

# Oxyfuel Combustion Retrofits for Existing Power Stations – Bringing “*Capture Ready*” to Reality

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## 1 INTRODUCTION

Because of global climate change which is assumed to be induced by rising CO<sub>2</sub>-emissions, public pressure to develop CO<sub>2</sub> lean technologies for electricity production from fossil fuels steadily increases. Two concepts are under development to be commercially available for future generations of conventional pulverized fuel (lignite or bituminous) fired power stations:

a) Post-combustion CO<sub>2</sub> capture: During post combustion capture, CO<sub>2</sub> - which is diluted (~13 vol%) in the flue gas - is removed by scrubbing with amine solutions or other agents. The energy demand for this absorption/desorption process is quite high and large amounts of low pressure steam from the turbine are required for CO<sub>2</sub> desorption. As a result, overall cycle efficiency is decreased by up to 12 percentage points. The advantage of this technology is that it can be applied as an additional downstream process after all flue gas treatments. Besides the energy requirements there are no other impacts on the power station boiler and APCS processes. Nevertheless, the high "area" demand for the CO<sub>2</sub> scrubbing equipment and large number of required changes in the steam cycle can make a retrofit of this technology expensive and complicated.

A simplification of CO<sub>2</sub> removal can be achieved by increasing the CO<sub>2</sub> concentration in the flue gas. Flue gas containing more than 90 wt.-% (db.) CO<sub>2</sub> can be compressed directly and the CO<sub>2</sub> can then be stored without further treatment – with the upstream removal of pollutants, like SO<sub>2</sub>, NO<sub>x</sub> and dust, assumed.

b) Oxyfuel combustion and direct CO<sub>2</sub> compression: In this process shown in Figure 1 the CO<sub>2</sub> concentration in the flue gas is greatly increased by using a mixture of recirculated flue gas and pure oxygen instead of air for coal firing. Recirculation of flue gas is necessary to provide sufficient mass flow of gas for cooling the flame and also heat capacity and flue gas velocity for convective heat transfer in the boiler.

In the oxyfuel process CO<sub>2</sub> purity is mainly influenced by

- where the flue gas is recycled in the process (the cleaning that has been done up to this point) (possibilities: 1-6 according to Figure 1)

- the sealing of boiler and other components (the boiler is still operated at a pressure slightly below ambient pressure for safety reasons)
- the purity of the oxygen from the Air Separation Unit (ASU)
- the performance of all air quality control systems (DeNOx, Figure 1 1-2, DeSOx 4-5, ESP 3-4)
- additional CO<sub>2</sub> purification during/after compression

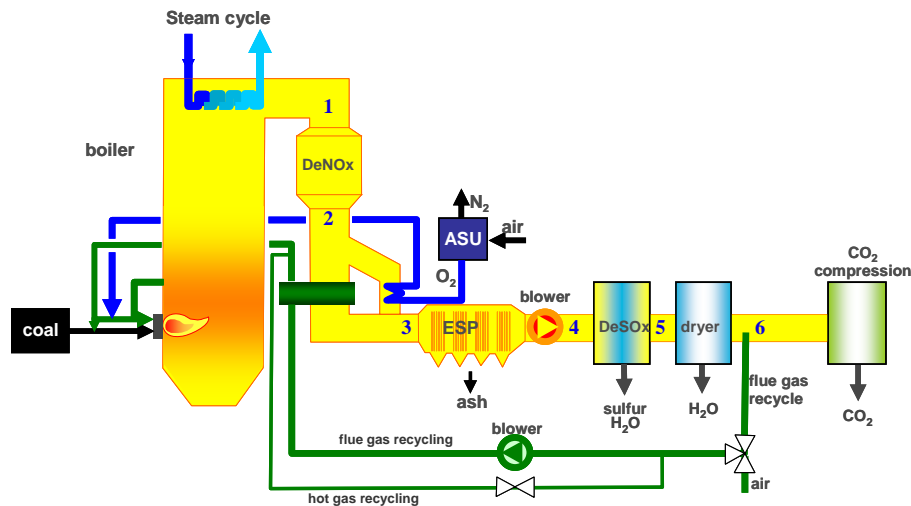


Figure 1: The oxyfuel process

In any event, CO<sub>2</sub> purity has to be sufficiently high so that it can be directly transported and stored. This can be achieved by increasing the effectiveness of traditional flue gas treatment or by the installation of (cryogenic) CO<sub>2</sub> purification afterwards. The recirculated gas usually has to be pre-treated to prevent the operation risk of increased corrosion and erosion.

In the following sections, an approach which includes highly sophisticated flue gas treatment instead of additional CO<sub>2</sub> treatment will be described.

The main advantage of this oxyfuel concept is that the steam generator and steam cycle for air firing and oxyfuel firing do not differ (no steam extraction required as in scrubbing processes) and that the efficiency loss and investment cost are potentially much lower than with other concepts. The electricity required for air separation contributes about 55% to this efficiency decrease and about 30% is related to CO<sub>2</sub> compression. Less than 15% of the efficiency decrease is due to other components or process modifications.

To ensure the value of actual investments in power stations and also maintain maximum flexibility for responses to future regulatory frameworks, it is necessary to prove that power stations constructed now can be retrofitted to oxyfuel firing and be operated as CO<sub>2</sub> lean power stations in future.

Below, the plant modifications and new components required for retrofitting oxyfuel firing to an existing power station will be described along with the changes in firing and flue gas cleaning

processes. A specific characteristic of the retrofit measures is that the power station can be operated both with oxygen and air firing after the retrofit. As a result, the plant can be started and shut down in air-firing mode. Also in the case of operational trouble of power plant systems, CO<sub>2</sub> compression, transport or storage, a switch to air firing can be done quickly – something which increases the reliability of electricity supply.

## 2 ORIGINAL POWER STATION: DESIGN FOR AIR COMBUSTION

The retrofit measures will be explained based on a state-of-the-art 600°C power station currently under construction; see Figure 2.

