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Mid-Load Operation of Large Coal-Fired Power Plants

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Abstract

The transformation of the German electricity market with ongoing increase of volatile renewable energy supply to the grid causes new demands on hard coal fired power plants. Even though these power plants are essential for the security of supply, they are pushed further and further from traditional base-load operation to mid-load and even peak-load operation. To meet these demands in an economic way, a reduction of the minimum load and increase of system flexibility in terms of control power and start-up properties is indispensable. Tests and subsequent implementations in STEAG's own hard coal power plants show that process control optimization can make a great contribution, even for existing power plants, to cope with these challenges. The increase in flexibility is partly achieved at the expense of efficiency losses. Adverse effects on fuel supply, combustion, water-steam cycle and flue gas cleaning system may occur. An economic operation under these conditions requires a thorough analysis of these effects. This contribution presents the essential variables, their effects on the overall system and the general approach that may enable an economic operation of large hard coal fired power plants in the lower mid-load operation under current market conditions.

1 Introduction

1.1 The German electricity market – A coal power plant operator's point of view

The increasing share of renewable electricity generation in Germany has led to several changes in the electricity market over the last years. In particular, three important changes have an effect on coal power plants:

1. General price level has decreased:
   As Figure 1 shows, both peak and base load spot market prices for Germany and Austria (Phelix) have had a falling tendency over the last years. This is mainly due to the fact that the renewables have feed-in privileges and reduce the so called residual load, which leads to a lower demand for conventional plants and hence to lower prices.
2. Typical daily price curve has changed:
   Figure 2 shows the hourly prices for a sunny week in March 2014. As the curves show, there is no peak at noon as there used to be in the past. On the contrary, there now is a dale at noon. The main reason is the big share of PV generation at that time. Moreover, prices are generally lower at the week-end.
3. Control reserve power becomes more attractive for coal fired power plants:
   Even though high volatility in the prices for control power, in particular for negative control power, makes an interpretation difficult, Figure 3 shows a positive tendency for secondary control power.

The measure for economic operation of coal power plants is the so called Clean Dark Spread (CDS). The CDS is given by the selling price reduced by the variable costs of generation, primarily fuel and CO_2 costs. Due to the changes in the market described above, today the price and consequently the CDS fluctuate more than in the past. At least for hard coal plants, periods with positive and negative CDS alternate, partly several times per day.

Up to now, the German electricity market is an "energy only market", meaning that the fact that the dispatchable capacity of conventional power plants secures the power supply is not

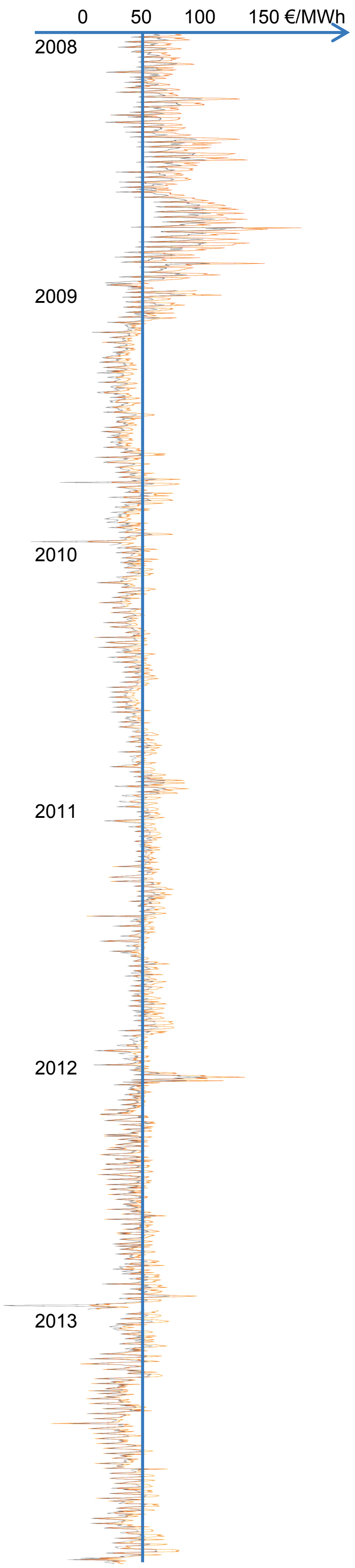


Figure 1: Phelix Base (grey) and Peak (orange) prices over the last years. Composed from [2].

recompensed. Hence, due to the changes listed above, large hard coal power plants are faced with the challenge to adapt their load to the CDS on short notice and for short time periods. One possibility to generate income in addition to the CDS is given by control power, as described in the third item of the list above.

This leads to a change in the kind of operation from base-load to mid- or even peak-load. For example, in periods of negative CDS, the utility will decide to operate at minimum load or even to shut down, depending on the length of the period and the related costs. Hence, in this context the term *mid-load operation* is different to what was considered to be mid-load in the past. Hard coal power plants are facing not only less operation hours, but also more fragmented and more irregular operation, since the CDS does not depend on the total, but on the residual load.

In short, large hard-coal plants are faced with an increased demand in flexibility with respect to load changes, start-up frequency, minimum load capability, and control power. Flexibility is expected to become even more important in the future. It is an essential prerequisite for the successful integration of an increasing share of electricity from renewable sources into the future energy mix of Germany as long as large scale storage for electrical energy is not available at competitive prices [1].

