TECHNIQUE**

The electrical resistance (ER) technique is the most commonly used method for continuous monitoring of corrosion rate in low-temperature plant. It provides a direct measure of the loss of metal from the exposed test element and also has the ability to monitor corrosion and erosion in both aqueous and non-aqueous environments.

The established commercial probes typically employ two similar elements; an exposed corrosion element and a protected reference element. The resistance of the corrosion element is highly temperature dependent and the reference element, normally contained within the body of the probe, provides compensation for any temperature variation of the exposed element. This temperature compensation system is only effective at relatively low temperatures, ie below 100°C and where no element cooling is required.

A variable temperature electrical resistance (VTER) probe, with associated electronics, has been developed for use in medium and high-temperature plant [4], which allows accurate and direct monitoring of the resistance of a single corrosion element without the need for a reference element contained within the probe body. The single element may be cooled, or heated, to monitor corrosion at any desired temperature. The temperature of the corrosion element may be directly measured to a resolution of 0.1°C. The resistance of the corrosion element may therefore be temperature compensated in software and the element thickness and corrosion rate calculated. The current system comprises a 10A multiplexed resistance instrument and temperature measurement/control instrumentation, data logger and VTER corrosion probe, Figures 2 and 3.

Both furnace wall and superheater probe designs are employed, which are air-cooled using proportional temperature controllers to an accuracy of around  $\pm 1.5^\circ\text{C}$ . Two type K thermocouples are embedded into the corrosion element to facilitate probe control and also to measure the heat flux through the element. The furnace wall probes typically operate around 400°C to 450°C and the superheater probes around 550°C to 700°C. If carbon or low alloy steels are being evaluated then their backs are protected using either a plasma sprayed Ni/Cr coating, or alternatively, a stainless

steel liner to restrict internal corrosion from the oxygen rich cooling air. The system is designed to allow the cooling air to swirl within the probe; this results in an improvement in temperature distribution of the element.

Twin stainless steel electrode leads are welded to both sides of the test element. In the case of a superheater probe, these are coupled at either end of a tubular test element. For furnace wall probes, these are coupled across a disc element. The system electronics uses a 4-wire resistance technique - this measures the potential across the corrosion element with and without current applied. The former relates to the resistance of the element in combination with the sum of the thermals at the electrode/element interface; the latter relates only to the thermals. The latter potential is deducted from the former, both for the test element and for a high-precision standard resistor, and an accurate resistance value for the probe element is generated. In addition, the thermals (generated from the sum of the opposing potentials on either side of the test element) give a measure of any small temperature gradients across the element; this is used to calculate an exact average temperature of the corrosion element. The resistance of the corrosion element is temperature compensated using software and the element thickness and corrosion rate at 20°C is calculated as follows:

$$R_t = R_{293} [1 + \alpha (t - 293) + \hat{\alpha} (t - 293)^2] \quad (1)$$

Where:

$$\begin{aligned} R_t &= \text{Resistance at test temperature, ohms.} \\ R_{293} &= \text{Resistance at 20°C (293K), ohms.} \\ \alpha &= \text{Temperature coefficient of resistance 1, K}^{-1}. \\ \hat{\alpha} &= \text{Temperature coefficient of resistance 2, K}^{-2}. \\ t &= \text{Test temperature, K.} \end{aligned}$$

Accurate determinations of  $\alpha$  and  $\hat{\alpha}$  may be made using laboratory test data by scanning through a range of temperatures. Alternatively, an improved determination may be made directly on the actual element in the plant and at the exact temperature of interest, by logging the small variations in temperature, around its set-point, with changes in resistance. The mean data may then be used to give the  $dR/dT$  value and thus the coefficients of resistance. In the case of a flat specimen, calculation of the remaining thickness at 20°C is made as follows:

$$D = \frac{\tilde{n} \times L}{W \times R_{293}} \quad (2)$$

Where:

$$\begin{aligned} \tilde{n} &= \text{Resistivity, ohms m.} \\ L &= \text{Element length, m.} \\ W &= \text{Element width, m.} \\ D &= \text{Remaining element thickness, m.} \end{aligned}$$

In the case of a tubular specimen a similar equation may be used.

