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Development of Oxyfuel Combustion Technology for Existing Power Plants

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ABSTRACT

Oxyfuel combustion is one of the promising technologies to enable CO_2 capture and sequestration (CCS) for new and existing coal-fired power plants. Hitachi has been working on an extensive development program to commercialize oxyfuel combustion technology through design studies, laboratory scale experiments, CFD modelling, as well as small and large pilot plant tests. The immediate focus is to ensure that the coal-fired power stations commissioned in recent years and in the near future can be converted to oxyfuel for CCS operation. The development work to date has shown that existing state-of-the-art coal-fired power stations can be converted to oxyfuel combustion with no change to the plant water-steam cycle. The boiler can be operated at relatively low oxygen concentration in oxyfuel mode and the original design coal range and boiler heat input can be maintained. Only minimal modifications to the boiler house equipments and limited alterations to the air quality control system will be needed. Major equipment additions for the air separation and CO_2 compression, handling, transportation and storage will require large capital investment and also result in reduction in plant power output / efficiency. The power plant after oxyfuel conversion will have the flexibility to operate in both air-fired and oxyfuel modes, an important feature to maintain generation reliability while the new CCS system is being implemented. This paper will present the results of design studies for converting 820 MWe class supercritical pulverized coal power units to oxycombustion, and also furnace numeric simulations and experiment data to support such conversion.

INTRODUCTION

Coal-fired power plants with CO_2 capture and sequestration (CCS) are widely expected to be an important part of the future technology portfolio to achieve overall global CO_2 reductions required for stabilizing atmospheric CO_2 concentration and global warming. New coal-fired plants built in the coming years will need to be "capture ready" which means that they can be retrofitted with CCS technologies as these technologies become commercially available and still offer competitive cost of electricity compared to other means of power generation. Oxyfuel combustion is one of the promising technologies to enable CCS for new and existing coalfired power plants. For retrofit applications, oxyfuel combustion is an attractive option because it does not affect the boiler-turbine steam cycle, and with proper design its impact on the boiler fire-side processes and auxiliary equipment can be minimized.

Oxyfuel combustion produces a flue gas stream containing mostly CO_2, which can be directly compressed and purified without further treatment, assuming upstream removal of other pollutants, such as SO_2, NOx and dust. In the process shown in Figure 1 the CO_2 concentration in the flue gas is greatly increased by using a mixture of recirculated flue gas and pure oxygen instead of air for firing coal. Recirculation of flue gas is necessary to provide sufficient mass flow of flue 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_2 purity is mainly influenced by (a) 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), (b) the sealing of boiler and other components to prevent air ingress, (c) the purity of the oxygen from the Air Separation Unit (ASU),

(d) the performance of all air quality control system equipment (SCR, FGD, and ESP), (e) additional CO_2 purification during/after compression.