820 MWe<sub>el</sub> / 2088 t/h  
 Once-through steam generator, Benson®  
 Bituminous Coal

Design parameters:  
 SH: 600 °C / 276 bar a  
 RH: 620 °C / 51 bar a  
 Commissioning: 2011/2012

Design coal:  
 LHV: 25100 kJ/kg  
 Ash: 13 %  
 Water: 10 %

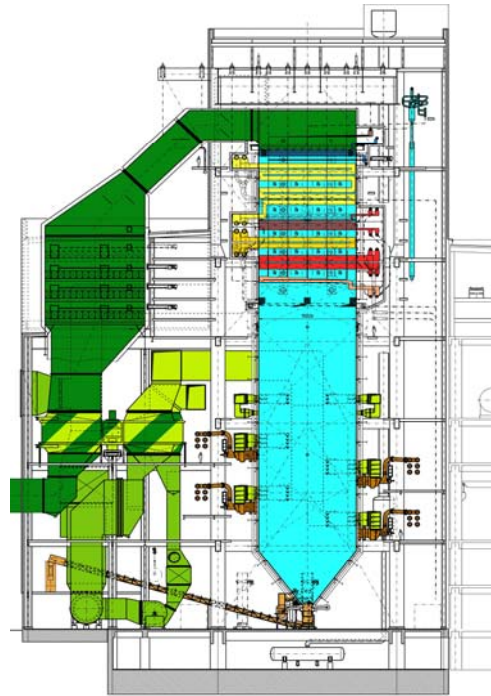


Figure 2: Power station and design coal

According to Figure 3 during air firing of the power station, the firing air is preheated in the flue gas air-preheater and distributed to mill (primary air), burner and overfire air (OFA) ports. A portion of the primary air enthalpy is used for feedwater preheat in the "mill air cooling cycle". This [1] increases the overall efficiency of the power station process by minimizing cold air to the mill to reduce exit temperature of the flue gas cycle by using additional waste heat from the flue gas. Additionally, less steam needs to be extracted from the turbine.

After combustion the flue gas is cooled in the air preheater, NO<sub>x</sub> concentration is decreased catalytically, dust is removed in the ESP and SO<sub>x</sub> is removed using limestone in a wet scrubber.

In the boiler the steam is mainly heated by radiation in the combustion chamber and by convective heat transfer in the heat exchangers (super heaters, reheaters, economizer) in the convective pass.

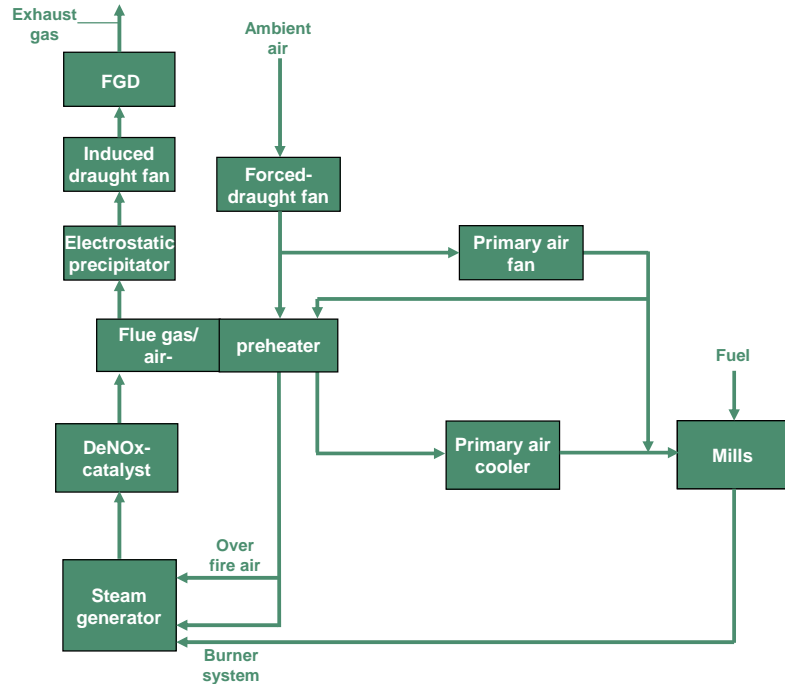


Figure 3: Firing process (air case)

### 3 RETROFIT TO OXYFUEL FIRING

Looking at the different options for flue gas recirculation (locations 1-6, Figure 1) it is obvious that the complexity of flue gas recycling is reduced from the progress made in flue gas treatment. Recycling high-temperature flue gas (before air preheater) is thermodynamically advantageous but requires a total change of the heat balance and a re-design of the plant (boiler and components). A high dust recirculation upstream of the ESP would increase the erosion of all firing and boiler parts. Without DeSOx the SO<sub>2</sub>/SO<sub>3</sub> concentration would be increased by accumulation (~factor of 3) and additionally SO<sub>3</sub> formation would increase from possibly more contacts with catalytic active surfaces. Therefore all firing and boiler components (flue gas and recycle gas ducts, blowers, mill, burners, heat exchangers, boiler materials) would be at risk from corrosion. Especially in retrofit cases, the original plants are not designed on the air side for such an operation involving high temperature, dust or SO<sub>2</sub>/SO<sub>3</sub> concentrations. Modifications would be quite expensive since all equipments in the boiler house would have to be replaced.

For all of these reasons the retrofit concept shown below is based on the recirculation of cold, cleaned and partially dried flue gas after (improved) DeSOx and additional flue gas cooling. This would allow all existing components including blowers and ducts – at least inside the boiler house - to be used as well after a retrofit. The only measure to be taken inside is to preheat the recycled flue gas by recycling a small amount of hot gas up to a temperature well above the saturation point so as to avoid condensation.

Then again, most of the retrofit measures need to be implemented outside the boiler house. A switch between oxyfuel and air operation mode can be done simply by using gas tight dampers at the former air inlet where the recycle duct is mounted.