1.2 Flexibilization of existing power plants

From the above, the question arises how existing hard coal power plants can meet the demand in flexibility at reasonable costs. While it may also be possible to increase flexibility by modifications in the process, this paper is focused on the optimization of the plant control and the application of advanced process control methods in order to increase flexibility.

Often, there is considerable potential that can be accessed by control optimization. This potential mostly is due to one or several of the following reasons:

- The control loops have never been commissioned for flexible operation.
- The control loop commissioning has been focused on standard, possibly outdated concepts with a

parameterization in order to “get it to work until the deadline”. Hence, the control performance may be far from optimal.

- The maintenance of the controls may suffer from a lack of specialized know-how, in particular if the plant has been modified over the years.
- Some advanced process control concepts cannot be directly realized in DCS systems, as only a limited library of function blocks is available.

In general, compared to modifications in the process, control optimization and application of advanced process control are low-cost solutions, as only minimal hardware investments are required.

Even if not in the focus of this paper, it is important to stress that changes in the process that influence its dynamical behavior should always be accompanied by corresponding modifications in the plant control. On the other hand, some advanced control methods may benefit from modifications in the process such as additional valves or measurements. Also, the general control performance can be improved by replacing valves or measurements that are too slow or that do not have sufficient precision.

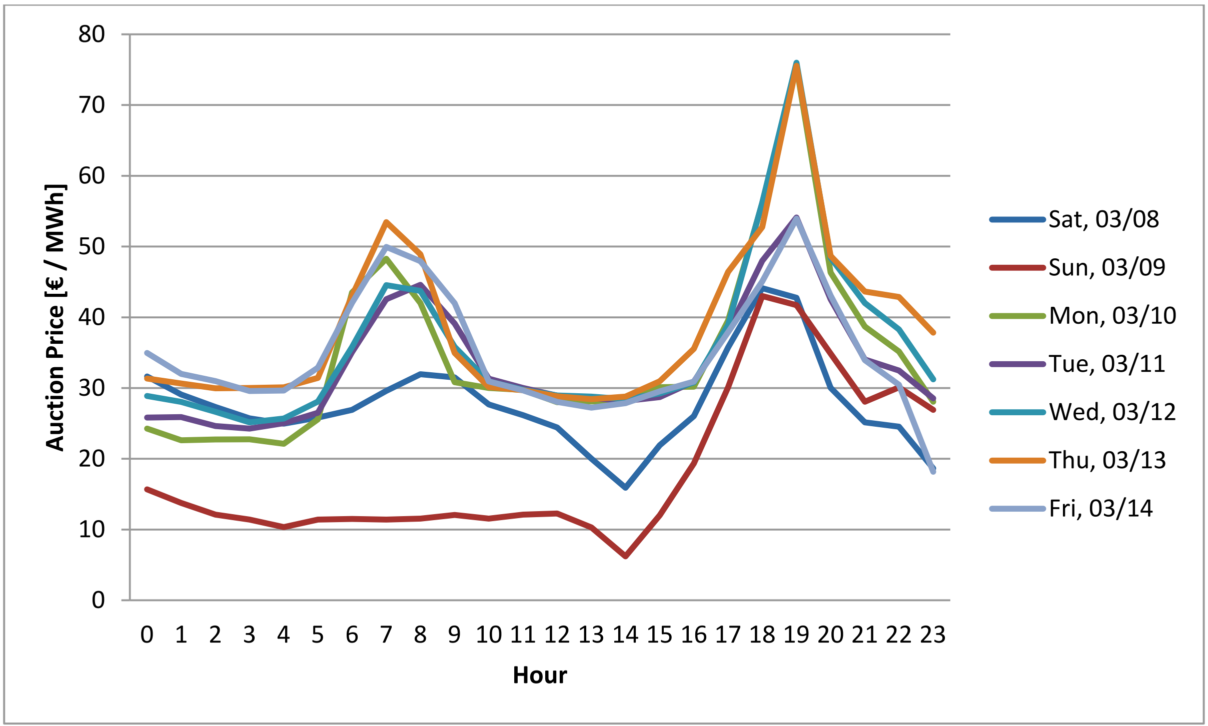
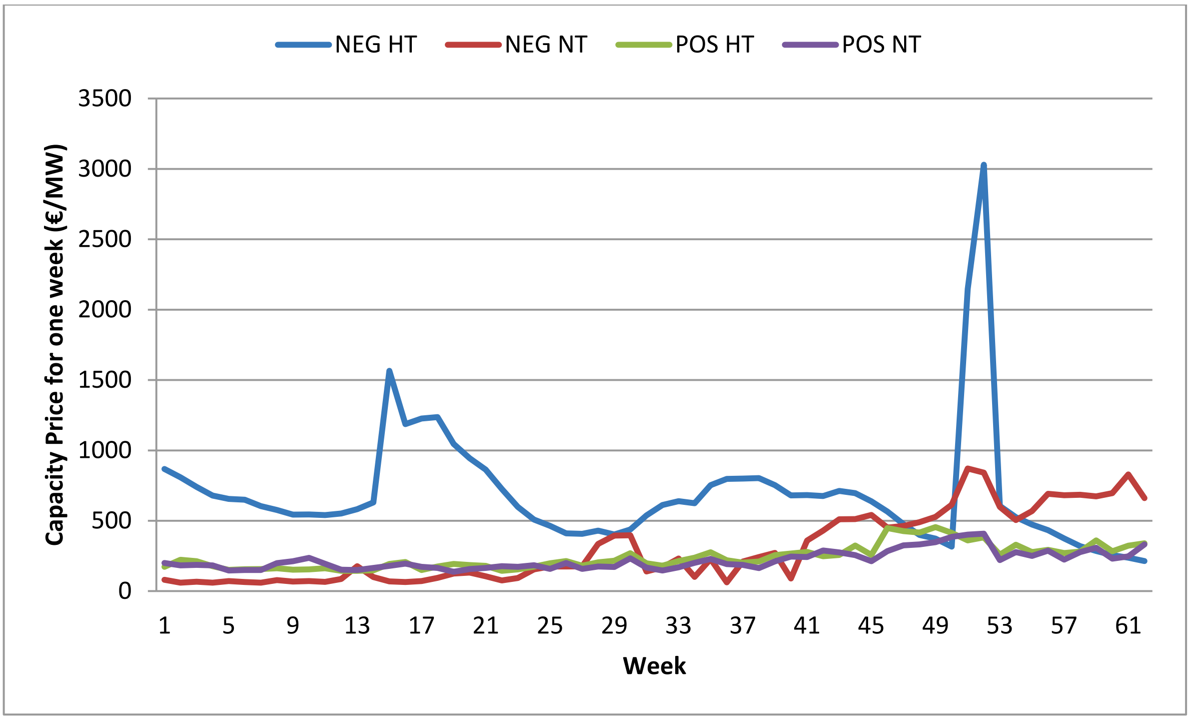


