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Modelling of flexible boiler operation in coal fired power plant

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Abstract. Polish energy market is comprised of numerous aged 200 MW_e coal units. In order to work in changing market conditions - with growing number of renewable energy sources as well as new supercritical coal power plants - these units will be forced to work with extended flexibility. It results in ability to change load level faster and to extend their designed load range. It is both challenge for turbine and boiler part of the power plant, designed to work as the base load unit. Study presented in the article was performed in order to analyse behaviour of one 225 MW_e coal unit, working in extended load range (from 90 – 225 MW_e), by using Ebsilon®Professional software. The major goal of study, was to verify crucial operation parameters in the load range below designed technical minimum (90-135 MW_e). Two models – turbine part and boiler part - were prepared and validated, using reliable data from test campaign performed in-situ. In this article, the boiler behaviour is comprehensively described with indication of issues that must be addressed when considering boiler operation in load range below its technical minimum.

1. Introduction

Polish energy system has been historically based on coal fired power plants. Both type of coal – bituminous and sub-bituminous are utilized, depending on the region of Poland. The majority of units that were built in the 70's and 80's have electrical power output of about 200 MW_e and are equipped with pulverized coal boilers with drums [1]. Those units are currently a matter of discussion due to their advanced age as well as significant share of energy market. Approximately 30 units have potential for renovation, which would add roughly 900 TWh of energy to the market until 2055 [2]. However, if aged coal fired units could operate for next decades, they must be able to work in different market condition than they were designed for. In the market with growing number of intermittent renewable energy sources, they have to become more flexible in operation [3-7]. There are two aspects of flexibility – one is ability to change load as quickly as possible and the second is ability to extend the possible load range[3,6]. Considering the latter, boilers of 200 MW_e class units constitute a large limitation, as they can typically decrease load only to 60%. The paper presents outcomes of boiler simulation at load decreased to 40%, which is below its designed minimum [3], and discusses issues related to 200 MW_e class boiler operation in new load regime. Modelled pulverized coal (PC) boiler OP-650 presented on Figure 1, has nominal steam capacity equal to 650 t/h and is equipped with 5 superheaters (SH), 2 reheaters (RH) and double economizer (water heater - WH). Firing system with fuel and air staging (in order to mitigate NOx emission) is located on the front wall. Boiler is equipped with single drum and natural water circulation as well as six mill units and three rotating air preheaters. Model was prepared using Ebsilon®Professional software [8] and validated with data from in-situ test campaign, performed on one 225 MW_e unit. During the campaign, the unit load was decreased from 390 t/h of steam and 135 MW_e (60%) to 260 t/h of steam and 90 MW_e (40%). Crucial

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parameters from power plant operator point of view are presented and discussed below, with analysis of potential consequences that may occur in decreased minimum load operation.

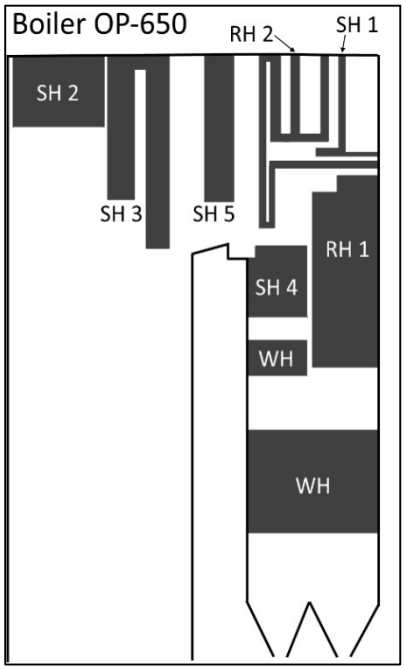

Figure 1. Boiler OP-650 with heat exchangers. SH – superheater, RH – reheater, WH – water heater.

2. Simulation

Ebsilon®Professional [8] is an advanced software for thermodynamic processes modelling with graphical interface. It is comprised of different elements that can be defined and adjusted to variety of models. Software allows to create an accurate models of power plants, including both the boiler and turbine part. Modelling of the former is discussed in this chapter.