Other changes outside the boiler house involve pure oxygen oxidation in the (improved) DeSOx plant, the addition of a flue gas cooler/condenser upstream of flue gas recycling and subsequent cleaning of the flue gas to reduce the SO<sub>2</sub>/SO<sub>3</sub> content still further. The purge gas of the mill is switched to CO<sub>2</sub>, the atomizing gas for the aqueous ammonia in the DeNOx is replaced by CO<sub>2</sub> and the ash removal at the ESP is replaced by a gas tight system. For oxygen preheating a tubular preheater parallel to the air preheater (now used as gas/gas preheater for the recycle gas) has to be installed.

### 3.1 Thermal Engineering and Combustion Technology

To prevent significant changes to the power plant heat balance, it must be assured that the heat transfer in furnace and heat exchangers in the convective pass match the original design. Additionally, the material temperatures have to be kept in a tolerable range and the steam temperatures and pressures should match the air combustion case. These requirements are fulfilled by the following variables in the oxyfuel case:

- Furnace exit gas temperature upper limit set by ash melting temperature
- Mass flow of recycled flue gas and split in gas for burner (primary gas and other), over-fire air and curtain gas
- Oxygen content in different gas flows

During the redesign under oxyfuel conditions the firing components (mill, burner) are recalculated as is the heat transfer in furnace and heat exchangers with respect to the changed flue gas properties so as to determine the optimal process parameters. For the retrofit case the modifications of existing components are minimized so as to reduce plant outage time.

#### 3.1.1 Mills

An important criterion for mill operation is the discharge of particles by flue gas. The dominating force is the flow resistance

$$F_{sw} = c_w \cdot A_s \cdot \frac{\rho_G \cdot w_G^2}{2} \quad \text{Eq.1}$$

with the drag coefficient  $c_w$ , the velocity  $w$  and the cross sectional area of the particle  $A$ . The drag coefficient  $c_w$  is a function of Particle-Reynolds number  $Re_p$

$$Re_p = \frac{\rho_G \cdot \Delta c \cdot d_p}{\eta_G} \quad \text{Eq.2}$$

with the density of the flue gas  $\rho_G$ , the difference of velocities of gas and particle  $\Delta c$ , the diameter  $d_p$  of the particle and the dynamic viscosity  $\eta_G$  of the gas. As a result, the force of flow resistance depends on temperature and composition of the carrier gas and therefore the massflow required for the transport of the fuel particles depends on location. The calculations proving that the gas can carry the fuel particles have to be carried out at least at the mill nozzle ring, upstream and downstream of the classifier and in the ducts. The volumetric flow has to be the same as for air firing operation to get a reliable and steady flow downstream of the classifier. The lower velocity at the nozzle ring in this case is compensated by the higher gas density.

### 3.1.2 Burner

The power station studied here uses Hitachi Power Europe's low NO<sub>x</sub> DS burners (Figure 4) [2].

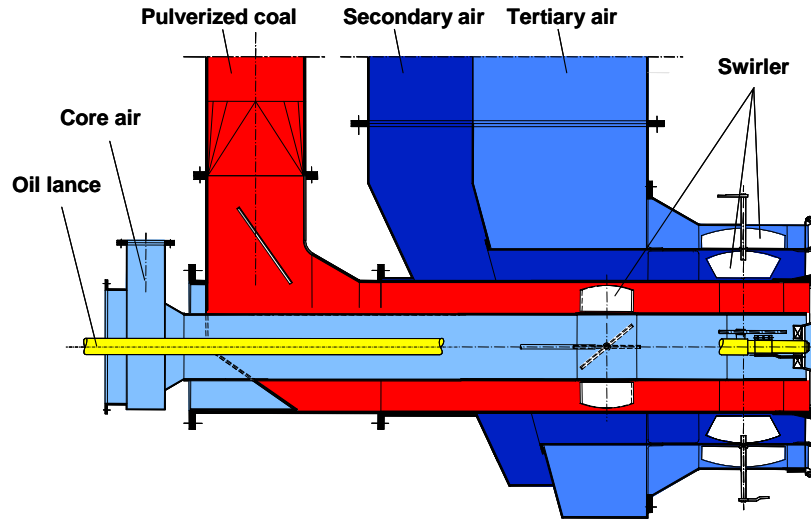


Figure 4: Low NO<sub>x</sub> DS burner

Except for the primary gas flow, which has to be adjusted to the mills' needs, the momentum gas flows at the burner are kept constant in the retrofit case so as to get a flame shape similar to that in the atmospheric mode.

The momentum flow is

$$\dot{I}_{PG,SG} = \dot{m}_{PG,SG} \cdot w_{PG,SG} \quad \text{Eq.3}$$

with

- $\dot{I}_{PG,SG}$  momentum flow of primary and secondary gas
- $\dot{m}_{PG,SG}$  mass flow of primary and secondary gas
- $w_{PG,SG}$  flow velocity of primary and secondary gas.

With unchanged cross section and the continuity equation, Eq.3 results in

$$\dot{m}_{PG,SG} = \dot{m}_{PL,SL} \cdot \sqrt{\frac{\rho_{PG,SG}}{\rho_{PL,SL}}} \quad \text{Eq.4}$$

with

- $\dot{m}_{PG,SG}$  mass flow of primary and secondary gas in oxyfuel case
- $\dot{m}_{PL,SL}$  mass flow of primary and secondary air in atmospheric case
- $\rho_{PL,SL}$  density of primary and secondary air
- $\rho_{PG,SG}$  density of primary and secondary gas

The flame temperature and burnout progress are adjusted to fulfil the needs of heat transfer utilizing the oxygen concentration as a variable. This is demonstrated by the findings from a rotational symmetric flame calculation.

Figure 5 depicts the difference between the temperature distribution of atmospheric and oxyfuel-fired flames. Whereas the upper half shows the temperature distribution of the atmospheric flame, the lower half reveals the findings for oxyfuel conditions. The difference is very small under the examined conditions. This shows that the chosen parameters for the oxyfuel case are appropriate for getting firing conditions inside the furnace similar to those under atmospheric conditions.