Figure 2: Hourly EPEX spot market auction prices for March 8 until March 14, 2014, a sunny week in spring. Data source: [1]



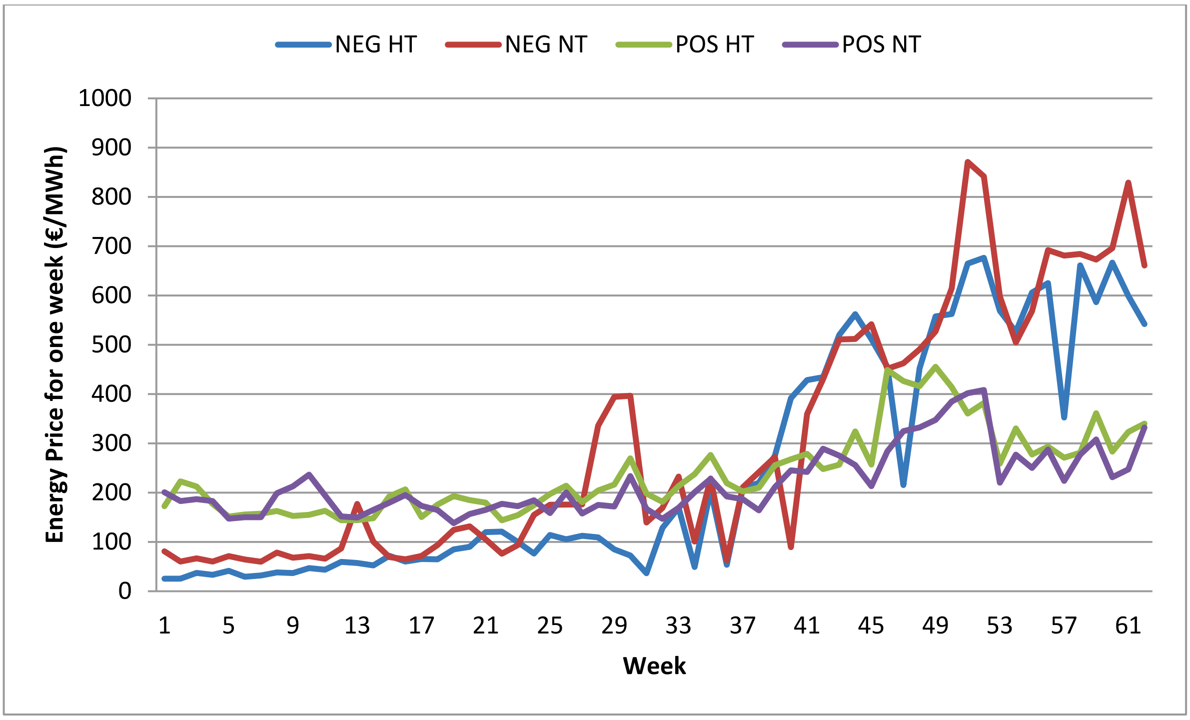


Figure 3: Mean capacity price (top) and mean energy price (bottom) for secondary control power for January 2013 until March 2014. (Data Source: [2])

NEG_xx: Product code for negative secondary control reserve
POS_xx: Product code for positive secondary control reserve
xxx_HT: Product code for secondary control reserve to be provided between the hours of 08:00h and 20:00h from Monday through Friday (excluding public holidays applicable to all of Germany)
xxx_NT: Product code for secondary control reserve to be provided during the remaining time

2 Minimum load reduction by process control optimization

2.1 Status quo

Typical minimum loads of existing hard coal power plants are in the range of 25% up to 40% of nominal load. For combined cycle gas plants (CCP) with one gas turbine, the typical minimum load is at 40-50% of nominal load, for lignite fired power plants at 50-60% [3].