## RESULTS

Examples are given in this section of monitoring data resulting from fireside corrosion in combustors and steam generating boilers.

The first examples are from short-term corrosion tests in a combustor to assess the 'corrosivity' of high chloride coals [5]. A photograph of a 3mm SA-210 steel element flush probe installed in the furnace zone at a temperature of 404°C is shown in Figure 3. The probe became covered with coal ash within a few hours. The corrosion data from this probe is shown in Figure 5. The remaining thickness initially increased over the first 20 hours due to conditioning - the coal ash deposition initially results in a decrease in heat flux through the probe which caused its mean temperature (but not its set-point temperature) to decrease; this was reflected by a measured decrease in resistance and an apparent increase in thickness. Thereafter the probe showed a small but discernable corrosion rate during the 60 hr test.

A superheater probe containing a 0.8mm thick SA-230-T11 corrosion element was also installed in the combustor at a set-point temperature of 582°C, Figure 6. The elements were internally coated with a plasma sprayed Ni/Cr coating to resist against internal corrosion by the 'wet' process air at elevated temperatures. The results showed significant corrosion of the test element, ie 100  $\mu$ m during combustion of a high sulphur coal, Figure 7. This was most probably due to the formation of a nonprotective scale on the low alloy steel under these conditions. Tests on this superheater during firing of low sulphur fuels showed far less corrosion.

The final data originates from superheater tests carried out in a 350MW coal fired power generation boiler in Austria. This boiler had suffered high corrosion rates during its early life and its steam temperature had subsequently been reduced. This had resulted in a reduction in steam output and the loss of electricity generation from the boiler. A corrosion monitoring trial is currently in progress to determine corrosion rate as a function of operating temperature, burner firing, plant modification and feedstock. The VTER instrumentation comprised a 2A unit and the probes comprised 1mm thick T22 corrosion elements with a 0.4mm thick stainless steel type 316 liner. The resistance of the stainless steel is significantly higher than that of the low alloy steels and is taken into account during data processing.

These data at a temperature of 580°C showed a low corrosion rate of 2nm/hr, Figure 8. The corrosion rate gradually increased with temperature to show a corrosion rate of 70 nm/hr at a temperature of 650°C, Figure 9. These data showed some deviations, probably due to deposit formation and exfoliation during the test which could not be removed by temperature compensation. The temperature coefficients of resistance ( $\alpha$  and  $\hat{\alpha}$ ) may be derived from the mean  $dR/dT$  value which was measured on-site and in the actual boiler to calculate these corrosion rates, Figure 10. The logged data also include heat flux information and cooling air requirements to cool the probes which relate to the degree of fouling in the boiler. This test programme is continuing.

## **DISCUSSION**

Systems are now available to monitor the condition of elevated temperature process plant and on sections of plant which may be subject high heat fluxes [6,7]. The probes and instrumentation are now being used to monitor corrosion at metal temperatures up to 800°C and in gas streams of temperatures up to 1500oC. The measurement system has the capability of monitoring wastage due to corrosion, erosion and erosion-corrosion. Probes may incorporate a heat flux measurement capability to enable the efficiency of a heat transfer surface to be monitored.

In combustion plant, the VTER system may be used to optimise the operation of a furnace or boiler, ie trimming the excess air, use of lower/higher sulphur/chlorine fuels or altering combustion conditions. The VTER system may also be used to indicate the remaining life of heat exchanger tubes and to optimise the injection of boiler additives into the fuel. The systems are currently installed in a number of boilers in the UK, USA and in Europe.

The Gd T11 and T22 alloys have largely been replaced for superheater tubing in UK power stations although it is still widely used in Europe and the USA where superheater steam temperatures are somewhat lower. This is due to its poor resistance to corrosion resulting from combustion of coals with high sulphur and chloride concentrations as frequently found in the UK.