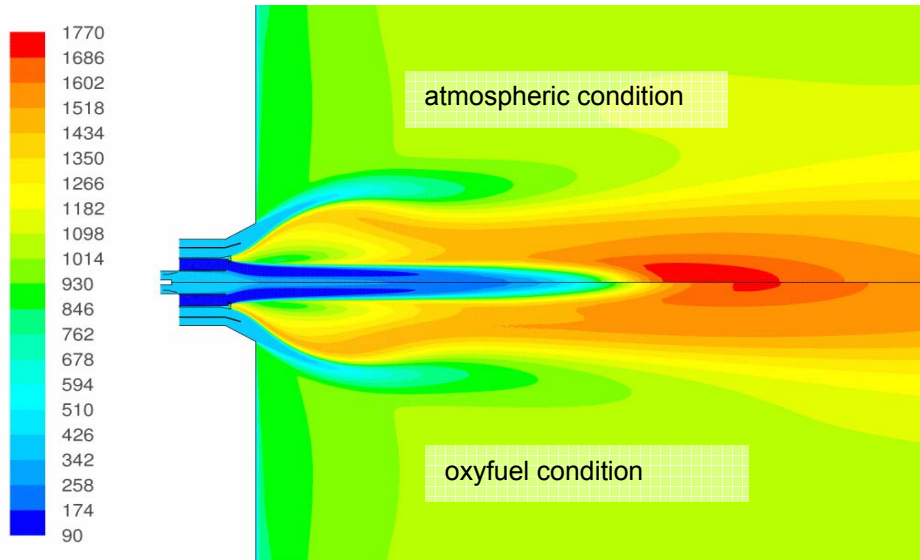


Figure 5: Temperature distribution in °C

It has to be pointed out that the flame temperature is very much affected by the volume fraction and the partial pressure of the oxygen in the oxygen carrying gas. The volume fraction is shown in Figure 6. Here the oxygen concentration is chosen to match temperature distributions of air and oxyfuel firing as shown in Figure 5. The often discussed decrease of oxyfuel flame temperature is countered by increasing the volume fraction of oxygen in the oxygen carrier gas.

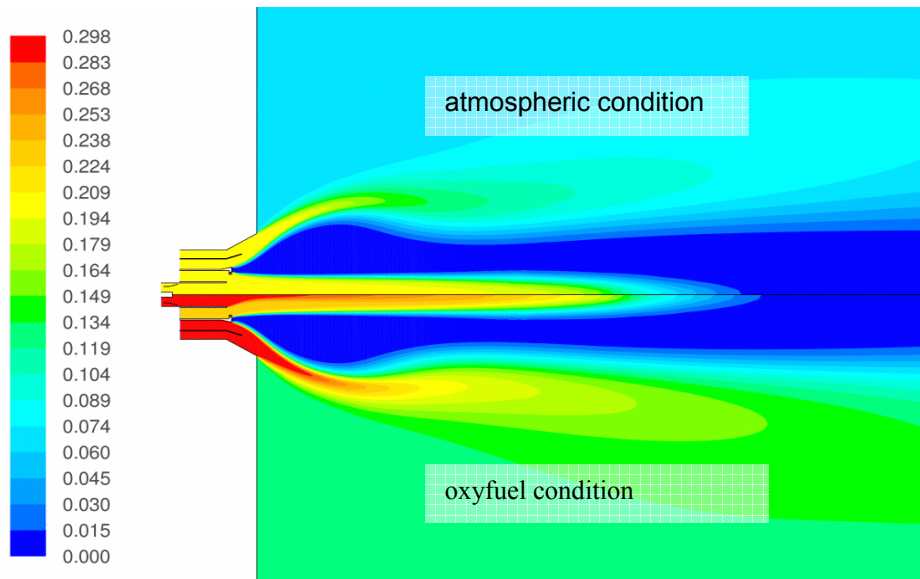


Figure 6: Volume fraction of oxygen

Comparison of the axial velocities (see Figure 7) shows that the rule for the momentum for the oxyfuel conditions really does result in similar flow fields for atmospheric and oxyfuel flames. In this figure, the white zones represent backflows. The backflow zone behind the tooth-ring of the primary air tube has nearly the same shape in both the atmospheric and oxyfuel modes. This backflow zone is essential for burner ignition purposes.

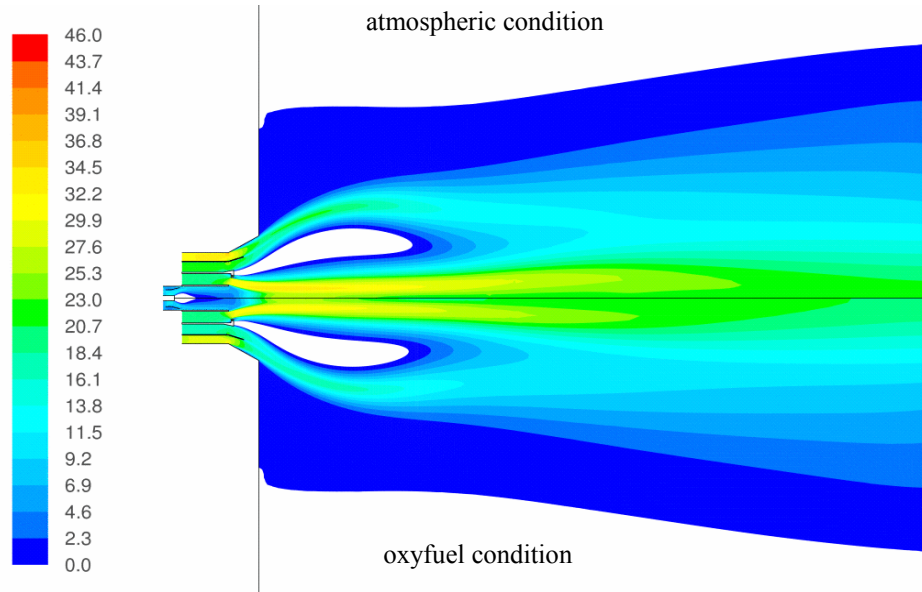


Figure 7: Axial velocities

The furnace exit gas temperature is similar to that in the air combustion case. Since NO<sub>x</sub> formation is reduced during oxyfuel combustion due to the absence of nitrogen in the combustion gas, the burner air ratio is increased.