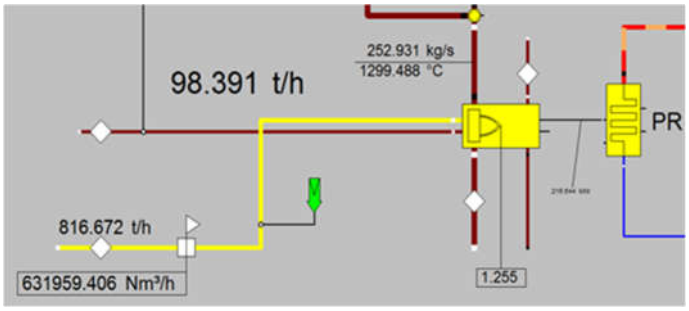

Figure 2. Graphical illustration of combustion chamber and evaporator model in Ebsilon®Professional.

Figure 2 shows the model of combustion chamber and evaporator (PR) with results of flue gas temperature at the outlet and mass flow (1292,3 °C and 247,9 kg/s) at the outlet of combustion chamber, amount of heat transferred to the evaporator (217,5 MW), air excess ratio calculated upstream the air preheater (1,255) and inputs: fuel and air delivered to combustion (98,7 t/h of coal and 618012 Nm3/h). Fuel composition is another important input variable – coal with roughly 51,5% of Carbon, 5,5 % of Sulphur and 27% of ash(as-received) and Lower Heating Value (LHV) equal to 20572 kJ/kg was taken into consideration. Results were calculated for nominal load (225 MW_e and 650 t/h of steam), which in the software states as Design Mode. In order to simulate part load operation, the Off-Designed Mode is used. Combustion model presented on Figure 2 is simplified due to the fact, that it does not take into account air and fuel staging (present in reference boiler). This

affects results for air excess ratio in the combustion zone as model calculates higher value than is present in real conditions (1,2 compared to 1,1 in the full load). Air excess ratio calculated upstream the air preheater (depicted on Figure 2) is consistent with the measurements. Major reason for implementing air and fuel staging combustion is NOx mitigation, however NOx emissions level was not under consideration in the project.

Figure 3 shows the model of one superheater stage (2'), which is connected to the component C. The latter represents area of the boiler, from which heat is taken to the superheater. Dimensions (height, width and depth) of the area can be defined in this component what requires a good knowledge of modelled boiler construction. In the upper-right part of the Figure 3, there is a system for steam cooling depicted. Amount of water that is injected to the pipeline can be controlled by defined temperature in the up-stream, which corresponds to the actual system installed in the boiler. Figure 4 shows the model of air preheater, which is used to recover heat from exhaust gas at the boiler outlet. Some important results that the model calculates are amount of oxygen in flue gas at the inlet of air preheater (4,5%), temperature of air at the preheater outlet (286,16 °C) and temperature of flue gas at the preheater outlet (154 °C). The last parameter is important for flue gas treatment installations, like Electrostatic Precipitator (ESP) or Flue Gas Desulphurization (FGD). The same type of boiler could also be equipped with DeNOx SCR technology, which would be located upstream the air preheater. All mentioned technologies are sensitive to the flue gas temperature.

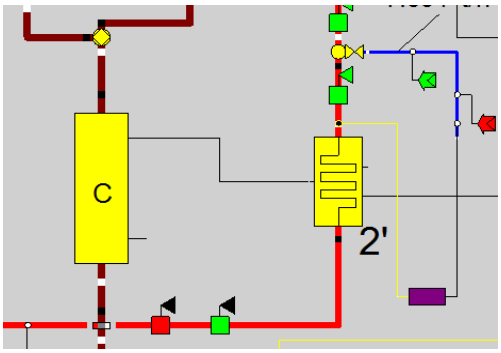

Figure 3. Graphical illustration of a superheater model in Ebsilon®Professional.