In particular, for modern once-through boilers, among others the following factors may limit the minimum load or adversely affect the plant dynamics:

- Once-through operation
- Live and reheat steam temperatures
- Turbine ventilation and erosion
- Flame stability
- Flue gas temperature
- Stability of unit control

As long as the boiler remains in once-through operation mode, a reduction of the minimum load is comparatively simple and may be reached by analyzing and modifying the corresponding limits for set-points in the DCS. Of course, it must be verified that these limits originally have been set overly conservative or without taking the minimum load into consideration. The new limits must be chosen such that the process can be run within the new range without damaging the plant.

The once-through operation mode is limited by the so-called Benson point, which is the point where the water mass flow reaches the minimum value required to guarantee stable flow in all evaporator tubes. The load where this point is reached depends on the boiler, but a typical value is at about 30% load. Hence, for a further reduction of the minimum load below the Benson point, the boiler must be able to leave the once-through operation and enter the circulation mode smoothly and vice versa. In addition, the boiler needs to operate stable in stationary circulation mode for several hours.

The live and reheat steam temperatures are affected in two ways: The attemperator control may perform poorly because the dynamical behavior of the superheater becomes slower due to low steam flow velocities. Oscillations and instability may occur. Moreover, the boiler may not be able to maintain the temperatures. This depends on the boiler design and on the distribution of the firing within the boiler. In any case, it must be guaranteed that the temperature time derivatives are limited to avoid excessive temperature stress in the turbine.

If the steam flow through the turbine is too low, inadmissibly high steam temperatures may occur due to ventilation. Ventilation means that part of the turbine actually acts as a ventilator, increasing the steam temperature. When and where exactly ventilation occurs also depends on the steam extractions of the turbine. This is particularly important for plants providing combined heat and power. Hence, it may not be possible to define a fixed load at which ventilation becomes a limiting factor. Rather, ventilation may be prevented by observing and limiting the steam temperatures at the turbine outlets. The turbine supplier can define maximum admissible values for outlet steam temperatures.

Also, at low loads the turbine blades may experience increased erosion in the last stages of the low pressure turbine. The turbine supplier should evaluate whether and when erosion may be a limiting factor.

Flame stability can be an issue at low loads, increasing the risk of a boiler trip if the flame detection fails. If the flame stability is a problem during dynamic load changes, the problem may be solved by modifying the primary and secondary air control loops. If flame instability is observed in stationary operation, a solution may be to reduce the number of mills in operation to one, accepting the increased risk of a unit trip.

The catalyst requires a minimum temperature to work. If the flue gas temperature falls below this minimum value, the chemical reaction does not function properly. As a consequence, the catalyst may be damaged, NOx-values will exceed their limit and the ammonium slip will increase.

The unit control must guarantee stable operation in the new load range. Moreover, it must be able to observe all limits and prevent them in a stable way from being exceeded. Only in this manner, the lowest load without a conservative safety margin can be reached.

Even though it does not pose a real limit, it should be considered that the boiler and turbine efficiency are reduced disproportionately with the load. The plant efficiency in the new load range should be evaluated in order to be able to decide, depending on the current market conditions, whether it is better to operate at a lower load or to shut down and restart.

2.2 What can be achieved with control?

There are two general steps to be followed. The first step is to collect information on the true process limits by means of tests. This information typically is not contained in the available documentation, as the latter deals with the design operation range only. By slowly and cautiously reducing the load, the process and occurring limits, such as temperature changes or stability problems, can be identified.

Some limits should be verified by the supplier if it is not possible to observe them directly and insufficient information is available. In particular, this may be the case with respect to turbine ventilation, turbine erosion, and evaporator flow stability.

In a second step, the low level control loops and the unit control need to be adapted such that

- all identified limits are adhered to automatically,
- the operation in circulation mode is stable for long time periods,
- the transition between once-through and circulation mode is smooth,
- no oscillations or inadmissible temperature time derivatives occur.

This means that after the optimization, the unit will operate with a dynamical minimum load which directly depends on physical limitations. For example, to avoid ventilation, the outlet steam temperature is limited to a maximum value. The boiler load is then automatically controlled such that this maximum value is not exceeded. Since the outlet steam temperature reacts with considerable delay on a change of the boiler load, modern model based control methods are helpful to prevent the unit from overshooting or oscillating at the limits without constraining the load in a too conservative way.

With the dynamical minimum load, the unit will either lower its load to the set-point or come to rest on one of the limits and thus remain at a higher load. If necessary, limits may even increase the dynamical minimum load during operation. The concept of a dynamical minimum load is of particular interest for power plants that are facing different operation conditions – for example a varying amount of heat production – that may lead to different limiting factors for the same load.

2.3 Results at STEAG

In one of STEAG's own power plants, STEAG Energy Services have implemented a minimum load reduction as follows. For this plant, the following limits have been identified:

- Reserve for extraction pressure control for heat
- Turbine ventilation
- Flue gas temperature
- Steam temperatures and temperature time derivatives.

In order to reach the minimum load reduction, the following has been realized:

- Optimization of the circulation control
- Analysis of admissible operation range of the turbine by the supplier
- Adaption of the turbine controller and turbine protection
- Implementation of a dynamical minimum load
- Active reduction of live steam temperatures with defined speed to prevent excessive temperature derivatives
- Support of flue gas temperature by controlling it using a high-pressure preheater supplied with live steam.

Figure 4 shows how the unit load is reduced. At about 130 min, the evaporator flow reaches its minimum value and the unit goes into circulation mode. At about 20% load, the boiler load is limited by the dynamical minimum load in order to prevent the outlet steam temperature from exceeding its limit and the position of the control valve to fall below its minimum position. The latter limit has been defined to have enough reserve to control the related pressure.