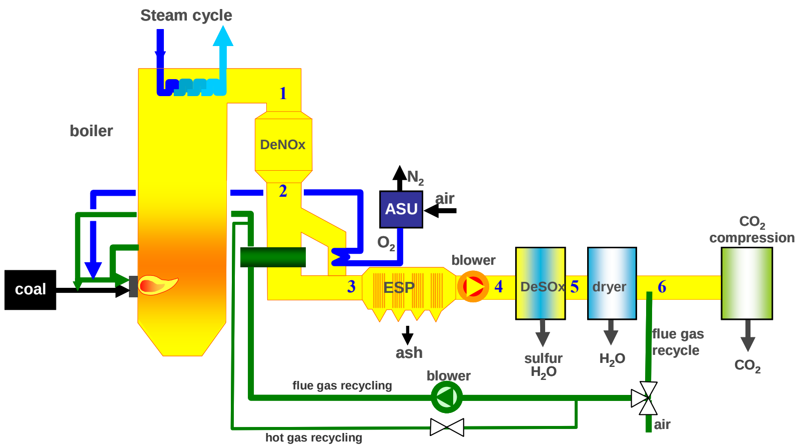


Figure 1: The oxyfuel process

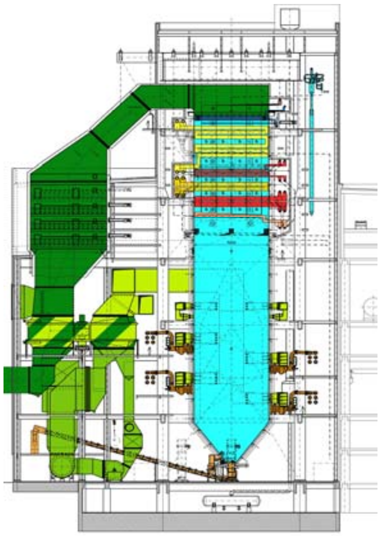
The objective of the current work is to develop a retrofit design that can be applied to the coal-fired power stations commissioned in recent years or in the near future to enable CCS operation. A special characteristic of the retrofit measures is that the power station can be operated both with oxygen and air firing after the retrofit. As a result, the plant can be started and shut down in air-firing mode. Also in the event of operational trouble with the new systems, such as CO_2 compression, transport and storage, switching to air firing can be done quickly to ensure reliable electricity supply.

In the following sections, the required plant modifications, expected boiler performance and plant system impact of oxyfuel conversion, as well as CFD modeling and pilot test studies to support such conversion will be discussed.

DESIGN STUDY AND MODELLING

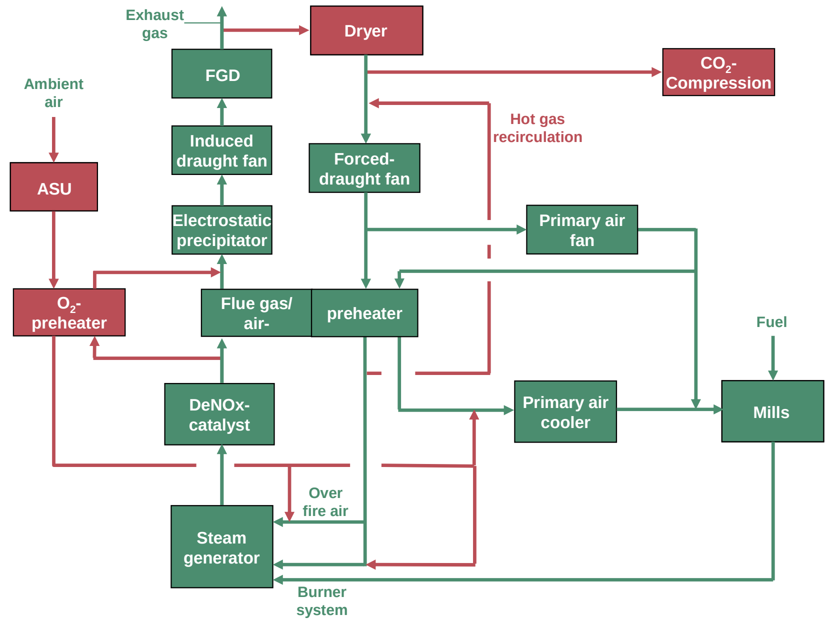
Basis of Design Study

The retrofit design study has been performed based on a state-of-the-art 600°C (1112 °F), 820 MWe power station currently under construction; see Figure 2. During air firing, the combustion air is heated in the flue gas air-preheater and distributed to mill (primary air), burner and over-fire air (OFA) ports. A portion of the primary air enthalpy is used for feedwater preheat in the "mill air cooling cycle". This increases the overall efficiency of the power station process by minimizing cold air to the mill and by reducing the flue gas exit temperature. Additionally, less steam needs to be extracted from the turbine. After combustion the flue gas is cooled in the air preheater, NOx concentration is decreased catalytically, dust is removed in the ESP and SO_2 is removed using limestone in a wet scrubber. In the boiler the steam is mainly heated by radiation in the furnace and by convective heat transfer in superheaters, reheaters, and economizer in the convective pass.



(a) Once-through steam generator, Benson®
820 MWe, 2088 t/h steam
SH: 600 °C / 276 bar a (1112 °F / 4003 psia)
RH: 620 °C / 51 bar a (1130 °F / 740 psia)
Commissioning: 2011/2012
Design coal: Bituminous Coal

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



(b) Firing process

air case = green components and lines

oxyfuel case = red components and lines added

Figure 2: Power station and design coal (a) and firing process (b)

Modifications for 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 FGD the SO_2/SO_3 concentration would be increased by accumulation (~factor of 3) and additionally SO_3 formation would increase from contacting with catalytic 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.

