



Simulation and Prediction of Pollutants in a Flexi-Burn™ Oxyfuel Pulverized Coal Power Plant

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ABSTRACT

Power plants designed to incorporate oxyfuel combustion are expected to play a major role in the capture and sequestration of CO₂ emissions from fossil fuel-based power generation. Foster Wheeler is working on the reduction of carbon-dioxide with its integrated Flexi-Burn™ Pulverized Coal steam generator technology, which allows a power plant to efficiently use either air or oxygen as the coal oxidant.

An accurate prediction of pollutants such as SO_x, NO_x, Hg, and CO in both the recirculated flue gas and flue gas sent to the CO₂ Processing Unit (CPU) is vital to the design of an oxyfuel power plant. These contaminants can have a major impact on the design and operation of the boiler, coal mills, and CPU.

A simulation of a 460 MWe subcritical Flexi-Burn™ PC power plant is presented. Using the ASPEN-Plus system simulation software and FW-FIRE and Fluent 3-D CFD computer programs, emissions are predicted in both air and oxyfuel modes. Detailed 3-D CFD simulations of the boiler furnace are conducted to determine the effect of recycled gas contaminants such as NO, SO₃, and CO on boiler microclimates and outlet conditions. Furthermore, CFD simulations are used to predict boiler heat transfer absorptions and metal surface temperatures in both air and oxyfuel modes. Overall power plant performance (excluding ASU and CPU) is predicted by the Aspen-Plus simulator.

INTRODUCTION

Coal-fired power plants currently account for more than 40% of man-made worldwide carbon dioxide emissions [1]. Oxyfuel combustion is one of the most promising methods of removing carbon dioxide from the exhaust gases of a coal power plant. Oxyfuel combustion is based on combusting coal with oxygen and recycled flue gas, to produce carbon dioxide and water vapor as the main components of the exhaust gas. This allows the carbon dioxide to be much more easily captured from the exhaust gas than in air combustion where nitrogen is the dominant flue gas component.

Since oxyfuel combustion is still a developing technology, it is advantageous to design oxyfuel combustion boilers with combustion conditions similar to those of air-fired boilers. Moreover,

producing similar combustion conditions in the boiler allows oxyfuel to be readily adaptable to retrofit applications, which is especially important since coal firing is currently the dominant means of power generation (43% worldwide, 50% USA) [1].

Due to the uncertainties in oxyfuel combustion technology, capture and storage of carbon dioxide, and carbon dioxide emission regulations, there is a need for Flexi-Burn boilers, i.e. boilers which can be changed from air-firing to oxyfuel combustion, with minimal changes in the plant equipment. To enhance power generation operability and availability, it may be advantageous to operate a Flexi-Burn boiler in air-firing mode, when, for example, the air separation unit (ASU), CO₂ purification/compression unit (CPU), or CO₂ storage system is unavailable. Another key advantage of the Flexi-Burn plant is the ability to reduce the risk of exposure to an uncertain market for CO₂ credits. The flexibility to operate in either air or oxyfuel mode allows adjustment of plant operation to a changing and unknown market for carbon-free electricity and will promote faster adoption of carbon capture and sequestration technology.

Presented herein is the development and evaluation of a Flexi-Burn pulverized coal (PC) oxyfuel boiler, constructed with conventional combustion equipment, which can readily operate in air or oxyfuel modes.

DESIGN

The Flexi-Burn design is capable of either running on air or oxygen. Consequently, such a design is adaptable to a new boiler or a retrofit of an existing boiler. By properly selecting the flue gas recirculation flow rate, the same boiler geometry, materials, and burners can be used in both air-fired and oxygen-fired modes. The oxyfuel combustion process can be readily retrofitted to an existing PC boiler by adding the flue gas recycle equipment, the air separation unit, and the CO₂ compression and purification equipment (assuming there is sufficient space for the ASU and CPU equipment).

In oxyfuel combustion (also termed oxygen-firing), the combustion air is separated into O₂ and N₂ and the boiler uses the O₂, mixed with recycled flue gas, to combust the coal. The products of combustion are thus only CO₂, water vapor, and small amounts of impurities comprising mainly of atmospheric gases. The water vapor is condensed, yielding a CO₂-rich stream that can be easily purified. The CO₂ effluent is compressed, purified and further compressed to supercritical pressure and is piped from the plant to be sequestered in geologic formations.

