Estimation of Steam-Side Scale Growth in Ferritic Alloy Boiler Tubes of Coal-Fired Power Plant

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Abstract. Coal remains to be considered as one of the future major energy sources. However, the formation of steam-side oxide scale as a result of the oxidation process during the steam power plant operation has been widely known to be a serious main root cause, leading to some risks/consequences. This paper presents a simple incremental method to determine the oxide scale growth in the ferritic alloy boiler (reheater and superheater) tubes for a given period of time making use of a classical heat flow formula and the correlation of the oxide scale thickness versus the Larson Miller Parameter (LMP). The ferritic alloy tubes have been used worldwide, especially in the supercritical steam power plants. The presented method may be used as a supplementary monitoring tool for estimating the growth of steam-side oxide scales in boiler tubes.

Keywords: Coal, steam power plant, ferritic alloy, boiler tubes, oxide scale growth.

1 Introduction

Coal remains to be one of the attractive energy sources in the future [1]. However, the oxide scale formation is a well known issue in the steam power plant operation (particularly in reheater and superheater). Port and Herro [2] reported that boiler tubes containing significant scales cause overheating problems. The scales will decrease coolant steam flow, leading to excessive heating at the fireside. Heat transfer would be influenced by a convective film on the tube fireside. However, deposits and other materials on the fireside will result in a slight decrease in the temperatures across the metal wall. Whereas the phenomenon of heat transfer due to the presence of oxide scale at the steam-side is reversed. The scales at the steam-side will act as an insulator to the tube metal from the coolant effects of the steam, and it will decrease the heat transfer into the steam and causing the increase of metal temperatures.

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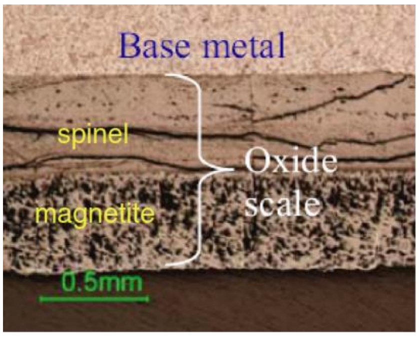

Fig. 1. Typical layers of oxide scale on the steamside of a tube at the elevated temperature [3].

The oxidation process resulting from the contact between the tube metal and steam for a period of time develops oxide scale layers (see **Figure 1**). For a prolonged exposure, the situation may get worse to potentially lead to a failure due the creep rupture. The steam-side scale formation in the superheater and reheater tubes is amongst the main causes to the boiler tube failures. A further consequence of the scale development will elevate the tube metal temperatures, causing the degraded strength of the tube alloy and finally leading to a tube rupture. It was reported that 10% of boiler tube failures in the steam power plants around the world are due to the creep ruptures initiated by the scale formations [4].

Clark et al. [5] presented a procedure utilizing computer codes for predicting the remnant life of SA213-T22 tubes used in the superheater and reheater regions. The oxide growth data in 2.25%Cr-1Mo alloy obtained by the ultrasonic method and measurements on tube geometries for different operating parameters were compiled. As reported by Viswanathan et al. [6, 7], Electric Power Research Institute (EPRI) proposed a methodology to support making decisions (run/replace) for tubes by combining the evaluations from the non-destructive and destructive testing. Next, Babcock & Wilcox Company, USA, developed a portable ultrasonic apparatus called Nondestructive Oxide Thickness Inspection System (NOTIS) for determining the steam-side oxide scale [8]. Measurements on a large number of superheater tubes become possible using NOTIS.

An accurate measurement of the steam-side scale growth of the boiler tubes (superheater and reheater) is greatly useful for predicting the remnant life of the tubes. French [9] described a method making use of an empirical formula correlating the oxide scale thickness versus the Larsen-Miller parameter [10] and the approximated temperature increase formulae for the scale growths in limited typical cases. Ennis and Quadakkers [11] elaborated the implication of the oxide scale growth in Cr steels exposed to steam on the remnant life of tubes. The porous oxide scales act as the thermal insulation layers causing overheating to the tube metal, eventually leading to a premature failure by creep rupture.