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

Most of the necessary retrofit measures will be implemented outside the boiler house. Switching 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 FGD plant and the addition of a flue gas cooler/condenser (150 MW_{th}, cooling to 30°C) upstream of flue gas recycling which leads to further reduction of the SO_2/SO_3 content. 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. For oxygen preheating a tubular preheater parallel to the air preheater (now used as gas/gas preheater for the recycle gas) will be installed. By total shutoff of the oxygen preheater, air firing can be enabled even after the retrofit.

The purge gas of the mill is switched to CO_2 and the sealing is retrofitted to ensure that no CO_2 enters the boiler house. The atomizing gas for the aqueous ammonia in the SCR is also replaced by CO_2 and the ash removal at the ESP is replaced by a gas tight system. A retrofit of the boiler ash removal system is not necessary since a minimum ingress of air is already ensured by a wet ash removal system which was implemented during the air firing design.

The modifications minimize the overall leakage/injection of air/nitrogen to the flue gas to 1% of the flue gas mass flow in the furnace. In the oxyfuel mode therefore the flue gas contains about 95 %wt of carbon dioxide. The mass flow is reduced to 25 % of the flue gas flow leaving an air-fired furnace. Purification and compression of this CO_2 rich flue gas is the last step of the oxyfuel process. During compression some of the remaining contamination gases, such as NOx and SOx, are separated and leave the process as condensate from the intermediate coolers as sulfuric and nitric acids. Most of the water is also removed from these intermediate coolers. Normally there is no other purification step since other trace gases such as nitrogen, oxygen and argon can remain in the compression stream for storage. To also remove these gases (depending on the use/storage option) cryogenic separation would be necessary. However, water has to be removed down to very low values to prevent corrosion in pipelines and tanks.

The only commercially available and proven technology today to supply an 820 MWe bituminous coal fired power plant with oxygen is the cryogenic process. In this case up to 13,500 t/d (including 10% reserve) of oxygen is required. The available size and required control range of air separation units (ASUs) will make 4 ASU lines necessary. An important issue is the load change rate of an ASU which typically is limited to 1%/min but the rate of a power plant is up to 5%/min. To compensate for this difference, a temporary buffer storage is necessary.

Combustion Process and Thermal Performance

To avoid 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 adjustment of the mass flow of recycled flue gas and the split in gas streams for burner (primary gas and other), over-fire and curtain gas as well as the adjustment of the oxygen content in different gas flows. The furnace exit gas temperature is set according to the upper limit given by the ash melting temperature.

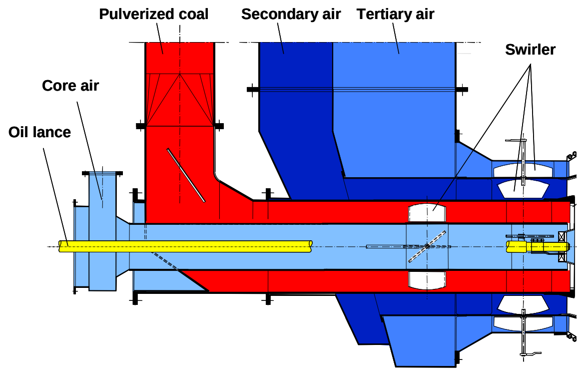
Under oxyfuel conditions the firing components (mill, burner) as well as the heat transfer in furnace and heat exchangers are reevaluated with respect to the changed flue gas properties so as to determine the optimal process parameters. For the retrofit case the modifications of existing components are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

Firing System

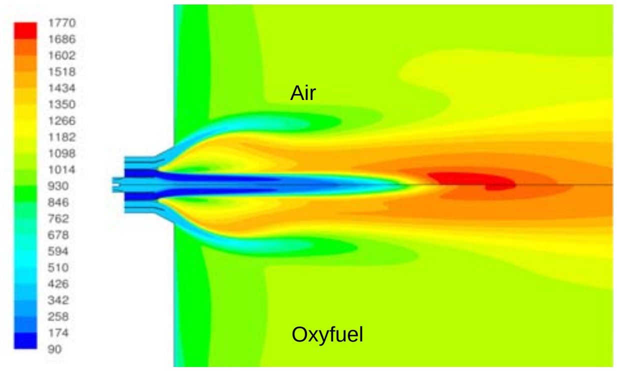
An important criterion for mill operation is the discharge of coal particles by flue gas. The dominating force here is the drag force which depends on temperature and composition of the carrier gas and therefore the mass flow required for the transport of the fuel particles depends on location. The calculations proving that the gas streams 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.