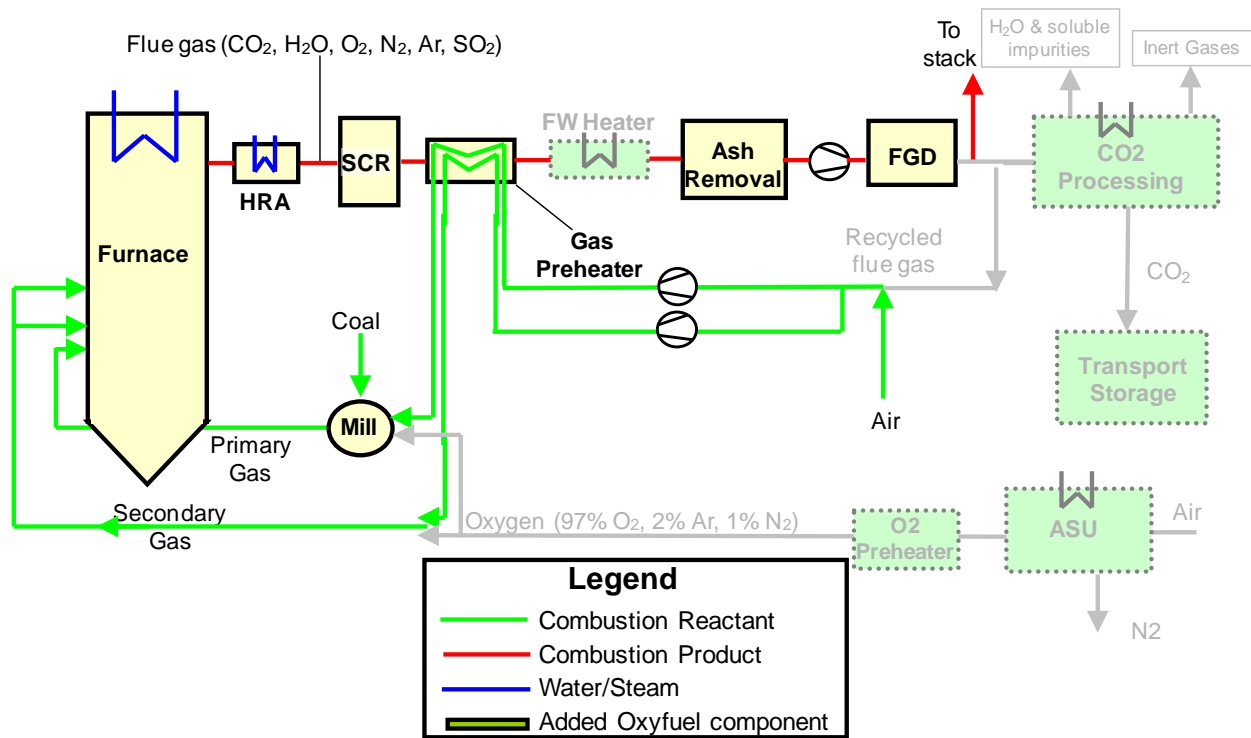
As shown in Figure 1, in the oxygen-firing mode, the coal is combusted in the furnace where the oxidizer consists of a mixture of O₂ and recycled flue gas (i.e. 70 – 80% by wt.), which contains primarily CO₂ gas. The net oxygen concentration in the furnace (before combustion) is similar to the air-fired operation (i.e. 23%-27%, vol. for O₂-firing vs. 21%, vol. for air-firing).

SIMULATION

The system design and analysis, which were performed using the Aspen-Plus computer program, were aimed at selecting the PC boiler plant operating parameters to allow the plant to run in either air-firing and oxygen-firing modes while minimizing the equipment modifications. The

reference plant is an actual subcritical pressure (2415psia/1000°F/1000°F) power station firing low-sulfur PRB or high-sulfur bituminous coal and generating 460 MWe gross and 418 MWe net (air-firing). The power plant model is shown in both air-fired and oxygen-fired operation in Figure 1.

Figure 1 - Process Schematic in Air-Firing and O₂-Firing Modes



The reference power plant selected employs a natural circulation boiler, selective catalytic reduction (SCR) for reducing NO_x, a wet flue gas desulfurization (FGD) for capturing SO_x, and a baghouse to remove particulates. The furnace has a total of 24 opposed wall-fired low NO_x burners and 10 over-fire air ports. The furnace heat transfer surfaces consist of waterwalls, radiant superheater partial division walls, and convective finishing superheater and reheater tube banks. After leaving the furnace, flue gas energy is recovered in a parallel-pass convective heat recovery area (HRA) and a regenerative rotary air heater. Final main steam temperature is controlled by spray water attemperation, while reheat steam temperature is controlled by a HRA gas flow proportioning damper, which regulates the flue gas flow to two parallel superheater and reheater passes. Primary air and secondary air are heated in the air heater after which the former is sent to vertical spindle MBF pulverizers to convey the coal and the latter is sent to the furnace windbox.

The scope of the model covers the majority of the power plant, exclusive of the ASU and CPU, as shown in Figure 2. Heat released from combustion is absorbed in the furnace by waterwalls, division walls, and roof and absorbed by the superheater, reheater, and economizer convective tube bundles in the heat recovery area. After exiting the economizer, flue gas passes through the

SCR for NO_x control and then through a regenerative air heater to heat up both primary air (PA) and secondary air (SA). Downstream of the air heater, a baghouse (BHG) removes particulates and a flue gas desulfurizer (FGD) captures SO_x using a sprayed limestone solution/slurry and reduces the gas temperature by sprayed water. An air ingress of 2%, vol. is assumed and lumped into BHG in the model.

