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Cost-effective flexibilisation of an 80 MW_e retrofitted biomass power plants: Improved combustion control dynamics using virtual air flow sensors

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ABSTRACT

As they deliver dispatchable renewable energy, biomass power plants are expected to play a key role in the stability of the future electricity grids dominated by intermittent renewables. Large-scale, biomass-fired power plants are often retrofitted from coal-fired plants. Such a fuel modification combined with decreasing pollutant emission limits and higher requirements in terms of load flexibility can lead to a decrease of the maximum power delivered by the unit. The limiting factors are partly related to the control systems of those plants. In this paper, we present the results of the upgrading of an 80 MW_e, retrofitted biomass power plant that was achieved by improving the dynamic control of the combustion process. Thanks to the addition of virtual air flow sensors in the control system and the re-design of the combustion control loops, the undesired effects of a recent 10% power increase on NO_x emissions were more than compensated. The accurate control of the local NO_x production in the furnace resulted in a decrease of these emissions by 15% with an increased stability. This study will help increasing the cost-effectiveness of such conversions, and facilitate the development of dispatchable, renewable power units able to contribute to the grid stability.

1. Introduction

Hydropower and bioelectricity are the two main dispatchable sources of renewable energy. In 2016, they provided 12% and 6% of the gross electricity generation in Europe, respectively. The two main intermittent renewable sources, sun and wind power, accounted for 9% and 3% of this gross generation, respectively [1,2]. In addition to energy storage and demand side management, the concomitant development of dispatchable and non-dispatchable renewable energy sources is a key factor to ensure the stability of the electricity grids in the future [3]. The further development of bioelectricity can be achieved in a cost-effective manner by taking advantage of the existing assets currently fed with fossil solid fuels [3–6]. Over 250 coal-fired, large scale power plants are currently

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operated in Europe [3]. Although in decline, the coal power capacity in construction worldwide still reached 235 GW_e in 2018 [7]. Retrofitting coal-fired boilers to biomass combustion is not always straightforward, but can be most of times achieved through limited adaptations of the existing equipment. In Europe, large coal power plants were successfully converted to wood pellet combustion in several countries (Denmark, UK, Netherlands, France, Belgium, among others) [3,8]. Although the retrofitted large-scale power plants currently in operation are fed with conventional wood pellets, the thermal pretreatment of biomass can improve the physical and chemical characteristics of the fuel and facilitate such conversions, leading to even more limited retrofitting and operational costs. It could also broaden the types of biomass resources used in large-scale power plants (e.g. agricultural residues and energy crops from marginal lands) by limiting the impact of their less favorable chemical and physical characteristics [8,9].

Coal and biomass are both carbonaceous solid fuels: they can be burned in the same types of boilers, the most common ones being grate-fired boilers, fluidised bed boilers and pulverised-fuel boilers. The latter type largely dominates the existing fleet of large-scale power plants worldwide [10], and it is used in approximately 50% of the biomass-fired power plants [8]. Coal and biomass however present some important differences in their physical and chemical characteristics. The first one is the lower heating value of biomass (18–22 MJ/kg, dry ash free basis) compared to coal (26–31 MJ/kg) [10]. Injecting the same thermal power in the furnace of a power plant therefore requires significantly larger fuel mass flow rates. Some handling or preparation equipment (e.g. the mills of pulverised-fuel boilers) can therefore limit the thermal input if they reach their maximum capacity in terms of mass or volume flow rate.