### 3.1.3 Overfire air/gas

The mass flow of gas in the OFA system is adjusted so that the heat transfer in the convective pass matches the values of the original design.

Table 1: Heat transfer in convective pass (average values for entire convective pass)

$\Delta O_{xy}/Air$ mode * 400-1200°C	Air mode	Oxy mode		$\Delta O_{xy}/ Air$ mode [%]
flue gas density $\rho_{FG}$	1.33	1.80	kg/m <sup>3</sup> (STP)	35.0%
heat capacity of fg* $c_{p,FG}$	1.23	1.29	kJ/kgK	4.7%
dyn. viscosity of fg* $\eta_{FG}$	42.87	40.84	μPa s	-4.7%
heat conductivity of fg * $\lambda_{FG}$	0.07	0.07	W/mK	2.8%
mass flow of flue gas $m_{FG}$	716.70	744.85	kg/s	3.9%
max. flow velocity $w$	10.70	8.00	m/s	-25.2%
$\Delta T$ (logarithmic)	318.20	301.80	K	-5.2%
$\alpha$ (convection) $\alpha_{outside,convective}$	38.88	39.91	W/m <sup>2</sup> K	2.7%
$\alpha$ (radiation) $\alpha_{outside,radiation}$	34.98	48.36	W/m <sup>2</sup> K	38.3%
K (heat transfer coefficient)	51.02	60.26	W/m <sup>2</sup> K	18.1%
Total heat transfer in convective pass Q	705.83	741.51	MW	5.1%

As is shown in Table 1 the flue gas density in oxyfuel firing is increased by 35%, the heat transfer coefficients for convective and radiative heat transfer by 2.7 and 38.3% respectively and the flue gas mass flow by 3.9%. These increases are partially compensated by a 17K or 5.2% decrease of the logarithmic temperature difference. The flue gas recycling rate is 75.08% and the overall stoichiometric factor 1.17 (upstream of air heater). This is equivalent to an excess of oxygen at the end of the furnace of 2.86 wt.% wet. The purity of the oxygen used is 99.8%.

### 3.2 Overall Process Design and Modifications / New Components

The overall process design is shown in Figure 8. Modifications of the existing components and design of new components are described below. They minimize the overall leakage of air to the flue gas to 1% of the flue gas mass flow in the furnace.

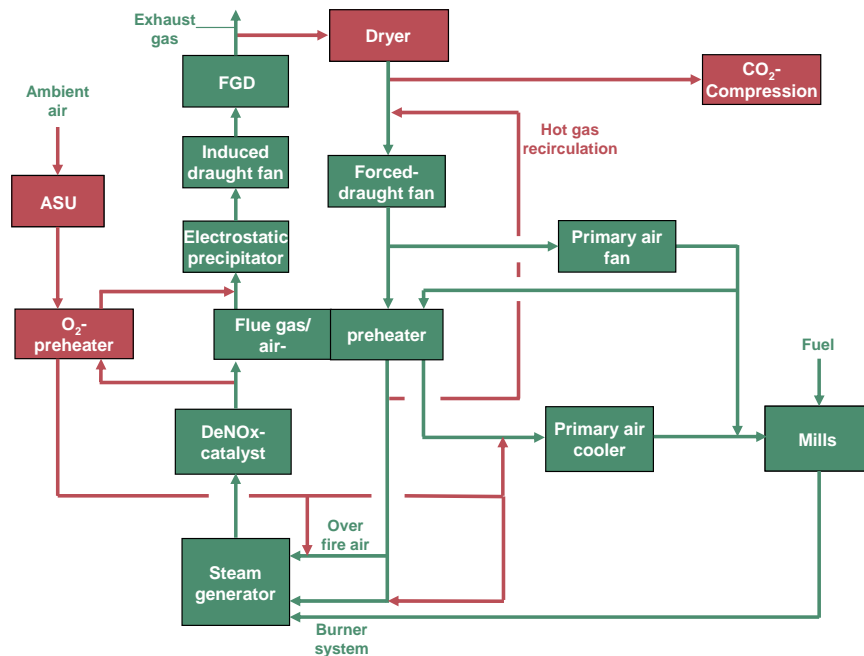


Figure 8: Firing process (oxyfuel case)

#### 3.2.1 Mill

The purge gas air used to protect the mill's rotating parts is replaced by CO<sub>2</sub> in the retrofit case. A special sealing system ensures that no CO<sub>2</sub> enters the boilerhouse.

#### 3.2.2 Regenerative air preheater

As Figure 1 shows the air preheater is also needed in oxyfuel firing to preheat the recycled flue gas. This gas cannot consume all the heat due to the absence of the mass of oxygen. Additionally, the oxygen cannot be mixed with the flue gas upstream of the air preheater – something which would increase the oxygen (and energy) demand by losses to the hot flue gas side and also reduce CO<sub>2</sub> purity.

#### 3.2.3 Oxygen preheating

As a consequence, a tubular heat exchanger is installed in a bypass to the air preheater to heat the oxygen. The oxygen preheater is located in a bypass duct parallel to the existing air preheater

(gas/gas heater) so that duct length is minimized. The inlet/outlet flue gas ducts are equipped with dampers for shutoff and control of the gas flow. By total shutoff of the oxygen preheater, air firing can be enabled even after the retrofit.

The flue gas leaving the oxygen preheater is remixed with the main flue gas duct downstream of the ESP. The area required for the O<sub>2</sub> preheater is about 250 m<sup>2</sup>, the volume is approx. 5000 m<sup>3</sup>.

### **3.2.4 Oxygen ducts in the boiler house**

Downstream of the oxygen preheater the oxygen is divided into the streams to different mixing points with recycled flue gas. Mixing with the primary gas is done downstream of the regenerative gas/gas heater (originally air preheater) but upstream of the mill gas heat exchanger. The O<sub>2</sub> mass flow to the secondary gas and over-fire gas is split into two ducts leading to mixing points on the left and right side of the boiler. Each duct is equipped with measurement points for volumetric flow rate and control dampers. At the mixing points static mixers are mounted in the ducts.