Viswanathan et al. [12] described three potential implications of the steam-side formation in a steam power plant: (i) the scale exfoliation causes the wall thinning, in turn, it leads to greater hoop stresses, resulting in creep rupture, (ii) the oxide scale has a low thermal conductivity that behaves as an insulator to the tube metal from the coolant steam, elevating the fireside metal temperature, thus accelerating the steam-side and fireside corrosion rates, (iii) during the shutdown of the steam power plant, the oxide scales can get exfoliated, thus it may obstruct the steam flow or if escaped from the tube-line can damage the steam turbine blades.

The ferritic alloy (up to 3% Cr) tubes have been used worldwide, particularly in the supercritical steam power plants. Purbolaksono et al. [13] proposed an estimation procedure for the oxide scale growth in the ferritic alloy tubes utilizing finite element method. In this work, a simple incremental method combining a one-dimensional heat flow formula and the data correlating the oxide scale thickness versus the LMP is presented to determine the oxide scale growth. No numerical modeling by the boundary element method (BEM) or the finite element analysis (FEA) or is needed.

2 Materials and method

2.1 Model of heat transfer

Figure 2 illustrates the phenomenon of heat transfer in boiler (superheater/reheater) tubes that is is considered as a steady-state flow with a forced convection condition on the steam-side by full turbulent fluid flow and a cross fluid flow over bare tubes on the fireside. The heat flow Q/A formula depicted in **Figure 2** can be expressed as

$$\frac{Q}{A} = \frac{T_{gas} - T_{steam}}{\frac{r_3}{r_1 . h_s} + \frac{r_3 \ln\left(\frac{r_2}{r_1}\right)}{k_s} + \frac{r_3 . \ln\left(\frac{r_3}{r_2}\right)}{k_m} + \frac{1}{h_g}} \tag{1}$$

where T_{gas} and T_{steam} (in ^{o}C), respectively, are the flue gas (fireside) and steam temperature, r_1 and r_3 (in mm) are the tube inner and outer radii, h_g and h_s (in W/m^2 ^{o}C) are the convection coefficients of the flue gas and the steam, k_m and k_s (in W/m ^{o}C), respectively, are the metal and oxide scale thermal conductivities, and r_2 is the metal/ scale interface radius. The variables T_1, T_2 and T_3 as depicted in **Figure 2** are, respectively, the temperatures at the steam-side, steam-side metal/scale and fireside.