The power station studied here uses Hitachi Power Europe’s low NOx DS burners (Figure 3a). 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 air firing mode.

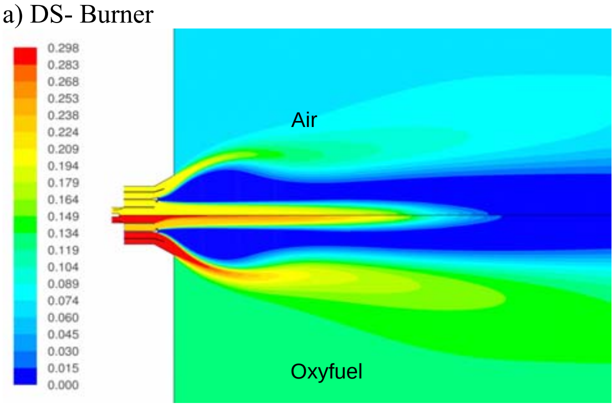
The flame temperature and burnout progress are adjusted to fulfill the needs of heat transfer utilizing the oxygen concentration as a variable. This is demonstrated by the findings from a rotational symmetric flame calculation.



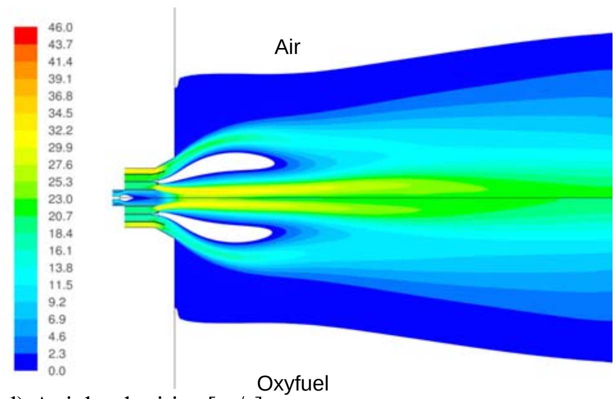
a) DS- Burner



b) Temperature distribution [°C]



c) Volume fraction of oxygen [-]



d) Axial velocities [m/s]

Figure 3: Low NOx DS burner (a) and results from CFD calculation results (b-d)

Figure 3b depicts the difference between the temperature distribution of air-fired and oxyfuel-fired flames. Whereas the upper half shows the temperature distribution of the air-fired 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 air-fired conditions.

It should be pointed out that the flame temperature is very much affected by the volume fraction of the oxygen in the oxygen carrying gas. The volume fraction is shown in Figure 3c. Here the oxygen concentration is chosen to match temperature distributions of air and oxyfuel firing as shown in Figure 3b. The often discussed decrease of oxyfuel flame temperature is countered by increasing the volume fraction of oxygen in the oxygen carrier gas.

Comparison of the axial velocities (see Figure 3d) shows that the rule for the momentum for the oxyfuel conditions really does result in similar flow fields for air-fired 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 air-fired and oxyfuel modes. This backflow zone is essential for burner ignition purposes.

Heat Balance

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. 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 75.1% and the overall stoichiometric factor is

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.

Table 1: Heat Transfer in Convective Pass (average values for entire convective pass).

	Air Mode	Oxy Mode	Unit	ΔOxy / Air Mode [%]
flue gas density	1.33	1.80	kg/m³ (STP)	35.0%
heat capacity of flue gas	1.23	1.29	kJ/kgK	4.7%
dynamic viscosity of flue gas	42.87	40.84	µPa s	-4.7%
heat conductivity of flue gas	0.07	0.07	W/mK	2.8%
mass flow of flue gas	716.7	744.9	kg/s	3.9%
maximum flow velocity	10.70	8.00	m/s	-25.2%
ΔT(logarithmic)	318.2	301.8	K	-5.2%
heat transfer coefficient, outside convective	38.88	39.91	W/m²K	2.7%
heat transfer coefficient, outside radiation	34.98	48.36	W/m²K	38.3%
overall heat transfer coefficient	51.02	60.26	W/m²K	18.1%
total heat transfer in convective pass	705.8	741.5	MW	5.1%