Due its fibrous structure, biomass also presents a lower grindability than coal. Roller mills are generally used in pulverised-coal boilers to crush the raw pieces of coal to μm-sized particles (typically 90 wt% < 300 μm). When they are fed with biomass pellets, roller mills can deliver 80 to 90 wt% of particles smaller than 1 mm [8], hence significantly larger than coal particles. The produced biomass particles also present a large aspect ratio than coal particles. The settings of roller mills can be adapted to optimise their performances with biomass, sometimes at the expense of their capacity. Hammer mills generally show better performances than roller mills with biomass [8]. Their rotating hammers literally cut the biomass fibres, leading to lower particle sizes, although still significantly larger than coal particles: the largest biomass particles can still reach $1-3$ mm [8,11]. Their aspect ratio is also reduced compared to roller mills [8]. Whether they are produced in roller mills or in hammer mills, the larger size and the anisotropy of biomass particles can lead to burnout issues if their residence time in the furnace is not sufficient [8,12,13]. When 100% biomass firing is applied, it is therefore recommended to reduce the maximum particle size down to 3 mm and to reduce the portion of large particles (e.g., $< 10-15$ wt% particles in the size range of $1-3$ mm) [8]. Even then, ensuring a complete burnout of biomass particles in a furnace designed for coal combustion might require a power derating: it decreases the volumetric flow of flue gas in the furnace and hence increases the residence time of the particles [14]. It should be noted that the thermal pre-treatment of biomass can however make this renewable feedstock more suitable for roller mills, leading to limited adaptation of the equipment [8,9]. Mild pyrolysis of raw biomass can modify its structure in such a way that it becomes more brittle. The lower investment required to retrofit the power plant and the less frequent operational issues can justify the additional pre-treatment step, although further efforts must be carried out to reduce the related costs in the future [8,9].

In addition to their lower heating value and their larger size, biomass particles also differ from coal in their combustion behaviour and their inorganic composition. While coal particles emit 5-40% of volatile compounds during pyrolysis (the first step of combustion), biomass releases 70 to 90% of volatiles [10]. This strongly modifies the heat release distribution in the flame. This large volatile content is also the cause for the higher propensity of biomass particles to create explosive atmospheres, which lead to additional safety requirements during handling and storage compared to coal [15].

The inorganic composition of biomass also differs from that of coal: although the ash content of biomass is significantly lower than for coal (0.4–3% vs. 1–30% [10]), which leads to lower particulate matter emissions, the higher concentrations of some inorganic elements, in particular potassium and/or chlorine, is a major source of operational issues [8,16,17]. Lower ash melting temperatures and higher concentrations of condensable inorganic volatiles are generally observed. They lead to a deposit build-up on the boiler's heat exchangers in both the radiative and convective parts (called slagging and fouling, respectively). In grate-fired and fluidised bed boilers, other mechanisms can also cause bed agglomeration issues. The main measure that can be taken to avoid such ash-related issues is to make sure that the flue gas temperatures close to the boiler wall, in the fuel bed and at the outlet of the furnace (Furnace Exit Gas Temperature, FEGT) are compatible with the characteristics of the fuel. In furnaces designed for coal combustion, this might also require a power derating. Alternatively, fuel blends or additives can be used to improve the ash characteristics and keep a higher FEGT [8,16,17]. Thermal pre-treatment can also modify these characteristics and reduce the needed power derating [8,9].

Biomass contains less nitrogen and much less sulfur than coal [10]. Hence, NO_x and SO_x emissions are expected to decrease after a retrofit, even though NO_x emissions are not only caused by the oxidation of the nitrogen from the fuel (fuel NO_x) but also by the oxidation of nitrogen from combustion air under high temperature and high O_2-concentration conditions (thermal NO_x) [10]. Due to the redistribution of the heat release in the flame and in the furnace, the NO_x emission reached after the retrofit of a boiler from coal to biomass are very difficult to predict [17,18]. When the retrofit to biomass is accompanied by a decrease of the legal Emission Limit Values (ELV's) applied to the power plant, the production of NO_x in the furnace can also become a limiting factor and therefore lead to a power derating.