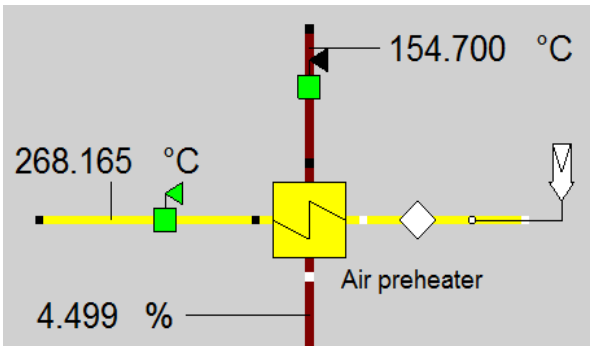

Figure 4. Graphical illustration of air preheater model in Ebsilon®Professional.

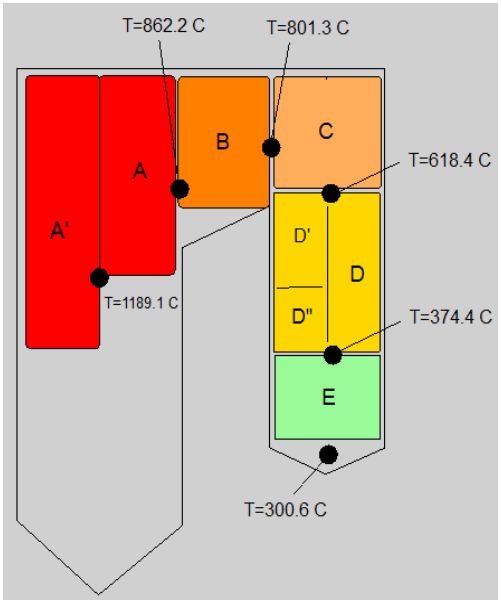

Figure 5. Graphical illustration of flue gas temperatures in the boiler for 60%. load.

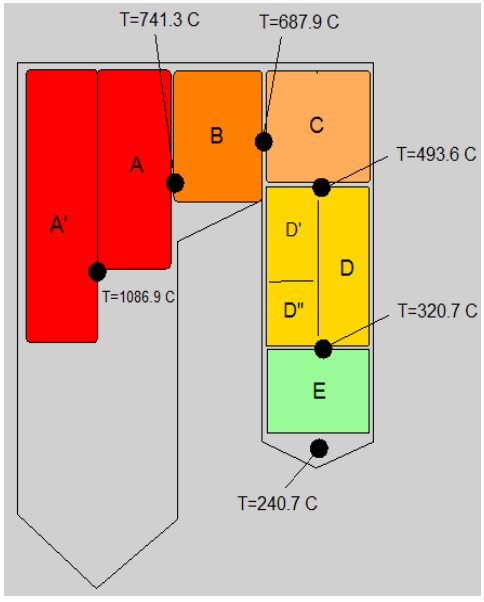

Figure 6. Graphical illustration of flue gas temperatures in the boiler for 40%. load.

3. Results

Figures 5 and 6 show flue gas distribution along the boiler as the outcome of modelling. What can be observed is that difference in temperature values drop significantly between minimum load (Figure 5) and decreased minimum load (Figure 6). For instance, temperature at the inlet of second pass decreases from 801,3°C to 687,9°C whereas tail end temperature, which is also temperature at the inlet of air preheater, decreases from 300,6°C to 240,7°C. Areas of boiler presented on Figures 5 and 6 (A, B,°C etc.) stand for regions of boiler, from which heat is taken to particular heat exchangers, thus presented temperatures locations should be treated as average from these regions and not as exact points in the boiler.

Figure 7 compares amount of heat power Q taken by each heat exchanger in the boiler for three load levels: 100%, 60% and 40%. Superheaters SH2, SH4 and SH5 do not show power drop between 60% and 40% load. Significant drop in power is visible for evaporator and superheater SH3, moderate drop for superheater SH1, reheaters RH1, RH2 as well as economizer WH. Figure 8 compares difference in temperature ΔT at the inlet and outlet of each heat exchanger in the boiler for three load levels: 100%, 60% and 40%. It can be seen that the superheaters SH2 and SH4 reveal significant difference between 40% load and 60% load. Interestingly, for reheaters RH1 and RH2 the value of ΔT at 40% load looks similar to this at 100% load, whereas value for 60% load is significantly different.

