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ASSESSMENT OF REMAINING LIFE OF SUPERHEATER AUSTENITIC STEEL TUBES IN OIL SHALE PF BOILERS

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Superheater surfaces in oil shale-fired steam boilers are subject to intensive corrosion,which causes thinning of tube wall and increased stresses. It leads to reduction of creep life of superheater tubes and results in the necessity of superheater repair every 3–4 years with replacement of up to 30–50% of austenitic tubes. The ability to predict accurately the remaining life of superheater tubes allows to reduce the amount and cost of repair. The method of assessment of remaining life for superheater austenitic steel tubes operating in conditions of intensive high-temperature corrosion is presented in this paper. The method is based on measurements of tube wall thickness and kinetic diagram of corrosion resistance of a particular steel.

Introduction

Estonian oil shale is an important local low-grade fuel, characterized by calorific value $Q_i^r \approx 8.4$ MJ/kg, ash fraction $A^d \approx 51.3\%$ and moisture content $W_i^r \approx 11.7\%$. The content of sulfur in the feed oil shale is 1.76% and that of chloride – 0.75%. Nearly all Estonian national electricity (95%) is produced at two major power plants, Balti and Eesti, by using oil shale PF and CFBC boilers. About $10 \cdot 10^6$ tons of oil shale are consumed per year to produce $8 \cdot 10^6$ MW·h electricity.

Estonian oil shale is one of the fossil fuels of most complicated composition. In the PF process inorganic matter yields several chemically active compounds leading to both fouling and accelerated high-temperature corrosion of superheater and reheater tubes. This is mainly due to the presence of KCl. Periodic removal of ash deposits from high-temperature heating surfaces accelerates the corrosion process. To mitigate intensive

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corrosion of tubes in oil shale boilers, temperatures of main and reheat steam have been reduced from design 540 °C to 515–525 °C.

Accelerated corrosion of tubes of heating surfaces in PF oil shale boilers results in the necessity of shutdown of boilers for the major overhaul including replacement of a significant part of superheater tubes every 3–4 years (or 25–30 thousand hours of operation). For example, after three years of operation of boilers TP-67 and TP-101, it is necessary to replace 1900–2700 sections of perlitic tubes (that makes 65-85 tons), and about 600 sections of austenitic tubes (3–5 tons or 30–50% of their total mass). Selection of the tubes subject to replacement is generally realised basing on the results of measurements of tube wall thickness. If wall thickness of a tube will not satisfy the requirements for strength properties during a forthcoming operational campaign, the tube should be replaced. In other words, if remaining life of a particular tube, determined on the basis of the wall thickness measurement and supposing the same corrosion rate, is exhausted before the next scheduled repair, the tube should be replaced at once. Thus the increasing of accuracy of estimation of remaining life allows to avoid unscheduled outages due to tube failures, to optimise frequency of inspection and to reduce amount and cost of repair.

Method of remaining life assessment

The prediction of the remaining life of heating surfaces is based on calculation of allowable reduction of tube wall thickness. Firstly the minimum required wall thickness of tubes should be calculated as follows [1]:

$$S = \frac{p \cdot D_i}{2f \cdot z - p}\text{, mm} \tag{1}$$

where:

p – steam pressure inside the tube, MPa;
D_i – inside diameter of the tube, mm;
f – design stress, N/mm^2;
z – joint coefficient, (for seamless pipe z=1).

Allowable reduction of the wall thickness can be obtained as [2]

$$\Delta S_{allowable} = \frac{S_0 - S - \Delta S_{igc}}{1.3} - 0.1\text{, mm;} \tag{2}$$

where:

S_0 – initial thickness of the wall, mm;
ΔS_{igc} – intergranular corrosion depth (for austenitic steels ΔS_{igc}= 1, for martensitic and ferritic steels ΔS_{igc}= 0), mm;
1.3 – safety coefficient (accounts the difference in corrosion depth along the perimeter of the tube);
0.1 – loss of wall thickness due to polishing of tube surface, mm.

Design stress in the creep range is a function of operating time and temperature. The longer is operating time, the less is design stress, and the more is minimum required wall thickness of the tube (e) and hence the less is allowable thinning of the tube ($\Delta S_{allowable}$). Thus, dependence of design stress on time should be generally taken into account in assessment of remaining life.