Furthermore, if the duty of the power plant is changed from ensuring base load to backing-up intermittent renewables, as expected in the future, more frequent load variations will also cause higher NO_x emissions [19]. During fast transients, the adequacy of the combustion air flow rate compared to the fuel flow rate is indeed not always guaranteed on the short-term: locally in the furnace, a temporary higher excess of oxygen can be observed, which results in a NO_x emission peak that will disappear as soon as the new regime is reached for both the air and the fuel flow rates, with the desired air-fuel ratio. The impact of such fast transients can be limited by an accurate control of the combustion process. When both the air and the fuel flow rates are measured and controlled at the level of the burners, rather than for the whole furnace, the local air excess can be directly monitored and controlled, in order to limit NO_x emission peaks and other operational issues [20]. This is however rarely the case in pulverised fuel boilers. An even distribution of air and/or fuel between the burners is often considered instead, which can lead to large uncertainties on the local air-fuel ratios [21].

When available, flue gas treatment systems such as Selective Catalytic or Non-Catalytic Reduction installations (SCR/SNCR) of course limit the impact of a retrofit on the NO_x emissions at the stack.

In summary, the retrofit of a coal-fired power plant to biomass combustion can lead to a power derating when one or several of the following limitations are faced:

- Limited fuel handling or milling capacity;
- Longer residence time required to ensure particle burnout;
- Lower Furnace Exit Gas Temperature required to avoid ash-related issues;
- Too high NO_x emissions in steady state, and/or too high NO_x emission peaks due to larger and/or more frequent load variations.

In this paper, we present the results of the recent upgrading that was carried out on the boiler of an 80 MW_e power plant converted from coal to biomass 10 years earlier, after its average power output was reincreased by 10%. The cost-effective implementation of virtual air flow sensors in the combustion control system allowed to do more than compensate the undesired effect of this recent power reincrease on NO_x emissions. Section 2 describes the power plant, the applied measures, as well as the measurements and data analysis that was carried out. Section 3 compares the performances of the power plant before and after the upgrade was applied.

2. Methodology

2.1. Les Awirs power plant

Les Awirs power plant, located in Belgium, was entirely converted from coal-to biomass-firing in 2005 [22]. The boiler is a pulverised-fuel boiler with tangential firing: the injection of fuel and combustion air occurs at the four corners of the furnace, at 4 different levels, which creates a rotating flow in the center of the boiler, as illustrated in Fig. 1. Wood pellets are delivered at the power plant and directly sent to two storage silos equipped with the safety features needed to fulfil the requirements of the European ATEX legislation (explosive atmospheres). Two hammer mills are then fed by gravity from the silos. Wood particles smaller than 2 mm are entrained by primary air from the bottom of the mills to the 16 burners. The burners are also fed with secondary air. The boiler was originally not equipped with a Over Fire Air system (OFA) for NO_x emission reduction through global air staging in the furnace, but the highest row of burners were put out of service to play the same role, following the Burner Out Of Service (BOOS) principle [10]. No secondary NO_x emission reduction system is installed (no SCR, nor SNCR). Natural gas is fired during start-up and allows for the ignition of the biomass particles once the furnace reached hot conditions. Natural gas also provides a support at low load and/or during maintenance on one of the two mills, for instance for the replacement of the hammers.

As the boiler was originally designed for fuel oil combustion, and then retrofitted to coal combustion, the furnace volume is rather limited, even for coal. The conversion to biomass therefore let some limitations appear: studies showed that a too short residence time of the largest particles and a high FEGT would have resulted in a large unburnt content in the fly ash and fouling issues on the first superheaters at high load. The high thermal power density in the furnace would also have lead to NO_x emissions exceeding the new legal ELV's, that evolved to the current value of 250 mg/Nm^3 at 6% O_2 (monthly average). A power derating was therefore applied: from the original maximum gross power of 125 MW_e to approximately 80 MW_e. In order to reach higher shares of dispatchable, renewable power, the average power output of the plant was however increased by 10% ten years after the initial retrofit (from 70 to 77 MW_e). This let some limitations appear in terms of NO_x emissions: their level as well as their variations became problematic, as will