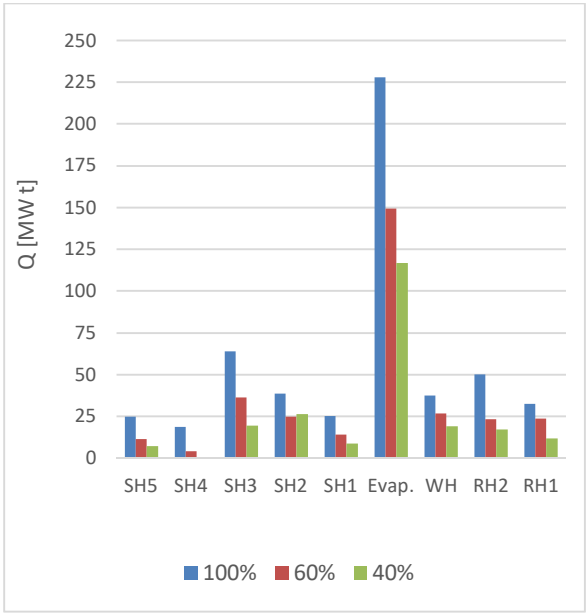

Figure 7. Comparison of power Q taken by heat exchangers for different load levels: 100%, 60% and 40%.

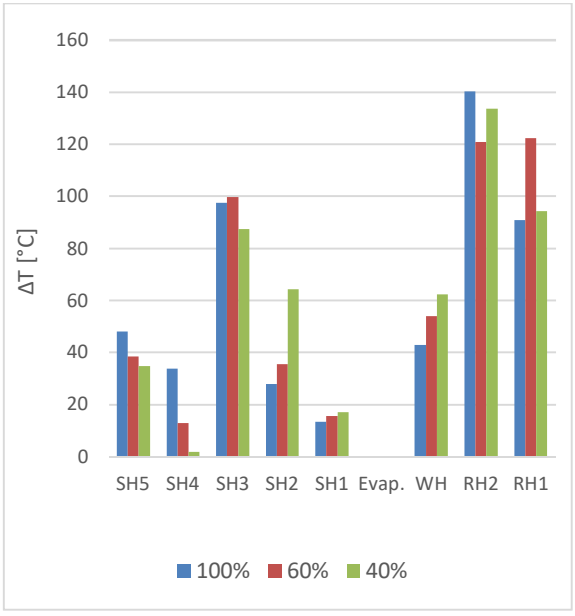

Figure 8. Comparison of steam temperature difference ΔT at the inlet and outlet of each heat exchanger for different load levels: 100%, 60% and 40%.

Figure 8 compares difference in temperature ΔT at the inlet and outlet of each heat exchanger in the boiler for three load levels: 100%, 60% and 40%. It can be seen that the superheaters SH2 and SH4 reveal significant difference between 40% load and 60% load. Interestingly, for reheaters RH1 and RH2 the value of ΔT at 40% load looks similar to this at 100% load, whereas value for 60% load is significantly different. Figure 9 presents gross efficiency of entire unit in function of electric power output. It can be observed that the decrease in efficiency between 135 MW_e and 90 MW_e (60% and 40% load) is much more significant that the decrease in efficiency between 225 MW_e and 135 MW_e (100% and 60% load). Figure 10 shows some other important parameters – temperature of live and reheated steam as well as flue gas temperature at air preheater outlet in different load levels. The analysis reveals that reheated steam temperature undergoes a massive drop, when load changes from 60% to 40%. This is also true for live steam temperature - fall is less severe though.