By the above measures, it was possible to reduce the minimum load from about 40% to about 20% in combined heat and power operation mode. This result was reached exclusively by means of control optimization without any changes in the process.

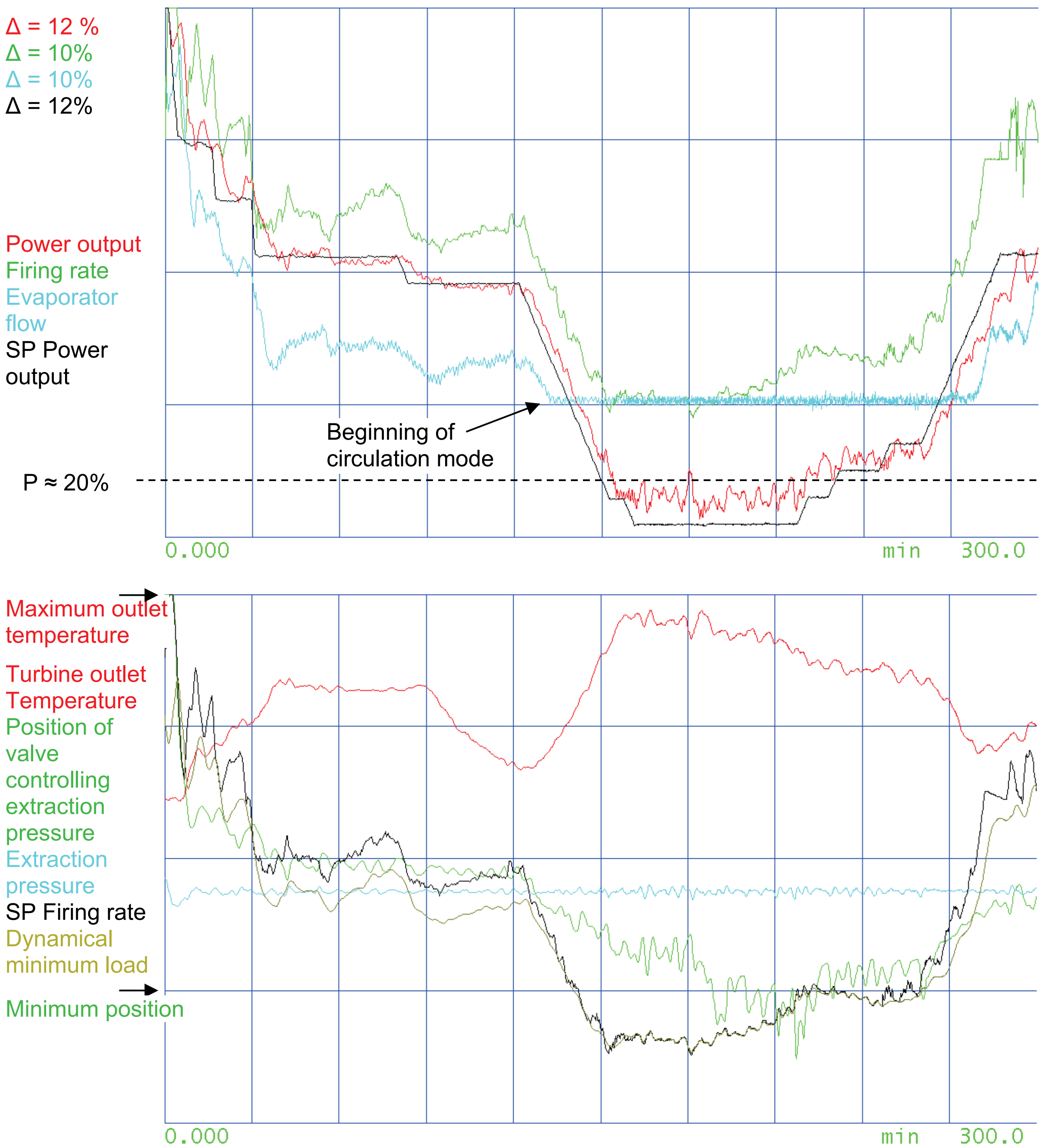


Figure 4: Minimum load operation (top) and selected limits and dynamical minimum load (bottom)

3 Start-up process automation and optimization

3.1 Status quo

In the past, coal power plants performed only a few start-ups per year, which is why their start-up costs were considered to be of secondary importance. However, due to the fact that the time periods with negative CDS have become more and more frequent, coal power plants are facing a higher number of shut-downs and start-ups.

The boiler start-up of existing coal fired power plants typically is done manually. The high pressure bypass (HPB) is set at a fixed position depending on the kind of start-up (cold, warm or hot). After filling the boiler and taking the circulation into operation, the firing rate is increased gradually by taking oil or gas burners in operation step by step. When the required hot air temperatures are reached, a coal mill may be started. The amount of steam produced increases, building up pressure in the boiler. In addition, the steam temperatures increase.

The boiler start-up is completed as soon as the following three variables reach their set-points:

- Live steam pressure (set-point usually is a fixed value, which may depend on the kind of start-up)
- Live steam temperature (set point depends on the turbine shaft and casing temperatures)
- Live steam mass flow (set point usually is a fixed value).

The cost of a start-up mainly depends on the amount of fuel that is used before synchronization of the turbine and generation of electrical power. In particular, the amount of oil or gas is important, since these fuels are more expensive than coal.