Main controlled operational variables are main steam temperature by two water attemperators, reheat steam temperature by an HRA parallel pass gas damper, pulverizer PA outlet temperature by tempering air, and steam generation by coal firing rate. The mole fraction of O₂ in the furnace flue gas is maintained at 2.35%, vol. for both air-firing and oxy-firing.

Emission predictions in the model include NO_x, SO_x, CO, PM, NH₃, VOC, HCl, and Hg. A wet FGD with limestone feed is applied to remove most of the SO_x to form gypsum (CaSO₄*2H₂O). For NO_x control, the power plant is equipped with low NO_x burners, air staging (over-fire air), and SCR. In the model, part of Hg is oxidized and removed by the combination of SCR/BHG/FGD. Fuel-Cl, released as HCl in the furnace, is effectively removed with SO_x in the FGD to form MgCl₂, which is drained together with gypsum.

Site ambient conditions are listed in Table 1. Coal analysis is presented in Table 2.

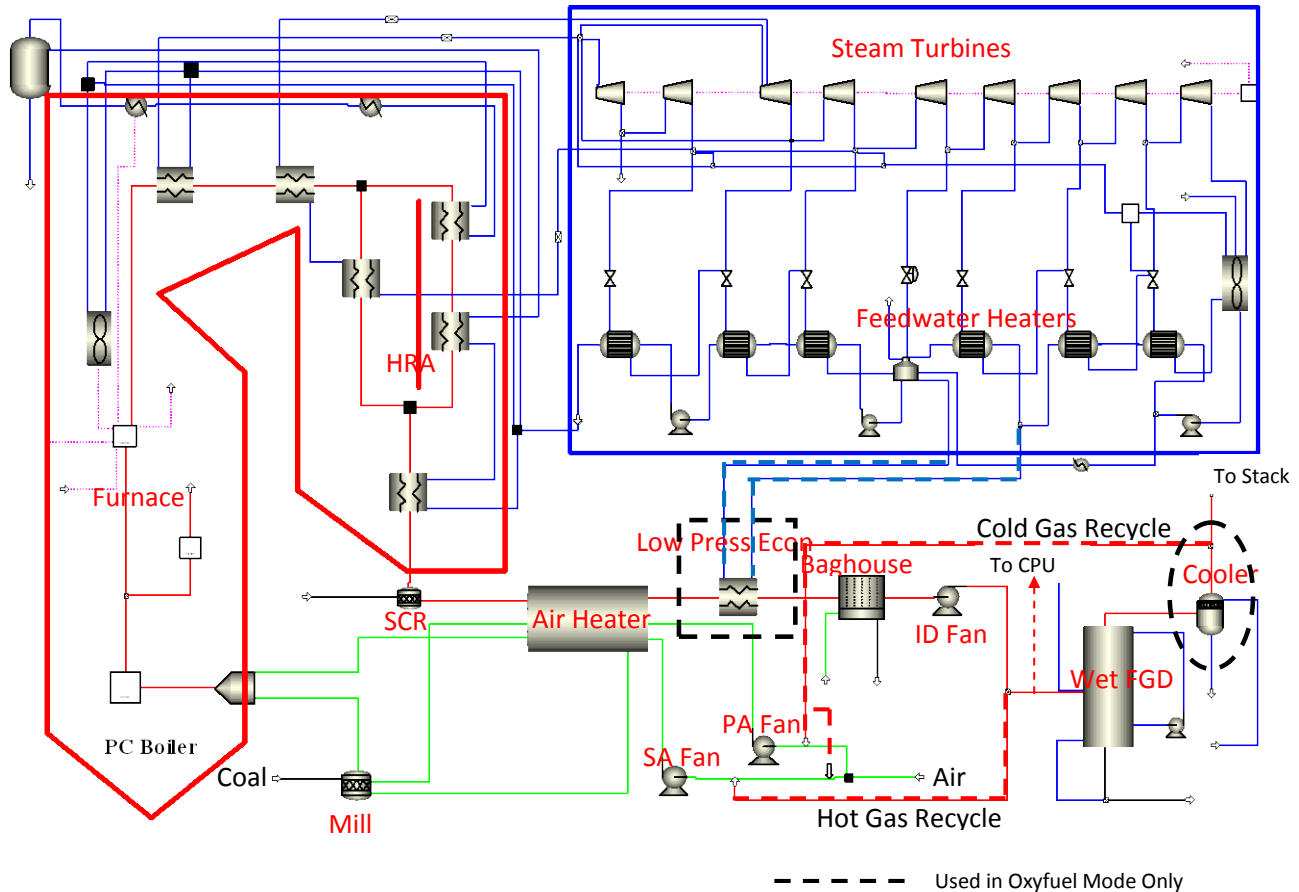
Table 1 – Site Conditions

Elevation	ft	7000
Ambient Pressure	psia	11.3
Ambient Dry Bulb	F	87
Ambient Wet Bulb	F	61
Ambient Humidity	%	26
Condensor Pressure	in Hg	2.75
Cooling Water Temp.	F	76