Developments are currently underway to further develop the VTER corrosion monitor with the use of AC signals (of various frequencies) in addition to the dc signal currently used. DC signals travel through the body of an electrically conductive element whereas ac signals travel through the surface layers. AC signals may be used to determine the 'degree of roughness' of a surface and therefore lead to an estimation of localised corrosion (pitting and cracking) on a test element.

## **CONCLUSIONS**

1. Systems are now available for monitoring corrosion at medium and elevated temperatures and under heat flux conditions either in-plant or alternatively in test rigs under laboratory conditions.
2. The VTER systems have been installed in furnace wall and superheater positions in both power generating boilers, black liquor boilers and combustors. They also have application in refinery overhead plant and in incineration systems.
3. A high sensitivity system which it is hoped will have the capability of monitoring corrosion rate in periods of less than 8 hours is currently being developed for EPRI.
4. It is anticipated that future VTER systems may incorporate variable frequency ac signals to give information about localised corrosion events.

## **REFERENCES**

1. Halstead, W.D. Progress Review No. 60: Some chemical aspects of fireside corrosion in oilfired boilers, J. Inst. Fuel, July 1970.
2. Davis, C.J., James, P.J. and Pinder, L.W. Combustion rig studies of fireside corrosion in coal fired boilers, Corrosion 97, New Orleans, Louisiana, USA, March 1997.
3. Latham, E.P., Flatley, T. and Morris, C.W. Superheater steam tube materials in PF plants, corrosion in coal conversion systems - conf. proc. London, 1982.
4. Farrell, D.M., Lee, M.J.B. Inspection and monitoring of fireside corrosion in coal fired boilers, UK Corr. 93, London, Oct. 1993.
5. Monroe, L.S. and Clarkson, R.J., Pilot Scale Evaluation of a High-Chlorine Illinois Basin Coal for Effects on Fireside Corrosion, Report SRI-ENV-94-346-8180, Apr 1994.
6. U.K. Patent No. GB2262608 Dec 1991.
7. USA Patent App. No. 990459, Dec. 1992.

## **ACKNOWLEDGEMENTS**

The authors express their thanks to the Electric Power Research Institute and Union Camp Corp. who supported this work. The authors also express their thanks to Larry Monroe (Southern Research Institute) for his assistance with the VTER on-site tests.

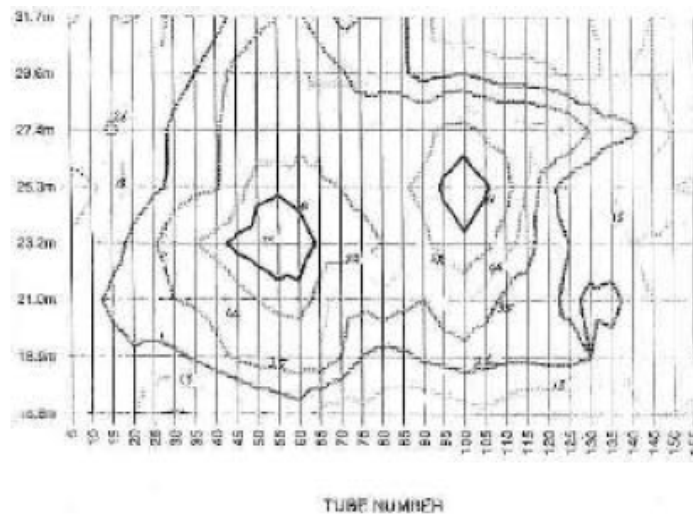


Figure 1: Contour map (ultrasonic survey) of the corrosion rate of a furnace sidewall in a 660MW coal fired boiler - rate given in nm/hr.



Figure 2: VTER superheater and furnace wall corrosion probes.



Figure 3: View of the VTER instrumentation and probe cooling system.





Figure 4: VTER furnace wall corrosion probe installed in the wall of a combustor.