Experience shows that with manual operation, each start-up is different, even with similar initial conditions. Each operator has different experience and a slightly different way of performing a start-up. In order to obtain optimal timing for the beginning of the start-up, it is desirable that the start-up process is reproducible. This means that similar initial conditions should lead to similar start-ups. If the time needed for the start-up is known with sufficient reliability, in general fuel can be saved by reducing waiting times at the end of the start-up before synchronization.

A second area of potential is given by the firing rate. The start-up is limited by the thermal stress in thick-walled components such as superheater headers. While each start-up causes such thermal stress, the boiler design implies a certain stress level to be admissible in order to avoid premature wear and tear. Often, the boiler operation manual contains a conservative approach with respect to the manual increase of the firing rate such that the thermal stress is guaranteed to remain in the admissible range.

The thermal stress can be evaluated as proportional to the temperature difference $T_m - T_i$ between the middle of the wall and the inner surface, as shown in Figure 5. For details, refer to [4]. From the boiler design and the number of start-ups, maximum temperature differences depending on the steam pressure can be calculated. These maximum values need to be adhered to during start-up. Usually, the available range of thermal stress is not exploited, since it is very difficult to make use of this potential by manual operation without exceeding the limits.

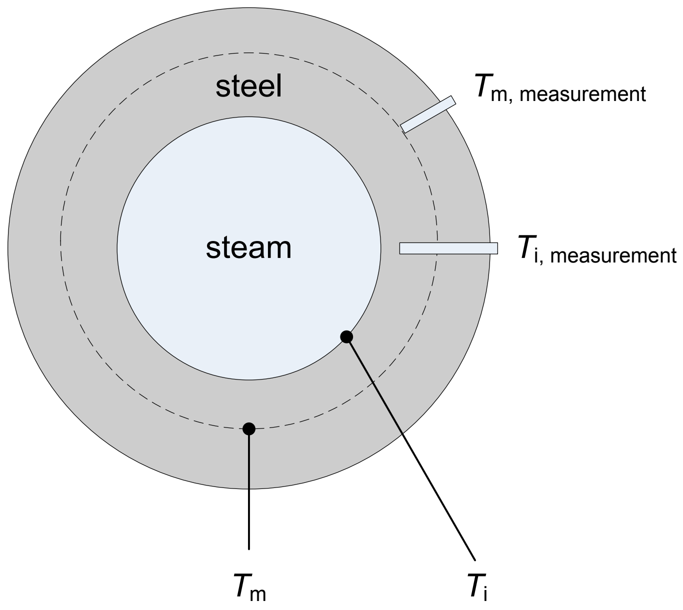


Figure 5: Temperatures for the evaluation of thermal stress at thick-walled boiler components

The third area with potential is the use of the HPB. All steam that is produced and passes through the HPB to the condenser is energetically lost. In order to save fuel, it makes sense to produce only as much steam as needed to build up pressure. The HPB then can be used to control the pressure, its time derivative and also influence the temperature as long as the steam still is saturated. Depending on the boiler, it must be checked that the reheater tubes are cooled as necessary. However, due to the fact that the pressure can be built up with less steam when the HPB is further closed, less firing is needed. This results in lower flue gas temperatures.

3.2 What can be achieved with control?

A start-up controller can be used to access the potential described in Section 4.1. Such a controller has the task to bring the live steam pressure, temperature and mass flow automatically to their set-points by using the following actuators:

- Firing rate
- High pressure bypass
- Attemperators

The controller must do this in such a way that

- Fuel consumption is minimized, in particular consumption of oil and gas
- Temperature differences do not exceed the limits but exploit the available range

The fuel consumption is minimized by starting with an almost fully closed HPB and using the firing rate which corresponds to the maximum admissible temperature increase. The HPB is then used to limit the pressure time derivative.

One approach to limit the temperature differences in the thick-walled components is to limit the time derivative of the steam temperatures accordingly. However, this is a conservative approach. For example, if the wall is in thermal equilibrium, even very fast temperature changes do not cause inadmissible stress if the amplitude is limited. Another approach is to evaluate thermal stress by two measurements, as also shown in Figure 5. This, however, has some disadvantages:

- The real temperature difference is underestimated, since the inner surface temperature T_i cannot be measured directly.
- It is difficult to use the temperature difference for control as both measurements cause additional delay. Also, since the measurements are not exact, there probably will remain a measured temperature difference even in stationary operation.
- The wall is weakened by additional drill holes.

For this reason, it makes sense to consider the real stress by calculating the temperature difference $T_m - T_i$ based on a model of the wall. Using a dynamical wall model with physical parameters, e.g., for heat transfer and heat distribution, it is possible to compute the temperature difference from the steam temperature, which usually is measured anyway. The available margin with respect to the thermal stress can be used as a feedback signal to the start-up controller. Thus, the controller keeps the temperature difference in its admissible range.

The start-up control should be accompanied by a start-up sequence control that automates the burner starts and the start of the coal mill, based on physical criteria. The combination of the control with the sequence control yields reproducible start-ups.

3.3 Results at STEAG

In the following, some results of the implementation of a start-up automation and optimization in one of STEAG's power plants by STEAG Energy Services are presented. The plant considered has a comparatively low oil firing rate. For this reason, the oil firing can run at maximum rate until the first coal mill is taken into operation.

The curves in Figure 6 show the most important physical variables for two cold start-ups: one manual start-up in red, which was carried out quite well, and one automated start-up in blue. The oil firing for manual start-up is done with constant pressure. For the automated start-up, the oil pressure is modified in order to control the firing rate.

