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Part-load Performance of Co-firing Coal and Biomass with Post-Combustion Capture and Compression

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Abstract:

Bioenergy with Carbon Capture and Storage (BECCS) is recognised as a key technology to mitigate CO_2 emissions and achieve stringent climate targets due to its potential for negative emissions. However, the cost for its deployment is expected to be higher than for fossil-based power plants with CCS. To help in the transition to fully replace fossil fuels, co-firing of coal and biomass provide a less expensive means. Therefore, this work examines the co-firing at various levels in a pulverised supercritical power plant with post-combustion CO_2 capture, using a fully integrated model developed in Aspen Plus. Co-firing offers flexibility in terms of the biomass resources needed. This work also investigates flexibility within operation. As a result, the performance of the power plant at various part-loads (40%, 60% and 80%) is studied and compared to the baseline at 100%, using a constant fuel flowrate. It was found that the net power output and net efficiency decrease when the biomass fraction increases for constant heat input and constant fuel flow rate cases. At constant heat input, more fuel is required as the biomass fraction is increased; whilst at constant fuel input, derating occurs, e.g. 30% derating of the power output capacity at firing 100% biomass compared to 100% coal. Co-firing of coal and biomass resulted in substantial power derating at each part-load operation.

Key words: Co-firing; post-combustion; part-load; CO_2 compression; BECCS

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1. Introduction:

Biomass is becoming increasingly more important for achieving EU emission reduction targets as a renewable energy source (Bertrand et al., 2014). In the UK, bioenergy is mostly used to provide heat or power, where 5.2 GW of bio-power and 3.1 GW of heat were produced at the end of July 2016 (BEIS, 2016). A recent report on trends and projections towards Europe's climate and energy targets for 2020 has shown that in 2013 the European greenhouse gas (GHG) emissions were 19 % lower than the 1990 levels and expected to be 24 % lower by 2020 (Barbu et al., 2014, 6/2014). However, a later report suggested that the pace of GHG reductions will slow down, and by 2030 the EU emissions reduction will be 27-30 % lower than the 1990 levels rather than the target value of 40 % (Barbu et al., 2015, 4/2015). In order to meet the target, there may be an increase in the use of biomass for heat and power to increase the renewable's share of the total energy produced. It is predicted that biomass exploitation capacity in the EU will increase to 1.5-1.8 billion tons in 2030 (Commission, 2006).

Most of the biomass power plants deployed are fairly small units (1-100MWe) and this is due to the limited local feedstock availability and high transportation costs (IEA, January 2007). Due to this reason, costs associated with bioenergy with Carbon Capture and Storage (BECCS) are likely to be higher as compared to those associated with fossil fuel fired power plants with CCS (Azar et al., 2006). However, in the UK Drax power plant has 4 GW total capacity with 70 % biomass share, and it is big enough to deliver economies of scale for capturing CO_2 (ETI, 2016). Moreover, there is sufficient potential for bioenergy to make a significant contribution to the global energy supply (Dornburg et al., 2010).

Biomass in combination with coal, termed as co-firing, represents one possible option for reducing CO_2 emissions (Heller et al., 2004; Jia et al., 2016; Mann and Spath, 2001; Ortiz et al., 2011; Rigamonti et al., 2012; Sebastián et al., 2011) and can add flexibility to the system. Co-firing is a proven technology with a significant experience in Europe (Al-Mansour and Zuwala, 2010). The share of biomass co-firing in conventional pulverised coal fired power stations have increased by up to 20 % in the past decade with some installations demonstrating a complete switch from coal to biomass (Cremers, 2009).

Biomass and coal have different burnout rates and therefore may be fed to the combustor at different locations (Jia et al., 2016). Also, coal and biomass can be mixed before combustion to achieve a better control of the combustion process (Sahu et al., 2014). In the co-firing process, biomass is mixed with coal to achieve over 35 % volatile matter for stable flame

(Biagini et al., 2002; Wang et al., 2009). In the UK, co-firing biomass with coal offers better opportunity as compared to a dedicated biomass plant due to relatively small bioenergy resources (Gough and Upham, 2011). In addition, biomass power is produced in either old coal plants converted to operate on imported biomass, e.g. Drax 2 and Ironbridge 1 and 2 (Verhoest and Ryckmans, June 2014), or purpose built biomass power plants, e.g. Stevens Croft (40MW), that use sawmill waste (AG., 2014).

In modern coal fired power plants, biomass can be co-fired up to 15 % without steam boiler modifications and existing environmental control systems can be used at higher biomass co-firing rates with minor modification (IEA, January 2007). Moreover, co-firing gives substantially higher net efficiency than that a dedicated biomass fired power plant can deliver (Hetland et al., 2016a). This makes co-firing a much less expensive option than building a dedicated biomass power plant (IEA, January 2007). In the absence of financial incentives for negative emissions and avoided carbon, co-firing can play a transitional role to minimise the positive emission penalties in a cost effective way (ETI, 2016). Moreover, the plant can be adjusted to perform optimally using different types of biomass (Hetland et al., 2016a). If the biomass supply is ceased, due to short of supply, natural calamities or logistic issues, coal is still available to keep the lights on and life moving. Biomass combustion can generate various types of pollutants depending upon the type of combustion technology employed, properties of the biomass used and pollutant control measures adopted (Loo and Koppejan, 2002). Also co-firing contributes to the reduction in emissions of obnoxious gases, such as SO_x and NO_x.

Immediate step changes in emissions reduction is required to control CO_2 concentration in the atmosphere. If drastic measures are not adapted, then by the end of the century CO_2 concentration in the atmosphere could reach 650 ppmv, or even higher (Anderson and Bows, 2008). Reduction in GHG emissions can improve air quality (Driscoll et al., 2015; Thompson et al., 2014; West et al., 2013) and also limit global warming. There are many GHG emissions reduction options, such as energy savings and renewable energy technologies but CCS, amongst others is considered to be a key technology to meet stringent climate targets (Koornneef et al., 2012). CCS comprises three steps; capture from the point source, transport and storage. Although the individual technologies have been demonstrated with much operational experience and are relatively well understood, the deployment of a large scale fully integrated commercial CCS process is a key challenge (Gough and Upham, 2011).

In order to meet the target of limiting the global warming to below 2 °C, more than 1 Gt/year of negative emissions are required (Gasser et al., 2015) and BECCS significantly enhances the chances of meeting these ambitious climate mitigation targets (Azar et al., 2010). Each unit of energy produced from BECCS is twice as effective in mitigating emissions as the ones without CCS (Muratori et al., 2016). BECCS may be referred to as process of capturing CO_2 emissions from biomass fired power plants and storing in geological formations, or using as a feedstock to produce algal biomass which is then converted to transport fuel, animal feed or plastics (Gough and Upham, 2011). BECCS can be used to produce electricity, heat, gaseous and liquid fuels and result in net removal of CO_2 from the atmosphere also termed as "negative emission" (ETI, 2016). BECCS potentially could have 33 % share of overall emissions mitigation by the end of the century (Klein et al., 2011). According to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) it will not be possible to achieve the target of limiting global warming without the wide spread deployment of Bio-Energy, CCS and their combination (IPCC, 2014). BECCS can reduce the cost of achieving the climate target by offsetting CO_2 from other sectors such as transportation, which are more expensive to decarbonise (Luckow et al., 2010).

BEECS is a natural technology to progress first as it is competitive with other clean technologies, can be deployed without any more fundamental research, adds flexibility to the system, has capacity to deliver negative emissions and reduces the overall cost of decarbonisation (Oxburgh, 2016). According to a recent report published by the Energy Technologies Institute (ETI), about half of UK's 2050 emissions reduction target (c.55 million tonnes of negative annual emissions) could be delivered by deploying BECCS and could reduce the cost of meeting GHG emissions targets of the UK by up to 1 % of GDP and that BECCS is one of the few practical, scalable and economic technologies having UK relevance for removing CO_2 from the atmosphere in large quantities (ETI, 2016).

The most significant barrier to the deployment of BECCS is not technical but economic and regulatory (Bhave et al., 2014). In the near future, cost saving will not be delivered through fundamental technology break-through but through reducing costs by deployment (ETI, 2016). According to the Global CCS Institute database, no BECCS demonstration project has, as yet, materialised (GCCSI, 2016). There are some bioethanol production based on BECCS projects currently in operation (GCCSI, 2011) but power based BECCS projects are almost non-existent. The Mikawa biomass power plant (49 MW) with CO_2 capture in Japan is aimed at being operational in 2020 and it will be the first power plant in the world that is capable of delivering negative emissions (Toshiba, 2016). Maasvlakte MPP3 power plant in the Netherlands having a capacity of 1070 MW_e became operational in 2015 is capable of accepting up to 30 % biomass and is CCS ready subject to commercial decision (GCCSI, 2015). According to a recent report by the Global CCS Institute (GCCSI, 2016), the Illinois Industrial CCS project (1 Mtpa CO_2 capture capacity) the world's first large scale industrial BECCS project is expected to begin operation in early 2017. The technology will move closer to commercialisation as more demonstration projects come online (Gough and Upham, 2011).