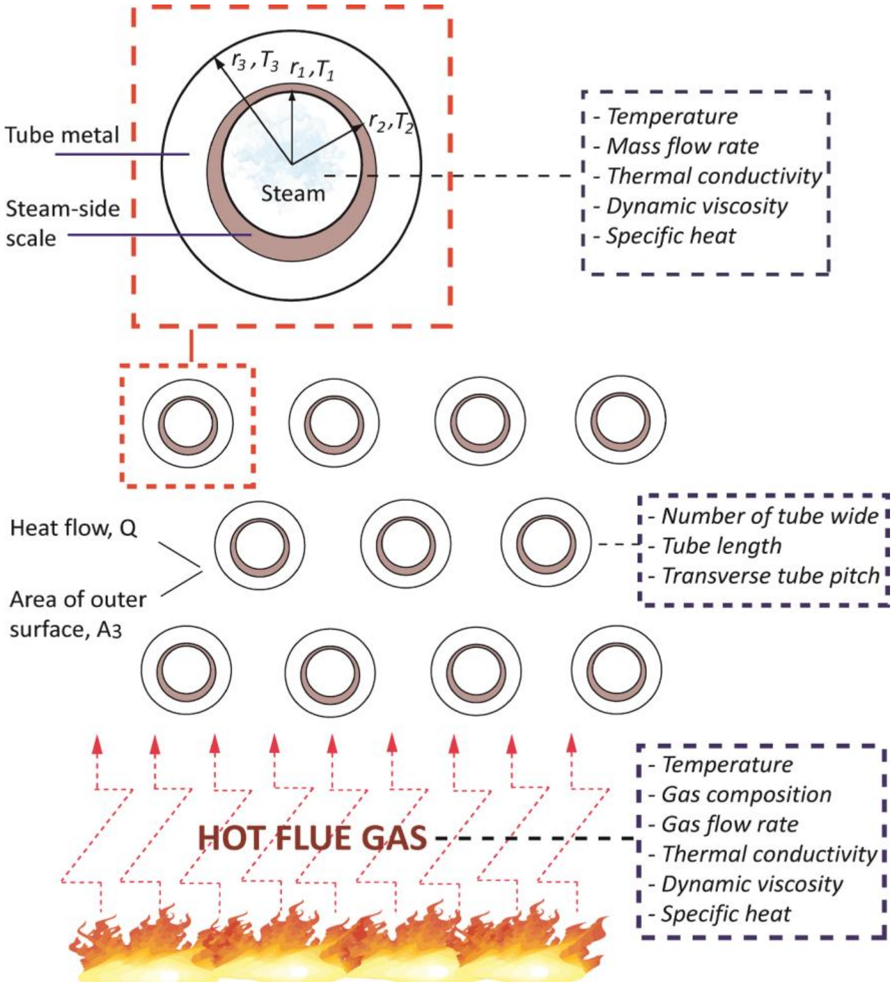

Fig. 2. Heat transfer diagram for the boiler tube arrangement (staggered) and steam-side scale formations in coal-fired power generation [14].

2.2 Oxide scale data

The corelation of the LMP versus the oxide scale thickness data for the ferritic alloy (up to 3% Cr) can be written as [10]

$$Log_{10}\left(\frac{X}{0.0254}\right) = C_1.LMP - C_2 \tag{2}$$

where the constant *C1* and *C2* are 0.00022 and 7.25, respectively, and *X* is the scale thickness in mm.

The Larson-Miller Parameter is a function of time and temperature as

$$LMP = \left(\frac{9}{5}T + 492\right)(20 + Log_{10}t) \tag{3}$$

where *T* is the temperature in degree Celcius and *t* is the service time in hours (*h*).

2.3 Physical data

In this work, the rate of 3600 kg/h for the steam mass flow is used. The heat transfer formulae refer to those presented by Purbolaksono et al. [13]. The simulations use a 50.8 mm OD (outer diameter) x 3.5 mm thick tube. For simplification and the purposes of this study, the oxide layer formed in ferritic steels is treated as to be all magnetite (Fe_3O_4). Steam, flue gas and related solid material properties from different sources [13] are used and shown in **Table 1**.

Table 1 Steam, flue gas and related solid material properties[13].

Properties of steam **at 4 MPa pressure**				
Temperature, °C	540	605		
Specific heat, J/kg °C	2161	2205		
Dynamic viscosity, N s/m^2	2.834 e-05	3.071 e-05		
Conductivity, W/m °C	0.0604	0.0662		
Convective coefficients, W/m^2 °C	2053.65	2118.21		
Tube wall properties				
Tube material	SA-213-T22			
Thermal conductivity,	34.606			
Fe_3O_4 ***iron oxide (magnetite)***				
Thermal conductivity	0.592 W/m C			
Flue gas composition		***Flue gas properties***		
Nitrogen, mole%	71.08	Temperature, °C	800	900
Oxygen, mole%	2.46	Dynamics viscosity, N s/m^2	0.0418	0.0442
Carbon Dioxide,	8.29	Specific heat, J/kg °C	3158	3220
Water, mole%	18.17	Conductivity, W/m °C	0.0410	0.0440
		Convective coefficients, W/m^2 °C	126.01	130.96
Tubes layout (staggered arrangement)				
Number of tube wide	32			
Gas flow rate, kg/h	400000			
Tube length, m	10			
Transverse pitch, m	2 x OD			