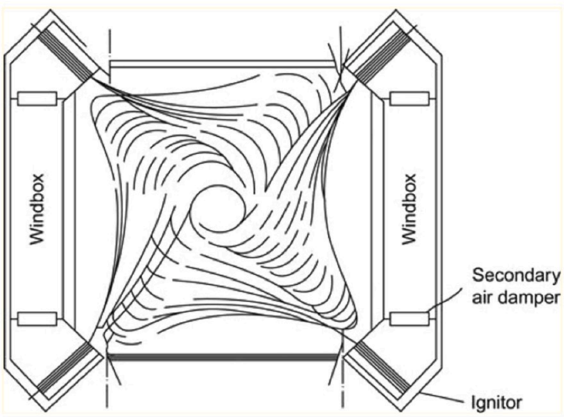

Fig. 1. Tangential firing in a pulverised-fuel boiler [23].

be showed further. These issues were very much related to the way the combustion air was controlled. The total air flow rate injected of the furnace was a function of the total fuel flow rate, and therefore of the total power output. The combustion air was supposed to be equally distributed among the burners in service by opening the primary and secondary air dampers homogeneously. As already stated, such a global regulation of the air-fuel ratio leads to high NO_x production zones in the furnace due to unavoidable unbalances between the burners, even temporarily [21].

2.2. Virtual sensor implementation

In order to move to a more accurate control of the combustion process and limit the production of NO_x in the furnace, especially during load variations, it is necessary to monitor and control the air-fuel ratio at the level of the burners, instead of the whole furnace [21]. This requires that both the fuel flow rate and the air flow rate are measured for each of the 16 burners. At Les Awirs power plant, the fuel flow rate per burner was already monitored using pressure drop measurements in primary air pipes. The relative difference in the pressure drops is correlated to the total amount of injected fuel to derive individual fuel flow rates per burners. Alternatively, microwave systems such as the EUCoal flow system described in Refs. [21,24] can also be implemented. In this case, the main challenge was therefore to provide the control system with an accurate feedback on the air flow rates per burner in a cost-effective manner to complement the available fuel flow rates. Rather than installing hardware flow measurements on every primary and secondary air ducts, virtual sensors were implemented.

The basic idea of a virtual sensor is to take advantage of existing, reliable measurements such as pressure drops and damper openings and to combine them with a physical model of the air distribution system to compute the air flow rates in all ducts. The physical relevance of the model allows for a robust process control with high dynamic capabilities that are essential during load variations.The EUSoft Air system already described in Refs. [20,21,25,26] was implemented at Les Awirs power plant. Each element of the air distribution system is modelled as an equivalent resistance to the air flow. The non-linearity of the air flow through the dampers is taken into account by considering sigmoidal damper flow curves. The system then uses the available physical inputs (pressure measurements, damper positions and total air flow measurements) to provide the main control system with the estimated air flow rates to each burner. Equivalent flow resistances ϕ_i are then determined, as illustrated in Fig. 2. Eq. (1) gives the general relationship between a pressure drop Δp, the associated equivalent resistance ϕ_{eq} and the mass flow rate Q.

$$\Delta p = \phi_{eq}\, Q^n \tag{1}$$

Fig. 3 compares the original and the new combustion process control system. In the original system, the total thermal load and the total fuel flow rates were the only parameters used to determine the total air flow and the opening of the burner air dampers. The Forced Draft Fan was used to deliver the total air flow required to burn the total amount of fuel injected in the furnace, as a function of the total load. The air dampers were controlled based on preset openings depending on the total load, in an open loop. If needed, the operators could adjust the individual damper openings to reduce the NO_x emissions by balancing the combustion air flow rates, without any feedback. During transient phases, a cross-limiting control ensured that the air excess was always sufficient: the air flow rate increased first during load increase, and the fuel flow rate decreased first during load decrease. In the new control system, the virtual sensors play the same role as physical air flow measurements and bring additional information that can be combined with the fuel flow rates to control the local air-fuel ratios. The individual burner air flow rates are therefore controlled by the air damper in a closed loop, in order to obtain the desired local air-fuel ratios, based on the individual fuel flow rates to the burners. The Force Draft fan controls the total air flow during start-up only and uses the wind box pressure as set point in normal operation. The cross-limiting control during transient phases is now applied at the burner level. Although a significant extension of the number of inputs and outputs of the control system was required to implement this new control philosophy, the required investment was of course much more limited than its hardware alternative.