In spite of all the benefits of BECCS, the deployment of CCS may be delayed due to the temptation that BECCS can remove the CO_2 already emitted to the atmosphere (Muratori et al., 2016) and thus can be deployed at a later date. However, this notion of delaying will lead to catastrophic consequences to the world in terms of environmental as well as economic implications. Process modelling is used as an effective mean for better understanding for different operating levels of the power plant with CO_2 capture due to lower cost in comparison to pilot-scale and demonstration studies. The base load performance of the power plant for fossil fuels is successfully investigated through process modelling and simulation. The reporting of part-load analysis of the power plant for fossil fuels with CO2 capture is limited and few studies can be found in the literature (Adams and Mac Dowell, 2016; Alobaid et al., 2014; Biliyok et al., 2012; Fernandez et al., 2016; Hanak et al., 2015; Jordal et al., 2012; Möller et al., 2007; Nord et al., 2009).

The above discussion has shown that BECCS is a key technology to meet GHG emissions reduction targets and that co-firing biomass in coal fired systems has several advantages over dedicated biomass firing systems. Since only a few studies have investigated the BECSS for the commercial-scale application, as reported in the literature (Berstad et al., 2011; Hetland et al., 2016b). Therefore, this paper presents a detailed investigation of the co-firing of coal and biomass for commercial-scale pulverised supercritical power plants. Further, the integration of the post-combustion CO_2 capture plant (CCP) and CO_2 compression unit (CCU) is also investigated. Two co-firing scenarios of coal and biomass are investigated at base-load operation of the power plants i.e. constant heat input (CHI) and constant fuel input (CFF), and the details of which is described in the respective sections. Furthermore, the part-load operation (80, 60 and 40 %) is analysed for co-firing of coal and biomass and integrated with CCP and CCU. The whole investigation is realised by the process modelling and simulation tool, Aspen Plus. The solvent employed is monoethanolamine (MEA) of 30 wt. % strength with 90 % of the CO2 capture efficiency. This paper is structured as follows. In Section 2, the process description, along with the modelling strategy, is described in detail. This is followed by the base-load and part-load modelling framework. In Section 3, the results and discussions for the base-load and part-load operation for the co-firing of coal and biomass is presented. Finally, conclusions are drawn in Section 4.

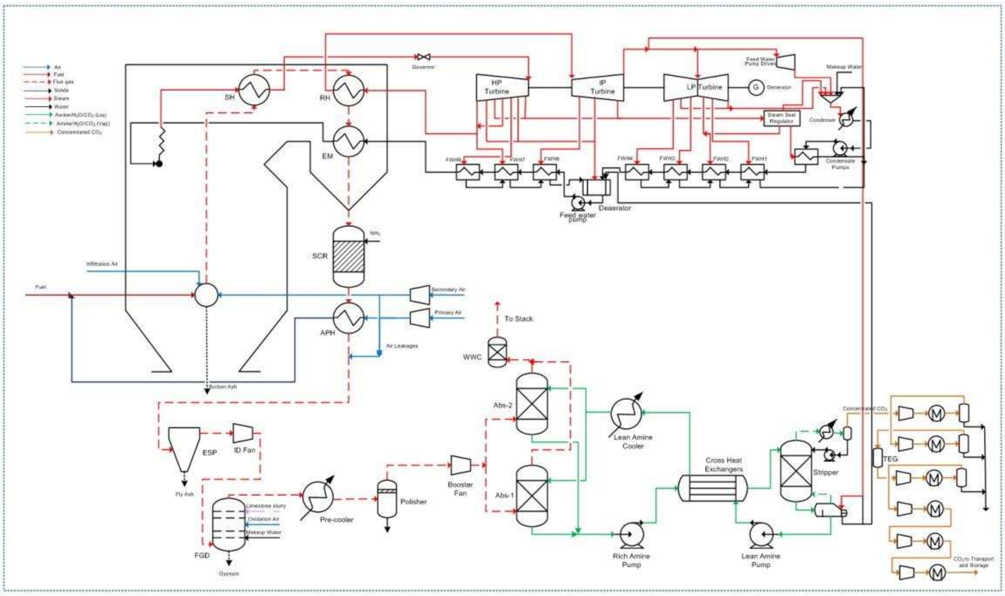

Figure 1 Basic schematic of solid fuel power plant integrated with MEA-based CO_2 capture plant and CO_2 compression unit (Ali et al., 2017).

2. Process Description

The power plant is based on the gross power output of 800 MW_e pulverised coal-fired supercritical power plant reported in the 2010 Report of the Department of Energy (Black, 2010). The schematic of the power plant model developed is shown in Figure 1. The steam generator for the supercritical-type boiler is once-through with superheater, reheater, economizer and air preheater. The steam specification for the supercritical steam turbine is 24.1/593/593 MPa/^{o}C/^{o}C with single reheat. Initially the feedwater is heated by bleeds of LP turbine, through four feedwater heaters, followed by the deaerator, and three feedwater heaters by the bleeds of the HP turbine. The condenser operates at a saturation pressure of 7 kPa. Further, the power plant is equipped with flue gas treatment units, including the selective catalytic reduction unit for the NOx removal using ammonia and catalyst; fabric filters for the particulates removal; the flue gas desulphurization unit for the removal of the SO_2 using the wet limestone forced oxidation process and the CO_2 capture plant for the removal of the CO_2 using MEA-based reactive absorption and desorption. More details of the flue gas treatment can be found in Ali et al. (2017).

The CO_2 capture plant (CCP) is based on post-combustion CO_2 capture technology using reactive absorption and desorption. The CO_2 capture plant consist of two absorbers and one stripper. The CO_2 released from the stripper is compressed to a final pressure of 153 bar using a six stage CO_2 compression unit (CCU) with intercoolers and knock-out drums. The tetra ethylene glycol unit is used at the third stage to maintain the H_2O specification of the dense phase CO_2 stream.

Table 1 Proximate, ultimate and heating value of coal (Black, 2010) and biomass (Al-Qayim et al., 2015).

	Coal		Biomass Pellets	
Proximate Analysis	As-received (wt. %)	Dry (wt. %)	As-received (wt. %)	Dry (wt. %)
Moisture	11.12	0.00	6.69	0.00
Volatile Matter	34.99	39.37	78.10	83.70
Ash	9.70	10.91	0.70	0.75
Fixed Carbon	44.19	49.72	14.51	15.55
Total	100	100	100	100
Ultimate Analysis	As-received (wt. %)	Dry (wt. %)	As-received (wt. %)	Dry (wt. %)
C	63.75	71.72	48.44	51.87
S	2.51	2.82	<0.02	0.02
H_2	4.50	5.06	6.34	6.79
H_2O	11.12	0.00	6.69	0.00
N_2	1.25	1.41	0.15	0.16
O_2	6.88	7.75	37.69	40.37
Ash	9.70	10.91	0.70	0.75
Cl	0.29	0.33	<0.01	0.01
TOTAL	100	100	100	100
Heating Value	As-received	Dry	As-received	Dry
HHV (kJ/kg)	27113	30506	19410	20802
LHV (kJ/kg)	26151	29444	18100	19398

2.1 Base-Load Modelling Framework

The reference base-load model for the coal is developed based on the 2010 Report of the Department of Energy (Black, 2010) with a boiler efficiency of 88 % which helps in the estimation of the fuel flow for 15 % excess air supplied to the boiler. The infiltration air is 2 % of the total air. The different assumptions applied for the modelling of the different sections of the power plant can be found in the quality guidelines provided by the US Department of Energy (Chou et al., 2012, 2014). After analysing the performance of the coal-based power plant integrated with CCP and CCU, the co-firing of coal and biomass is performed. The ultimate and proximate analysis of the coal and biomass are shown in Table 1. It is clear form the properties of the biomass, as given in Table 1, that biomass will behave differently when fired in the commercial-scale power plant due to the reduced heating value and higher O/C ratio compared to coal. The co-firing of the coal and biomass is incorporated by mixing the biomass with coal, thus defining the common fuel feed composition. The different case studies for the co-firing of coal and biomass are listed in Table 2.

Table 2 Pulverised supercritical co-firing of coal and biomass cases classification*.

Cases	Coal/Biomass percentage in fuel feed stream
Coal	100/0
C8B2	80/20
C6B4	60/40
C4B6	40/60
C2B8	20/80
Biomass	0/100

*where 'C' represents coal and 'B' represents biomass.

Table 3 MEA-based CCP design and operating parameters (Agbonghae et al., 2014).