The next step in the prediction of remaining life is estimation of wall loss due to high-temperature corrosion of the outside (fire-side) and inside (steam-side) surfaces of the tube. Fire-side corrosion depth of the tube is a function of operating time τ, ash characteristics, grade and temperature of the metal and amount of periodic cycles of partial or complete destruction of the oxide scale m (that sharply increases corrosion rate). Steam-side corrosion depth of the tube depends on operating time τ, grade and temperature of the metal.

At the first stage of the estimation of wall loss the fire-side (on the outside surface of the tube) corrosion depth under the layer of a stable ash deposit $\Delta S'$, is calculated by the following equation:

$$\ln \Delta S' = \alpha - \beta T^{-1} + (\gamma + \varepsilon T) \ln \tau , \qquad (3)$$

where:

T – metal temperature, K;

τ – time, h;

α, β, ε, γ – coefficients depending on ash characteristics of fuel, grade and temperature of metal and generally determined experimentally. Coefficient ($\gamma+\varepsilon \cdot T$) is defined as exponent of the corrosion process.

The coefficients in equation (3) in each particular case are to be determined on the basis of laboratory experiments carried out in conditions as close as possible to real operating conditions. The results of laboratory experiments of some austenitic steels under the impact of oil shale ash deposits are presented in [3].

Industrial experiments have shown that shutdown of a boiler and cleaning of heating surfaces from external ash deposits additionally accelerate the corrosion process by partial or complete destruction of the oxide scale. At the second stage accelerating influence of periodic destruction of the oxide scale on corrosion depth is taken into account that, according to [4], can be obtained as:

$$\Delta S_o = [1 + \xi \cdot (B \cdot m^{1-n} - 1)] \cdot \Delta S' \qquad (4)$$

where:

ξ – degree of periodic destruction of the oxide scale;

B – coefficient taking into account the influence of the initial stage on the whole corrosion process;

m – number of periodic destructions of the oxide scale;

$\Delta S'$ – corrosion depth under the layer of a stable ash deposit according to equation (3), (without destruction of the oxide scale).

Corrosion depth of the internal surface of the tube (in the steam medium) ΔS_i is calculated by using empirical equation similar to (3).

So, the total corrosion depth of the tube is:

$$\Delta S = \Delta S_o + \Delta S_i \text{, mm.} \tag{5}$$

Prediction of remaining life of tubes includes drawing a kinetic diagram of corrosion resistance of a steel according to (5) (for various numbers of periodic destructions of the oxide scale $m = \tau/\tau_0$, where τ_0 – period between destructions of the oxide scale). Also the line defining the allowable reduction in tube wall thickness depending on operating time should be plotted in the diagram. Such a diagram for austenitic steel 12Cr18Ni12Ti (metal temperature $T = 580$ °C, chlorine content of oil shale ash – 0.5%) is presented in Fig. 1. Then the values of corrosion depth of the tubes (determined on the basis of wall thickness measurement) should be shown in the diagram. Ideally the point of the real value of corrosion depth should be on the line of corrosion depth prediction depending on time at point A_1 and corresponding operating time τ_1 (Fig. 1). In this case the point A_2 and corresponding time τ_2 define the lifetime of the tube (or the time when the tube wall thins to its maximum allowable value $\Delta S_{allowable}$), and (τ_2-τ_1) gives us remaining life of the tube.

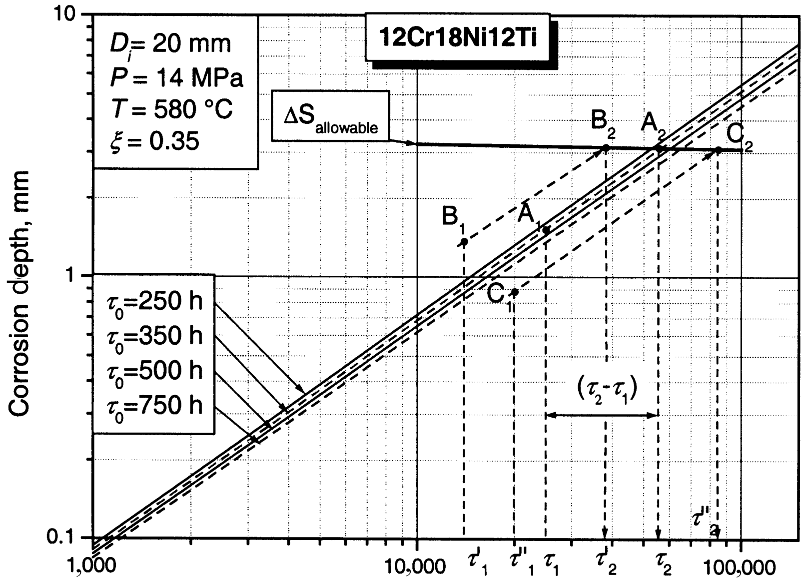

Fig.1. Diagram of prediction of remaining life of austenitic steel 12Cr18Ni12Ti in an oil shale PF boiler.