### **3.2.5 Ash removal**

A retrofit is not necessary since a minimum ingress of air is already ensured by a wet ash removal system for the boiler which was implemented during the air firing design

### **3.2.6 DeNO<sub>x</sub> (SCR)**

The air used for spraying anhydrous or aqueous ammonia into the flue gas in the DeNO<sub>x</sub> system is replaced by heated carbon dioxide (from the third or fourth pressure level of final carbon dioxide compression) so as to decrease the oxygen and nitrogen concentration in the flue gas.

In so doing, it should not be forgotten that urea is also produced by ammonia and carbon dioxide via the intermediate product of ammonium carbonate [3]. This can lead to unintentional by-products with ammonia injection. The impacts of these products on SCR-catalysts are unknown. Given that water enhances the formation of these by-products a gaseous ammonia injection is preferred.

Except for controlling the formation of unintentional products, no other modifications are needed. This is because the changed flue gas conditions are not expected to impact in other ways on the SCR-reaction.

### **3.2.7 Electrostatic precipitator**

Changes in the performance of the electrostatic precipitator from changes in the flow characteristics are not expected because turbulences in the range of the changing Reynolds numbers are comparable.

The changed operation mode of the power block will have impacts on the electrostatic precipitator performance [4]. Lower peak burning temperatures can result in the ash composition and sizing - depending on coal types - being different. This is of real consequence for the ultrafine fraction within the electrostatic precipitator due to the effect on the dust resistance values. This effect can be either positive or negative for the ESP performance. Since precipitation of the coarse fraction is mainly by gravity, these impacts are more significant for the fine and ultrafine fractions.

A limited change in precipitator performance is not critical for modern units with a full air quality control system. This is because FGD and even the flue gas cooler are effective in capturing dusts. Overall, dedusting is adequate for flue gas recirculation and carbon dioxide compression.

Additionally, air leakages at the electrostatic precipitator have to be avoided. This is possible by replacing its discharge units by air-tight comparable units. This means e.g. air-tight rotary feeders or double flap valves instead of normal ones to avoid a leakage of pneumatic conveying air to the electrostatic precipitator. To stop any back leakage stream of pneumatic air, the discharge units are to be provided with a small amount of sealing carbon dioxide.

### 3.2.8 Preheating recycled flue gas

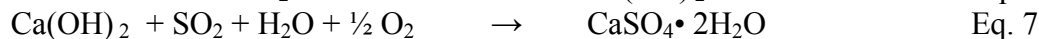
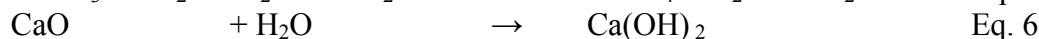
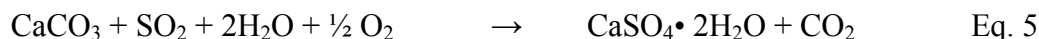
Preheating the recycled flue gas is done by a limited back-recycle of hot, cleaned flue gas so as to reach a temperature significantly above the saturation point and thus avoid condensation. This – and the improved DeSO<sub>x</sub> described below – will stop corrosion in the ducts and on all existing components.

### 3.2.9 DeSO<sub>x</sub> (FGD)

State-of-the-art desulfurization units are open-spray tower absorbers with limestone as the absorbent. For oxidation of the calcium sulfite to calcium sulfate, air is blown to the absorber sump directly in front of the agitators.

In the oxyfuel process, all reactions within the absorber have to work under a carbon dioxide atmosphere. As already shown on a laboratory scale the desulfurization performance is lowered under oxyfuel conditions [5] when scrubbing is done with limestone. This effect is probably even more marked under real conditions because limestone solubility is hindered by the carbon dioxide atmosphere in the absorber. Saturation of the slurry with carbon dioxide will see the solubility of limestone drop significantly.

For this reason the reagent should be changed to calcium oxide (quicklime). It does not need to release carbon dioxide to the flue gas while being dissolved. For better understanding, the total chemical reaction in the absorber is shown for CaCO<sub>3</sub> (1) and CaO (2) - including the slaking process.



At least the same performance is expected from running the absorber with calcium oxide as it is from running the absorber with limestone under normal conditions. Using quicklime under normal conditions, experience shows that a lower recirculation amount is necessary for the same absorber efficiency.

To oxidize the calcium sulfite to calcium sulfate in the absorber sump, gaseous oxygen produced in the air separation unit replaces the existing oxidation air in the oxyfuel process desulfurization unit. In new power plants, external oxidation of the sulfite in a separate tank might be favoured,

but in retrofitting a plant this will be hard to handle due to the piping of the absorber and its recirculation pumps.

The conclusion is to change the absorbent mixing station from limestone to lime which only needs an additional slaking system. Furthermore, the absorber oxidation air system should be changed to use pure oxygen, necessitating a retrofit of the oxidation blowers and agitator system.

### **3.2.10 Flue gas drying cooler**

In the described oxyfuel process the flue gas must be dried before being recirculated or compressed. This entails cooling down the flue gas to 30°C as a saturated flue gas. The needed thermal power for this cooling is approximately 150 MW(th) for a 820 MWel power plant.

There are two alternatives for this cooling. First, one can use a closed spray cooling absorber, which needs energy for cooling water recirculation and internal recirculation, or one can use a heat exchanger which although only needing energy for cooling water recirculation has a worse heat exchange capability. The closed spray cooling absorber can additionally deliver sodium hydroxide to the process to achieve a very clean flue gas. Nevertheless, both cooling types are technical possible solutions and still in competition with each other in technical details.

In the cooler, approximately 190 m<sup>3</sup>/hr of condensate is produced for an 820 MWel unit. One stream of this condensate can be used as makeup water for the desulfurization absorber.

Due to the large amount of condensates the cooler also operates as a flue gas cleaning system. Nevertheless, flue gas ducts for recirculation and ducts to the carbon dioxide compression stage should all be made corrosion-resistant (i.e. FRP material).