Parameter	Value
Absorber	
Number of Absorbers	2
Packing	Mellapak 250Y
Diameter [m]	16.13
Packing Height [m]	23.04
Stripper	
Number of Stripper	1
Packing	Mellapak 250Y
Diameter [m]	14.61
Packing Height [m]	25.62
Specific Reboiler Duty [MJ/kg CO_2]	3.69
Flue Gas Flowrate [kg/s]	821.26
MEA concentration [kg/kg]	0.3
Lean CO_2 loading [mol/mol]	0.2
Liquid/Gas Ratio [kg/kg]	2.93
Stripper pressure [bara]	1.62

To understand the behaviour of the biomass, two case studies are investigated based on the fuel flowrate. First, the constant heat case (CHI), in which the heat transfer from the boiler to the steam side is kept constant by varying the fuel flowrate while the second one, constant fuel flowrate (CFF) case in which the heat transfer from the boiler to the steam side is varied by keeping the fuel flowrate constant. The base-load performance of the co-firing of coal and biomass is developed for both the CHI and CFF cases integrated with CCP and CCU. A standard MEA-based CCP model which can service the commercial-scale power plant at 100 % load operation is developed which can capture 90 % of the CO_2 from the flue gas using a 30 wt. % aqueous MEA solution with a lean loading of 0.2. The design and operating parameters of the MEA-based CCP are given in Table 3.

2.2 Part-Load Modelling Framework

After developing the base-load performance, the CFF case will be evaluated for the part-load performance assessment as it will not result in a major redesign of the boiler section of the power plant. The coal-fired power plant will be considered as the basis for each part-load assessment and then the fuel switch from coal to biomass and co-firing of coal and biomass is evaluated at each part-load operation. The part-load performance of the co-firing of coal and biomass power plant integrated with CCP and CCU is analysed in this study within a 40 to 100 % envelope in intervals of 20 %. Hence, part-load performance is estimated at 40, 60, 80 % of the base-load (100 %) performance is estimated. The methodology discussed by Hanak et al. (2015) is adopted for the boundary condition estimation at the part-load operation. From the fixed pressure control for the boiler which allows steam throttling and the sliding pressure control for the boiler in which steam pressure follows the turbine load and is dictated by the boiler feed water pump. The sliding pressure control for the boiler is adopted as it results in reduced power consumption (Fernandez et al., 2016; Hanak et al., 2015). The heat transfer areas and temperature differences for the superheater, economiser reheater, and air preheater are kept constant as estimated by the coal-fired power plant case at base-load performance. Similarly, the heat transfer areas and temperature differences for the feedwater heaters are also kept constant as estimated from the coal-fired power plant case at base-load. However, the pressure drop for the heat exchangers is estimated following the equation:

$$\Delta p = \frac{fV^2L}{2g\rho d} \qquad (1)$$

Further, the pressure drops which are based on homogenous flow conditions (Green, 2008) at the part-load performance are updated using average velocity at base and part-load and pressure drops at base load, using the following equation (Hanak et al., 2015):

$$\Delta p_{part} = \frac{\left(\frac{V_{in_{part}} + V_{out_{part}}}{2}\right)^2}{\left(\frac{V_{in_{base}} + V_{out_{base}}}{2}\right)^2} \Delta p_{base} \tag{2}$$

The sliding pressure control of the boiler requires the estimation of the steam flowrates and pressure at different points of the steam turbine section along with the efficiencies for each turbine section. The constant temperature is maintained at each part-load performance from the 40 to 100 % load range by controlling the steam generation rate by the design specification rate (Hanak et al., 2015). The well-known equation, Stadola's Law of Cones (Cooke, 1983; Salisbury, 1950) is widely used in power plants for the off-design steam specifications estimation. The Stadola's Law of Cones isused in an iterative manner for the fixed condenser pressure, and it is given as follows:

$$\frac{m_{in}}{m_{in_{base}}} = \frac{\mu\, p_{in}}{\mu_{base} p_{in_{base}}} \sqrt{\frac{p_{in_{base}} v_{in_{base}}}{p_{in} v_{in}}} \sqrt{\frac{1 - \left(\frac{p_{out}}{p_{in}}\right)^{\frac{n+1}{n}}}{1 - \left(\frac{p_{out_{base}}}{p_{in_{base}}}\right)^{\frac{n+1}{n}}}} \tag{3}$$

The isentropic efficiency is updated based on the base-load isentropic efficiencies of the turbine section. Knopf (2011) proposed the estimation of the isentropic efficiency based on the optimal design with 50 % of the reaction blading (a = 0.7071), for a constant shaft speed at different part-loads. Hence, the isentropic efficiency at the part-load can be estimated by the following equation (Knopf, 2011; Salisbury, 1950):

$$\frac{\eta_{part}}{\eta_{base}} \cong 2 \frac{a}{\frac{V_{in_{base}}}{V_{in_{part}}}} \left[\left(a - \frac{a}{\frac{V_{in_{base}}}{V_{in_{part}}}} \right) + \sqrt{\left(a - \frac{a}{\frac{V_{in_{base}}}{V_{in_{part}}}} \right)^2 + 1 - a^2} \right] \tag{4}$$

At each part-load operation from 40 to 100 %, the effect of the integration of the CCP and CCU is also investigated. The CCP at the part-load performance of the power plant is kept to be the same size as reported in Table 3, as it is common engineering practice to employ oversize units for better performance (Jordal et al., 2012). Therefore, the CO_2 capture rate is fixed at 90 % for part-load performance with 0.2 lean loading of the MEA 30 wt. % aqueous solution. At reduced flowrates, the CCU operation may be effected due to the flowrates approaching surge conditions. It is understood that anti surge control option is available for the CCU.

3. Results and discussion

3.1 Base-Load Performance

The reference coal-fired power plant integrated with CCP and CCU model is developed based on information provided in Section 2.1, 2.2 and Ali et al. (2017). Further, co-firing of coal and biomass for the CHI and CFF cases is evaluated for integration with CCP and CCU. The key performance results for supercritical co-firing coal and biomass power plants integrated with CCP and CCU for CHI case are reported in Table 4 for the base-load performance. The key performance results for supercritical co-firing coal and biomass power plants integrated with CCP and CCU for CHI case are reported in

Table 5 for the base-load performance.

Table 4 Summary of the key performance results for the pulverised supercritical co-firing of coal and biomass power plants integrated with CCP and CCU for CHI case at base-load performance.

Fuel type	Coal	C8B2	C6B4	C4B6	C2B8	Biomass
Fuel [kg/s]	71.3	75.6	80.4	85.9	92.3	99.6
Total air [kg/s]	729	726	723	720	712	702
Slag + Fly Ash [kg/s]	6.9	6	4.9	3.7	2.3	0.7
Main steam [kg/s]	630	630	630	630	630	630
Reheat from boiler [kg/s]	514	514	514	514	514	514
Steam to stripper [kg/s]	233	225	226	228	230	230
Flue gas, absorber inlet [kg/s]	832	830	829	827	819	804
CO_2 composition in flue gas [mol%]	13.28	13.42	13.56	13.73	13.93	14.35
Lean MEA solution, absorber inlet [kg/s]	2403	2414	2403	2453	2464	2470
Specific reboiler duty [MJ/kg CO_2]	3.686	3.679	3.677	3.675	3.674	3.673
Total compression duty [MW_e]	44.9	45.26	45.03	46.04	46.29	46.46
Fuel heat input, HHV [MW_{th}]	1933	1933	1933	1933	1933	1933
Power without steam extraction [MW_e]	800	800	800	800	800	800
Power with steam extraction [MW_e]	664	662	659	658	657	656
Power without CCP and CCU [MW_e]	758	758	758	758	758	758
Power with CCP only [MW_e]	602	600	598	597	596	596
Power with CCP and CCU [MW_e]	557	554	553	551	550	549
Efficiency without CCP and CCU [%]	39.22	39.3	39.3	39.3	39.3	39.3
Efficiency with CCP only [%]	31.16	31.02	30.94	30.86	30.83	30.82
Efficiency with CCP and CCU [%]	28.84	28.68	28.61	28.48	28.43	28.41

Table 5 Summary of the key performance results for the pulverised supercritical co-firing of coal and biomass power plants integrated with CCP and CCU for CFF case at base-load performance.

Fuel type	Coal	C8B2	C6B4	C4B6	C2B8	Biomass
Fuel [kg/s]	71.3	71.3	71.3	71.3	71.3	71.3
Total air [kg/s]	729	685	641	598	550	502

Slag + Fly Ash [kg/s]	6.9	5.6	4.4	3.1	1.8	0.5
Main steam [kg/s]	630	596	560	528	485	452
Reheat from boiler [kg/s]	514	486	457	431	396	369
Steam to stripper [kg/s]	233	212	198	188	176	163
Flue gas, absorber inlet [kg/s]	833	784	735	686	634	575
CO_2 composition in flue gas [mol%]	13.28	13.41	13.56	13.72	13.92	14.34
Lean MEA solution, absorber inlet [kg/s]	2403	2278	2128	2023	1889	1744
Specific reboiler duty [MJ/kg CO_2]	3.686	3.673	3.666	3.654	3.643	3.634
Total compression duty [MW_e]	44.9	42.8	40.06	38.22	35.82	33.21
Fuel heat input, HHV [MW_{th}]	1933	1823	1713	1603	1477	1384
Power without steam extraction [MW_e]	800	759	713	673	618	576
Power with steam extraction [MW_e]	664	627	590	555	509	475
Power without CCP and CCU [MW_e]	758	718	672	633	579	538
Power with CCP only [MW_e]	602	567	532	499	455	423
Power with CCP and CCU [MW_e]	557	524	492	461	419	390
Efficiency without CCP and CCU [%]	39.22	39.36	39.25	39.50	39.19	38.86
Efficiency with CCP only [%]	31.16	31.09	31.04	31.11	30.78	30.58
Efficiency with CCP and CCU [%]	28.84	28.75	28.70	28.72	28.36	28.18

The co-firing of coal and biomass results in more fuel requirement as the fraction of the biomass in the fuel stream increases for the CHI case and resulted in 40 % higher fuel flowrate for 100 % biomass as the fuel feed. However, the co-firing of coal and biomass results in considerable derating as the fraction of the biomass in the fuel stream increases for the CFF case and an overall 30 % derating of the power output capacity is expected for a complete switch to biomass compared to the reference coal power plant either integrated with CCP and CCU or not. The 44 and 49 % decrease in power output is expected when CCP and CCU, respectively, is integrated with the biomass fired plant compared with a standalone coal power plant.