Table 2 – Coal Analysis

		PRB		Bituminous	
		wet	dry	wet	dry
C	%w	51.47	70.60	63.75	71.73
H	%w	3.43	4.71	4.50	5.06
O	%w	12.73	17.46	6.88	7.74
N	%w	0.66	0.91	1.25	1.41
S	%w	0.20	0.27	2.51	2.82
Ash	%w	4.40	6.04	9.70	10.91
Moisture	%w	27.10	0.00	11.12	0.00
He	%w	0.01	0.01	0.29	0.33
sum	%w	100.00	100.00	100.00	100.00
HHV	Btu/lb	8870	12167	11666	13126
Hg	ppmdw	0.8		0.09	

Figure 2 -- Aspen-Plus Model



Modifications to adapt the plant to accommodate oxyfuel firing include the addition of hot/wet and cold/dry flue gas recirculation ducts, oxygen distribution piping, two additional steam extractions for the ASU/CPU, added flue gas cooler for CPU, increased size of HRA lower economizer, a low pressure economizer downstream of the air-heater, and a quench tower as well as increased cooling tower duty and equipment size.

Primary gas recycle is taken after the FGD and quench tower since the coal mill requires low moisture for proper performance and nearly SO_x-free gas to avoid acid corrosion. Gas extracted to the CPU is taken before the FGD. Secondary gas recycle is taken before the FGD for the low sulfur PRB whereas for the high-sulfur bituminous fuel it is split 45% before the FGD and 55% after the FGD to limit the boiler corrosive SO_x concentration.

An additional low pressure economizer is required to cool the gas temperature down in oxy-firing because when the air heater functions as a recuperator, the air heater duty is reduced since recycled flue gas flow is less than the air-firing air flow and the secondary gas inlet temperature is significantly greater than the air inlet temperature.

Due to air heater leakage, the O₂ from the ASU is not mixed with the recycled gas before the air heater to avoid O₂ leakage to the flue gas. Oxygen from the ASU is assumed to be supplied at

97%, vol. purity and 120°F. Oxygen can be mixed either at the burners or prior to the burners depending on the burner design and piping constraints.

Heat is extracted from the boiler via steam and hot water for ASU and CPU thermal loads. Ammonia to the SCR is shut-off, but the SCR catalyst remains in place. Limestone fed to the FGD is reduced to the amount required to remove SO_x from the recycled primary gas stream and partially from the recycled secondary gas stream for bituminous-firing.

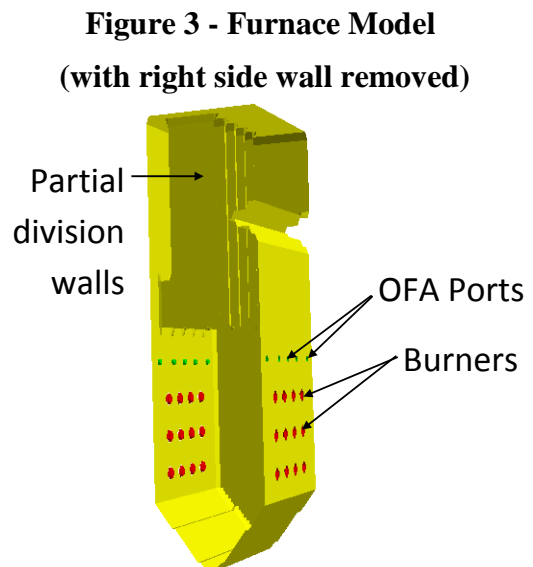
Emissions generated in the boiler were predicted by 3-D CFD simulations: NO_x and CO by FW-FIRE and SO₃ by Fluent. For PRB-firing over-fire gas (OFG) was set at 25% of the total combustion gas (the same as for air-firing). For bituminous-firing over-fire gas was shut off to increase NO_x so as to shift emission control duty to the CPU as proposed by Praxair.

PERFORMANCE

An air-fired simulation was run at full load. The reference air-fired plant has a boiler efficiency (PRB/Bituminous) of 86.7%/89.3% and a plant net efficiency of 35.8/36.7%. The Foster Wheeler CFD computer program, FW-FIRE, was used to determine the furnace performance. The furnace was designed with opposed wall-firing burners and over-fire ports located at one burner pitch above the top burner row as shown in Figure 3. Figure 4 presents a plot of gas temperature in a vertical plane through the second burner column for PRB-firing. The heat flux at the furnace water wall for PRB-firing is also shown in Figure 4.