2.3. Measurements and data analysis

The results showed in Section 3 are based on the continuous monitoring of the gross power output and the NO_x emissions of the power plant. The power output was measured at the transformer with an accuracy of 0.2%. The NO_x emissions were retrieved from the Continuous Emission Monitoring System (CEMS) of the power plant, based on extractive Automated Monitoring System (AMS): the flue gas is sampled and dried, before NO_x and O_2 concentrations are determined using UltraViolet Resonance Absorption Spectroscopy (UV-RAS) and paramagnetic devices, respectively. The O_2 measurement is used to correct the NO_x emissions to the reference oxygen level (6%). The global accuracy on NO_x concentration taken into account for legal reporting is 20%, taking into account the flue gas sampling process. The analysers themselves show a much better accuracy [27].

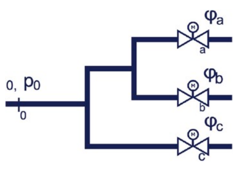

Fig. 2. Working principle of the EUSoft Air virtual sensors.

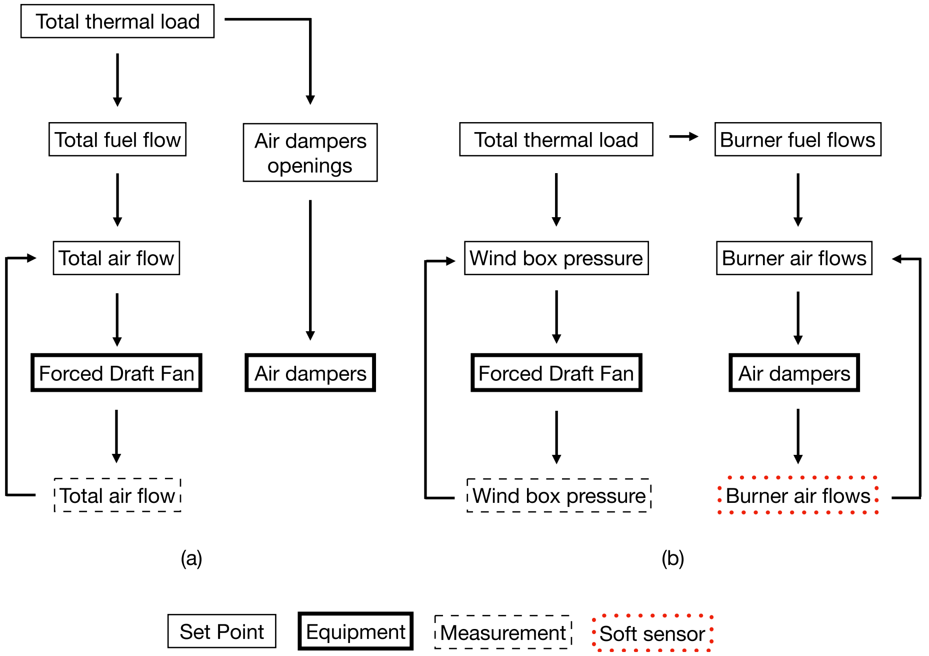

Fig. 3. Original (a) and new (b) principles of the combustion process control. The virtual sensors are used to provide the feedback on the individual air flows sent to the burners.

In order to determine the impact of the virtual sensor control on the overall performances of the plant, 5 years of minute-average data were analysed: 1 year before the 10% power increase, 1 year at higher load with the original control system, and 3 years after the implementation of the new control system. In Section 3, the considered years are therefore referred to as Y_{-1}, Y_0, and then Y_1, Y_2 and Y_3.