However, the amount of the flue gas decreases and the CO_2 content in the flue gas increases, for the increased fraction of the biomass in the fuel due to the higher O/C ratio in the biomass for both the CHI and CFF cases. Also this results in higher specific CO_2 emissions from power plants when the biomass share in the fuel feed stream increases; however, it results in more specific CO_2 capture from the power plant.

Further, if the biomass used is sustainably-grown biomass, it will result in more negative emissions from the system. The lower flow rate of the flue gas with higher CO_2 concentration and lower solvent requirements for scrubbing, results in the decrease of the specific reboiler duty. The effect of co-firing coal and biomass on the CO_2 composition in the flue and specific reboiler duty is given in Figure 2. However, there is a large decrease in specific reboiler duty for the CFF cases as compared to the CHI cases and this is due to the lower flue gas flowrates for the CFF cases and this result in the lower specific reboiler duty.

Due to the low sulphur content in the biomass, as reported in Table 1, the amount of gypsum produced decreases with the increased share of biomass in the fuel feed stream. Due to this trend, the FGD unit may not be required in the co-firing of coal and biomass at the higher biomass shares and the polisher unit may be enough to meet the SO_2 requirements at the absorber inlet of the CCP. In addition, the slag and fly ash amounts decrease substantially when coal is replaced by biomass for both the CHI and CFF cases. The detailed key performance results for the different cases of the co-firing of the coal and biomass can be found in Table A.1 and A.2 in the Appendix A for the CHI and CFF, respectively, for the base-load operation for more interpretation and explanation.

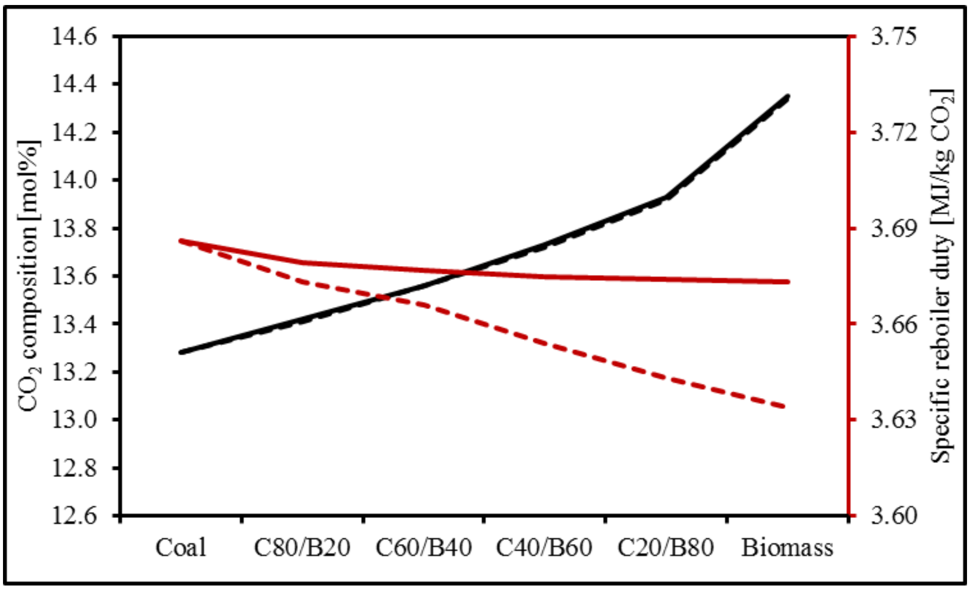

Figure 2 Effect of co-firing coal and biomass on the CO_2 composition in the flue gas and specific reboiler duty (where solid line represents CHI case and dashed line represents CFF case).

The net power output and net efficiency decreases when the biomass fraction in the feed stream increases and this is due to a larger auxiliary load on the system for the CHI cases. It is observed that the efficiency penalty with CO_2 capture and compression systems increases by approximately 4.8 % when coal is totally replaced by biomass in the CHI cases. However, there is a slight increase in specific CO_2 compression work per unit of the CO_2 captured and the specific losses per unit of the CO_2 captured.

Table 6 Summary of the key performance results for the pulverised supercritical co-firing of coal and biomass power plants integrated with CCP and CCU for the CFF case at 80, 60 and 40 % part-load performance.

Fuel type	**Coal**	**C8B2**	**C6B4**	**C4B6**	**C2B8**	**Biomass**
			80 % part-load operation			
Fuel heat input, HHV [MW_{th}]	1615	1523	1432	1340	1248	1156
Power without steam extraction [MW_e]	640	604	567	530	493	457
Power with steam extraction [MW_e]	523	488	452	423	393	365
Power without CCP and CCU [MW_e]	606	571	534	499	461	426
Power with CCP only [MW_e]	472	439	405	377	349	323
Power with CCP and CCU [MW_e]	435	403	371	345	319	295
Efficiency without CCP and CCU [%]	37.52	37.46	37.33	37.15	36.97	36.86
Efficiency with CCP only [%]	29.24	28.87	28.27	28.14	27.95	27.92
Efficiency with CCP and CCU [%]	26.91	26.47	25.90	25.76	25.55	25.52
			60 % part-load operation			
Fuel heat input, HHV [MW_{th}]	1262	1190	1118	1046	975	903
Power without steam extraction [MW_e]	480	452	425	398	370	343
Power with steam extraction [MW_e]	388	364	343	320	298	276
Power without CCP and CCU [MW_e]	454	427	400	374	346	320
Power with CCP only [MW_e]	349	326	307	296	264	244
Power with CCP and CCU [MW_e]	320	298	280	260	241	222
Efficiency without CCP and CCU [%]	35.98	35.85	35.79	35.72	35.50	35.40
Efficiency with CCP only [%]	27.66	27.42	27.43	27.24	27.1	26.99
Efficiency with CCP and CCU [%]	25.34	25.08	25.06	24.85	24.71	24.59
			40 % part-load operation			
Fuel heat input, HHV [MW_{th}]	882	832	781	731	681	631
Power without steam extraction [MW_e]	320	301	281	263	245	226
Power with steam extraction [MW_e]	268	252	235	220	204	189
Power without CCP and CCU [MW_e]	303	284	264	247	229	210
Power with CCP only [MW_e]	241	226	210	196	181	167
Power with CCP and CCU [MW_e]	221	207	192	179	165	152
Efficiency without CCP and CCU [%]	34.30	34.12	33.84	33.73	33.61	33.32
Efficiency with CCP only [%]	27.37	27.20	26.91	26.82	26.58	26.48
Efficiency with CCP and CCU [%]	25.04	24.86	24.54	24.43	24.18	24.07

The efficiency penalty of the CFF cases is the same as that observed for the CHI cases as the base power output considered for comparison is the de-rated power output and not 800 MWe. Due to the decreased flow rate of the flue gas, the amount of the CO_2 captured also decreases and hence results in a 30 % decrease in solvent requirement to scrub CO_2. This result in a considerable increase in the specific CO_2 compression work per unit of the CO_2 captured and specific losses per unit of the CO_2 captured for co-firing of coal and biomass for the CFF cases.