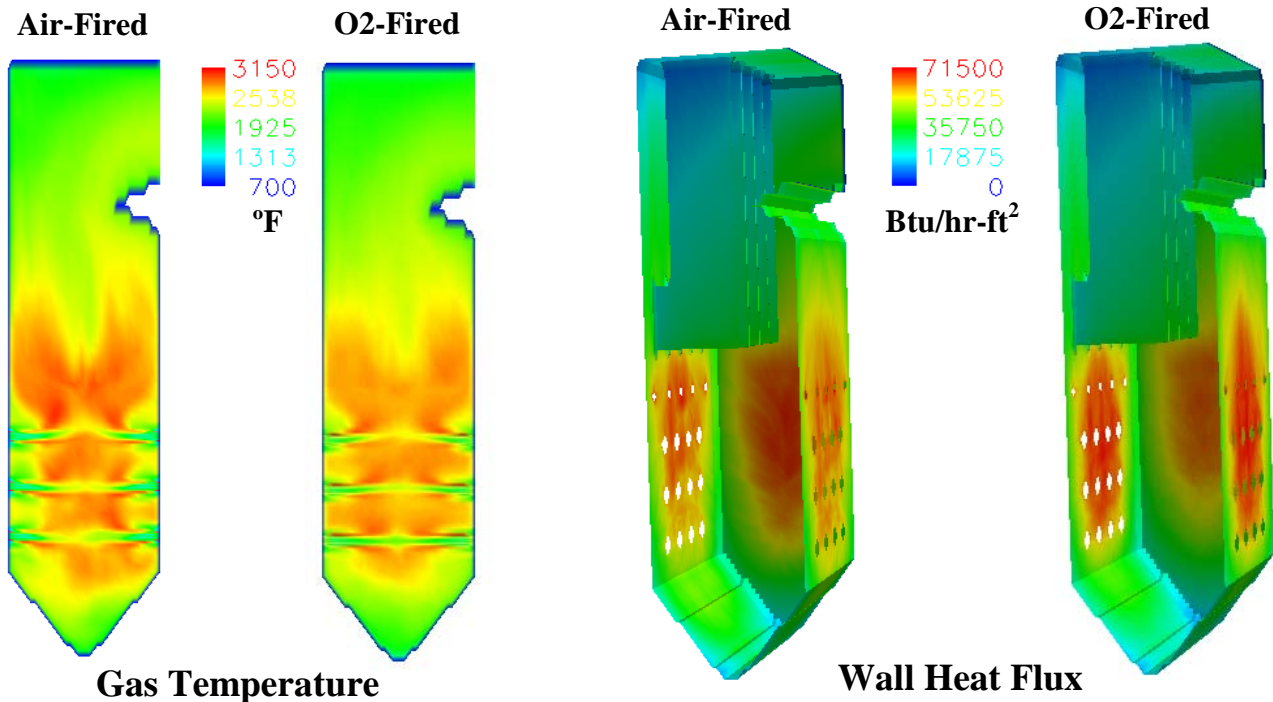
Iterations were performed between the Aspen-Plus system model and FW-FIRE CFD furnace model to determine the required amount of flue gas recirculation. The quantity of flue gas recirculation was selected to minimize changes to the boiler by approximately matching heat transfer and maximum metal temperatures. The flue gas recirculation flow to the boiler for PRB-firing is 68% of the flue gas (44% as secondary gas at 325°F after ID fan and 24% as primary gas at 102°F after wet FGD and quenching tower) and is recuperated to 670°F. The flue gas recirculation flow to the boiler for bituminous-firing is 72% of the flue gas (34% as secondary gas at 310°F after ID fan and 38% as primary + secondary gas at 102°F after wet FGD and quenching tower) and is recuperated to 670°F. Note the temperature of 670°F is limited by the hot side temperature pinch point.

The oxyfuel plant has a boiler efficiency (PRB/Bituminous) of 89.4%/91.3% and a power plant net efficiency of 36.4/37.1% (without including the power consumption of the ASU and CPU, but including heat extraction to the ASU and CPU).



FW-FIRE was used to determine the furnace performance. Figure 4 presents a plot of gas temperature in a vertical plane through the second burner column for PRB-Firing. The heat flux at the furnace water wall is also shown in Figure 4. The resulting maximum tube wall temperatures in the furnace and HRA are all less than 10°F higher than in air-firing.