2.4 Estimation procedure

The procedure presented here adopts that proposed by Yeo et al. [14, 15]. The tube metal temperature and the thickness of oxide scale in the boiler tubes can be estimated using Equations (1) and (2). The procedure may be described as follows [15]:

Step 1: The steam temperature T_{steam} at the inlet of the boiler tube is set to a specified value. Initially, with free scale (X_0), Equation (1) is used to calculate the temperature on the tube steam-side that is considered to be the average temperature of T_{ave1}. For the service time of 1 h and 1000 h (see **Table 2**), Equation (2) is used to determine the oxide scale thickness of X_{1a} and X_{1b} using T_{ave1}. Next, the scale increase of ΔX_1 (=X_{1b} - X_{1a}) can be calculated to obtain a new scale thickness of X_1 (=X_0 + ΔX_1).

Step 2: The thickness of steam-side scale is used to determine the radius of steam-side metal/scale interface. Equation (1) is used to calculate the average temperature of T_{ave2} (the average temperature between the tube ID and the steam-side metal/scale interface). Based on T_{ave2}, the oxide scale thickness of X_{2a} and X_{2b} for the following service time of 1000 and 2500 h can be calculated using Equation (2). The oxide scale increase of ΔX_2 (=$X_{2b} - X_{2a}$) can be calculated to obtain a new scale thickness of X_2 (=$X_1 + \Delta X_2$). Repeat ***Step*** 2 for further incremental calculation until the final step time as shown in **Table 2**.

Table 2. The incremental service time used in the procedure.

Step	hours
1	250
2	500
3	1000
.	2500
.	5000
.	10000
.	20000
.	40000
.	60000
.	80000
.	100000
12	120000
13	140000
14	160000

3 Results and discussion

To demonstrate the accuracy of estimations, the comparisons are made with the actual data (**Figure 3**) and the estimations by using finite element modeling (**Figure 4**) reported by Purbolaksono et al. [12], that are the data from two actual cases from two different locations. The details of the data are presented in **Table 3**. The sample data for Case 1 was collected from the first row facing to the furnace/burner. The sample data for Case 2 was taken from the location a relatively away from the furnace/burner. The steam temperature of both sample tubes is around 576^{o}C with the flue gas temperatures were varying from 800^{o}C to 900^{o}C. The calculated convection coefficients h_s and h_g for the steam-side and fireside, respectively, are depicted in **Table 4**.

Table 3. The geometry of the sample tubes and scale thickness [13].

Case	Inner radius, m	Wall thickness, mm	Service time, h	Year of failure	Scale thickness, mm
1	0.0225	4	92,525	2001	0.68
2	0.0219	3.5	117,522	2003	0.58

Table 4. The calculated convection coefficients h_s (steam-side) and h_g (fireside) [13].