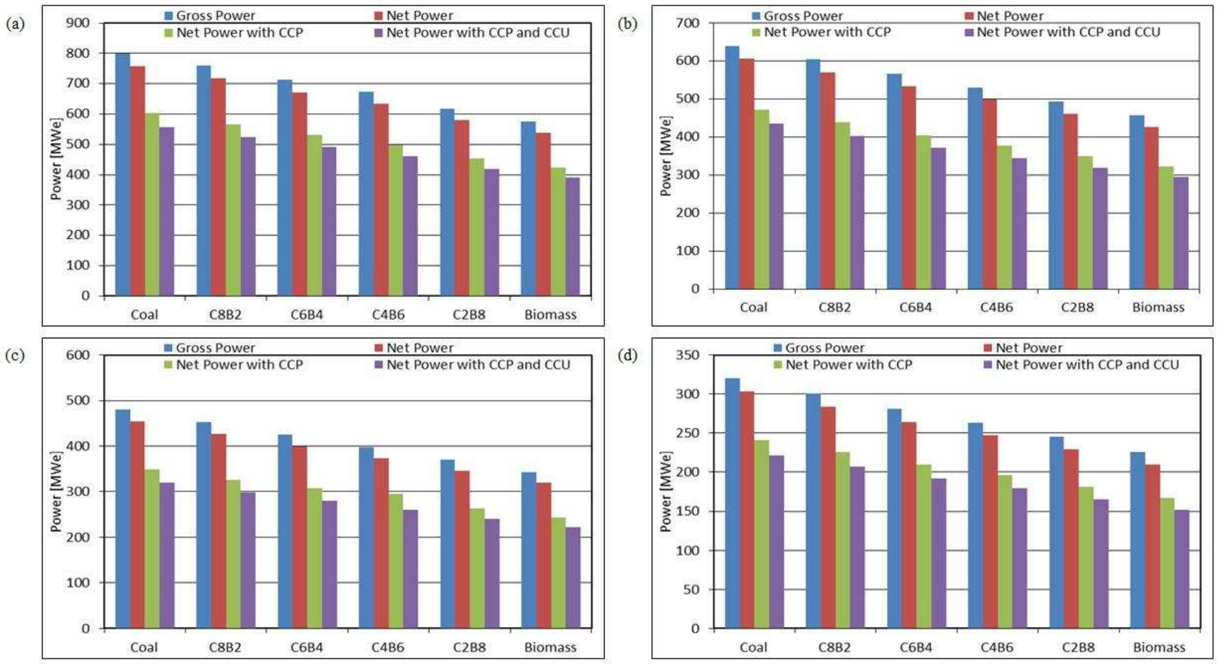

Figure 3 Power output from supercritical co-firing of coal and biomass power plants integrated with CCP and CCU for the CFF case at different part-load operations; (a) 100 % base-load operation; (b) 80 % part-load operation; (c) 60 % part-load operation; and (d) 40 % part-load operation.

3.2 Part-Load Performance

The part-load performance of the co-firing of coal and biomass integrated with CCP and CCU from 40 to 100 % load is evaluated for the CFF case. The operating conditions for the part-load operations were estimated based on the details provided in Section 2.2 for the referenced coal-fired power plant and then the co-firing of coal and biomass is assessed for integration with CCP and CCU for the CFF case for the part-load at 80, 60 and 40 % operation. Since, the case evaluated is CFF the fuel flowrate for each of the part-load operation is kept constant at the same value as for the coal case at that part-load operation. Hence, this results in variable heat input and variable power output from the power plant with and without integration with CCP and CCU. However, co-firing of coal and biomass resulted in substantial power derating at each part-load operation. The power derating for different part-load operation integrated with CCP and CCU for CFF case is shown in Figure 3 and listed in Table 6. The detailed performance results for part-load operation at 80, 60 and 40 % are given in Tables A.3, A.4 and A.5, respectively. The derating in power output efficiency of the power plant not only occurs horizontally when fuel is switched from coal to biomass at constant load operation, but, it also degrades perpendicularly downward when the load is shifted to the lower ones for the same fuel type as listed in Table 2.

Furthermore, the behaviour of the power plant in terms of the power derating when fuel is switched from coal to biomass at constant part-load operation is similar as clearly observed in Figure 3. An overall 30 to 32 % derating of the power output capacity is expected for complete switch to biomass compared to the reference coal power plant at the each of the part-load operations either integrated with CCP and CCU or not. The 44 to 47 % and 49 to 51 % decrease in power output is expected when CCP and CCU, respectively is integrated with the biomass fired plant compared with a standalone coal power plant at each part-load operation.

The specific reboiler duty behaviour is similar at each part-load operation as discussed in Section 3.1 for the base-load operation. However, for a specific ratio of coal and biomass co-firing, and subsequent part-load operation resulted in a decrease in specific reboiler duty, although this decrease is not linear. The decrease in specific reboiler duty is 0.74 % for load change from 80 % to 60 % and is 1.05 % for the for load change from 60 % to 40 % of the part-load operation of the coal-fired power plant. Similarly, the decrease in specific reboiler duty is 0.71 % for load change from 80 % to 60 % and is 1.13 % for the for load change from 60 % to 40 % of the part-load operation of the C8B2-fired power plant. Similarly, the by-products gypsum from FGD, fly-ash from ESP, slag from boiler and NH_3 requirement in SCR decreases not only with part-load operation for the specific fuel feed, however, also for the co-firing at any of the part-load operation. The decrease due to fuel switch from coal and biomass at different part-load conditions, on average, is 99 % in gypsum production, 92 % in fly-ash, 94 % in slag and 53 % for NH3 requirement.

As observed in the base-load operation, the flue gas treatment units may not be required when the biomass share in the fuel increases. A similar observation is found for the part-load co-firing of coal and biomass at different load operations. Process analysis revealed that the part-load operation of coal-fired power plant resulted in only 28 % of the total power ($800MW_e$) available on integration with CCP and CCU at 40 % load operation. The rest is degraded firstly due to load change and secondly due to the parasitic load of the CCP and CCU. Similarly at part-load operation of the C8B2-fired power plant resulted in only 26 % of the total power (800MW$_e$) available on integration with CCP and CCU at 40 % load operation and 24 % for the C4B6 and eventually 19 % of the total power (800MW$_e$) available on integration with CCP and CCU at 40 % load operation for the biomass-fired power plant. The decrease in the power output due to the load change and further integration with CCP and CCU for different co-firing of coal and biomass at various load changes in the form of percentage of the total name plate power output of the power plant (800MW$_e$) is shown in Figure 4.

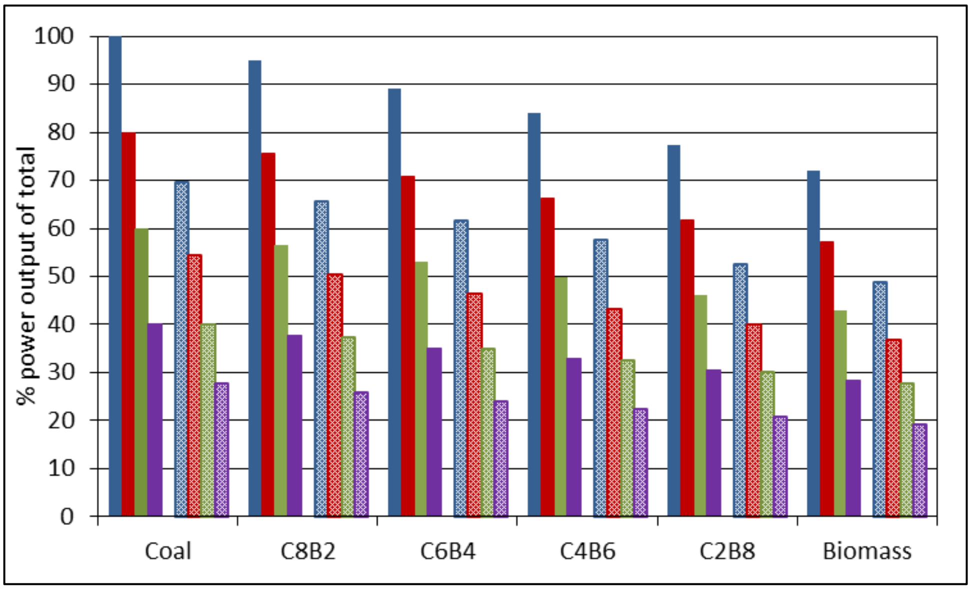

Figure 4 Percentage power output of the total name plate power output of the power plant (800MW$_e$) for integration with CCP and CCU for CFF case at different part-load operation where solid coloured bars are for % of the gross power output (of 800 MW$_e$) and hatched bars are for % of the net power output (of 800 MW$_e$) when integrated with CCP and CCU. Where blue: 100 % base-load operation; red: 80 % part-load operation; green: 60 % part-load operation; and purple: 40 % part-load operation.

4. Conclusions

This paper investigated the co-firing of coal and biomass in a commercial-scale pulverised supercritical power plant, integrated with an amine-based post-combustion CO_2 capture plant (CCP) and CO_2 compression unit (CCU). Two co-firing scenarios of coal and biomass were investigated at base-load operation, and the following was concluded:

- At constant heat input (CHI), more fuel is required as the percentage of biomass is increased; e.g. for firing 100% biomass, 40% more fuel is fed than for 100% coal.

- At constant fuel input (CFF), derating occurs as the fraction of the biomass in the fuel stream increases, e.g. 30% derating of the power output capacity at firing 100% biomass compared to 100% coal.
- Higher specific CO_2 capture from the power plant is observed from when the biomass share in the fuel feed increases due to increases in the CO_2 content in the flue gas, for both the CHI and CFF cases; it will result in negative emissions from the system if sustainably-grown biomass is used.
- A larger decrease in specific reboiler duty is observed for the CFF cases as compared to the CHI cases, due to the lower flue gas flowrates.
- A FGD unit may not be required at the higher biomass shares, and a polisher unit may be enough to meet the SO_2 requirements at the absorber inlet due to the low sulphur content in biomass.
- The net power output and net efficiency decrease when the biomass fraction increases for both cases. An efficiency penalty with CO_2 capture and compression systems increases by approx. 4.8 % when firing 100% biomass in the CHI case.