Figure 4 - Gas Temperature and Wall Heat Flux – PRB-Firing



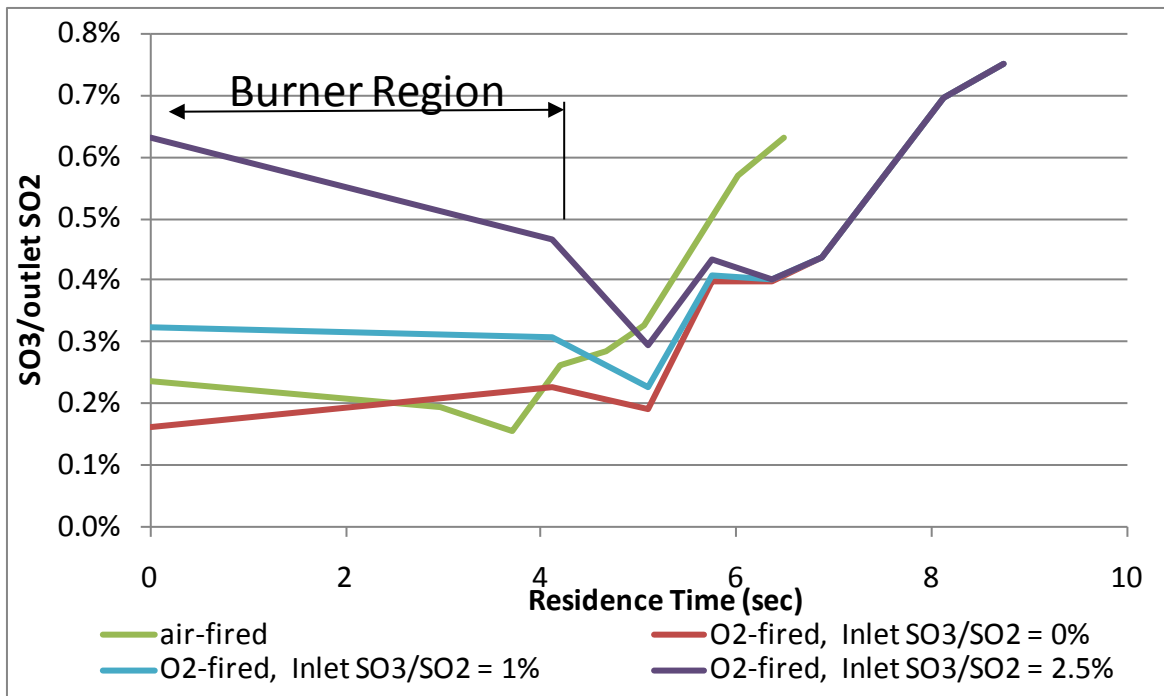
EMISSIONS

For PRB-firing, since the wet FGD is used to treat only the recycled primary gas (35% of the recycled gas), the SO₂ at furnace exit is about 500 ppmv (assuming 98% FGD efficiency) compared to air-firing at 210 ppmv. The SO₂ is 465 ppmv (0.23 lb/Mbtu) to the CPU compared to air-firing at 52 ppmv (0.13 lb/Mbtu) to the stack. For the recycled primary flue gas, 98% SO₂ is removed by the wet-FGD and water quenching producing a SO₂ concentration of 12 ppmv.

For bituminous-firing, the wet FGD is used to treat the recycled primary gas (23% of the recycled gas) and 36% of the secondary gas to reduce the SO_x concentration in the furnace to be similar to that resulting from a “maximum” sulfur eastern bituminous coal (i.e. 5.5% S, dry). The resultant SO₂ at furnace exit is about 4080 ppmv compared to air-firing at 2050 ppmv. Without any FGD treatment of the secondary gas, SO₂ at the furnace exit would be 5690 ppmv. The SO₂ is 3840 ppmv (1.62 lb/Mbtu) to the CPU compared to air-firing at 35 ppmv (0.08 lb/Mbtu) to the stack. The SO_x emission control duty is shifted to the CPU as proposed by Praxair. For the FGD treatment of the recycled primary flue gas and 36% of the secondary flue gas, 99% SO₂ is removed by the wet-FGD and water quenching producing a SO₂ concentration of 43 ppmv in the recycled flue gas.

Fluent was used to determine the SO₂ to SO₃ conversion. Small amounts of SO₃ are formed in the boiler by oxidation of SO₂. For air-firing, the ratio of SO₃/SO₂ at the furnace outlet is 0.57%/0.65 (PRB/bituminous). For oxy-firing, the ratio of SO₃/SO₂ at the furnace outlet is 0.61%/0.73 (PRB/bituminous). The outlet SO₃ was found to be independent of the amount of SO₃ in the recycle flue gas since SO₃ is destroyed in the high temperature regions of the furnace and formed only in the upper sections of the furnace (100% recycling of SO₃ resulted in only a 0.5% increase in outlet SO₃). Furthermore, the ratio of SO₃/SO₂ was determined to be independent of the amount of SO₂ in the recycle flue gas. Based on these Fluent simulations, it is concluded that the ratio of SO₃/SO₂ in the flue gas will be only about 7%/12% (PRB/bituminous) higher for oxy-firing as air-firing. This can be explained by the fact that the formation of SO₃ occurs in the upper section of the furnace where the oxy-fired furnace O₂ concentration and temperature are very similar to that of the air-fired furnace. The 7%/12% (PRB/bituminous) increase for oxy-firing is presumably due to longer residence time of oxy-fired flue gas in the furnace (volumetric flow of oxy-fired flue gas is about 25% less than air-fired flue gas). This is shown in Figure 5 which presents the SO₃ in the furnace versus residence time for the air-fired and O₂-fired cases. Based on published test results, the SO₃/SO₂ generally peaks at about 1% near the furnace outlet and then decreases to as low as 0.2% due to adsorption and reaction (i.e. to form H₂SO₄) with fly ash. For conservatism, the SO₃ predicted by Fluent at the furnace outlet is applied. Additional SO₃ is created by the SCR catalyst where approximately 0.5% of SO₂ is oxidized to SO₃. Normally H₂SO₄ levels and not SO₃ levels are measured at the stack due to the operating temperatures at the test locations. The SO₃ levels noted here are the precursors to the H₂SO₄ levels tested at the stack in air-firing.