The curves have been synchronized at the time of the ignition of the first burner. The following can be observed with respect to the automated start-up:

- Similar initial conditions (ambient pressure, 80-90°C live steam temperature measurement) as for the manual start-up
- Faster pressure build-up due to lower HPB position and slightly higher oil flow (maximum oil pressure)
- Faster reduction of oil flow after start of the first coal mill
- About 30 minutes earlier start-up of the turbine (opening of the turbine control valve)
- About 30 minutes earlier synchronization of the turbine
- About 20% less oil and 12.5% less coal consumption (from ignition until synchronization)

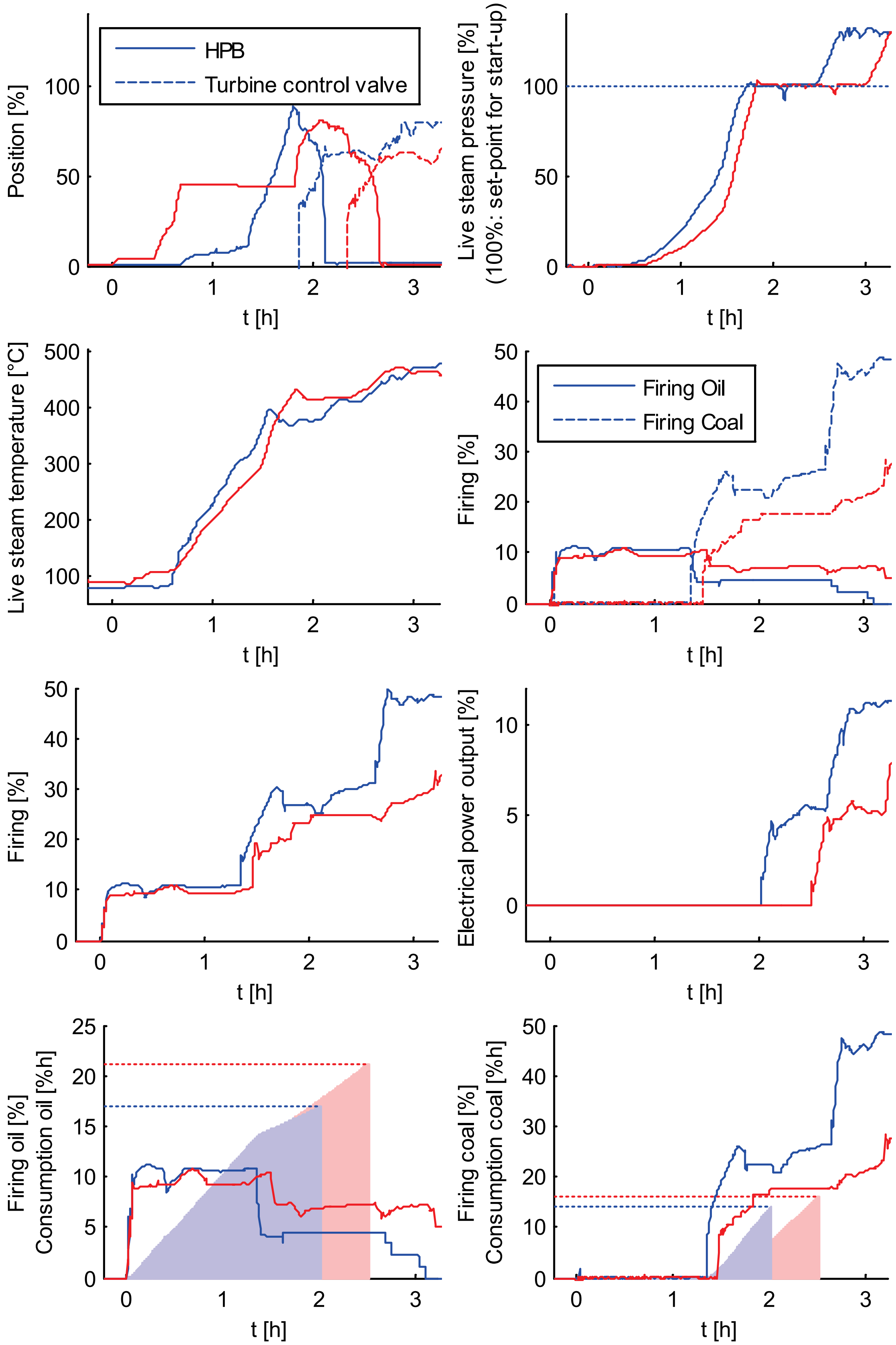


Figure 6: Cold start-up of a coal power plant. Red: manual, Blue: automated.

4 Control power

4.1 Status quo

As described in Section 2.1, control power can serve as an additional source of income. To participate in this market, the plant must comply with the prequalification criteria of the transmission system operator (TSO). These also include dynamic performance criteria. For Germany, the criteria are described in the Transmission Code of the TSOs [5] and in the corresponding appendices. According to the code, primary control power must be fully delivered within 30 seconds, secondary control power within five minutes.

4.2 What can be achieved with control?

To comply with the TSO criteria, the unit control must be optimized and control all subsystems in a coordinated way. The coordinated unit control makes use of the energy storage capacities inherent to the thermodynamic cycle of the plant. With these, the plant is able to change its load quickly without the need to stress the plant by overloading the fuel rate. Typical storage capacities are condensate throttling, HP preheater, steam storage of the boiler, coal mills and – if present – district heating. Moreover, the coordination ensures that fast load changes do not excite oscillations. Thus, several fast load changes can be performed in rapid succession. For more details on the coordinated unit control the reader is referred to [6].