For part-load operation (80, 60 and 40 %) using the CFF case, the following was found:

- As expected, the power output decreases due to load change and further integration with CCP and CCU for different levels of co-firing of coal and biomass. Co-firing of coal and biomass resulted in substantial power derating at each part-load operation. An overall 30 to 32 % derating of the power output capacity is expected for 100% biomass.
- At each part-load operation, specific reboiler duty decreases when the biomass fraction increases.
- The by-products –gypsum from FGD, fly-ash from ESP, slag from boiler and NH_3 requirement in SCR– decrease for the co-firing at any part-load operation.

Nomenclature

Abbreviations

Abs	absorber
APH	air preheater
BECCS	bioenergy carbon capture and storage
CCP	CO_2 capture plant

CCS	carbon capture and storage
CCU	CO_2 compression unit
CFF	constant fuel flowrate
CHI	constant heat input
EM	economiser
ESP	electro static precipitator
ETI	Energy Technology Institute
FGD	flue gas desulphurization
FWH	feedwater heater
GHG	greenhouse gases
HP	high pressure
ID	induced draft
IP	intermediate pressure
IPCC	Intergovernmental Panel on Climate Change
LP	low pressure
MEA	monoethanolamine
RH	reheater
SCR	selective catalytic reduction
SH	superheater
WWC	water wash column
TEG	tetra ethylene glycol

Parameters

d	diameter (m)
f	friction factor
g	9.8 m/s^2
L	length of section (m)
m	mass flowrate (kg/s)
p	pressure (bar)
V	velocity (m/s)
v	specific volume (m^3/kg)

η	efficiency (%)
μ	kinematic viscosity (m^2/s)
ρ	density (kg/m^3)

Subscripts

base	at base-load condition
in	input
part	at part-load condition
out	output

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APPENDIX A

Table A. 1 Detailed key performance results for the pulverised supercritical co-firing of coal and biomass power plants integrated with CCP and CCU for CHI case at base-load performance.

Fuel type	**Coal**	**C8B2**	**C6B4**	**C4B6**	**C2B8**	**Biomass**
Fuel [kg/s |bar |ºC]	71.3 |1.01 |15	75.6 |1.01 |15	80.4 |1.01 |15	85.9 |1.01 |15	92.26 | 1.01 | 15	99.6 |1.01 |15
Primary air [kg/s |bar |ºC]	168 |1.01 |15	168 |1.01 |15	167 |1.01 |15	167 |1.01 |15	164.7 | 1.01 | 15	162 |1.01 |15
Secondary Air [kg/s |bar |ºC]	548 |1.01 |15	547 |1.01 |15	545 |1.01 |15	543 |1.01 |15	536.2 | 1.01 | 15	528 |1.01 |15
Air Infiltration [kg/s |bar |ºC]	12.4 |1.01 |15	11.19|1.01 |15	11.23 |1.01 |15	11.25 |1.01 |15	11.3 | 1.01 | 15	11.4 |1.01 |15
NH_3 injected [kg/s |bar |ºC]	1.70 |7.24 |15	1.60 |7.24 |15	1.50 |7.24 |15	1.4 |7.24 |15	1.27 | 7.24 | 15	1.10 |7.24 |15
Slag [kg/s]	1.4	1.19	0.99	0.74	0.46	0.1
Main steam [kg/s |bar |ºC]	630 |242.3 |593	630 |242.3 |593	630 |242.3 |593	630 |242.3 |593	630 |242.3 |593	630 |242.3 |593
Reheat to furnace/boiler [kg/s |bar |ºC]	514 |49 |348	514 |49 |348	514 |49 |348	514 |49 |348	514 |49 |348	514 |49 |348
Reheat from furnace/boiler [kg/s |bar |ºC]	514 |45.2 |593	514 |45.2 |593	514 |45.2 |593	514 |45.2 |593	514 |45.2 |593	514 |45.2 |593
Steam to stripper reboiler [kg/s |bar |ºC]	233 |5.07 |296	225 |5.07 |296	226 |5.07 |296	228 |5.07 |296	223 |5.07 |296	230 |5.07 |296
Condensate return from stripper [kg/s |bar |ºC]	233 |3 |130	225 |3 |130	226 |3 |130	228 |3 |130	223 |3 |130	230 |3 |130
Condensate, condenser outlet [kg/s |bar |ºC]	246 |0.07 |38	225 |0.07 |38	243 |0.07 |38	242 |0.07 |38	240 |0.07 |38	239 |0.07 |38
Boiler feed water, economiser inlet [kg/s |bar |ºC]	630 |288.5 |283	630|288.5 |283	630 |288.5 |283	630 |288.5 |283	630 |288.5 |283	630 |288.5 |283
EPS/FGD						
Fly ash [kg/s]	5.53 |1.01 |169	4.77 |1.01 |169	3.93 |1.01 |169	2.96 |1.01 |169	1.8 |1.01 |169	0.55 |1.01 |169
Lime slurry [kg/s]	19.50|1.03 |15	16.60|1.03 |15	13.3 |1.03 |15	9.5 |1.03 |15	3.6 |1.03 |15	0.21 |1.03 |15
Gypsum, moisture-free (kg/s]	9.6	8.2	6.5	4.7	2.55	0.1
CO_2 Capture Plant						
Flue gas, absorber inlet [kg/s |bar |ºC]	833 |1.2 |40	830 |1.20 |40	829 |1.20 |40	827 |1.20 |40	819 |1.20 |40	597 |1.20 |40
Lean MEA solution, absorber inlet [kg/s |bar |ºC]	2403 |3.00 |40	2414 | 3.00 |40	2423 |3.00 |40	2453 | 3.00 |40	2464 | 3.00 |40	1816 | 3.00 |40

Rich MEA solution, absorber outlet [kg/s |bar |ºC]	2628 |1.01 |44	2640 |1.01 | 44	2628 |1.01 |44	2681 |1.01 |45	2692 |1.01 |45	1980 |1.01 |45
CO_2 captured [kg/s]	152	153	154.4	155.7	156.5	116.7
Specific reboiler duty [MJ/kg CO_2]	3.686	3.679	3.677	3.675	3.674	3.638
Stripper condenser duty [MW_{th}]	226.6	269.9	269.8	231.4	232.2	171
Lean MEA solution cooler duty [MW_{th}]	72.3	72.5	71.8	75.9	78	55.8
Lean/Rich heat exchanger duty [MW_{th}]	604.4	607.3	604.9	614.8	615.9	455.4
Lean MEA solution pump duty [kW_e]	388	390.9	389.1	397.2	399	294
Rich MEA solution pump duty [kW_e]	550.8	553.3	550.8	561.9	564.2	414.4
Booster fan duty (MW_e]	19.1	19.4	19	19.3	19.1	13.8
CO_2 Compression System						
Total compression duty [MW_e]	44.9	45.26	45.03	46.04	46.29	34.53
Total intercooling duty [MW_{th}]	76.9	77.57	77.18	78.92	79.35	59.14

Table A. 2 Detailed key performance results for the pulverised supercritical co-firing of coal and biomass power plants integrated with CCP and CCU for CFF case at base-load performance.

Fuel type	**Coal**	**C8B2**	**C6B4**	**C4B6**	**C2B8**	**Biomass**
Fuel [kg/s |bar |ºC]	71.3 | 1.01 | 15	71.3 | 1.01 | 15	71.3 | 1.01 | 15	71.3 | 1.01 | 15	71.3 | 1.01 | 15	71.3 | 1.01 | 15
Primary air [kg/s |bar |ºC]	168 | 1.01 | 15	158 | 1.01 | 15	148 | 1.01 | 15	138 | 1.01 | 15	127 | 1.01 | 15	116 | 1.01 | 15
Secondary Air [kg/s |bar |ºC]	548 | 1.01 | 15	515 | 1.01 | 15	482 | 1.01 | 15	450 | 1.01 | 15	414 | 1.01 | 15	378 | 1.01 | 15
Air Infiltration [kg/s |bar |ºC]	12 | 1.01 | 15	11.5 | 1.01 | 15	10.7 | 1.01 | 15	10.0 | 1.01 | 15	9.2 | 1.01 | 15	8.4 | 1.01 | 15
NH_3 injected [kg/s |bar |ºC]	1.7 | 7.24 | 15	1.5 | 7.24 | 15	1.5 | 7.24 | 15	1.2 | 7.24 | 15	1.0 | 7.24 | 15	0.8 | 7.24 | 15
Slag [kg/s]	1.4	1.1	0.9	0.6	0.4	0.1
Main steam [kg/s |bar |ºC]	630|242.3 | 593	596|242.3 | 593	560|242.3 | 593	528|242.3 | 593	485|242.3 | 593	452|242.3 | 593
Reheat to furnace/boiler [kg/s |bar |ºC]	514 |49 | 353	486 |49 | 353	457 |49 | 353	431 |49 | 353	396 |49 | 353	369 |49 | 353
Reheat from furnace/boiler [kg/s |bar |ºC]	514 |45.2 |593	486|45.2 |593	457|45.2 |593	431|45.2 |593	396|45.2 |593	369|45.2 |593
Steam to stripper reboiler [kg/s |bar |ºC]	233|5.07 | 296	212|5.07 | 296	198|5.07 | 296	188|5.07 | 296	176|5.07 | 296	163|5.07 | 296
Condensate return from stripper [kg/s |bar |ºC]	233 |3 | 130	212 |3 | 130	198|3 | 130	188|3 | 130	176|3 | 130	163|3 | 130
Condensate, condenser outlet [kg/s |bar |ºC]	246 |0.07 | 38	232 |0.07 | 38	219 |0.07 | 38	205 |0.07 | 38	185|0.07 | 38	174|0.07 | 38
Boiler feed water, economiser inlet [kg/s |bar |ºC]	630|289| 283	596|289| 283	560|289| 283	528|289| 283	485|289| 283	452|289| 283
EPS/FGD						
Fly ash [kg/s]	5.5 |1.01 | 169	4.5 |1.01 | 169	3.5 |1.01 | 169	2.5 |1.01 | 169	1.4|1.01 | 169	0.4|1.01 | 169
Lime slurry [kg/s]	19.5 |1.03 | 15	15.7 |1.03 | 15	8.3 |1.03 | 15	5.5 |1.03 | 15	2.8 |1.03 | 15	0.1 |1.03 | 15
Gypsum, moisture-free (kg/s)	9.6	7.7	5.8	3.9	2.0	0.1
CO_2 Capture Plant						
Flue gas, absorber inlet [kg/s |bar |ºC]	833 |1.2 | 40	784 |1.2 | 40	735 |1.2 | 40	686 |1.2 | 40	634 |1.2 | 40	575 |1.2 | 40
Lean MEA solution, absorber inlet [kg/s |bar |ºC]	2403 |3.00 | 40	2278 |3.00 | 40	2128 |3.00 | 40	2023 |3.00 | 40	1889 |3.00 | 40	1744 |3.00 | 40
Rich MEA solution, absorber outlet [kg/s |bar |ºC]	2628 |1.01 | 44	2492|1.01 | 44	2328|1.01 | 44	2212|1.01 | 44	2066|1.01 | 45	1902|1.01 | 45
CO_2 captured [kg/s]	152	145	135	129	121	112