### **3.2.11 Recirculation duct and link to oxygen system**

Downstream of the dryer the flue gas is split and one flow is directed to the boiler house. The duct is connected to the outside air inlet with leak-tight dampers which also provides air in the case of air firing. A small proportion of the already preheated recirculated flue gas is used to pre-heat the main stream of the recirculation to a temperature above the dew point before entering the existing ductwork. The hot gas duct (internal recirculation) is connected to the flue gas duct downstream of the gas/gas preheater. Both the hot gas duct and recirculation duct are equipped with control dampers and measurement points for volumetric flow rate.

### **3.2.12 Carbon dioxide purification and compression**

In the oxyfuel mode the flue gas contains about 93 %wt of carbon dioxide. The mass flow is reduced to 25 % of flue gas flow leaving an air-fired furnace. Purification and compression of this CO<sub>2</sub> rich flue gas is the last step of the oxyfuel process. This plant is divided into 3 to 4 compression units.

Some of the remaining contamination gases, such as NO<sub>x</sub> and SO<sub>x</sub>, are separated during compression of the flue gas and leave the process as condensates from the intermediate coolers as sulfuric and nitric acids. Most of the water is also removed from these intermediate coolers. There is no other purification step; the other trace gases such as nitrogen, oxygen and argon remain in the compression stream.

To also remove these gases, liquefaction of the carbon dioxide is necessary to make a phase separation possible. This process, as shown in Figure 9, is to be done just below the critical point of the carbon dioxide to avoid low temperatures for liquefaction.

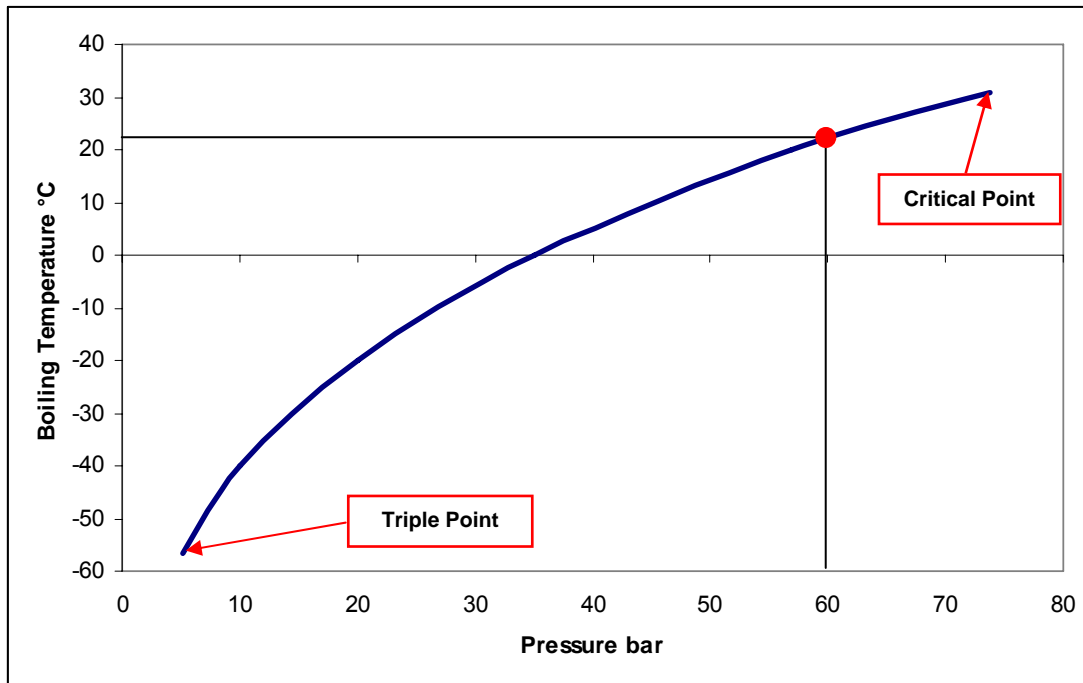


Figure 9: Boiling temperature vs. pressure for CO<sub>2</sub> [6]

Whether this is necessary or not is decided by the requirements of transport and later storage of the carbon dioxide. For enhanced oil or gas recovery, no oxygen in the gas is wanted. For other storage alternatives such as deep aquifers no oxygen limits have as yet been set up. Research on this has not been concluded. In fact it has only started in most countries.

As long as their concentration is kept down, the trace gases of nitrogen and argon do not hinder carbon dioxide storage or use for enhanced oil and gas recovery. Water has to be removed down to very low values to prevent corrosion in pipelines and tanks.

### 3.2.13 Air separation unit (ASU)

For the oxyfuel process, an ASU (air separation unit) is indispensable. The only commercially available and proven technology to supply an 820 MWe bituminous coal fired power plant from today's perspective is the cryogenic process.

The oxygen requirement for an 820 MWe power plant averages up to 13,500 t/d (including 10% reserve). The largest-ever ASU to date is of 3,600 t/d. ASUs with capacities up to 4,800 t/d are currently being planned. According to leading manufacturers, capacities up to 7,200 t/d will be developed in the future. This will make a number of ASU lines necessary. Furthermore the number of ASU-lines depends on the control range of one unit to cover the whole load range of a power plant.

For the 820 MWe<sub>el</sub> gross power station the ASU has to be designed with 4 lines. The different modules are connected by an O<sub>2</sub> output manifold. Each line connected to the manifold is equipped with shutoff dampers to isolate the individual lines from the plant. This reduces the energy requirement for the ASU in cases of partial load. Also each line can be serviced independently from plant operation. From the manifold the O<sub>2</sub> duct is routed to the O<sub>2</sub> preheater. The space required for this plant is roughly 2.6 hectares.

An important issue is the load change rate of an ASU. A typical rate is 1%/min but the rate of a power plant, depending on the “grid code”, is up to 5%/min. To compensate for this difference, a temporary buffer storage is essential.