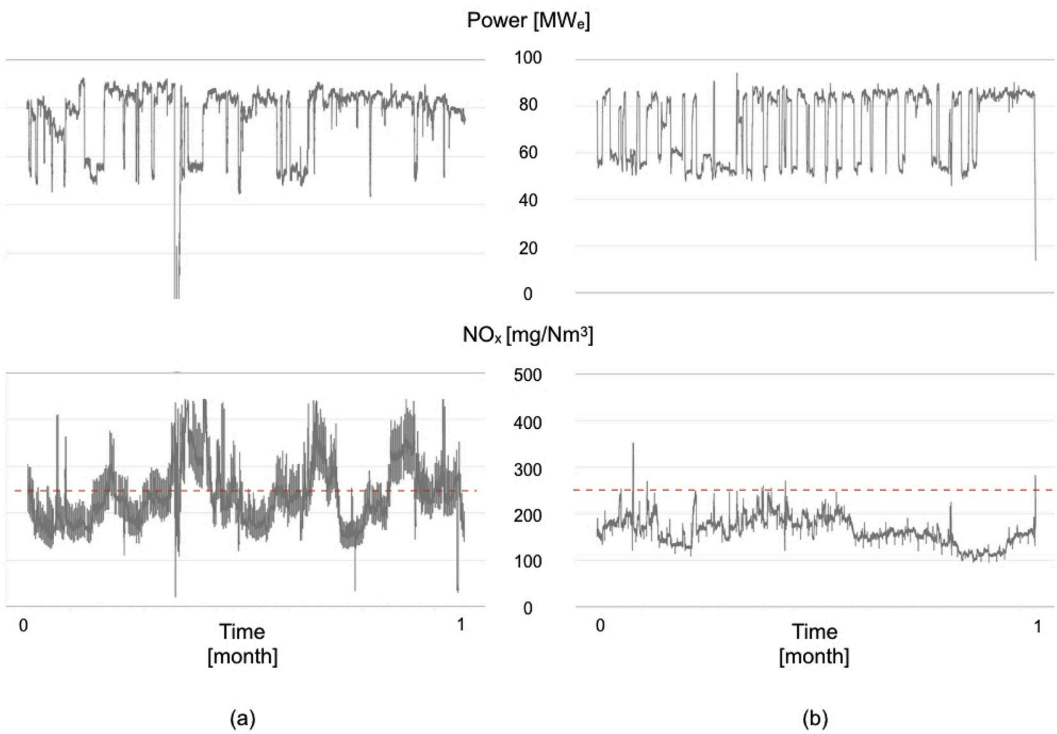

Fig. 4. Evolution of the power output [MW_e] and NO_x emissions [mg/Nm^3 @ 6% O_2] during a typical month of year Y_0 (a) and year Y_3 (b).

3. Results and discussions

Fig. 4 illustrates the typical evolution of the gross power output and the NO_x emissions before and after the upgrade of the control system (month (a) and month (b), respectively). While the power fluctuates between 50 and 90 MW_e in both cases, the NO_x emissions are much higher for month (a). They are also much less stable, i.e. much more sensitive to load variations. The monthly and the daily averaged emission limits were almost reached, which called for a cost-effective improvement of the system stability. This stability is obviously reached for month (b), where almost no minute-average NO_x concentration goes beyond 250 mg/Nm^3, even though the load and its variation are comparable to month (a).

The distribution of the minute-averaged power outputs, NO_x emissions and O_2 concentrations are given in Fig. 5, together with their yearly averages, for the 5 years of data that were retrieved.

A clear shift towards higher power outputs can be seen between Y_{-1} and Y_0 (70–77 MW_e) although with lower load variations, together with a slight increase of the yearly average NO_x emissions (175–179 mg/Nm^3) and a large increase of their variations. The lower load variations are correlated with a lower oxygen excess: the O_2 concentration decreases from 5.7 to 4.7 vol% in average.