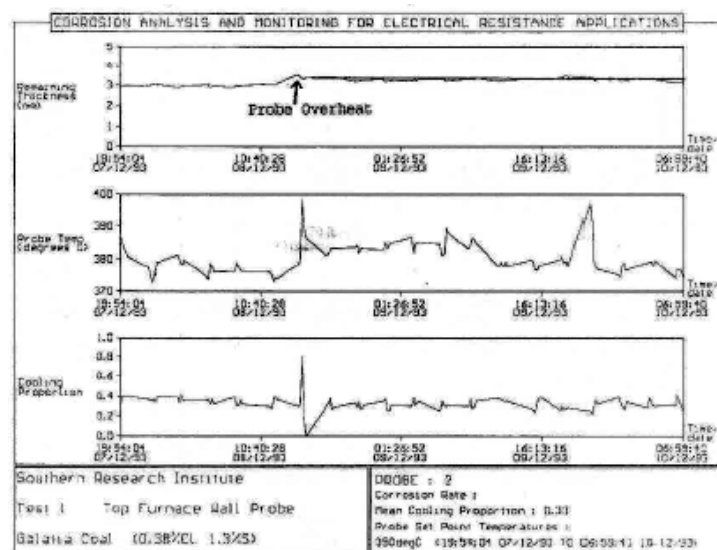


Figure 5: Corrosion data (remaining thickness) from the furnace wall corrosion probe.

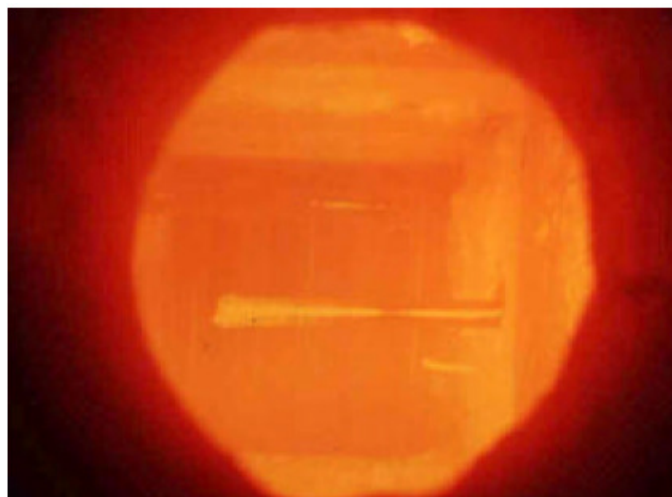


Figure 6: VTER tubular corrosion probe installed in the superheater of a combustor.

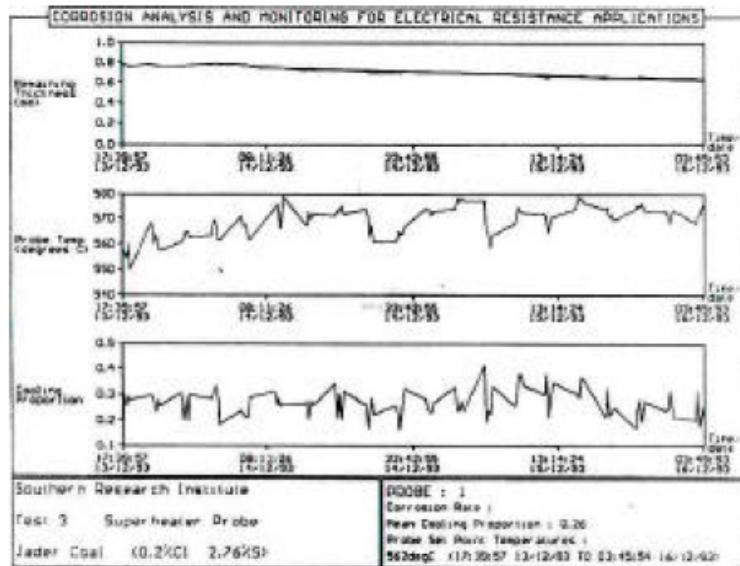


Figure 7: Corrosion data (remaining thickness) from the superheater probe.