Furnace Modeling

CFD-simulations of both the air firing and oxyfuel modes were made, which allow for the comparison of the different conditions in the furnace. The furnace geometry simulated is shown in Figure 4. In the vertical section of the temperature field in Figure 5a and 5c the positions of the individual burners can be clearly recognized in both operating modes by their relatively cold inlet flows. At the same time the high temperature gradients clearly reveal the burner ignition zones. As the chosen conditions lead to similar flame shapes, the temperature distributions in both operating modes are very similar especially at the burner levels. The lower mass flow through the OFA system in the oxyfuel mode leads to a slight tilt in the temperature field above the burner levels. At the furnace exit the temperature distribution is homogenized by the pressure loss induced by the convective section above the furnace. The furnace exit gas temperature is similar to that in the air combustion case.

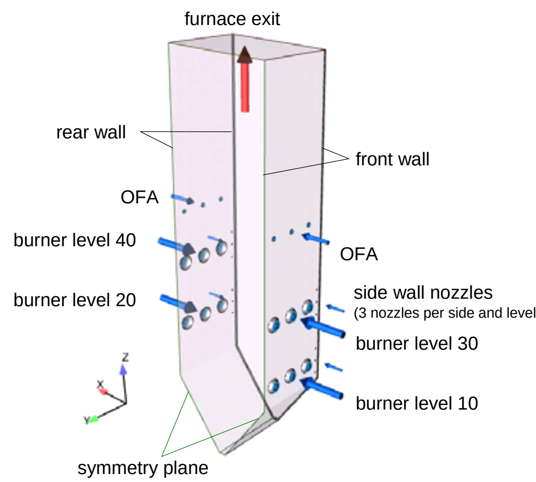
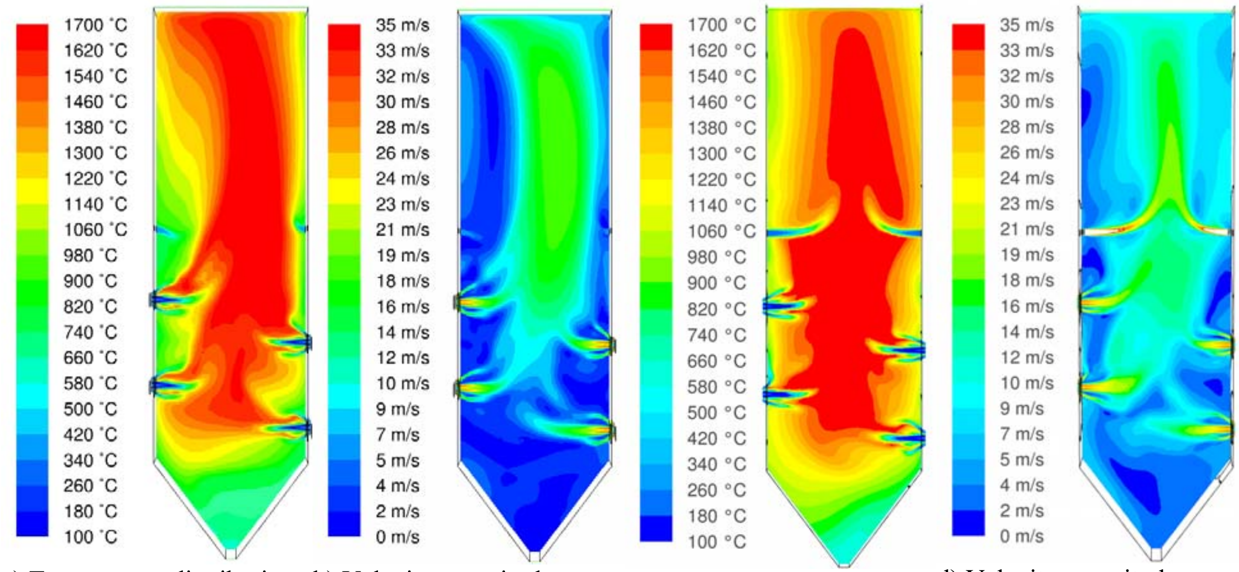