After the implementation of the virtual air flow measurements (year Y_1), the average power output further increased (81 MW_e), while the average NO_x emissions decreased drastically (down to 133 mg/Nm^3), despite an increased O_2 excess in the flue gas (5.3 vol%). During years Y_2 and Y_3, the load variations were gradually brought back to the same intensity as for year Y_0, which resulted in a slight increase of the NO_x emissions (up to 160 and 159 mg/Nm^3, respectively), due to the higher number of transient phases and the related reincrease of the average oxygen excess (up to 6.6 and 6.2 vol%, respectively). In average, the power output increased by 4% after the implementation of the virtual sensors, while the NO_x emissions decreased by 15%.

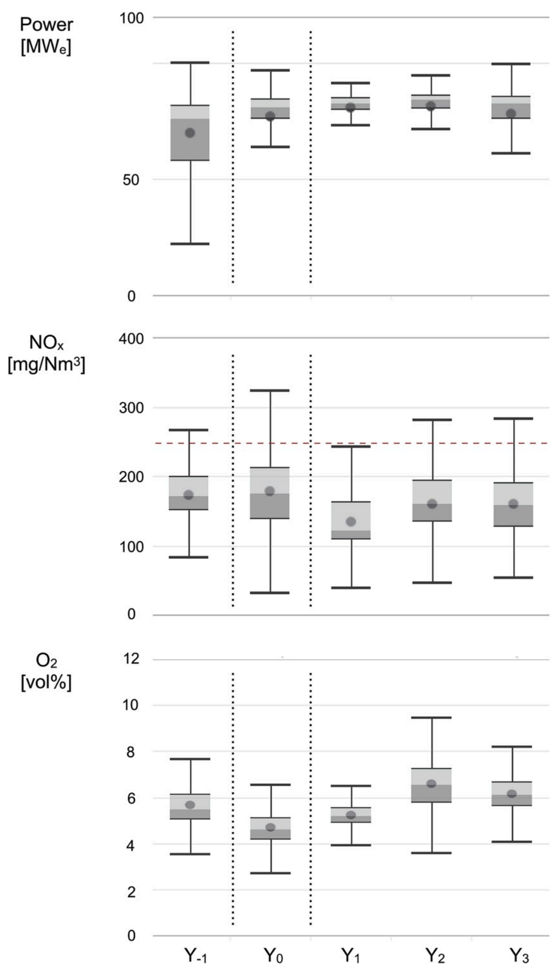

Fig. 5. Yearly distributions (box-plots) and average values (dots) of the minute-averaged power output [MW_e], NO_x emissions [mg/Nm^3 @ 6% O_2] and O_2 concentration in the flue gas [vol% dry]: 1 year before the 10% power increase, 1 year at higher load with the original control system, and 3 years after the implementation of the new control system.

4. Conclusions

In this paper, we showed the results of the cost-effective flexibilisation of an 80 MW_e, retrofitted biomass-fired power plants that was achieved by implementing virtual air flow sensors for the accurate control of the combustion process. This modification of the control system lead to a limitation of the production of NO_x in the furnace during both steady state and transient phases. This was required by the increase of the NO_x emissions observed after a recent 10% power reincrease, that was also accompanied by larger emission fluctuations. These undesired effects were more than compensated after the upgrade of the control system: the power output further increased by 4%, while the NO_x emissions decreased by 15% and exhibited a much more stable behaviour.

These results illustrate that the conversion of existing coal-fired power plants design for base-load operation into load-flexible biomass-fired power plants can be partially achieved thanks to smart, ad hoc modifications of the control systems that can contribute to limit power derating. This will help increasing the cost-effectiveness of such conversions, and facilitate the development of dispatchable, renewable power units able to contribute to the grid stability.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

J. Blondeau: Conceptualization, Data curation, Formal analysis, Writing - original draft. **T. Museur:** Conceptualization, Investigation, Methodology, Writing - review & editing. **O. Demaude:** Conceptualization, Investigation, Methodology, Writing - review & editing. **P. Allard:** Conceptualization, Investigation, Methodology, Project administration. **F. Turoni:** Conceptualization, Methodology, Funding acquisition, Supervision. **J. Mertens:** Conceptualization, Methodology, Funding acquisition, Supervision, Writing - review & editing.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.csite.2020.100680.

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