How much potential there is in a certain plant depends on several factors. A reliable estimate of the potential is only possible by means of tests on site. Moreover, a prerequisite for the optimal functioning of the unit control is that the low level controls work reliably and are well tuned. Their task is to realize the set-points that are provided by the unit control. Hence, the unit control cannot perform well if the low level controls do not.

A typical procedure for the implementation of control power capability would be as follows:

- Rough potential analysis
- Potential analysis with tests
- Optimization of low level controls (as required)
- Optimization of unit control
- Prequalification

4.3 Results at STEAG

After optimization of the unit control by STEAG Energy Services, several of STEAG's power plants have been prequalified by the TSO for primary and secondary control power marketing. Figure 7 shows the reaction of a hard coal power plant to step-wise changes of the set-point as a test of secondary control capability. The plant is able to follow the steps, whose height is about 15% of the nominal power, within five minutes, as required. As the Figure shows, no oscillation is excited even after repeated steps in direct succession.

Some changes in the process have been necessary to reach these results. Major changes have been control valves in the steam ducts to HP preheater and feedwater tank. If measurements and or actuators are too slow, changes may be required here as well.

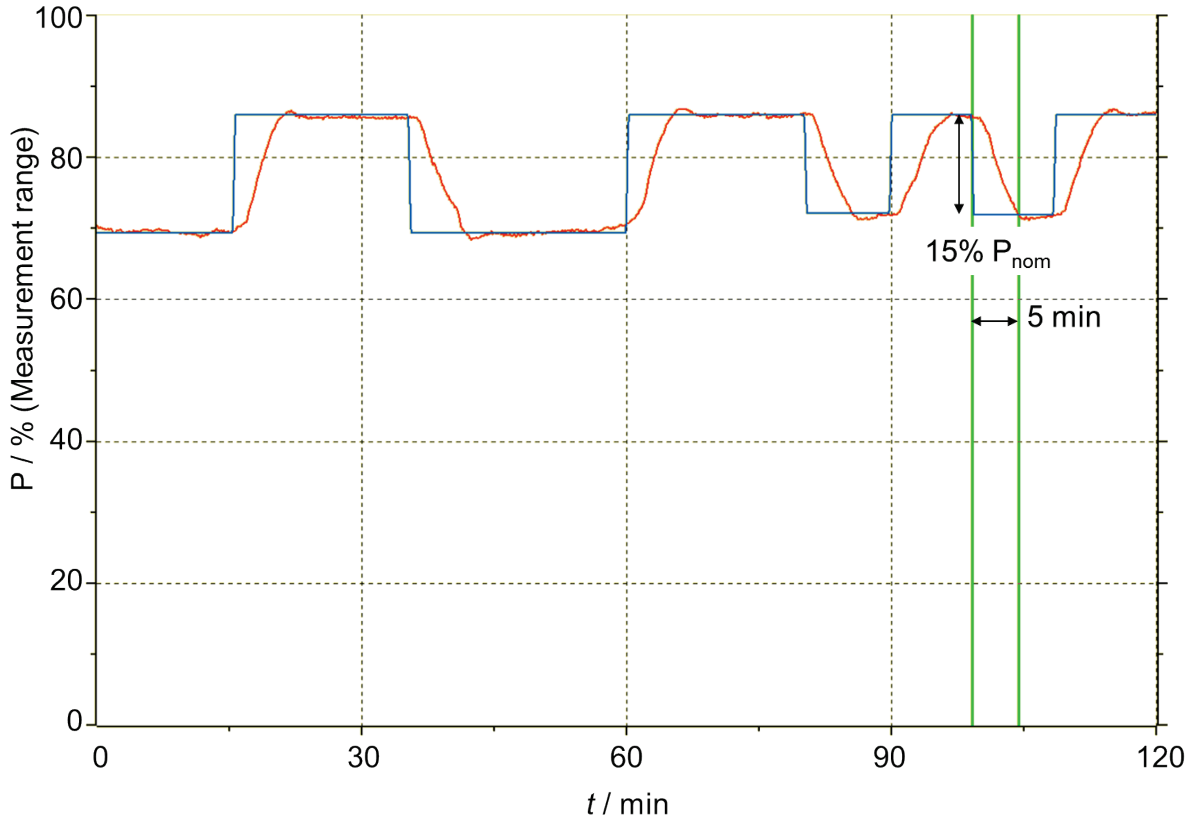


Figure 7: Secondary control power tests

5 Conclusions

The operation of hard coal fired power plants has shifted to mid-load due to the increased share of renewable energy sources in the market. To cope with mid-load operation, the plants are required to become more flexible than in the past. In this paper, examples of how control optimization may help to increase the flexibility of hard coal power plants have been discussed. Moreover, this contribution provides results from successful implementations in power plants of STEAG.

Keeping in mind that for each plant individual issues may apply, the following can be said as general conclusions:

- Depending on the plant and on the limitations due to combined heat and power, it is possible to reach minimum loads below 15% of nominal load by means of control optimization.
- With an optimized start-up controller and sequence control, the oil consumption can be reduced by 20% or more compared to classical manual start-ups.
- If enough potential is present, hard coal power plants can be equipped with an optimized, coordinated unit control that enables the plant to meet the prequalification criteria for primary and secondary control power.

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