Figure 5 – Furnace SO₃/Outlet SO₂ Vs. Residence Time



For PRB-firing, the SCR outlet SO₃ concentration is 6.2 ppm for oxy-firing versus 2.5 ppm for air-firing. Model outlet SO₃ concentration is 5.8 ppm (3.6 lb/Bbtu) for oxy-firing versus 1.3 ppm

(4.0 lb/Bbtu) for air-firing. For the recycled primary flue gas 90% SO₃ is removed by the wet-FGD and water quenching producing a SO₃ concentration of 0.7 ppmv.

For bituminous-firing, the SCR outlet SO₃ concentration is 50 ppm for oxy-firing versus 24 ppm for air-firing. Model outlet SO₃ concentration is 47 ppm (25 lb/Bbtu) for oxy-firing versus 2.4 ppm (7.3 lb/Bbtu) for air-firing. For the recycled primary flue gas 95% SO₃ is removed by the wet-FGD and water quenching producing a SO₃ concentration of 2.7 ppmv.

FW-FIRE was used to determine boiler outlet NO_x. For PRB oxy-firing with no ammonia injection into the SCR (full amount of NO_x was recycled in the flue gas) the NO_x was predicted to be 156 ppm at the boiler outlet (0.056 lb/Mbtu to CPU) compared to the air-fired NO_x of 147 ppm (0.22 lb/Mbtu) at the boiler outlet and 36 ppm at the SCR outlet (0.062 lb/Mbtu to stack). For bituminous oxy-firing with no ammonia injection into the SCR (full amount of NO_x was recycled in the flue gas) the NO_x with 0% OFG was predicted to be 397 ppm at the boiler outlet (0.127 lb/Mbtu to CPU) (with 25% OFG NO_x would be 220 ppm) compared to the air-fired NO_x of 166 ppm (0.25 lb/Mbtu) at the boiler outlet and 40 ppm at the SCR outlet (0.069 lb/Mbtu to stack).

FW-FIRE was used to determine boiler outlet CO. For oxy-firing the outlet CO mole fraction was predicted to be about 2.2 times that of air-firing for both PRB-firing and bituminous-firing. The outlet CO was determined to be independent of the amount of CO in the recycle flue gas since CO (and likewise VOC) is destroyed in the high temperature high oxygen regions of the near burner region (100% recycling of CO resulted in only a 0.75% increase in outlet CO). Thus, the increase in CO can be explained by the greater equilibrium CO concentration for oxy-firing which at the equilibrium temperature is approximately 2.3 times that of air-firing. For PRB-firing the CO at the model outlet is predicted to be 280 ppm (0.06 lb/Mbtu to the CPU) compared to the air-fired emission of 128 ppm (0.13 lb/Mbtu to the stack). For bituminous-firing the CO at the model outlet is predicted to be 284 ppm (0.05 lb/Mbtu to the CPU) compared to the air-fired emission of 133 ppm (0.14 lb/Mbtu to the stack).

For PRB-firing, mercury exits the furnace at 18 ppbv and is reduced to 10 ppbv (15.7 lb/Tbtu) by the SCR catalyst before exiting to the CPU compared to the air-fired boiler outlet (to stack after wet FGD) Hg of 1.4 ppbv (10.5 lb/Tbtu). For bituminous-firing, mercury exits the furnace at 1.7 ppbv and is reduced to 1.0 ppbv (1.3 lb/Tbtu) by the SCR catalyst before exiting to the CPU compared to the air-fired boiler outlet Hg of 0.2 ppbv (1.1 lb/Tbtu). For the recycled primary flue gas all Hg is essentially removed by the wet-FGD and water quenching.

For PRB-firing, HCl exits the furnace and the model (to the CPU) at 18 ppmv (5.2 lb/Bbtu) compared to the air-fired boiler outlet HCl (to stack) of 0.14 ppmv (0.2 lb/Bbtu). For bituminous-firing, HCl exits the furnace and the model (to the CPU) at 402 ppmv (97 lb/Bbtu) compared to the air-fired boiler outlet HCl of 3.7 ppmv (5.0 lb/Bbtu). For the recycled primary flue gas nearly all HCl is removed by the wet-FGD and water quenching.