Another major issue is the energy demand of an ASU. Oxygen-purity and the pressure at the interface are the vital factors here. With consideration given to the carbon capture part, the best point of balance is achieved at higher oxygen purity. A typical statement put out by leading manufacturers is a specific energy consumption of 0.35 kWh/Nm<sup>3</sup>; for an optimized plant a value of 0.3 kWh/Nm<sup>3</sup> is stated. (All values refer to oxygen with ambient temperature and only slight overpressure). This results in 137MW and 117MW including 10% reserve.

#### 4 SUMMARY

The process engineering for retrofitting the power plant to oxyfuel firing is described in this paper to enable CO<sub>2</sub> capture after the combustion process. The flue gas composition for normal air firing and oxyfuel firing is shown in Table 2. The concentration of CO<sub>2</sub> in the flue gas after cooling is nearly 95 wt% (db.) in the case of oxyfuel firing. This gas can be directly compressed and directed to the storage site without further purification.

Table 2: Comparison of flue gas composition

gas species	air firing (Composition after ESP)		oxyfuel-firing (Composition after cooling)	
	wt % wet	wt % dry	wt % wet	wt % dry
H <sub>2</sub> O	5.9	-	1.8	-
CO <sub>2</sub>	19.4	20.6	89.9	94.9
N <sub>2</sub>	68.7	73.1	2.0	2.1
O <sub>2</sub>	4.5	4.7	2.9	3.0

Table 3: Demand of el. energy, cooling power and area for retrofit.

	minimum area required [m <sup>2</sup> ]	P <sub>el</sub> [MW]	Q <sub>th</sub> (cooling) [MW]
ASU	26000	107	117
Cooling & AQCS modifications	900	4	150
CO <sub>2</sub> Compression	2000	85	

The required area for some new components as well as the demand for electrical energy and cooling capacity is shown in Table 3. The required area for AQCS modification is rather small compared to the ASU which has to be installed as new. Nevertheless, the ASU can also be constructed at some distance from the power station when the oxygen is transported to the boiler-house by pipeline. Hence, there is normally enough space for the remaining modifications on the site. The arrangement of new components and plant modifications is shown in Figure 10.

Table 3 also provides the energy requirements for a number of modifications. The ASU and compressors require a large amount of electrical energy. Using the numbers given, the gross electrical output of the power plant in a worst case is reduced by more than 24%.

While it has been shown that retrofitting existing power plants is technically feasible, all processes have to be further optimized in future to decrease the efficiency penalty of CCS.

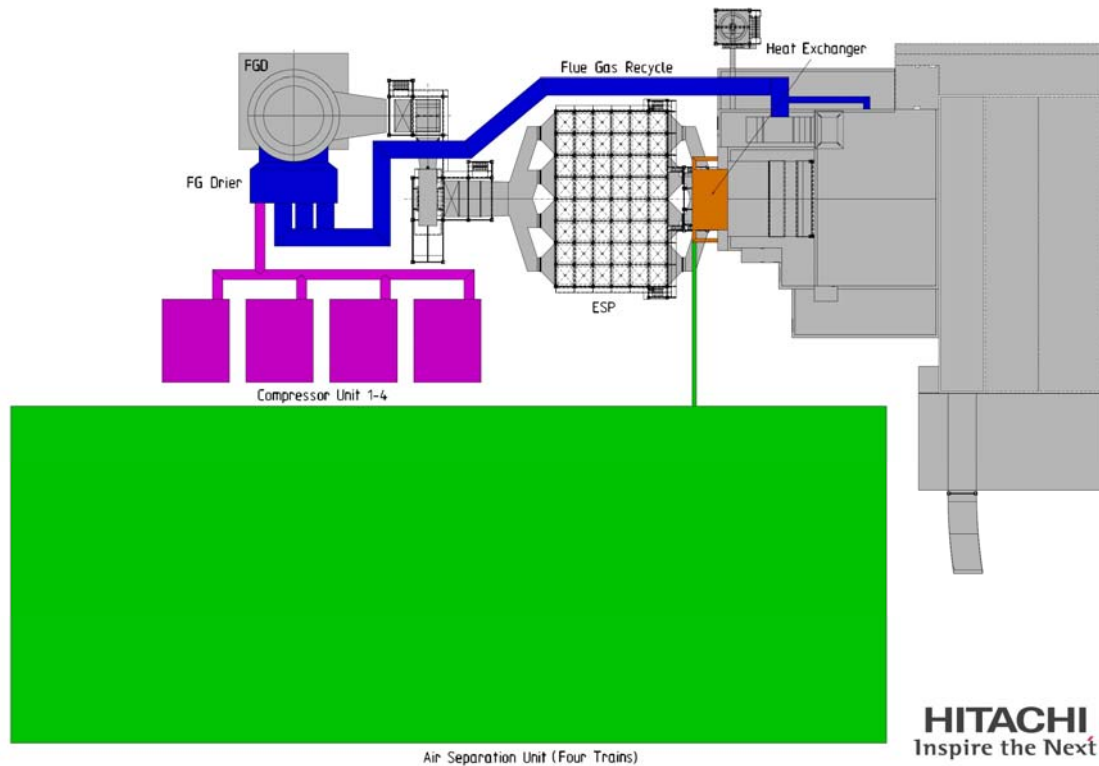


Figure 10: Arrangement planning for retrofitted power station

Assuming emission costs of 30€/t of CO<sub>2</sub>, the emission cost of a 820 MWe<sub>el</sub> power station during the 40 years lifetime is up to 7 billion € while the fuel cost increase is 24%. These figures justify larger and more expensive modifications and enhancements of the power station and new components like ASU to decrease still further the energy requirements of CO<sub>2</sub> capture in newly built and retrofitted power stations.

This could also cut the use of natural resources, residual emissions and demand of CO<sub>2</sub> storage volume to more acceptable figures in the future. Hitachi is currently undertaking extensive development work to improve basic technologies for oxyfuel combustion and other CCS options. This is being done so as to supply highly efficient, overall solutions for CO<sub>2</sub> lean fossil fuel power stations to the global market as a contribution to society by combating climate change.

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