Case	h_s, W/m^2 ^{0}C	h_g, W/m^2 ^{0}C
1	1990.59	125.31
2	2053.65	126.01

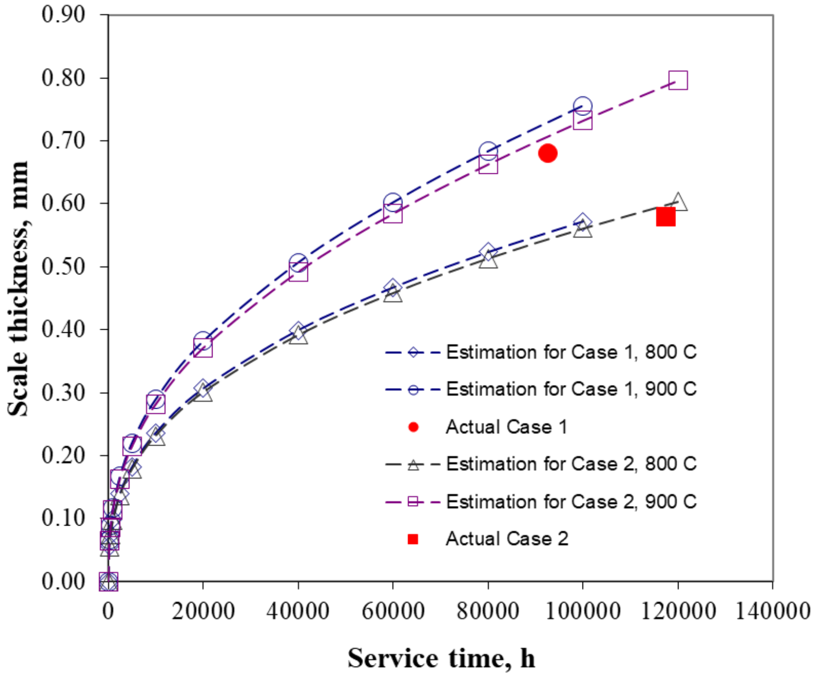

Fig. 3. The actual sample data reported in [13] and the oxide scale thickness estimations.

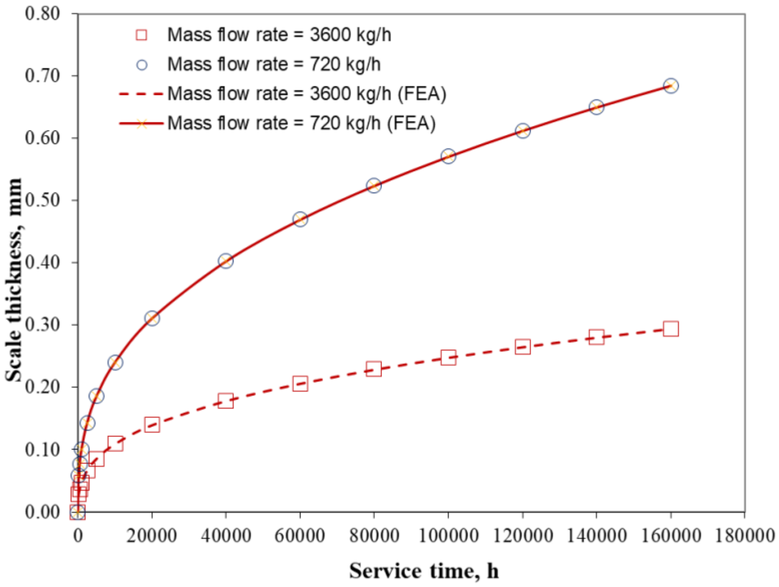

Fig. 4. The oxide scale thickness estimations for different steam mass flow rates by the FEA [13] and the presented procedure.

The the actual data and the calculated scale thickness are plotted in **Figure 3**. The oxide scale thickness estimation for the flue gas temperature of 900 °C is in agreement with of the actual data for Case 1. Meanwhile, the estimation for the flue gas temperature of 800 °C also fairly agrees with the actual data for Case 2. The comparisons between the previous results by the FEA modeling [13] and those by the present procedure are shown to be in very good agreement. To have better estimations, it is important to have a proper system to monitor the real-time heat transfer and operating parameters.