A summary of the power plant performance and emissions is presented in Table 3.

Table 3 - Performance and Emissions Summary in Air-Fired and O2-Fired Modes

		low S PRB		High S Bit	
		Air-fired	O2-fired	Air-fired	O2-fired
Fuel Flow	klb/h	449	452	331	334
Air Flow	klb/h	3585	0	3567	0
Oxygen Flow	klb/h	0	725	0	725
Recirc. Flue Gas	%	0.0%	67.7%	0.0%	72.5%
Limestone	klb/h	2.14	1.40	27.20	17.10
Boiler eff	%	86.7	89.4	89.3	91.3
Gross Power	MWe	461	466	460	463
Aux. Power	MWe	43	38	45	39
Net Power	MWe	418	428	416	424
Net efficiency	%	35.8	36.4	36.7	37.1

(O₂-fired Net Power and Net efficiency do not include ASU and CPU power consumption)

	low Sulfur PRB				High Sulfur Bit.			
	Air-Fired at Stack		O2-Fired to CPU		Air-Fired at Stack		O2-Fired to CPU	
	ppmv	lb/Mbtu	ppmv	lb/Mbtu	ppmv	lb/Mbtu	ppmv	lb/Mbtu
CO	128	0.13	280	0.06	133	0.14	284	0.05
SO2	52	0.13	465	0.23	35	0.08	3837	1.62
SO3	1.3	0.0040	5.8	0.0036	2.4	0.0073	47.4	0.0251
NOx	36	0.062	156	0.056	40	0.069	391	0.127
NH3	0.7	0.00037	0	0.000	0.6	0.00041	0.0	0.00000
HCl	0.1	0.00020	18	0.00520	3.7	0.00503	402.1	0.09690
PM		0.012		0.012		0.020		0.017
VOC	1.8	0.0030	1.3	0.0004	1.4	0.0024	1.2	0.0003
	ppbv	lb/Tbtu	ppbv	lb/Tbtu	ppbv	lb/Tbtu	ppbv	lb/Tbtu
Hg	1.4	10.5	10.1	15.7	0.2	1.1	1.0	1.3

CLOSING REMARKS

To ensure continued U.S. power generation from the country's abundant domestic coal resources, new coal combustion technologies must be developed to meet future emissions standards, especially CO₂ sequestration. Current conventional coal-fired boiler plants burn coal using 15-20% excess air producing a flue gas, which is only approximately 15% CO₂. Several different technologies for separation of the CO₂ from fluegas have been proposed, including amine-based absorption and membrane gas absorption. However, these techniques require substantial energy for regeneration, typically from low-pressure steam.

A more promising approach to capturing carbon dioxide is oxyfuel combustion where the combustion air is separated into O₂ and N₂ and the boiler uses the O₂, mixed with recycled flue gas, to combust the coal. The products of combustion are thus only CO₂ and water vapor with small amounts of impurities. The water vapor is condensed, yielding a nearly-pure CO₂ stream that can be easily purified and compressed for sequestration. The CO₂ effluent as a liquid or supercritical fluid is piped from the plant to the sequestration site.

A conceptual oxyfuel Flexi-Burn (Flexi-Burn is a trademark of Foster Wheeler) design was developed based on the retrofit of a 460 MWe (gross) subcritical PC power plant burning either low-sulfur PRB or high-sulfur bituminous coal. The plant design was modified to accommodate oxyfuel firing by recycling 68-72% of the flue gas. At the furnace outlet, compared to air-firing, SO₃/SO₂ mole fraction is about the same, NO_x mole fraction is about 10-30% higher with the same OFA and 2.5 times higher for bituminous-firing with no OFA, and CO mole fraction is approximately double. At the furnace outlet, the approximate ratio of O₂-fired emission to air-fired emission on a lb/Mbtu basis is 0.25 for NO_x with the same OFA, 0.5 for NO_x with bituminous-firing and no OFA, and 0.4 for CO.

By proper selection of the quantity of flue gas recycle flow, the boiler (furnace, HRA, air-heater, etc.) can be completely reused in oxy-fuel mode. Boiler retrofit challenges mostly center on the flue gas recycle and the oxygen distribution systems. These challenges include physical routing of ducts and pipes, selection of materials to avoid corrosion, and proper mixing of gases. Another challenge is the development of a control system and control logic for power plant start-up, shutdown, and switchover from air-firing to oxyfuel firing. An additional area for development is improved sealing of the boiler to increase the effectiveness of the CO₂ capture. Overall power plant retrofit constraints include proximity to geologic sequestration, space availability (especially for ASU and CPU), and access to additional water supply for increased cooling load.

ACKNOWLEDGEMENT

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