Specific reboiler duty [MJ/kg CO_2]	3.686	3.673	3.666	3.654	3.643	3.634
Stripper condenser duty [MW_{th}]	227	215	239	225	209	182
Lean MEA solution cooler duty [MW_{th}]	72	68	62	60	56	53
Lean/Rich heat exchanger duty [MW_{th}]	604	574	537	510	476	438
Lean MEA solution pump duty [kW_e]	388	369	345	328	306	282
Rich MEA solution pump duty [kW_e]	551	522	488	463	433	398
Booster fan duty (MWe]	19.1	18.3	17.2	17.2	14.8	13.3
CO_2 Compression System						
Total compression duty [MW_e]	44.9	42.8	40.06	38.22	35.82	33.21
Total intercooling duty [MW_{th}]	76.9	73.3	68.64	65.49	61.36	56.88

Table A. 3 Detailed key performance results for the pulverised supercritical co-firing of coal and biomass power plants integrated with CCP and CCU for CFF case at 80 % part-load performance.

Fuel type	**Coal**	**C8B2**	**C6B4**	**C4B6**	**C2B8**	**Biomass**
Fuel [kg/s |bar |ºC]	59.6 | 1.01 | 15	59.6 | 1.01 | 15	59.6 | 1.01 | 15	59.6 | 1.01 | 15	59.6 | 1.01 | 15	59.6 | 1.01 | 15
Primary air [kg/s |bar |ºC]	141 | 1.01 | 15	132 | 1.01 | 15	124 | 1.01 | 15	115 | 1.01 | 15	106 | 1.01 | 15	97 | 1.01 | 15
Secondary Air [kg/s |bar |ºC]	458| 1.01 | 15	431| 1.01 | 15	403| 1.01 | 15	376| 1.01 | 15	346| 1.01 | 15	316| 1.01 | 15
Air Infiltration [kg/s |bar |ºC]	10.2 | 1.01 | 15	9.6 | 1.01 | 15	9.0 | 1.01 | 15	8.4 | 1.01 | 15	7.7 | 1.01 | 15	7.0 | 1.01 | 15
NH_3 injected [kg/s |bar |ºC]	1.4 | 7.24 | 15	1.3 | 7.24 | 15	1.1 | 7.24 | 15	1.0 | 7.24 | 15	0.8 | 7.24 | 15	0.7 | 7.24 | 15
Slag [kg/s]	1.2	0.9	0.7	0.5	0.3	0.1
Main steam [kg/s |bar |ºC]	512|193 | 593	484|193 | 593	453|193 | 593	424|193 | 593	394|193 | 593	366|193 | 593
Reheat to furnace/boiler [kg/s |bar |ºC]	418|39.8 | 356	395|39.8 | 356	370|39.8 | 356	346|39.8 | 356	322|39.8 | 356	299|39.8 | 356
Reheat from furnace/boiler [kg/s |bar |ºC]	418 |36.7 |593	395 |36.7 |593	370 |36.7 |593	346 |36.7 |593	322|36.7 |593	299 |36.7 |593
Steam to stripper reboiler [kg/s |bar |ºC]	186|4.7 | 317	176|4.7 | 317	166|4.7 | 317	156|4.7 | 317	146|4.7 | 317	135|4.7 | 317
Condensate return from stripper [kg/s |bar |ºC]	163|3 | 130	176|3 | 130	166|3 | 130	156|3 | 130	146|3 | 130	135|3 | 130
Condensate, condenser outlet [kg/s |bar |ºC]	195 |0.07 | 38	165 |0.07 | 38	155 |0.07 | 38	146|0.07 | 38	133.8 |0.07 | 38	125 |0.07 | 38
Boiler feed water, economiser inlet [kg/s |bar |ºC]	512|234| 269	484|234| 269	453|234| 269	424|234| 269	394|234| 269	366 |234| 269
EPS/FGD						
Fly ash [kg/s]	4.6 |1.01 | 169	3.8|1.01 | 169	2.9|1.01 | 169	2.1|1.01 | 169	1.2|1.01 | 169	0.3|1.01 | 169
Lime slurry [kg/s]	11 |1.03 | 15	9 |1.03 | 15	6.9|1.03 | 15	4.6|1.03 | 15	2.3|1.03 | 15	0.1|1.03 | 15
Gypsum, moisture-free (kg/s)	8.0	6.4	4.8	3.2	1.6	0.1
CO_2 Capture Plant						
Flue gas, absorber inlet [kg/s |bar |ºC]	695 |1.2 | 40	655 |1.2 | 40	614 |1.2 | 40	574|1.2 | 40	530|1.2 | 40	480|1.2 | 40
Lean MEA solution, absorber inlet [kg/s |bar |ºC]	1997 |3.00 | 40	1893|3.00 | 40	1786|3.00 | 40	1680|3.00 | 40	1568|3.00 | 40	1446|3.00 | 40
Rich MEA solution, absorber outlet [kg/s |bar |ºC]	2186|1.01 | 44	2071|1.01 | 44	1954|1.01 | 44	1839|1.01 | 44	1716|1.01 | 44	1577|1.01 | 44
CO_2 captured [kg/s]	127	121	114	108	101	94

Specific reboiler duty [MJ/kg CO_2]	3.661	3.654	3.644	3.634	3.624	3.614
Stripper condenser duty [MW_{th}]	189	180	170	160	175	137
Lean MEA solution cooler duty [MW_{th}]	57	54	51	47	44	42
Lean/Rich heat exchanger duty [MW_{th}]	506	479	452	426	397	365
Lean MEA solution pump duty [kW_e]	323	307	289	272	254	234
Rich MEA solution pump duty [kW_e]	458	434	409	385	359	330
Booster fan duty (MWe]	16.3	15.3	14.3	13.4	12.3	11.1
CO_2 Compression System						
Total compression duty [MW_e]	37.66	35.78	33.86	31.96	29.92	27.70
Total intercooling duty [MW_{th}]	64.52	61.29	57.99	54.73	51.23	47.42

Table A. 4 Detailed key performance results for the pulverised supercritical co-firing of coal and biomass power plants integrated with CCP and CCU for CFF case at 60 % part-load performance.