Figure 4: Furnace geometry

The flue gas flow velocities in the furnace are shown in Figure 5b and 5d. The positions of the burners can be clearly identified from the high velocities there with nearly equal values both in oxyfuel and air-fired mode. It can also be seen that in Oxyfuel mode the low mass flow through the OFA system has no significant impact on the flow in the furnace. Therefore due to the staggered burner levels the hot flame gases are directed somewhat more to the front wall than in the air-firing mode. This effect could be overcome by a lower mass flow through the top burner level than through the level below. In air firing mode the highest velocities, which lie beyond the scaling, exist at the OFA system. The high mass flow through the OFA system counteracts the slight tilt induced by the staggered burner levels.

In general the CFD-Simulations show similar conditions in both the air firing and oxyfuel modes, thus the stable operation of the furnace in oxyfuel mode can be expected.



a) Temperature distribution - Oxyfuel mode

b) Velocity magnitude - Oxyfuel mode

c) Temperature distribution - air-fired mode

d) Velocity magnitude - air-fired mode

Figure 5: Simulated temperatures and velocity magnitudes in Oxyfuel and air-fired mode

Impact on Power Plant System

The flue gas composition for normal air firing and oxyfuel firing is shown in Table 2. The concentration of CO_2 in the flue gas after cooling is nearly 95 wt% (dry) 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) wt % wet	wt % dry	Oxyfuel-firing (Composition after cooling) wt % wet	wt % dry
H_20	5.9	-	4.8	-
CO_2	19.4	20.6	89.9	94.9
N_2	68.7	73.1	2.0	2.1
O_2	4.5	4.7	2.9	3.0

The required area for the 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 the new components and plant modifications is shown in Figure 6.

Table 3: Power Demand, Cooling Duty and Area Required for The Retrofit

	Area Required [m²]	Power Demand [MW]	Cooling Duty [MW]
ASU	26000	107	117
Cooling & AQCS modifications	900	4	150
CO_2 Compression	2000	85	

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

It should be pointed out again that this study is focused on retrofit and with the intention to minimize the equipment modifications and to ensure the power plant after the retrofit can still be operated in oxyfuel or air fired modes. These measures are necessary for early retrofit applications of oxyfuel-based CCS to maintain power grid reliability. Future power plants designed solely for oxyfuel combustion can significantly reduce the penalties in plant efficiency and output by using improved furnace / boiler design and flue gas recirculation arrangement targeting oxyfuel as the only firing mode.

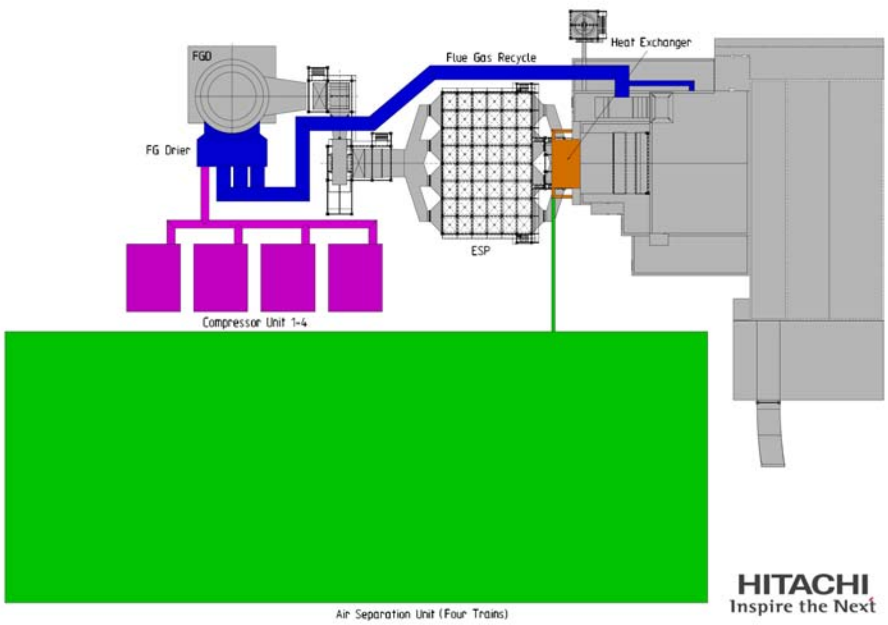


Figure 6: Arrangement for retrofitted power station

COMBUSTION TEST STUDIES

Combustion test studies have been carried out in bench scale and pilot scale to support the oxyfuel retrofit design development, in some cases in cooperation with partners and customers of Hitachi. Combustion experiments are essential to provide data for burning behavior and ash characteristics under oxyfuel conditions. These tests also help verify the numerical simulation tools used extensively in the design study, and generate data for integrated control and operation of the combustion system, air separation unit, and the air quality control system.