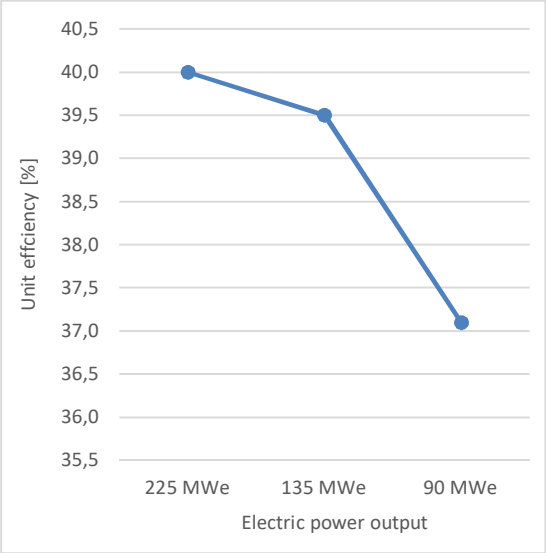

Figure 9. Reference unit gross efficiency in different load levels.

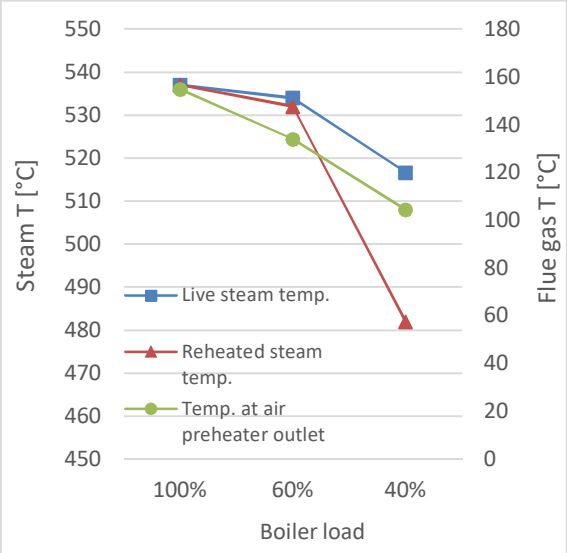

Figure 10. Temperatures of live and reheated steam and flue gas at the air preheater outlet in the function of boiler load (100%, 60% and 40%).

4. Discussion

What can be concluded from results presented in chapter 3, is that some parameters change significantly when boiler load moves from 60% to 40% and it can bring about various consequences. Figure 10 compares steam temperatures at the boiler outlet. Live steam and reheated steam temperatures in 60% load operation are above 530°C . In 40% load however, temperatures decrease to 516°C and 482°C respectively. The significant difference is derived from the fact, that boiler was not designed to work with 40% load. However, despite very low steam temperatures, boiler is able to sustain combustion with three mills in operation and without auxiliary oil burners, what was confirmed during in-situ tests.

What is also depicted on Figure 10, is that flue gas temperature at the air preheater outlet experiences linear drop from more than 150°C in 100% load to around 100°C in 40% load. Flue gas temperature is strictly correlated with corrosion and fouling issues - one of the major concerns for power plant operators is sulfuric acid (H_2SO_4) condensation. The dew point temperature of H_2SO_4 is typically in the range of 160-95°C. If the flue gas temperature drops below acid dew point temperature, acid vapor condensates and - by absorbing water vapor - acid solution is created. If its concentration is high (at flue gas temperatures roughly above 100 °C), condensation only occurs on fly ash particles boosting their stickiness. If concentration of acid solution drops below 60% (at flue gas temperatures roughly below 75°C), condensation becomes dangerous for heating surfaces [9-11]. Temperature of flue gas at the air preheater outlet is close to 100°C in 40% load, which imply risk of corrosion ash deposition on the air preheater surface [10]. The sulfuric acid itself is formed from reaction of sulfur trioxide SO_3 and water vapor in temperature roughly between 400°C and 200°C, therefore amount of formed H_2SO_4 depends on the content of these components in flue gas [9]. Amount of sulfur trioxide in flue gas is, in turn, determined by SO_2 to SO_3 conversion rate[12]. Another problem would be ammonium bisulfates (ABS) formation on the air preheater surface. This compound is formed due to reaction of ammonium escaped from SCR/SNCR installations and H_2SO_4. The formation of ABS is usually responsible for plugging air preheaters, thus it is highly undesirable from power plant operation point of view [13]. Temperature range for ABS formation is between 214°C and 252°C and dew point is equal to about 150°C [10,13]. Typically, air preheaters are protected against ABS by dedicated coating made at the cold inlet. However, according to results presented on Figures 4, 5, and 8, in 40% load area of ABS deposition can move towards the center of