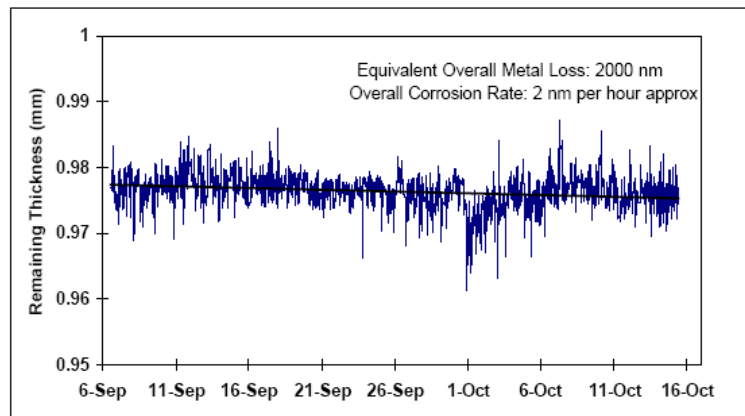


Figure 8: Corrosion data (remaining thickness) from a superheater probe installed in a 350MW coal fired boiler at a temperature of 580°C

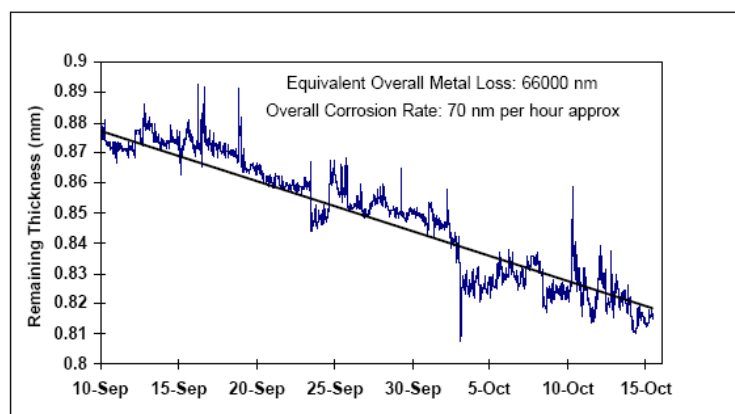


Figure 9: Corrosion data (remaining thickness) from a superheater probe installed in a 350MW coal fired boiler at a temperature of 650°C.

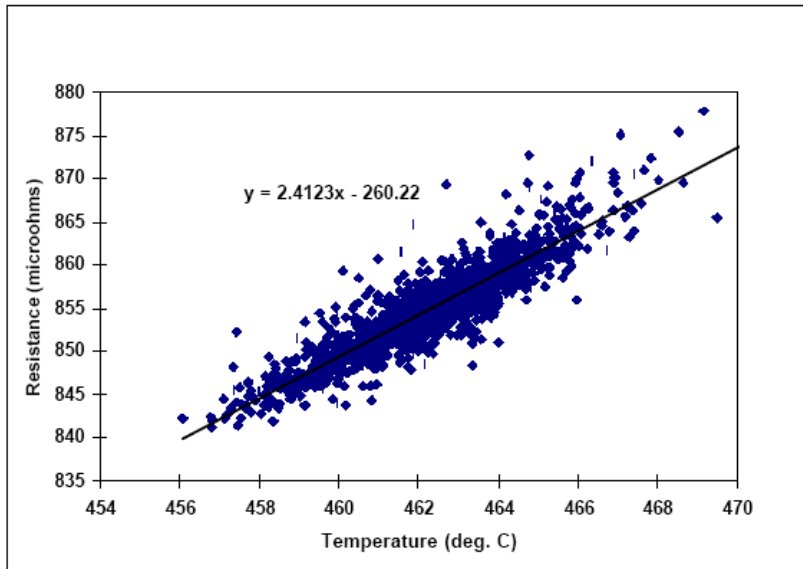


Figure 10: Typical values of  $dR/dT$  measured directly from small temperature fluctuations of the probe inserted in a boiler - this is used to calculate corrosion rates.