A number of small and large pilot plants have been used for this development program, including:

- 0.5 MW_{th} combustion test facility at IVD in University of Stuttgart, Germany
- 1 MW_{th} E.ON combustion test facility in Ratcliff, UK
- 1 MW_{th} combined combustion – air quality control system test facility in Akitsu, Japan
- 4 MW_{th} combustion pilot plant in Kure, Japan

Table 4 gives an example of the pilot test data. The data are from the 1 MW_{th} E.ON pilot plant firing a bituminous coal from South Africa and the 0.5 MW_{th} IVD test facility firing a German lignite. The CO_2 concentrations are approximately 94 vol.% dry from the 0.5 MW_{th} test facility, and only about 80% from the 1 MW_{th} plant due to its higher air in-leakage.

Table 4: Data from 1 MW_{th} and 0.5 MW_{th} Combustion Tests

Test Facility		1 MW_{th}	1 MW_{th}	0.5 MW_{th}	0.5 MW_{th}
Test Coal		Bituminous	Bituminous	Lignite	Lignite
Test Mode		Air	Oxy	Air	Oxy
O_2	%vol, dry	2.0	3.3	2.7	5.4
CO_2	%vol, dry	16.7	79.9	17.1	93.7
H_2O	%vol.	7.0	17.2	8.0	31.0
CO	ppm, dry	44	124	7	72
	lb/MMBtu	0.044	0.082	0.007	0.020
NOx	ppm, dry	245	329	451	499
	lb/MMBtu	0.34	0.09	0.67	0.23
SO_2	ppm, dry	513	1738	590	1366
	lb/MMBtu	0.96	0.62	1.18	0.88

NOx and SO_2 concentrations are higher because in both cases there are no post-combustion DeNOx or DeSOx and therefore NOx and SO_2 concentrations are increased due to the accumulation effect of flue gas recirculation. The NOx emission rates are significantly lower for oxyfuel tests, partly because the absence of air nitrogen under oxyfuel combustion conditions. The SO_2 emission rates for oxyfuel are also clearly lower than air firing. It is likely that the much elevated SO_2 concentration during oxyfuel firing leads to enhanced retention of SO_2 by the flyash which contains significant amounts of calcium oxide and magnesium oxide, based on the analyses of both coals. CO is higher for oxyfuel firing both in terms of concentrations in flue gas and the emissions rates. This increased formation of CO could be partially due to the much higher CO_2 concentration under oxyfuel firing condition which intensifies the gasification reaction between CO_2 and coal char, with CO as a product.

The next step of the pilot program is to prove and optimize flame temperature, radiation, burnout, and emission behavior in large pilot scale. Hitachi is currently working with Vattenfall to test the dual-firing (air /oxy) capable DS burner (a low NOx, staged combustion swirl burner) at Vattenfall's Schwarze Pumpe Oxyfuel Pilot Plant in Germany. The combustion test facility is equipped with integrated ASU, AQCS, CPU and produces liquid CO_2 for truck transportation to a storage site. The test burner, with a heat input of 30 MW, is nearly the size of those applied in Hitachi's commercial boilers. The combustion test is scheduled to start in early 2010.

SUMMARY

In summary, existing state-of-the-art coal-fired power stations can be converted to oxyfuel combustion with no change to the plant water-steam cycle and minimal modifications to the boiler island. Limited alterations to the air quality control system are needed. Major equipment additions for the air separation and CO_2 compression and handling are necessary. The converted power plant will have the flexibility to operate in both air-fired and oxyfuel modes.

While it has been shown that retrofitting existing power plants is technically feasible, all processes have to be further optimized in future to reduce the cost and efficiency penalty of CCS. 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, reliable and cost-effective solutions for CO_2 lean fossil fuel power generation to the global market as a contribution to the long-term sustainable growth of the society.