air preheater. Therefore, current coating location may not be sufficient to protect the device in decreased minimum load scenarios. Another facility that is vulnerable for flue gas temperature is Electrostatic Precipitator (ESP). Its operation highly depends on dust resistivity which high value can bring about undesired back-corona effect. However, low load operation is beneficial at this point, due to decreased flue gas temperature which will effect in reduced dust resistivity [14]. On the other hand, there is still high risk of corrosion occurrence inside the ESP, due to low flue gas temperature.

Boiler slagging and fouling phenomenon depends on flue gas temperature as well. Slagging occurs in regions with temperature higher than 1000°C and is strongly correlated with amount of silica in the fly ash [15,16]. Silicates usually melts in temperature range between 1600-2000°C (depending on Si concentration) which is typical range of combustion zone temperatures in PC boilers [16,17]. Decreasing this temperature can possibly results in lower amount of melted silica and, in turn, reduced slagging phenomenon [17]. However, basing on performed modelling it is difficult to assess how much the temperature of combustion will decrease due to lower load level. In order to evaluate this with sufficient precision, more advance modelling techniques should be employed. Fouling, on the other hand, occurs usually in boiler regions with temperature below 1000°C [15-17], where components of fuel like alkalis and earth alkalis (K, Na, Ca, Mg) as well as chlorine and sulfur, combine and undergo phase changes creating deposit on the heat exchangers surfaces. By reducing load from 60% to 40%, the area of boiler that is vulnerable for fouling would shift upstream the flue gas path. Therefore, different heating surfaces would be affected in decreased minimum load than in minimum or nominal loads. What is more, in boilers equipped with SNCR technology, injection of reagent into the boiler should be able to adjust to new temperature window. Typically SNCR installation is comprised of several levels of injectors. Depending on measured flue gas temperature, different levels are activated in order to spray reagent in temperature as close as possible to the temperature of about 950°C, where NOx reduction achieves highest efficiency [18,19].

One of the project goals was to verify behaviour of measurements installed on the reference unit. However, there is significant level of uncertainty in obtained results, due to complexity of processes occurring in the boiler. What can be concluded, is that some measurements and calculation algorithms embedded in DCS start to deviate from model outcomes, when 40% load is analyzed. This potentially indicate need for measurement sensors calibration as well as for algorithms verification if operation in decreased minimum load is under consideration.

5. Conclusions

Modelling of 200 MW_e class boiler delivered some important information about its behaviour as well as potential issues related to operation in load regime that it was not designed for. Shifting from designed minimum load equal to 60% to decreased minimum load equal to 40% was examined. Flue gas temperatures, steam temperatures and power of each heat exchanger in the boiler were compared. In general, boiler operation is possible and combustion is sustained without usage of auxiliary oil burners, what was proved during in-situ tests. Ebsilon®Professional turned out to be a valuable software for boiler decreased load scenario simulations. From modelling outcomes, it can be derived that steam temperature values as well as flue gas temperature decrease significantly in 40% load comparing to 60% load. Low flue gas temperature can potentially bring about risk of corrosion occurrence on air preheater or ESP surfaces due to sulfuric acid condensation. In boilers equipped with de-NOx installations (SNCR or SCR), possibility of higher ammonium bisulfates precipitation should be also considered. Regarding superheaters fouling, different heating surfaces might be affected in 40% load level than in 60% load. For SNCR operation, optimal injection temperature window might also be shifted.

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[19] Daood S S, Javed M T, Gibbs B M and Nimmo W, "NOx control in coal combustion by combining biomass co-firing, oxygen enrichment and SNCR," Fuel ; **105**, pp. 283-292, 2013 Finally, crucial measurement sensors installed on the boiler should be verified if decreased minimum load operation is considered by power plant.