Fuel type	**Coal**	**C8B2**	**C6B4**	**C4B6**	**C2B8**	**Biomass**
Fuel [kg/s |bar |ºC]	46.5 | 1.01 | 15	46.5 | 1.01 | 15	46.5 | 1.01 | 15	46.5 | 1.01 | 15	46.5 | 1.01 | 15	46.5 | 1.01 | 15
Primary air [kg/s |bar |ºC]	110 | 1.01 | 15	104 | 1.01 | 15	96.8 | 1.01 | 15	90.2 | 1.01 | 15	83 | 1.01 | 15	75.8 | 1.01 | 15
Secondary Air [kg/s |bar |ºC]	358| 1.01 | 15	337 | 1.01 | 15	315| 1.01 | 15	294| 1.01 | 15	270.3| 1.01 | 15	247| 1.01 | 15
Air Infiltration [kg/s |bar |ºC]	7.96 | 1.01 | 15	7.50 | 1.01 | 15	7.01 | 1.01 | 15	6.54 | 1.01 | 15	6.0 | 1.01 | 15	5.5 | 1.01 | 15
NH_3 injected [kg/s |bar |ºC]	1.1 | 7.24 | 15	1.0 | 7.24 | 15	0.9 | 7.24 | 15	0.8 | 7.24 | 15	0.6 | 7.24 | 15	0.5 | 7.24 | 15
Slag [kg/s]	0.9	0.74	0.57	0.4	0.2	0.1
Main steam [kg/s |bar |ºC]	389|145 | 593	367|145 | 593	345|145 | 593	323|145 | 593	301|145| 593	278|145 | 593
Reheat to furnace/boiler [kg/s |bar |ºC]	318|29.4 | 340	299|29.4 | 340	282|29.4 | 340	264|29.4 | 340	245|29.4 | 340	227|29.4 | 340
Reheat from furnace/boiler [kg/s |bar |ºC]	318 |27.1 |593	299 |27.1 |593	282 |27.1 |593	264 |27.1 |593	245 |27.1 |593	227 |27.1 |593
Steam to stripper reboiler [kg/s |bar |ºC]	144|4.2 | 292	137|4.2 | 292	129|4.2 | 292	121|4.2| 292	113|4.2 | 292	104.9|4.2 | 292
Condensate return from stripper [kg/s |bar |ºC]	144|3 | 130	137|3 | 130	129|3 | 130	121|3 | 130	113|3 | 130	104.9|3 | 130
Condensate, condenser outlet [kg/s |bar |ºC]	146 |0.07 | 38	137 |0.07 | 38	128 |0.07 | 38	119 |0.07 | 38	111 |0.07 | 38	103 |0.07 | 38
Boiler feed water, economiser inlet [kg/s |bar |ºC]	389|182| 198	367|182| 198	345|182| 198	323|182| 198	301|182| 198	278|182| 198
EPS/FGD						
Fly ash [kg/s]	3.6 |1.01 | 169	2.9|1.01 | 169	2.3|1.01 | 169	1.6|1.01 | 169	0.9|1.01 | 169	0.3|1.01 | 169
Lime slurry [kg/s]	8.9 |1.03 | 15	7.1 |1.03 | 15	5.4|1.03 | 15	3.6|1.03 | 15	1.8|1.03 | 15	0.07|1.03 | 15
Gypsum, moisture-free (kg/s]	6.3	5	3.8	2.54	1.3	0.01
CO_2 Capture Plant						
Flue gas, absorber inlet [kg/s |bar |ºC]	543|1.2 | 40	512|1.2 | 40	480|1.2 | 40	448|1.2 | 40	413|1.2 | 40	375|1.2 | 40
Lean MEA solution, absorber inlet [kg/s |bar |ºC]	1545|3.00 | 40	1465|3.00 | 40	1384|3.00 | 40	1303|3.00 | 40	1211|3.00 | 40	1123|3.00 | 40
Rich MEA solution, absorber outlet [kg/s |bar |ºC]	1692|1.01 | 44	1604|1.01 | 44	1516|1.01 | 44	1427|1.01 | 44	1326|1.01 | 44	1226|1.01 | 44
CO_2 captured [kg/s]	99	96	91	86	79	73

Specific reboiler duty [MJ/kg CO_2]	3.634	3.628	3.617	3.608	3.596	3.588
Stripper condenser duty [MW_{th}]	147	140	132	125	116	107
Lean MEA solution cooler duty [MW_{th}]	41	39	37	35	32	31
Lean/Rich heat exchanger duty [MW_{th}]	394	373	353	332	309	285
Lean MEA solution pump duty [kW_e]	250	237	224	211	196	182
Rich MEA solution pump duty [kW_e]	354	336	317	299	278	256
Booster fan duty (MWe]	12.7	11.8	11.2	10.5	9.6	8.7
CO_2 Compression System						
Total compression duty [MW_e]	29.39	27.93	26.47	24.99	23.32	21.71
Total intercooling duty [MW_{th}]	50.32	47.81	45.31	42.76	39.9	37.14

Table A. 5 Detailed key performance results for the pulverised supercritical co-firing of coal and biomass power plants integrated with CCP and CCU for CFF case at 40 % part-load performance.

Fuel type	**Coal**	**C8B2**	**C6B4**	**C4B6**	**C2B8**	**Biomass**
Fuel [kg/s |bar |ºC]	32.5 | 1.01 | 15	32.5 | 1.01 | 15	32.5 | 1.01 | 15	32.5 | 1.01 | 15	32.5 | 1.01 | 15	32.5 | 1.01 | 15
Primary air [kg/s |bar |ºC]	77 | 1.01 | 15	72 | 1.01 | 15	67.6 | 1.01 | 15	63.0 | 1.01 | 15	58| 1.01 | 15	52.9| 1.01 | 15
Secondary Air [kg/s |bar |ºC]	250| 1.01 | 15	235 | 1.01 | 15	220| 1.01 | 15	205| 1.01 | 15	189| 1.01 | 15	172| 1.01 | 15
Air Infiltration [kg/s |bar |ºC]	5.56 | 1.01 | 15	5.23| 1.01 | 15	4.90 | 1.01 | 15	4.57 | 1.01 | 15	4.2 | 1.01 | 15	3.8 | 1.01 | 15
NH_3 injected [kg/s |bar |ºC]	0.77 | 7.24 | 15	0.69 | 7.24 | 15	0.61 | 7.24 | 15	0.53 | 7.24 | 15	0.45 | 7.24 | 15	0.36| 7.24 | 15
Slag [kg/s]	0.6	0.5	0.4	0.28	0.16	0.0
Main steam [kg/s |bar |ºC]	261|96.9 | 593	246|96.9 | 593	230|96.9 | 593	215|96.9 | 593	200|96.9 | 593	185|96.9 | 593
Reheat to furnace/boiler [kg/s |bar |ºC]	213|19.6 | 213	201|19.6 | 213	189|19.6 | 213	176|19.6 |213	163|19.6 |213	151|19.6 |213
Reheat from furnace/boiler [kg/s |bar |ºC]	213 |18.1 |593	201 |18.1 |593	189 |18.1 |593	176 |18.1 |593	163 |18.1 |593	151 |18.1 |593
Steam to stripper reboiler [kg/s |bar |ºC]	99.5|2.03 | 254	94|2.03 | 254	89|2.03 | 254	84|2.03 | 254	78|2.03 | 254	73|2.03 | 254
Condensate return from stripper [kg/s |bar |ºC]	99.5|1.8 | 117	94|1.8 | 117	89|1.8 |117	84|1.8 | 117	78|1.8 | 117	73|1.8 | 117
Condensate, condenser outlet [kg/s |bar |ºC]	95 |0.07 | 38	89|0.07 | 38	82 |0.07 | 38	76 |0.07 | 38	71|0.07 | 38	65 |0.07 | 38
Boiler feed water, economiser inlet [kg/s |bar |ºC]	261|129| 185	246|129| 185	230|129| 185	215|129| 185	200|129| 185	185|129| 185
EPS/FGD						
Fly ash [kg/s]	2.5 |1.01 | 169	2.1|1.01 | 169	1.6|1.01 | 169	1.1|1.01 | 169	0.6|1.01 | 169	0.2|1.01 | 169
Lime slurry [kg/s]	6.2 |1.03 | 15	5.0 |1.03 | 15	3.8|1.03 | 15	2.5|1.03 | 15	1.6|1.03 | 15	0.05|1.03 | 15
Gypsum, moisture-free (kg/s]	4.4	3.5	2.6	1.77	0.9	0.03
CO_2 Capture Plant						
Flue gas, absorber inlet [kg/s |bar |ºC]	379|1.2 | 40	357|1.2 | 40	335|1.2 | 40	313|1.2 | 40	289|1.2 | 40	262|1.2 | 40
Lean MEA solution, absorber inlet [kg/s |bar |ºC]	1067|3.00 | 40	1009|3.00 | 40	955|3.00 | 40	900|3.00 | 40	838|3.00 | 40	776|3.00 | 40
Rich MEA solution, absorber outlet [kg/s |bar |ºC]	1170|1.01 | 44	1106|1.01 | 44	1047|1.01 | 44	987|1.01 | 44	918|1.01 | 44	848|1.01 | 44
CO_2 captured [kg/s]	69	66	64	59	55	52

Specific reboiler duty [MJ/kg CO_2]	3.596	3.587	3.579	3.57	3.559	3.55
Stripper condenser duty [MW_{th}]	102	97	92	87	81	74
Lean MEA solution cooler duty [MW_{th}]	26	25	23	22	21	20
Lean/Rich heat exchanger duty [MW_{th}]	274	260	245	231	215	199
Lean MEA solution pump duty [kW_e]	173	163	155	146	136	126
Rich MEA solution pump duty [kW_e]	245	231	219	206	192	177
Booster fan duty (MWe]	8.9	8.3	7.8	7.3	6.7	6.1
CO_2 Compression System						
Total compression duty [MW_e]	20.56	19.5	18.5	17.49	16.34	15.2
Total intercooling duty [MW_{th}]	35.15	33.33	31.62	26.88	27.91	25.97