If the actual operating time τ'_1 is less than the predicted time (that could be caused by the difference between calculation and actual operating conditions of the tube), in order to determine the remaining life, the line from point B_1 parallel to the line of corrosion depth prediction should be drawn. New point B_2 defines the lifetime of the tube, and the remaining life, in this case, is (τ'_2–τ'_1). Similarly the remaining life should be determined if actual operating time is longer than predicted time, point C_1. In this case, the remaining life is equal to (τ''_2–τ''_1).

Prediction of remaining life of tubes of austenitic X8CrNiNb1613 steel in an oil shale PF boiler

Several tubes ∅31.8×6.3 manufactured from austenitic X8CrNiNb1613 steel were installed in the superheater of the oil shale PF boiler No. 3A at Eesti Power Plant. Wall thickness of these tubes was measured after 24,700 hours of operation (Table 1). During industrial tests the period between destructions of the oxide scale was τ_0 = 240 hours, and the mean temperature of metal of examined tubes was 511 °C. Mean temperature of the metal was calculated on the basis of mean temperature of steam in places where the investigated tubes were installed. However, temperature of metal of some tubes can be 40-50 °C above the mean temperature due to nonuniform heat flux along the superheater and irregularity of flow rate of steam inside the tubes. Thus, in further prediction of remaining life temperature of the metal was taken at the range of 511-560 °C.

Table 1. **Corrosion depth of the tubes in the superheater of the oil shale PF boiler No. 3A at Eesti Power Plant**

Platen number	Tube number	Height, m	Corrosion depth, mm
10	44	23.8–29.8	0.45
11	38	27.5–29.8	1.2
12	31	29.8–34.8	0.3
14	42	27.8–34.8	0.5
15	44	25.8–34.8	0.38
17	30	27.8–29.8	0.37
18	35	27.8–29.8	0.78
20	41	27.8–29.8	0.35
22	32	27.8–31.8	0.5
23	28	23.8–25.8	0.46

Earlier investigations [5] have established that the oxide scale on X8CrNiNb1613 steel loses its adhesion properties, the film becomes loose and porous and, in the presence of oil shale deposits, it consists of several layers. It leads probably to total destruction of the oxide scale in every cycle of cleaning heating surfaces from deposits and shutdowns of boiler. According to [5] the degree of periodic destruction of the oxide scale of X8CrNiNb1613 steel could be $\xi = 1$. This value has been used in further prediction of remaining life.

Design stress of X8CrNiNb1613 steel was determined according to [6]. The minimum required thickness of the wall and allowable thinning of the tube wall calculated according to (1, 2) are presented in Table 2.

Table 2. **Design stress, minimum required thickness of the wall and allowable reduction of the wall thickness of tubes manufactured from X8CrNiNb1613 steel**

Steel grade	X8CrNiNb1613	
Tube size, mm	∅31.8×6.3	
Steam pressure, MPa	14	
Metal temperature, °C	560	
Operating time, h	10^4	$2 \cdot 10^5$
Design stress, N/mm^2	121.3	92
Minimum required thickness of the wall, mm	1.15	1.54
Allowable reduction of the wall thickness, mm	3.71	3.40