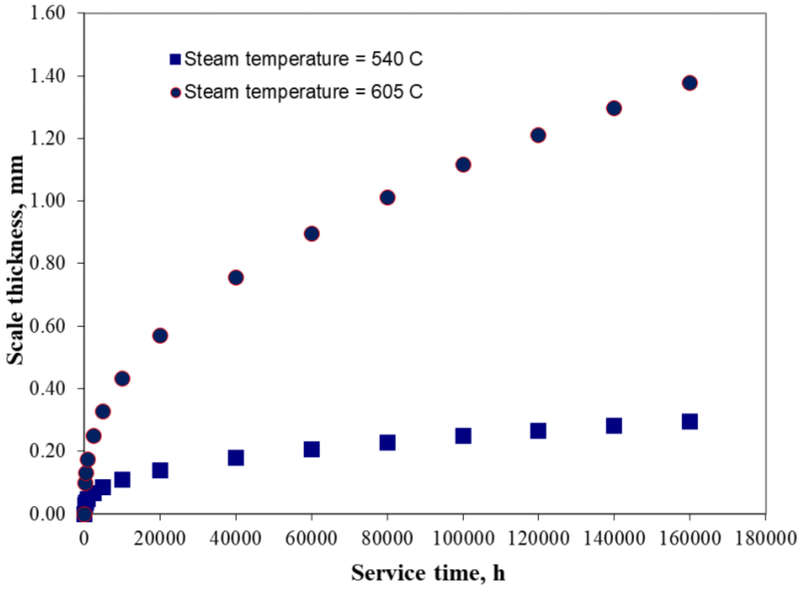

Fig. 5. The oxide scale stimations for different steam temperatures.

Figures 4, 5 and **6** show the effects of steam mass flow rate and steam and flue gas temperatures on the oxide scale growths. The steam mass flow rate determines the forced convection coeeficient. As can be seen from **Figure 4**, a lower steam lower mass flow rate causes the increase of the oxide scale growth. It simply means that the poor steam mass flow rate, e.g. a restricted steam flow, will lead to increase of the metal temperature, in turn it will accelerate the oxide scale growth. The estimations by the presented analytical formula and FEM via the incremental procedure are shown to be identical (**Figure 4**).

As can be seen from **Figure 5**, the steam temperature of 605 °C tends to have a higher oxide scale growth for given service hours. It indicates that the higher tube metal temperature causes the reduced oxidation resistance**. Figure 6** shows that a higher flue gas temperature results in a greater oxide scale growth. To have a more accurate estimation, the flue gas temperature shall be specified based on the actual location of the tube, for eample, the location of tube that is close to the furnace/burner.

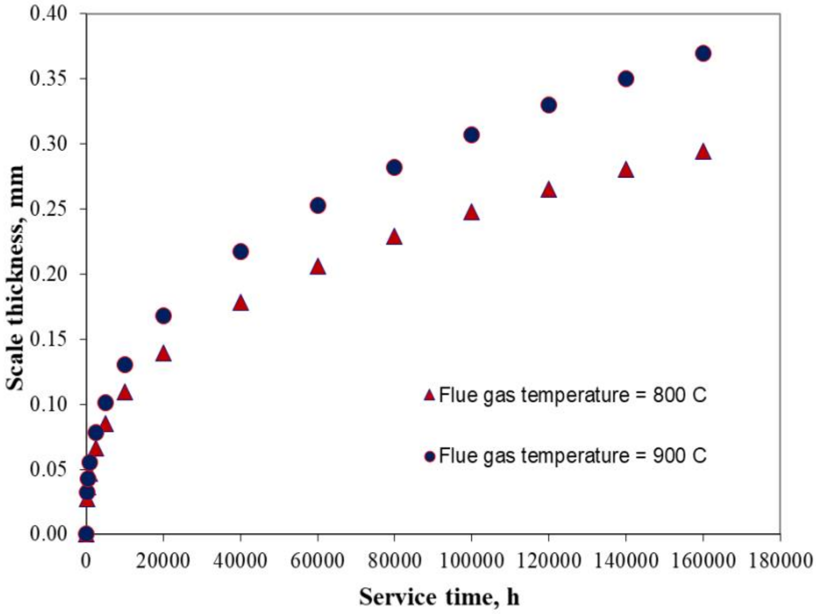

Fig. 6. The oxide scale stimations for different flue gas temperatures.

4 Concluding remarks

The procedure for predicting the oxide scale growth in the ferritic alloy boiler (superheater and reheater) tubes utilizing the LMP correlating to the scale thickness data and the heat flow formula was presented. The estimation procedure was simple and requires no numerical modelling such as using FEA and BEM. A few concluding remarks may be deduced as follows:

- Lower steam mass flow rate and higher steam and flue gas temperatures led to greater oxide scale growths.
- The estimations by the presented procedure were fairly in agreement with the actual data and found to be identical with those by the FEA modelling.
- To have more accurate calculations of the oxide scale growths, all the corresponding operating data and heat transfer parameters need to be well defined and specified.

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