The diagram of estimation of corrosion depth and prediction of remaining life of austenitic X8CrNiNb1613 steel is presented in Fig. 2. The diagram takes into account both fire-side corrosion (under influence of oil shale deposits) and steam-side corrosion (corrosion depth in the steam medium was estimated according to equation for austenitic 12Cr18Ni12Ti steel [7]). As mentioned above, temperature of the metal was not measured directly and therefore the diagram was made for two temperatures – 511 °C and 560 °C. Thereafter the line defining the allowable reduction of the tube wall thickness $\Delta S_{allowable}$ (calculated according to (1)-(2)) depending on operating time τ was plotted in the diagram. Since the exponent of the corrosion process of X8CrNiNb1613 steel does not depend on temperature [2], the lines of corrosion prediction for different temperatures are parallel. In view of such uncertainty of temperature determination, predicted remaining life can vary from 90 to 190 thousand hours. It should be mentioned that the predicted data of corrosion depth are quite close to the data obtained at testing the boiler, but scattering of prediction results is too high to use it in the practice. Estimating remaining life on the basis of actual corrosion depth data determined on the basis of measurement of tube wall thickness could increase the accuracy of prediction. In this case actual conditions of corrosion such as metal temperature, aggressiveness of corrosive environment, the degree of oxide scale destruction etc. are taken into account integrally. Thus the use of the proposed method allows significantly to increase the accuracy of prediction of remaining life thanks to eliminating uncertainty of corrosion conditions. So the lines from "reference points" of real values of corrosion depth parallel to the line of corrosion depth prediction were drawn (Fig. 2). The points, where these lines cross the line of allowable thinning of tube wall, define the remaining life of tubes. As it could be seen in Fig. 2, in particular case corrosion depth of the most damaged tube (tube No. 38, platen No. 11) will achieve the allowable value about 50 thousand hours later. The remaining life of the tube No. 35, row No. 18 is about 80 thousand hours. For the rest the remaining life is more than 150 thousand hours. So, all of the investigated tubes could be operated till the next major overhaul.

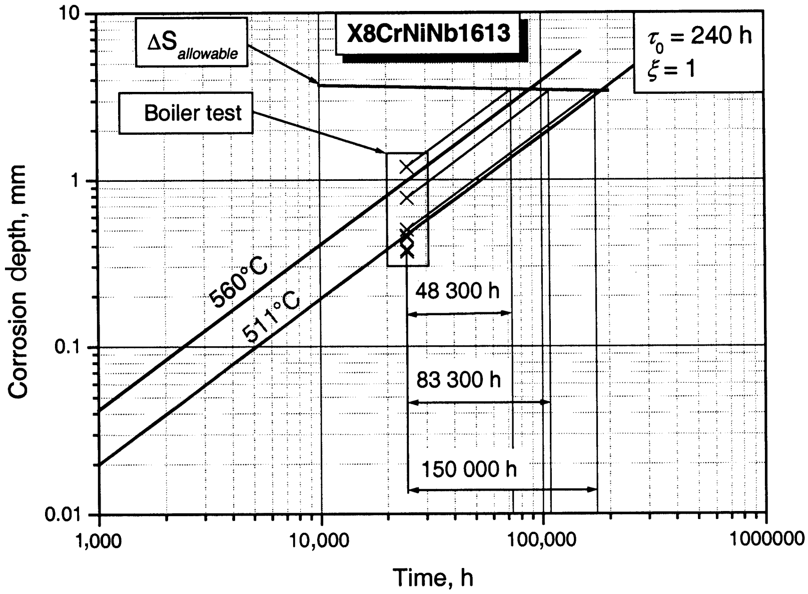

Fig. 2. Diagram of assessment of remaining life of austenitic steel tubes (X8CrNiNb1613 ∅31.8×6.3) of the superheater of the oil shale PF boiler No. 3A at Eesti Power Plant

Conclusion

1. The results of long-term industrial tests of tubes manufactured from X8CrNiNb1613 austenitic steel according to DIN 17459 in the superheater of an oil shale PF boiler are close to the results obtained at testing of widely used austenitic steel 12Cr18Ni12Ti (ТУ 14-3-460-75 [2]). The main feature of austenitic tubes is the loss of oxide scale adhesion and its spalling in the presence of oil shale deposits on the tubes of the boiler that sharply accelerates the

corrosion process in comparison with laboratory experiments. It leads to the fact that corrosion depth could be 1.2 mm after 25 thousand hours of operation and the remaining life of the tube from X8CrNiNb1613 steel (that, according to DIN 17459, is supposed to be operated at least for 100 thousand hours) would be only 50 thousand hours.

2. Assessment of remaining life according to the suggested method which is based on measurements of tube wall thickness allows to increase essentially the accuracy of estimation and hence to avoid unscheduled outages due to tube failures and reduce amounts and costs of repair.

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